enerPLUS
RESOURCES FUND

RENEWAL ANNUAL INFORMATION FORM

For the year ended December 31, 2002

May 16, 2003

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GLOSSARY OF TERMS

Unless the context otherwise requires, in this Renewal Annual Information Form, the following terms and abbreviations have the meanings set forth below.

"EGEM" means Enerplus Global Energy Management Company, an indirect wholly owned subsidiary of the Fund and, prior to its acquisition by Enerplus, the former manager of Enerplus pursuant to the Management Agreement;

"EnerMark" means EnerMark Inc., a corporation amalgamated under the *Business Corporations Act* (Alberta) and a wholly owned subsidiary of the Fund;

"Enerplus" means Enerplus Resources Fund and its subsidiaries, taken as a whole;

"ERC" means Enerplus Resources Corporation, a corporation amalgamated under the *Business Corporations Act* (Alberta) and a wholly owned subsidiary of EnerMark;

"Established Reserves" means Proven Reserves plus 50% of Probable Reserves, before the deduction of royalties and based on escalated price and cost assumptions, unless otherwise indicated;

"Fund" means Enerplus Resources Fund;

"Governance Agreement" means the governance agreement dated June 21, 2001 among the Fund, EnerMark, ERC, the Trustee and EGEM, as may be amended, restated or supplemented from time to time;

"Internalization Transaction" means the acquisition by the Fund, through a wholly owned subsidiary, of all of the outstanding shares of EGEM on April 23, 2003, as more fully described under the heading "General Development of Enerplus Resources Fund - Recent Developments Since Fiscal Year-End - Management Internalization Transaction" in this Renewal Annual Information Form;

"Management Agreement" means the Amended and Restated Management, Advisory and Administrative Agreement dated June 21, 2001, as amended December 31, 2001, made among the Fund, EnerMark, ERC, the Trustee and EGEM, as may be amended, supplemented or restated from time to time, and in respect of which EGEM has assigned its interest to EnerMark effective April 23, 2003;

"Merger" means the merger of Enerplus Resources Fund and EnerMark Income Fund effective June 21, 2001, pursuant to which such entities continued as "Enerplus Resources Fund";

"Proven Reserves" and **"Probable Reserves"** have the meanings given to those terms in the notes under "Oil and Gas Reserves";

"Sproule" means Sproule Associates Limited, independent petroleum consultants;

"Sproule Report" means the independent engineering evaluations of Enerplus' oil, NGLs and natural gas interests prepared by Sproule dated February 10, 2003 and effective January 1, 2003, utilizing commodity price forecasts of Sproule dated January 1, 2003;

"Tax Act" means the *Income Tax Act* (Canada);

"Trust Indenture" means the Amended and Restated Trust Indenture dated June 21, 2001 among EnerMark, ERC and the Trustee, as may be amended, supplemented or restated from time to time;

"Trust Units" means the trust units of the Fund, each representing an equal undivided beneficial interest in the Fund; and

"Trustee" means CIBC Mellon Trust Company, or its successor as trustee of the Fund.

ABBREVIATIONS

Oil and Natural Gas Liquids

Bbls - barrels

Bbls/d - barrels per day

Mbbls - thousand barrels

MMbbls - million barrels

NGLs - natural gas liquids

Natural Gas

Bcf - billion cubic feet

Mcf - thousand cubic feet

Mcf/d - thousand cubic feet per day

MMcf - million cubic feet

MMcf/d - million cubic feet per day

MMBTU - million British Thermal Units

Other

ARTC means Alberta Royalty Tax Credit.

BOE means barrel of oil equivalent, using the conversion factor of 6 Mcf of natural gas being equivalent to one barrel of oil. The conversion factor used to convert natural gas to oil equivalent is not necessarily based upon either energy or price equivalents at the relevant time.

BOE/d means BOE per day.

MBOE means thousand barrels of oil equivalent.

WTI West Texas Intermediate at Cushing, Oklahoma, the benchmark crude oil for pricing purposes.

CONVERSION

The following table sets forth certain standard conversions between Standard Imperial Units and the International System of Units (or metric units).

To Convert from	To	Multiply By
Mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
Bbls	cubic metres	0.159
cubic metres	Bbls	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometres	miles	0.621
acres	hectares	0.405
hectares	acres	2.471
GJ	MMBTU	0.950

PRESENTATION OF ENERPLUS' FINANCIAL, OPERATIONAL AND RESERVES INFORMATION

The financial information included and incorporated by reference in this Renewal Annual Information Form has been prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). Canadian GAAP differs in some significant respects from U.S. GAAP and therefore this financial information may not be comparable to the financial information of U.S. companies. The principal differences as they apply to the Fund are summarized in Note 10 to the Fund's audited consolidated financial statements for the year ended December 31, 2002.

The United States Securities and Exchange Commission (the "SEC") generally permits oil and gas issuers, in their filings with the SEC, to disclose only proved reserves net of royalties and interests of others that an issuer 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 issuers, in their filings with Canadian securities regulators, to disclose not only proved reserves (described by Enerplus as "Proven Reserves") but also probable reserves (see the definition of "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 Proven Reserves. Because Enerplus has prepared this Renewal Annual Information Form in accordance with Canadian disclosure requirements, Enerplus has disclosed reserves designated as "Probable Reserves" and "Established Reserves." 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, Enerplus has determined and disclosed estimated future net cash flow from its 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.

In this Renewal Annual Information Form, all estimates of oil and natural gas reserves and production are on a gross basis before deduction of royalties, unless otherwise indicated. Enerplus' actual oil and gas reserves and production will be greater than or less than the estimates provided herein.

Enerplus has adopted the standard of 6 Mcf:1 BOE when converting natural gas to BOE.

In this Renewal Annual Information Form, unless otherwise indicated, all dollar amounts are in Canadian dollars and all references to "**$**" are to Canadian dollars.

FORWARD-LOOKING STATEMENTS

This Renewal Annual Information Form contains forward-looking statements which are based on Enerplus' current internal expectations, estimates, projections, assumptions and beliefs. Forward-looking statements are made by Enerplus in light of its experience and its perception of historical trends.

All statements that address expectations or projections about the future, including statements about Enerplus' strategy for growth, expected future expenditures, commodity prices, costs, schedules, production volumes, operating and financial results and expected impact of future contractual commitments, are forward-looking statements. Some of the forward-looking statements may be identified by words such as "expects", "anticipates", "believes", "projects", "plans" and similar expressions. These statements are not guarantees of future performance and involve a number of risks and uncertainties. Such forward-looking statements necessarily involve known and unknown risks and uncertainties, which may cause Enerplus' actual performance and financial results in future periods to differ materially from any projections of future performance or results expressed or implied by such forward-looking statements.

These risks and uncertainties include, among other things, changes in general economic, market and business conditions; changes or fluctuations in production levels, commodity prices, currency exchange rates, capital expenditures, reserves or reserves estimates and debt service requirements; changes to legislation, investment eligibility or investment criteria; Enerplus' ability to comply with current and future environmental or other laws; Enerplus' success at acquisition, exploitation and development of reserves; actions by governmental or regulatory

authorities including increasing taxes, changes in investment or other regulations; and the occurrence of unexpected events involved in the operation and development of oil and gas properties. The foregoing factors are not exhaustive.

Many of these risk factors and other specific risks and uncertainties are discussed in further detail throughout this Renewal Annual Information Form and in Enerplus' Management's Discussion and Analysis, incorporated by reference herein. Readers are also referred to the risk factors described in this Renewal Annual Information Form and in other documents Enerplus files from time to time with securities regulatory authorities. Copies of these documents are available without charge from Enerplus. Enerplus disclaims any responsibility to update these forward-looking statements.

NOTES TO READER

Merger of Enerplus Resources Fund and EnerMark Income Fund

On June 21, 2001, Enerplus Resources Fund and EnerMark Income Fund merged and continued as Enerplus Resources Fund. The nature of the business combination was such that, as the former unitholders of EnerMark Income Fund held approximately 69% of the outstanding Trust Units of the combined Enerplus Resources Fund at the date of the Merger, the Merger has been accounted for using the reverse take-over form of the purchase method of accounting for business combinations.

Accordingly, unless otherwise noted, all historical financial and operational information for the 2001 fiscal year contained in this Renewal Annual Information Form, including 2001 information contained in the management's discussion and analysis of financial condition and results of operations incorporated by reference in this Renewal Annual Information Form, is that of EnerMark Income Fund up to June 21, 2001 and that of the merged Fund thereafter. Where applicable, historical per Trust Unit information has been restated to reflect the exchange ratio of 0.173 of an Enerplus Trust Unit for each trust unit of EnerMark Income Fund effective under the Merger.

Management Internalization Transaction

On April 23, 2003, the Fund, through a wholly owned subsidiary, acquired all of the outstanding shares of EGEM pursuant to the Internalization Transaction. The result of this transaction was to effectively eliminate the payment of external management and administration fees by Enerplus to EGEM under the Management Agreement. Although the Management Agreement still exists, EGEM has assigned and transferred its rights under the Management Agreement to EnerMark and as a result, no external management or administration fees are paid by Enerplus and all executives and employees who provide services to Enerplus are now employed by wholly owned subsidiaries of the Fund. As a result, this Renewal Annual Information Form does not contain a detailed description of the Management Agreement or the external management services that, prior to April 23, 2003, were provided to Enerplus by EGEM.

ENERPLUS RESOURCES FUND

Renewal Annual Information Form
For the year ended December 31, 2002

STRUCTURE OF ENERPLUS RESOURCES FUND

Enerplus Resources Fund

Enerplus Resources Fund is an energy investment trust created under the laws of the Province of Alberta in 1986 pursuant to the Trust Indenture. The Fund's assets currently consist of the securities of several direct and indirect operating subsidiaries (the primary of which are EnerMark and ERC), an unsecured note issued by EnerMark to the Fund and 95% and 99% royalties on the crude oil and natural gas property interests of EnerMark and ERC, respectively. The head, principal and registered office of Enerplus is located at The Dome Tower, Suite 3000, 333 - 7th Avenue S.W., Calgary, Alberta T2P 2Z1. The Trustee of the Fund is CIBC Mellon Trust Company located at 600 The Dome Tower, 333 – 7th Avenue S.W., Calgary, Alberta T2P 2Z1.

The Fund's primary focus is to maintain and enhance cash distributions to its unitholders through the development of its operating subsidiaries' existing crude oil and natural gas properties, the acquisition of new producing properties and the monetization, by the way of sale or farm out, of its operating subsidiaries' undeveloped lands. Development efforts are concentrated on optimizing production from existing and new crude oil and natural gas reserves.

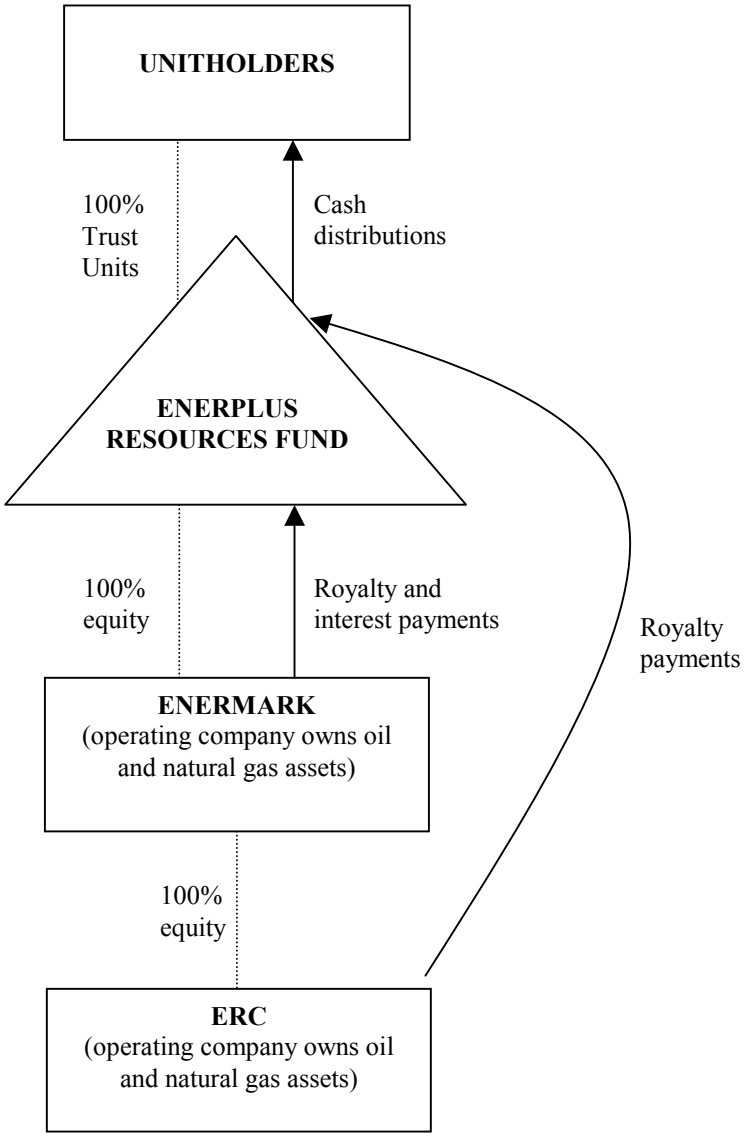
EnerMark Inc. and Enerplus Resources Corporation

Each of 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. The board of directors of EnerMark is the entity responsible for the governance of Enerplus. All of the employees responsible for the operations of Enerplus are employed by subsidiaries of the Fund.

EnerMark and ERC, together with the Fund's other direct and indirect operating subsidiaries, acquire, exploit and operate crude oil and natural gas assets in western Canada for the benefit of the Fund. See "Operational Information" and "Oil and Natural Gas Reserves" for information regarding the operations and oil and natural gas reserves of Enerplus.

Organization Chart

The simplified organizational structure of Enerplus, including the material subsidiaries of the Fund, and the flows of cash from EnerMark and ERC to the Fund and from the Fund to its unitholders are set forth below:



GENERAL DEVELOPMENT OF ENERPLUS RESOURCES FUND

Historical Overview

Enerplus was formed in 1986 and was historically one of a group of royalty trusts, income funds and other entities managed by companies within the Enerplus organization. In recent years, Enerplus Resources Fund has grown significantly as a result of consolidation of many of those entities, as discussed below, and a series of corporate and asset acquisitions.

Merger with Westrock Energy Income Fund I and Westrock Energy Income Fund II

On June 8, 2000, Enerplus, Westrock Energy Income Fund I ("Westrock I") and Westrock Energy Income Fund II ("Westrock II") merged and continued as "Enerplus Resources Fund". Enerplus issued an aggregate of 8,911,667 Trust Units to former unitholders of Westrock I and Westrock II in connection with the merger. Enerplus, Westrock I and Westrock II were managed by affiliated management companies which were part of the Enerplus organization (and each of which was a predecessor of EGEM). The transaction was negotiated on an arm's length basis on behalf of each of Enerplus, Westrock I and Westrock II by independent special committees of the boards of directors responsible for each entity.

Strategic Affiliation with El Paso Corporation

On August 3, 2000, Enerplus announced that it had formed a strategic affiliation with El Paso Corporation ("El Paso") of Houston, Texas through the acquisition, by an indirect wholly owned subsidiary of El Paso, of the companies responsible for the management of various public and private funds within the Enerplus organization, including EGEM. On April 23, 2003, Enerplus acquired EGEM from El Paso pursuant to the Internalization Transaction, which resulted in the termination of this affiliation. See "Recent Developments Since Fiscal Year-End - Management Internalization Transaction".

Listing on the New York Stock Exchange

On November 17, 2000, the Trust Units were listed and posted for trading on the New York Stock Exchange (the "NYSE") under the trading symbol "ERF". Enerplus was the first Canadian royalty trust to have its securities trade on the NYSE.

Merger with EnerMark Income Fund

On June 21, 2001, Enerplus and EnerMark Income Fund completed the Merger pursuant to which each trust unit of EnerMark Income Fund (an "EIF Unit") was exchanged for 0.173 of a Trust Unit of Enerplus. A total of 43,525,961 Trust Units of the Fund (as well as 2,507,330 warrants to acquire Trust Units) were issued to former securityholders of EnerMark Income Fund pursuant to the Merger.

Enerplus and EnerMark were managed by affiliated management companies which were part of the Enerplus Group of Companies. Although it was concluded that the Merger was not subject to the provisions governing "related party transactions" within the meaning of certain Canadian securities laws, due to the common management of the two funds, the Merger was effectively treated as a related party transaction by the funds and their respective boards in order to avoid the perception of any conflict of interest or any informational disadvantage arising from the Merger, including complying with certain valuation, disclosure and minority approval requirements. The transaction was negotiated on an arm's length basis on behalf of Enerplus and EnerMark Income Fund by independent special committees of the boards responsible for each entity.

EnerMark Income Fund was created on April 3, 1996 as a result of a corporate reorganization of Mark Resources Inc. by way of a plan of arrangement. From 1997 through 2000, EnerMark Income Fund made several corporate and asset acquisitions, including the acquisitions of Quest Oil & Gas Inc. in 1997, Derrick Energy Corporation in 1999

and Western Star Exploration Ltd., Pursuit Resources Corp., EBOC Energy Ltd. and Cabre Exploration Ltd., in addition to an asset acquisition in the Hanna, Alberta area in 2000.

Acquisition of Celsius Energy Resources Ltd.

On October 21, 2002, Enerplus acquired all of the outstanding shares of Celsius Energy Resources Ltd. ("Celsius"), a private oil and gas producer based in Calgary, Alberta, which was a wholly owned Canadian subsidiary of U.S.-based Questar Market Resources Inc., for total consideration of $161.4 million, after working capital adjustments. On October 22, 2002, Celsius was amalgamated with EnerMark.

The Celsius properties were primarily located in Alberta and northeastern British Columbia. Many of the Celsius properties were located in areas in which Enerplus was 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/d consisting of 22,476 Mcf/d of natural gas, 1,724 Bbls/d of crude oil and 280 Bbls/d of NGLs. Enerplus estimates that the Celsius properties contained approximately 18 MMBoe of Established Reserves as of July 31, 2002. Included in the acquisition were approximately 103,000 net acres of undeveloped land.

Cross-Border Equity Offering

On November 29, 2002 (and an over-allotment option completed on December 6, 2002), Enerplus completed a cross-border offering of 7,959,300 Trust Units at a price of $26.00 per Trust Unit for proceeds of approximately $193.7 million, net of issuance costs. The net proceeds of the offering were used to repay bank indebtedness of Enerplus which was incurred in connection with the Celsius acquisition and to fund Enerplus' ongoing acquisition and development activities, including the subsequent acquisition of PCC described below. See "Recent Developments Since Fiscal Year-End".

Recent Developments Since Fiscal Year-End

Acquisition of PCC Energy Inc. and PCC Energy Corp.

On March 5, 2003, Enerplus acquired all of the outstanding shares of PCC Energy Inc. and PCC Energy Corp. (collectively, "PCC"), which were wholly owned Canadian subsidiaries of U.S.-based PetroCorp Incorporated, for total cash consideration of $167.6 million, before final working capital adjustments and costs of the acquisition. A portion of the PCC properties acquired are subject to a royalty arrangement structured as a net profits interest ("NPI") with a private U.S. company. Enerplus estimates that, as of October 1, 2002 (the economic effective date for the transaction) and after giving effect to the NPI, the PCC properties contained 17.2 MMBOE of Established Reserves and produced approximately 4,380 BOE/d, consisting of 19.4 MMcf/day of natural gas and 1,140 Bbls/day of crude oil and NGLs. The production from the PCC properties is weighted approximately 74% natural gas and 26% crude oil and NGLs. The PCC properties are located primarily in Alberta, with 85% of the value of the assets located within Enerplus' strategic areas of operation, and are concentrated in the significant central Alberta natural gas producing areas of Hanlan, Basing, Shaw, Pine Creek, Kaybob South and Minehead. Also included in the acquisition was approximately 22,850 net acres of undeveloped land plus seismic data.

The oil and natural gas reserves of PCC acquired by Enerplus are not included in Enerplus' reserve information under the heading "Oil and Natural Gas Reserves", and the production and other operational information attributable to the acquired PCC properties has been included in Enerplus' results since March 5, 2003 but is not included in the information contained in this Renewal Annual Information Form as the transaction was completed in 2003.

Management Internalization Transaction

On April 23, 2003, following receipt of unitholder approval, Enerplus acquired all of the outstanding shares of EGEM from an indirect wholly owned subsidiary of El Paso for cash consideration of $48.9 million plus adjustments for the working capital of EGEM. Prior to the acquisition, EGEM received management fees for Enerplus for

providing administrative and management services to the Fund and its operating subsidiaries pursuant to the Management Agreement. As part of this Internalization Transaction, EGEM agreed to fix the total fees payable under the Management Agreement from January 1, 2003 to April 23, 2003 at $3.2 million. Immediately following the Internalization Transaction, EGEM assigned and transferred all of its rights and obligations under the Management Agreement to EnerMark.

Property Disposition Program

Enerplus routinely evaluates its property portfolio and disposes of properties that are viewed as non-core holdings. Enerplus has undertaken a process to sell several non-core properties that range from southeastern Saskatchewan to northwestern British Columbia. Enerplus estimates that the properties being considered for sale will produce approximately 4,315 BOE/d in 2003, comprised of approximately 3,108 Bbls/d of crude oil and NGLs and 7.2 MMcf/d of natural gas. Enerplus has established price retention thresholds on all properties and all sales will be contingent upon exceeding those minimum thresholds.

OPERATIONAL INFORMATION

As stated in the "Notes to Reader", all historical operational information for the 2001 fiscal year contained in this Renewal Annual Information Form is based on the historical operational results of EnerMark Income Fund. The production and operational information relating to the pre-Merger Enerplus Resources Fund has only been included since June 21, 2001, the effective date of the Merger. The historical operational information for the 2002 fiscal year, as well as the reserve information as of both January 1, 2002 and January 1, 2003, is information of the merged Fund.

Description of Principal Properties

All of Enerplus' oil and natural gas property interests are located in western Canada in the provinces of Alberta, British Columbia and Saskatchewan (with a minimal landholding interest in the province of Manitoba). All of Enerplus' major properties have related field production facilities and infrastructure to accommodate Enerplus' production. Enerplus does not own or operate any transportation pipelines. Production volumes for the year ended December 31, 2002 from Enerplus' properties consisted of approximately 44% crude oil and NGLs and 56% natural gas on a BOE basis. This is comprised of average daily production of 23,288 Bbls/d of crude oil, 4,410 Bbls/d of NGLs and 210.5 MMcf/d of natural gas for a total of 62,784 BOE/d, compared to 20,592 Bbls/d of crude oil, 3,978 Bbls/d of NGLs and 176.7 MMcf/d of natural gas for a total of 54,015 BOE/d during 2001. For the last six months of 2001, following the Merger, Enerplus' property interests yielded average production of 22,765 Bbls/d of crude oil, 4,415 Bbls/d of NGLs and 202.1 MMcf/d of natural gas, for a total of 60,871 BOE/d. As at January 1, 2003 the oil and natural gas property interests held by Enerplus were estimated to contain Established Reserves of 141.3 MMbbls of crude oil and NGLs and 1,141 Bcf of natural gas for a total of 330.4 MMBOE. See "Oil and Natural Gas Reserves".

During 2002, Enerplus reorganized from a functionally aligned organization into a business unit structure, with four geographically distinct high working interest Enerplus-operated business units which accounted for approximately 65% of 2002 average daily production, and a joint venture business unit which accounted for approximately 35% of 2002 daily production. This restructuring will enable Enerplus to better focus its activities and is expected to improve operational and technical performance, operating results and capital efficiency. Each of these five business units is a profit center with a complement of engineers, geologists, operations personnel, and landmen supported by an efficient corporate structure. Skill sets within each business unit are tailored to compliment the unique demands and opportunities within each area.

The following paragraphs discuss each of the Enerplus business units and their principal producing properties including, where applicable, the additional properties or working interests acquired through acquisitions during 2002. All production information represents Enerplus' net working interest in these properties before deduction of royalty interests owned by others. All references to reserve volumes are based upon the estimated volumes contained within the Sproule Report applicable to Enerplus' gross working interest reserves, before deduction of any royalties.

Joint Venture Business Unit

The Joint Venture Business Unit accounts for approximately one third of Enerplus' production and encompasses all partner-operated properties in western Canada from northeastern British Columbia to southeastern Saskatchewan. These properties provide exposure to a wide variety of reservoirs, play types, and enhanced recovery projects that offer diversification to Enerplus' asset base. This business unit also provides exposure to higher impact, more technically sophisticated projects than Enerplus might pursue on its own.

Production for the year ended December 31, 2002 in this business unit averaged 5,492 Bbls/d of crude oil, 2,331 Bbls/d of NGLs and 85.5 MMcf/d of natural gas for a total of 22,068 BOE/d. As at January 1, 2003, the Joint Venture Business Unit's property interests contained 106,546 MBOE of Established Reserves consisting of 33,094 Mbbls of crude oil and NGLs and 440.7 Bcf of natural gas.

The key properties within this business unit include the sweet, liquids rich natural gas plays in Deep Basin which encompasses the Elmworth, Karr, Wapiti, and South Wapiti producing fields, primarily operated by Burlington Resources Canada Ltd., Devon Canada Corporation and BP Canada Energy Company; interests in the Progress Halfway Gas Unit and Hayter operated by Anadarko Canada Corporation; and interests in the Mount Benjamin property operated by Petro-Canada. The Mount Benjamin property is a foothills deep natural gas property where, during 2002, three wells were drilled, completed and tied-in late in the year. Since acquiring this property in 2000, a total of five wells have been drilled with a 100% success rate, increasing production in a prolific natural gas area where significant production declines are common.

The Joint Venture Business Unit is also participating in a unique nitrogen injection pilot in the Turner Valley area outside of Calgary. This project, operated by Talisman Energy Inc., began operation in September of 2002 and, if successful, will lead to a full scale development program designed to recover an additional 3% to 10% of the estimated one billion barrels of crude oil reserves in place (approximately 1.5 to 5.0 million barrels of crude oil net to Enerplus).

Major production facilities within this business unit include: a 6% interest in the Elmworth Gas Plant; a 3% interest in Wapiti Gas Plants; a 10% interest in the Progress Gas Plant; an 8% interest in a sweetening and absorption facility at Minnehik Buck Lake; a 2% interest in the Ram River sweetening & refrigeration facility; and an 11% interest in an emulsion treating and water disposal facility at Hayter.

Enerplus expects 2003 capital expenditures for this partner-operated business unit to remain consistent with 2002 or to increase, with approximately 75% of Enerplus' joint venture capital budget focused on natural gas-weighted projects and 25% on oil-weighted projects. Additionally, as a continuation of its strategic investments in the Athabasca oil sands fairway, Enerplus will be funding the initial phases of the Oil Sands Lease #24 steam assisted gravity drainage ("SAGD") development project and expects to spend up to $7.0 million on this project in 2003, with initial production expected in 2004.

Southern Business Unit

The Southern Business Unit is Enerplus' most active development area encompassing long-life properties in southern Alberta and Saskatchewan. It contains Enerplus' core shallow natural gas development areas as well as a broad range of crude oil interests. The majority of Enerplus' operated natural gas production and development drilling is conducted in this business unit with over 200 operated shallow natural gas wells drilled in 2002. The Medicine Hat Glauconitic "C" Pool, in which Enerplus acquired additional working interests in 2002, is also in this business unit along with the Midale/Ratcliffe area, which has significant crude oil production.

Production for the year ended December 31, 2002 in this business unit averaged 3,236 Bbls/d of crude oil, 14 Bbls/d of NGLs and 56.3 MMcf/d of natural gas for a total of 12,638 BOE/d. As at January 1, 2003, the Southern Business Unit's property interests contained 99,809 MBOE of Established Reserves consisting of 23,254 Mbbls of crude oil and NGLs and 459.3 Bcf of natural gas.

The Southern Business Unit's key natural gas producing properties include Hanna Garden Plains, Bantry, Verger, and Medicine Hat Sun Valley, all of which have major compression and dehydration facilities. The major crude producing property for this business unit is the previously mentioned Medicine Hat Glauconitic "C" Pool, which is under a waterflood recovery program. Various other minor properties contribute to the remainder of this business unit's production, including the Heward, Saskatchewan area, where some significant emulsion treating and water disposal facilities are located.

Enerplus plans to continue shallow natural gas development drilling in 2003, including higher density drilling within existing producing areas. The Celsius acquisition, completed in late 2002, has added approximately 300 locations to the existing project inventory. Confirmation of the viability of the increased density of well spacing will add further development opportunities in the future. Enerplus also plans to continue crude oil development of the Medicine Hat Glauconitic "C" Pool and pursue other waterflood opportunities in the area.

Eastern Business Unit

The Eastern Business Unit focuses on waterflood development projects and encompasses operated properties and lands in eastern Alberta and western Saskatchewan along the provincial border. This business unit is predominantly oil weighted with properties producing light sweet, medium quality and conventional heavy oil. The majority of these oil properties are under secondary recovery projects designed to improve production and enhance recoverable oil reserves. Optimization of these secondary recovery projects is key to maximizing the value of the assets in this business unit.

Production for the year ended December 31, 2002 in this business unit averaged 8,681 Bbls/d of crude oil, 202 Bbls/d of NGLs and 10.0 MMcf/d of natural gas for a total of 10,558 BOE/d. As at January 1, 2003, the Eastern Business Unit's property interests contained 51,618 MBOE of Established Reserves consisting of 41,265 Mbbls of crude oil and NGLs and 62.1 Bcf of natural gas.

The key properties within this business unit include Joarcam, Giltedge and Gleneath. Significant crude oil production installations for emulsion treating and water disposal or injection are found at Chauvin, David, Giltedge, Joarcam, and Shorncliffe. In addition, Joarcam also has major facilities for natural gas compression, dehydration and processing.

Joarcam is Enerplus' largest single producing field, producing both light sweet crude oil and natural gas, and has experienced a significant decrease in the production decline rate since Enerplus acquired and assumed operatorship of the property in late 2000. Through a series of optimization and development efforts, Enerplus has improved the decline rate from approximately 30% per year to approximately 10% per year and added approximately 2.9 million BOE of Established Reserves.

The key waterflood recovery projects in this business unit were reviewed in 2002 to ensure that they were fully optimized. These reviews provided opportunities to infill drill, recomplete and restimulate wells to improve production capability and enhance oil recovery. Development activities for 2003 will build on Enerplus' historical success and continue to focus on improving and expanding its existing waterfloods to increase production and recovery. Enerplus also intends to pursue new shallow natural gas from coal bed methane potential in the area. Divestments of minor interests and acquisitions in Enerplus' core properties will increase the operational focus in the area.

Central Business Unit

The Central Business Unit is a mature producing area which lies to the west and southwest of the city of Edmonton, Alberta and provides a variety of production predominantly weighted to light quality sweet oil and liquids rich natural gas. Given the relatively higher operating costs in many fields in this area, profitability is sensitive to commodity pricing and Enerplus' focus is on controlling operating costs in order to maximize the value of these assets.

Production for the year ended December 31, 2002 from this business unit averaged 3,099 Bbls/d of crude oil, 1,367 Bbls/d of NGLs and 36.1 MMcf/d of natural gas for a total of 10,485 BOE/d. As at January 1, 2003, the Central Business Unit's property interests contained 52,730 MBOE of Established Reserves consisting of 33,174 Mbbls of crude oil and NGLs and 117.3 Bcf of natural gas.

The Central Business Unit's key producing property for 2002 is Pembina, primarily an oil producing area with significant facilities for emulsion treating and water injection. Other significant properties within this business unit include Ferrier, Sylvan Lake, Kaybob South, and Cherhill.

Development activity during 2002 was primarily targeted at maintaining light oil production in the Pembina and Sylvan Lake areas and developing new shallow natural gas production in Pembina, Bashaw and Sylvan Lake. Pembina is a large, low decline Cardium zone oil field that has benefited from ongoing development which has increased production by 27% within the past two years. An initiative to exploit the shallow natural gas potential in

the Central Business Unit was commenced in the latter half of 2002. The early results of this project have been encouraging, as natural gas production has grown significantly, and have led to further development planned in 2003 to assess the economic viability of the program.

The focus of Enerplus' investment activity in 2003 will be to further develop its shallow natural gas program, including the continued evaluation of natural gas from coal bed methane potential. Enerplus also intends to continue the infill drilling and recompletion initiatives to maintain its light oil production in this region.

Northern Business Unit

The Northern Business Unit is a less developed region that encompasses all Enerplus-operated lands and production in northwest Alberta and northeast British Columbia. This business unit provides exposure to both light crude oil and liquids rich natural gas through a variety of Triassic to Cretaceous age reservoirs and tends to offer high impact potential per well, although there are fewer drilling locations than in other business units. The Northern Business Unit's key properties are two adjacent areas, Valhalla and Progress, both of which produce crude oil and natural gas. Other less significant properties include Bonanza, Pouce Coupe, and Utikima.

Production for the year ended December 31, 2002 from this business unit averaged 2,780 Bbls/d of crude oil, 496 Bbls/d of NGLs and 22.6 MMcf/d of natural gas for a total of 7,035 BOE/d. As at January 1, 2003, the Northern Business Unit's property interests contained 19,740 MBOE of Established Reserves consisting of 9,539 Mbbls of crude oil and NGLs and 61.2 Bcf of natural gas.

During 2002, development activities were primarily directed to improving light oil production at Valhalla and optimizing natural gas production at Progess, Bonanza, Komie and Valhalla through facility upgrades and development drilling. Since 1996, and particularly in the last two years, Enerplus has steadily increased Valhalla production through development efforts. In 2002, two additional wells were drilled in the crude oil portion of the Valhalla Halfway J pool to enhance oil recovery and optimize the production from this pool.

Development activities for 2003 will target additional development at Valhalla and Progress to further enhance production and recoverable reserves. Enerplus intends to lever its existing positions of undeveloped acreage and extensive seismic inventory, along with a review of non-productive wellbores, to further enhance this business unit's development opportunities in 2003 and into the future. The divestment of non-core properties in the north central Alberta area surrounding Slave Lake is being considered to further focus operations in this business unit.

Summary of Production Locations

During the year ended December 31, 2002, on a BOE basis, 89% of Enerplus' production was derived from Alberta, 8% from Saskatchewan and 3% from British Columbia. The following table describes the major properties in each of Enerplus' five business units and the average daily production from those properties during the year ended December 31, 2002:

	Product				**Location**		
Business Unit and Property	Crude Oil (Bbls/d)	NGLs (Bbls/d)	Natural Gas (Mcf/d)	**Total (BOE/d)**	Alberta (BOE/d)	Saskatchewan (BOE/d)	B.C. (BOE/d)
Joint Venture Business Unit							
Mount Benjamin	-	10	11,063	**1,854**	1,854	-	-
Elmworth	-	360	5,001	**1,194**	1,194	-	-
Progress	45	73	4,104	**802**	802	-	-
South Wapiti	-	168	3,491	**750**	750	-	-
Hayter	679	-	16	**682**	682	-	-
Other	4,768	1,720	61,795	**16,786**	14,044	1,519	1,223
Total	**5,492**	**2,331**	**85,470**	**22,068**	**19,326**	**1,519**	**1,223**

Business Unit and Property	Product				Location		
	Crude Oil (Bbls/d)	NGLs (Bbls/d)	Natural Gas (Mcf/d)	**Total (BOE/d)**	Alberta (BOE/d)	Saskatchewan (BOE/d)	B.C. (BOE/d)
Southern Business Unit							
Bantry	-	-	13,757	**2,293**	2,293	-	-
Hanna Garden	2	-	12,616	**2,105**	2,105	-	-
Medicine Hat	1,226	-	1,222	**1,430**	1,430	-	-
Verger	8	-	7,609	**1,276**	1,276	-	-
Medicine Hat Sun Valley	-	-	7,318	**1,220**	1,220	-	-
Other	2,000	14	13,808	**4,314**	2,256	2,058	-
Total	**3,236**	**14**	**56,330**	**12,638**	**10,580**	**2,058**	-
Eastern Business Unit							
Joarcam	2,075	160	5,726	**3,189**	3,189	-	-
Giltedge	1,635	-	386	**1,699**	1,699	-	-
Gleneath	1,004	22	407	**1,094**	-	1,094	-
Auburndale	582	-	553	**674**	674	-	-
Kessler	571	-	101	**588**	588	-	-
Other	2,814	20	2,876	**3,314**	2,833	481	-
Total	**8,681**	**202**	**10,049**	**10,558**	**8,983**	**1,575**	-
Central Business Unit							
Pembina	2,151	114	1,450	**2,507**	2,507	-	-
Ferrier	6	212	4,358	**944**	944	-	-
Sylvan Lake	463	111	1,959	**901**	901	-	-
Kaybob South	-	227	2,920	**714**	714	-	-
Cherhill	170	1	2,901	**655**	655	-	-
Other	309	702	22,525	**4,764**	4,764	-	-
Total	**3,099**	**1,367**	**36,113**	**10,485**	**10,485**	-	-
Northern Business Unit							
Valhalla	372	125	8,755	**1,956**	1,956	-	-
Progress	705	21	2,318	**1,112**	1,112	-	-
Bonanza	-	12	3,406	**580**	580	-	-
Pouce Coupe	279	20	555	**392**	392	-	-
Utikima	352	1	53	**362**	362	-	-
Other	1,072	317	7,468	**2,633**	2,132	-	501
Total	**2,780**	**496**	**22,555**	**7,035**	**6,534**	-	**501**
TOTAL	**23,288**	**4,410**	**210,517**	**62,784**	**55,908**	**5,152**	**1,724**

Drilling Activities and Results

During 2002, Enerplus participated in the drilling of 421 gross wells (299.5 net wells) with a 99% net well success rate. The following table summarizes the number and type of wells that Enerplus drilled or participated in the drilling of for the years ended December 31, 2002 and 2001. Enerplus did not participate in drilling any exploratory wells in any such period. Other than wells designated as "Dry" in the table below, all wells described in the table are capable of production.

	Year Ended December 31,			
	2002		2001[3]	
Development Wells	Gross[1]	Net[2]	Gross[1]	Net[2]
Oil	78	30.7	104	37.7
Natural gas	335	264.6	429	279.4
Dry	8	4.2	13	4.5
Total working interest wells [3]	421	299.5	546	321.6

Notes:
(1) "Gross" means the number of wells in which Enerplus has an interest.
(2) "Net" means the product of the total number of gross wells multiplied by Enerplus' percentage working interest in those wells.
(3) In 2001, the pre-Merger Enerplus Resources Fund participated in the drilling of 14.6 net oil wells and 13.4 net natural gas wells, for a total of 28.0 net working interest wells, which are not included in the above table.

Oil and Natural Gas Wells and Undeveloped Landholdings

The following table summarizes, as at December 31, 2002, Enerplus' interests in producing and shut-in wells which may be capable of production, along with Enerplus' interests in undeveloped oil and natural gas leases and rights. Although many wells produce both oil and natural gas, a well is categorized as an oil well or a natural gas well based upon the proportion of oil or natural gas production. As of December 31, 2002, Enerplus had assigned a value of $23.2 million to its undeveloped land holdings.

	Producing Wells				Shut-in Wells[1]				Landholdings	
	Oil		Natural Gas		Oil		Natural Gas		(thousands of acres)	
Area	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]	Gross[2]	Net[3]
Alberta	2,720	1,170	4,460	2,108	556	215	206	75	907.5	382.7
British Columbia	92	26	114	27	13	3	52	16	121.6	56.1
Saskatchewan	2,344	453	330	237	244	33	7	1	34.1	23.8
Other	-	-	20	20	-	-	-	-	0.6	0.6
Total	5,156	1,649	4,924	2,392	813	251	265	92	1,063.8	463.2

Notes:
(1) "Shut-in" wells means wells which are not producing but which may be capable of production.
(2) "Gross" wells and acres are defined as the total number of wells and acres in which Enerplus has an interest.
(3) "Net" wells and acres are defined as the aggregate of the numbers obtained by multiplying each gross well and acre by Enerplus' percentage working interest therein.

Reserves Reconciliation

The table below reconciles the oil and natural gas reserves of Enerplus from January 1, 2002 to January 1, 2003.

	Crude Oil (Mbbls)		Natural Gas (MMcf)		NGLs (Mbbls)		Total (MBOE)		Established Reserves (MBOE)
	Proven	Probable[(1)]	Proven	Probable[(1)]	Proven	Probable[(1)]	Proven	Probable[(1)]	
Reserves as of January 1, 2002	94,847	37,643	951,133	260,689	16,114	4,674	269,482	85,765	312,365
Production	8,500	-	76,839	-	1,610	-	22,917	-	22,917
Acquisitions	7,787	5,458	79,333	19,541	1,096	424	22,105	9,139	26,675
Divestments	615	-	183	-	-	-	646	-	646
Drilling, Development and Revisions	11,728	(9,652)	48,469	(2,652)	436	(460)	20,243	(10,554)	14,966
Reserves as at January 1, 2003	105,247	33,449	1,001,913	277,578	16,036	4,638	288,269	84,350	330,444

Note:
(1) No discount factor has been applied to the Probable Reserves to account for the risk associated with the probability of obtaining production from such reserves.

Historical Production Revenues

Gross production revenues (excluding hedging and before deduction of royalties payable to others) for each of Enerplus' products during the years ended December 31, 2002 and 2001 are as follows:

	2002		2001	
	$ Million	% of Total Revenue	$ Million	% of Total Revenue
Crude Oil	$292.2	46%	$229.1	39%
NGLs	41.3	7%	45.2	8%
Natural gas	296.7	47%	315.0	53%
Total	$630.2	100%	$589.3	100%

Quarterly Production History

The following tables show Enerplus' average working interest sales volumes (before deduction of royalties payable to others) for each of the last eight fiscal quarters and the years then ended.

Average Daily Production

	Year Ended December 31, 2002				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
Crude oil					
Light/medium (Bbls/d)	17,077	16,834	16,876	17,244	**17,008**
Heavy (Bbls/d)	5,889	5,986	6,684	6,551	**6,280**
Total crude oil (Bbls/d)	22,966	22,820	23,560	23,795	**23,288**
NGLs (Bbls/d)	4,374	4,431	4,095	4,740	**4,410**
Total liquids (Bbls/d)	27,340	27,251	27,655	28,535	**27,698**
Natural gas (Mcf/d)	211,713	203,370	198,452	228,480	**210,517**
Total (BOE/d)	62,626	61,146	60,730	66,615	**62,784**

	Year Ended December 31, 2001				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Crude oil					
Light/medium (Bbls/d)	14,273	13,425	16,535	17,468	**15,437**
Heavy (Bbls/d)	4,513	4,561	5,933	5,593	**5,155**
Total crude oil (Bbls/d)	18,786	17,986	22,468	23,061	**20,592**
NGLs (Bbls/d)	3,127	3,936	4,559	4,272	**3,978**
Total liquids (Bbls/d)	21,913	21,922	27,027	27,333	**24,570**
Natural gas (Mcf/d)	152,367	149,201	199,823	204,467	**176,671**
Total (BOE/d)	47,308	46,789	60,331	61,411	**54,015**

Quarterly Netback History

The following tables show Enerplus' average netbacks received for each of the last eight fiscal quarters and the years then ended.

Crude oil and NGLs Netbacks ($ per Bbl)

	Year Ended December 31, 2002				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Sales price	$26.66	$33.57	$35.69	$35.76	**$32.99**
Hedging gains (costs)	(0.09)	(0.20)	(0.68)	(0.71)	**(0.42)**
Royalties	(5.01)	(6.33)	(6.56)	(7.96)	**(6.49)**
Operating costs[(1)]	(7.02)	(6.19)	(8.17)	(8.34)	**(7.45)**
Netback	$14.54	$20.85	$20.28	$18.75	**$18.63**
Average selling price					
Crude oil					
Light/medium	$29.88	$37.08	$39.17	$38.70	**$36.23**
Heavy	$23.67	$29.82	$32.96	$30.19	**$29.34**
Total crude oil	$28.29	$35.18	$37.41	$36.36	**$34.37**
NGLs	$18.15	$25.28	$25.81	$32.74	**$25.68**

	Year Ended December 31, 2001				
	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total for Year**
Sales price	$35.13	$33.58	$33.62	$21.63	**$30.58**
Hedging gains (costs)	-	(0.78)	(0.63)	3.41	**0.61**
Royalties	(6.98)	(6.70)	(6.45)	(3.89)	**(5.91)**
Operating costs[(1)]	(5.90)	(6.49)	(7.89)	(8.28)	**(7.25)**
Netback	$22.25	$19.61	$18.65	$12.87	**$18.03**
Average selling price					
Crude oil					
Light/medium	$37.10	$36.86	$37.95	$24.04	**$33.55**
Heavy	$20.93	$22.34	$27.20	$14.39	**$21.27**
Total crude oil	$33.22	$33.18	$35.11	$21.70	**$30.48**
NGLs	$46.61	$35.44	$26.29	$21.23	**$31.12**

Natural Gas Netbacks ($ per Mcf)

	Year Ended December 31, 2002				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
Sales price	$3.04	$3.93	$3.37	$4.99	**$3.87**
Hedging gains (costs)	0.02	(0.09)	0.05	(0.19)	**(0.06)**
Royalties	(0.74)	(0.94)	(0.67)	(1.07)	**(0.86)**
Operating costs[(1)]	(0.68)	(0.84)	(0.76)	(0.79)	**(0.77)**
Netback	$1.64	$2.06	$1.99	$2.94	**$2.18**

	Year Ended December 31, 2001				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
Sales price	$8.59	$5.81	$3.43	$3.01	**$4.91**
Hedging gains (costs)	(0.21)	0.01	1.03	1.51	**0.69**
Royalties	(2.46)	(1.60)	(0.92)	(0.39)	**(1.24)**
Operating costs[(1)]	(0.77)	(0.83)	(0.82)	(0.96)	**(0.85)**
Netback	$5.15	$3.39	$2.72	$3.17	**$3.51**

Note:

(1) Operating costs are expenses incurred in the operation of producing properties and include items such as field staff costs, power, fuel, chemicals, repairs and maintenance, property taxes, lease rentals, processing and treating fees, overhead fees and other costs.

Quarterly Capital Expenditures

The ongoing capital expenditures of Enerplus are financed through the issuance of additional Trust Units, bank borrowing, the withholdings of amounts from cash distributions to unitholders and the use of working capital. The following table summarizes Enerplus' capital expenditures in the categories and for the periods indicated.

	Year Ended December 31, 2002				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
			(in thousands)		
Development drilling and completions	$ 18,322	$ 12,158	$ 31,977	$ 27,412	**$ 89,869**
Plant and facilities	10,563	9,278	12,842	14,151	**46,834**
Office and other expenditures	2,093	2,510	1,297	3,513	**9,413**
Subtotal	30,978	23,946	46,116	45,076	**146,116**
Property acquisitions	21,205	1,705	25,360	12,311	**60,581**
Corporate acquisitions	-	-	-	158,063	**158,063**
Property dispositions	(218)	(1,920)	(308)	(612)	**(3,058)**
Net capital expenditures	$ 51,965	$ 23,731	$ 71,168	$ 214,838	**$ 361,702**

	Year Ended December 31, 2001				
	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total for Year
			(in thousands)		
Development drilling and completions	$ 8,529	$19,218	$25,941	$29,316	**$ 83,004**
Plant and facilities	14,006	6,981	15,190	17,417	**53,594**
Office and other expenditures	1,448	2,899	771	1,564	**6,682**
Subtotal	23,983	29,098	41,902	48,297	**143,280**
Property acquisitions	367	2,388	57,214	17,463	**77,432**
Corporate acquisitions	32,420	689,784	-	-	**722,204**
Property dispositions	(9,427)	(10,548)	(34,826)	(13,695)	**(68,496)**
Net capital expenditures	$47,343	$710,722	$64,290	$52,065	**$874,420**

Exploration and Development

The primary operational focus of Enerplus is to pursue growth opportunities through the development of existing reserves, the monetization of Enerplus' exploratory lands and the acquisition of new properties. High risk exploration plays, as well as Enerplus' undeveloped acreage, will continue to be farmed out, sold, or exchanged for producing properties with upside potential. Development efforts will concentrate on optimizing production from existing and new reserves, and developing new properties in a cost effective manner. Enerplus will continue its ongoing property rationalization program and any sale proceeds may be used to acquire interests in core areas or new prospects with exploitation opportunities.

Marketing Arrangements

No individual customer accounts for more than 10% of Enerplus' crude oil, NGLs or natural gas production.

Crude oil and NGLs

Enerplus' crude oil and NGLs production are marketed to a diverse portfolio of intermediaries and end users on 30 day continuously renewing contracts whose terms fluctuate with monthly spot market prices. Enerplus received an average price before hedging of $34.37/Bbl for its crude oil and $25.68/Bbl for its NGLs for the year ended December 31, 2002, compared to $30.48/Bbl for crude oil and $31.12/Bbl of NGLs for the year ended December 31, 2001.

Natural Gas

In marketing its natural gas production, Enerplus' efforts are directed to achieve a mix of contracts, customers and geographic markets. Enerplus' percentage of 2002 revenues attributable to natural gas, before hedging, was 47% compared to 53% in 2001 (notwithstanding that natural gas represented approximately 55% of Enerplus' total production in both 2001 and 2002). The average price received by Enerplus, before hedging, for its natural gas in 2002 was $3.87/Mcf compared to $4.91/Mcf in the year ended December 31, 2001.

Future Commitments

Enerplus uses various types of financial instruments and fixed price physical sales contracts to manage the risk related to fluctuating commodity prices. Absent such hedging activities, all of the crude oil and NGLs and the majority of natural gas production of Enerplus is sold into the open market at prevailing spot prices, which exposes Enerplus to the risks associated with commodity price fluctuations and foreign exchange rates. See "Risk Factors". Information regarding Enerplus' financial instruments is contained in Note 7 to Enerplus' audited annual consolidated financial statements for the year ended December 31, 2002 and under the heading "Pricing and Price Risk Management" in the Fund's management discussion and analysis for the year ended December 31, 2002 which is contained on pages 42 to 44 of the Fund's 2002 Annual Report, both of which are incorporated herein by reference.

Enerplus has firm commitments for gathering, processing and transmission services that require Enerplus to deliver certain minimum quantities of crude oil and NGLs and natural gas to third parties or pay the corresponding tariffs. With respect to natural gas, Enerplus has contracted to transport 10 MMcf/day of natural gas into Chicago on the Foothills and Northern Border pipelines until October 31, 2008. It has also agreed to transport 5 MMcf/day to Marshfield, Illinois on the TransCanada and Viking pipelines until October 31, 2008. In addition, Enerplus has pipeline commitments to transport 5 MMcf/day into Chicago on the Alliance Pipeline until October 31, 2015.

Impact of Environmental Protection Requirements

Enerplus carries out its activities and operations in compliance with all relevant and applicable environmental regulations and good industry practice. See "Information Respecting Enerplus Resources Fund - Operations of Enerplus - Environmental Obligations". At present, Enerplus believes that it meets all existing environmental standards and regulations and has included appropriate amounts in its capital expenditure budget to continue to meet

its environmental obligations. The costs incurred by Enerplus for compliance with environmental matters and site restoration costs amounted to approximately 3% of the total development expenditures incurred by Enerplus in 2002. Since the environmental standards and regulations to which Enerplus is subject (including the newly ratified Kyoto Protocol) generally apply to all participants in the oil and gas industry, it is not anticipated that Enerplus' competitive position within the industry, particularly among issuers holding properties with similar characteristics, will be adversely affected. See "Industry Conditions - Environmental Regulation" and "Risk Factors".

OIL AND NATURAL GAS RESERVES

Sproule Associates Limited, a firm of independent petroleum engineers, has evaluated Enerplus' "major" properties which comprise approximately 86% of Enerplus' proven developed producing crude oil and gas reserve value discounted at 12%, and 84% of Enerplus' proven plus probable oil and gas reserves value discounted at 12%. Enerplus has evaluated the balance of the properties using similar evaluation parameters, including the same escalated price forecasts utilized by Sproule. The constant price cases contained herein were extracted from a separate report prepared by Sproule dated February 10, 2003, which was based upon the escalated case Sproule Report.

In preparing its report, Sproule obtained basic information from Enerplus, which included production and land data, well information, geological information, reservoir studies, estimates of on-stream dates, contract information, current hydrocarbon product prices, operating cost data, capital budget forecasts, financial data and future operating plans. Other engineering, geological or economic data required to conduct the evaluation and upon which the Sproule Report is based, was obtained from public records, other operators and from Sproule's non-confidential files. Information concerning the extent and character of ownership of Enerplus' interests and the accuracy of all factual data supplied to Sproule by third parties was accepted by Sproule as represented and neither title searches nor field inspections were conducted.

Enerplus follows the Canadian practice of reporting gross production and reserve volumes, which are prior to the deduction of royalties and similar payments. In the United States, production and reserve volumes are reported after deducting these amounts. The Canadian practice of using escalating prices and costs when estimating the quantities of reserves is also followed by Enerplus. In the United States, reserve estimates are calculated using prices and costs held constant at amounts in effect at the date of the reserve report. Enerplus also follows the Canadian practice of using "Established Reserves", which include Proven Reserves and the Probable Reserves portion that has been reduced by a risk factor of 50%. As a consequence, Enerplus' production volumes and reserve estimates may not be comparable to those made by companies utilizing United States disclosure standards.

The following is a summary, as at January 1, 2003, of Enerplus' crude oil, NGLs and natural gas reserves attributable to Enerplus' properties and the present worth value of the estimated future net cash flows associated with such reserves, based on escalated and constant price and cost assumptions and do not give effect to any commodity price hedging contracts to which Enerplus is a party. The tables summarize the data contained in the evaluations and as a result may contain slightly different numbers than the evaluations due to rounding. **All future cash flows are stated prior to provision for income taxes, interest, general and administrative expenses and after deduction of royalties and estimated future capital expenditures. It should not be assumed that the present worth of estimated future cash flows shown below is representative of the fair market value of the reserves. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of Enerplus' crude oil, NGLs and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual reserves may be greater than or less than the estimates provided herein. The probable additional reserve volumes and the present value of estimated future cash flows from such reserves as shown in the tables have been reduced by a factor of 50% to account for risk.**

Oil and Natural Gas Reserves and Present Value of Estimated Future Cash Flows Including ARTC Based on Escalated Price Assumptions[11]

	Working Interest Reserves[1]						Present Value of Estimated Future Net Cash Flow, $000 Discounted at Rates of:			
	Gross			Net						
	Oil Mbbls	Gas MMcf	NGLs Mbbls	Oil Mbbls	Gas MMcf	NGLs Mbbls	0%	10%	15%	20%
Proven Reserves[2]										
Developed Producing[3][4]	94,901	787,333	14,020	86,023	628,699	9,803	3,864,497	1,805,685	1,500,461	1,301,190
Developed Non-Producing[3][5]	720	23,306	372	626	18,669	258	80,246	31,542	24,147	19,578
Undeveloped[6]	9,626	191,274	1,643	8,143	158,149	1,248	490,135	193,461	133,143	94,155
Total Proven Reserves	105,247	1,001,913	16,036	94,792	805,517	11,309	4,434,879	2,030,688	1,657,751	1,414,922
Probable Reserves at 50%[7]	16,725	138,789	2,318	14,506	114,034	1,631	660,362	163,301	110,063	80,123
Established Reserves	121,972	1,140,702	18,354	109,298	919,551	12,940	5,095,241	2,193,989	1,767,814	1,495,045

Oil and Natural Gas Reserves and Present Value of Estimated Future Cash Flows Including ARTC Based on Constant Price Assumptions[12]

	Working Interest Reserves[1]						Present Value of Estimated Future Net Cash Flow, $000 Discounted at Rates of:			
	Gross			Net						
	Oil Mbbls	Gas MMcf	NGLs Mbbls	Oil Mbbls	Gas MMcf	NGLs Mbbls	0%	10%	15%	20%
Proven Reserves[2]										
Developed Producing[3][4]	99,547	809,546	14,711	90,118	645,134	10,267	5,452,264	2,635,744	2,171,552	1,864,942
Developed Non-Producing[3][5]	736	23,319	372	635	18,665	257	106,775	44,842	34,531	27,992
Undeveloped[6]	9,744	193,148	1,646	8,186	159,474	1,249	792,389	352,078	259,486	198,236
Total Proven Reserves	110,027	1,026,013	16,729	98,939	823,273	11,773	6,351,427	3,032,664	2,465,569	2,091,170
Probable Reserves at 50%[7]	18,012	141,145	2,325	15,473	115,643	1,632	889,509	255,792	179,912	135,592
Established Reserves	128,039	1,167,158	19,054	114,412	938,916	13,405	7,240,936	3,288,456	2,645,481	2,226,762

Notes:

(1) "Gross Reserves" are the remaining reserves owned by Enerplus, before deduction of any royalties. "Net Reserves" are the gross remaining reserves of the properties in which Enerplus has an interest, less all royalties and interests owned by others.

(2) "Proven Reserves" are 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. There is relatively little risk with these reserves.

(3) "Proven Developed Reserves" are Proven Reserves which can be expected to be recovered through existing wells with existing equipment and operating methods.

(4) "Proven Developed Producing Reserves" are Proven Reserves which are presently being produced from completion intervals open for production in existing wells. As at January 1, 2003, these reserves were on production and represent approximately 78% of Enerplus' total gross proven and risked probable oil and NGLs reserves and 69% of Enerplus' total gross proven and risked probable natural gas reserves.

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

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

(7) "Probable Reserves" are those reserves which may be recoverable as a result of the beneficial effects which may be derived from the future institution of some form of pressure maintenance or other secondary recovery method, or as a result of a more favourable performance of the existing recovery mechanism than that which would be deemed proven 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 proven reserves. **Probable reserve values for the petroleum and natural gas properties and the future net cash flow from probable reserves have been discounted by a factor of 50% to account for the risk associated with the probability of obtaining production from such reserves**.

(8) Includes the ARTC based on current legislation in place on January 1, 2003.

(9) Natural gas reserves are reported at a base pressure of 14.65 pounds per square inch and a base temperature of 60º F.

(10) Prices for oil F.O.B. Edmonton are based upon 40º API oil having less than 0.4% sulphur. Prices for natural gas are based upon a base pressure of 14.65 pounds per square inch and base temperature of 60ºF. The wellhead oil prices were adjusted for quality and

transportation to reflect the actual price to be received. The natural gas prices were adjusted, where necessary, only for heating values and the differing costs of service applied by various purchasers. The natural gas liquids prices were adjusted to reflect current prices received.

(11) The escalated price and cost case assumes the continuance of current laws and regulations, and any increase in selling prices also takes inflation into account. The product price forecasts used are as follows:

			Natural Gas Liquids				Natural Gas		
				Edmonton			Plant Gate		
Year	WTI Cushing Oklahoma	Edmonton Par Price 40° API	Plant Gate Ethane	Propane	Butane	Pentanes	Alberta	Sask.	B.C.
	(US$/Bbl)	($/Bbl)	($/Bbl)	($Bbl)	($/Bbl)	($/Bbl)	($/MMBTU)	($/MMBTU)	($/MMBTU)
2003	25.99	38.43	16.32	21.53	24.35	39.36	5.72	5.89	5.94
2004	23.60	34.82	14.92	19.50	22.06	35.66	5.21	5.38	5.43
2005	21.63	32.22	13.22	18.05	20.42	33.00	4.60	4.77	4.82
2006	21.96	32.78	12.34	18.36	20.77	33.57	4.27	4.45	4.48
2007	22.29	33.90	12.77	18.99	21.48	34.72	4.42	4.61	4.66
2008	22.62	34.42	12.95	19.28	21.81	35.25	4.48	4.67	4.74
2009	22.96	35.58	13.45	19.93	22.54	36.44	4.67	4.86	4.93
2010	23.31	36.13	13.70	20.24	22.89	37.00	4.75	4.94	5.01
2011	23.66	36.69	13.95	20.55	23.24	37.57	4.84	5.03	5.10
2012	24.01	37.26	14.20	20.87	23.60	38.16	4.94	5.13	5.20
2013	24.37	37.83	14.46	21.19	23.97	38.76	5.03	5.22	5.29
2014	24.74	38.42	14.72	21.52	24.34	39.35	5.12	5.31	5.38

Escalation Rate of 1.5% thereafter

(12) The constant price and cost case assumes the continuance of product prices at January 1, 2003 and operating costs projected for 2003, and the continuance of current laws and regulations. Product prices have not been escalated beyond this date nor have operating and capital costs been increased on an inflationary basis. The annual revenue to be received from the production of the reserves was based on the following prices:

Oil	Edmonton Par Price 40° API ($/Bbl)	$48.24
Natural Gas:	Alberta ($/MMBTU)	$6.02
	Saskatchewan ($/MMBTU)	$6.13
	British Columbia ($/MMBTU)	$6.10
Natural Gas Liquids:	Ethane ($/Bbl)	$17.85
	Propane ($/Bbl)	$29.21
	Butanes ($/Bbl)	$33.21
	Pentanes Plus ($/Bbl)	$46.30

(13) Capital expenditures required to achieve the future net revenue attributable to Proven Reserves in the escalated price and cost case were estimated to be $207 million, of which $88 million is required in 2003 and $59 million is required in 2004. Capital expenditures required to achieve the future net revenue attributable to Probable Reserves in the escalated price and cost case are estimated to be $105 million, of which $37 million is required in 2003 and $18 million is required in 2004.

(14) Capital expenditures required to achieve the future net revenue attributable to Proven Reserves in the constant price and cost case are estimated to be $203 million of which $88 million is required in 2003 and $59 million is required in 2004. Capital expenditures required to achieve the future net revenue attributable to Probable Reserves in the constant price and cost case are estimated to be $103 million, of which $37 million is required in 2003 and $17 million is required in 2004.

(15) "Estimated Future Net Production Revenue" has been calculated before deduction of income tax. **The present worth of estimated Future Net Production Revenue is not to be construed as fair market value.**

Estimated Future Net Pre-Tax Cash Flows Established Reserves[1]
Escalating Cost and Price Case
($000's except for production)

Year	Annual Production (MBOE)	Company Interest Revenue[2]	Royalty Burdens	Net Revenue After Royalty Burdens	Operating Expenses	Net Production Revenue[3]	Net Capital Investment	Net Cash Flow Before Income Taxes[4][5]
2003	25,295	851,444	185,496	665,948	145,811	520,138	107,317	412,821
2004	24,928	763,025	159,998	603,028	150,070	452,958	69,856	383,102
2005	22,968	627,204	122,976	504,228	148,434	355,794	45,132	310,663
2006	20,580	542,886	101,778	441,108	143,744	297,364	25,131	272,234
2007	18,512	506,458	92,576	413,882	140,146	273,736	8,144	265,592
2008	16,528	459,071	81,725	377,347	133,432	243,915	7,420	236,495
2009	14,776	426,294	74,607	351,688	125,831	225,857	4,784	221,074
2010	13,337	390,232	67,607	322,625	117,951	204,674	3,612	201,062
2011	12,037	358,290	61,043	297,248	111,808	185,440	3,287	182,154
2012	10,834	329,500	55,506	273,994	105,229	168,765	4,062	164,703
Remaining	150,646	6,196,999	769,198	5,427,801	2,859,542	2,568,259	122,916	2,445,343
TOTAL:	330,442	11,451,401	1,772,507	9,678,894	4,181,996	5,496,899	401,659	5,095,240

Cash Flow Before Income Taxes[5] Discounted to January 1, 2003 at:
10%: $2,193,989,000
15%: $1,767,814,000
20%: $1,495,045,000

Notes:
(1) Proven Reserves plus 50% Probable Reserves.
(2) Includes working interest revenue, royalty interest revenue and third party processing and other income.
(3) Company interest revenue less royalty burdens and operating expenses.
(4) Undiscounted.
(5) Cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.

Estimated Future Net Pre-Tax Cash Flows Established Reserves[1]
Constant Cost and Price Case
($000's except for production)

Year	Annual Production (MBOE)	Company Interest Revenue[2]	Royalty Burdens	Net Revenue After Royalty Burdens	Operating Expenses	Net Production Revenue[3]	Net Capital Investment	Net Cash Flow Before Income Taxes[4][5]
2003	25,707	974,960	203,963	770,997	148,153	622,844	106,639	516,205
2004	25,333	957,907	194,496	763,411	151,099	612,312	68,528	543,784
2005	23,369	881,372	169,700	711,672	148,618	563,054	43,576	519,478
2006	20,989	790,429	147,517	642,912	142,635	500,277	23,814	476,464
2007	18,892	710,556	128,071	582,485	137,599	444,886	7,102	437,784
2008	16,911	635,771	111,482	524,289	129,524	394,765	6,949	387,817
2009	15,150	568,596	97,481	471,115	121,071	350,044	4,637	345,407
2010	13,704	512,598	86,805	425,793	112,362	313,431	3,564	309,867
2011	12,367	462,023	76,891	385,132	104,539	280,593	2,428	278,166
2012	11,169	418,582	68,681	349,901	98,036	251,865	3,471	248,394
Remaining	158,031	5,957,991	758,902	5,199,089	1,949,507	3,249,582	72,012	3,177,570
TOTAL:	341,620	12,870,782	2,043,990	10,826,792	3,243,141	7,583,651	342,716	7,240,936

Cash Flow Before Income Taxes[5] Discounted to January 1, 2003 at:
10%: $3,288,456,000
15%: $2,645,481,000
20%: $2,226,762,000

Notes:
(1) Proven Reserves plus 50% Probable Reserves.
(2) Includes working interest revenue, royalty interest revenue and third party processing and other income.
(3) Company interest revenue less royalty burdens and operating expenses.
(4) Undiscounted.
(5) Cash flow before income taxes is stated prior to interest, general and administrative expenses and management fees.

INFORMATION RESPECTING ENERPLUS RESOURCES FUND

Operations of Enerplus

Management Policies

The board of directors of EnerMark, as the publicly-elected body which oversees the business and affairs of Enerplus, supervises the management of Enerplus as it manages and administers the business and operations of Enerplus in accordance with general policies and principles established by the EnerMark directors. The strategies employed and activities undertaken by the EnerMark directors and Enerplus management are directed towards maximizing distributable income to the unitholders while at the same time striving for long-term growth in the value of the assets of Enerplus. These two objectives are fundamental to the operation of Enerplus and are balanced to maximize benefit to the unitholders. Enerplus utilizes its extensive experience and employs prudent oil and gas business practices to increase the value of the assets of Enerplus through the acquisition and development of producing oil and gas properties.

Acquisition and Development Activities

The primary operational focus of Enerplus is to pursue growth opportunities through the acquisition and lower-risk development of mature, long-life oil and natural gas properties. Since Enerplus does not engage in exploration activities, it relies primarily upon acquisitions to both replenish and add to its oil and natural gas reserves. Enerplus acquires properties and assets which are consistent with the guidelines for acquisitions which may be established from time to time by the board of directors of EnerMark. Any asset or property acquisition (or disposition) with a value of greater than $10 million requires the approval of the directors of EnerMark. In pursuing acquisitions, Enerplus employs a focused and disciplined strategy to ensure that the reserves being considered are a strategic fit with its existing portfolio of properties. Enerplus has typically funded its acquisitions through either borrowings from its 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 Enerplus with the flexibility to respond to acquisition opportunities.

To the extent its acquisitions include undeveloped properties, Enerplus enters into farmout or swap agreements under which an exploration and production company will explore and drill the undeveloped properties on Enerplus' behalf, generally at no cost to Enerplus, in exchange for a portion of Enerplus' interests in the property. Other exploration properties may be sold to allow Enerplus to focus on its traditional lower-risk development activities, as discussed below.

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

Environment and Safety

Enerplus is committed to its goal of conducting business in a safe and environmentally responsible manner. Emphasis is focused on providing the best possible protection and safety to employees, the public, stakeholders and the environment. Enerplus' comprehensive Environment and Safety ("E&S") Management Program is constantly reviewed and upgraded to meet this commitment. In 2002, Enerplus registered its existing E&S Management Program with the Canadian Association of Petroleum Producers' Environment, Health and Safety Stewardship Program at the Platinum level, the highest attainable rating, which reflects Enerplus' standing within the industry.

Environment

Enerplus has evaluated its existing solution gas flares in each of British Columbia, Alberta and Saskatchewan. All sites met or exceeded regulatory requirements. However, Enerplus continues to evaluate its operations to reduce or eliminate flaring.

Enerplus has also evaluated benzene emissions in its operations and by the end of 2002 all sites met industry recommended criteria. Newly acquired properties are added to both the flaring and benzene inventories and are subject to ongoing assessment.

In order to prevent environmental damage from corrosion related incidents, Enerplus continues to utilize its Corrosion Risk Management Program throughout its operations. This helps identify properties where improvements can have the largest positive impact and has resulted in pipeline replacements, installation of pipeline liners and improved corrosion protection programs.

Safety

Enerplus' Job Performance Management System ("JPMS") is a comprehensive approach to managing risk and worker competencies in Enerplus' field operations. JPMS is used to manage an employee's or contractor's progress and competence and to ensure that hazardous tasks are carried out safely, responsibly and effectively. This is a key component of Enerplus' training program.

In addition, Enerplus continues to promote its Loss Control Council, a rotating team of experienced and knowledgeable employees consisting of both field and office staff. This team conducts inspections of operated properties each year, allowing for cross training between disciplines and sharing of information between operating areas regarding best practices.

Compliance

Since acquisitions are an integral part of Enerplus' business, a thorough due diligence investigation is conducted on potential acquisitions to ensure that they meet both regulatory and Enerplus' requirements. A team that includes both employees and third party consultants typically conducts site inspections and file reviews prior to completing an acquisition. Potential contamination and operational issues can be identified at this stage, which is designed to protect Enerplus from purchasing properties with significant liabilities. In 2002, investigations were conducted in respect of several acquisitions, including the Celsius acquisition, and no material environmental or safety-related liabilities were noted.

As part of its ongoing due diligence program, Enerplus conducts both internal (through its Loss Control Council) and third party site inspections at selected operated and non-operated facilities, construction and drilling projects each year. In this way, Enerplus ensures that its own operations, as well as the operations of its partners in industry, meet regulatory and industry requirements for environment and safety issues.

Enerplus also maintains an active abandonment and reclamation program dedicated to decommissioning unneeded facilities and restoring these lease sites to their original state as well as an active idle wellbore abandonment program.

Insurance

Enerplus carries insurance coverage to protect its assets at or above the standards typical within the oil and natural gas industry. Coverages are determined and placed by Enerplus after considering the perceived risk of loss, limit of coverage determined appropriate and the cost of coverages. Coverages currently in place include protection against third party liability, property damage or loss, and, for certain properties, business interruption. In addition, director and officer liability coverage is also carried for directors and officers of Enerplus.

Borrowing

The Fund may, provided that the approval of the board of directors of EnerMark has been obtained, borrow, incur indebtedness, give any guarantee or enter into any subordination agreement on behalf of the Fund, or pledge or provide any security interest or encumbrance on any property of the Fund. At present, all indebtedness of Enerplus is incurred directly by its primary operating subsidiary, EnerMark. Details of these long-term debt arrangements are contained in Note 2 of the Fund's audited annual consolidated financial statements for the year ended December 31, 2002 and under the heading "Liquidity and Capital Resources" in Enerplus' management discussion and analysis, contained on pages 50 to 51 of the Fund's 2002 Annual Report, each of which is incorporated herein by reference. The indebtedness of Enerplus to its lenders and senior noteholders ranks senior and is in priority to the royalty, interest and distribution payments that are made to the Fund by its operating subsidiaries, and therefore ahead of distributions from the Fund to its unitholders. See " - Description of the Royalty Agreements and Subordinated Notes" and "Risk Factors".

Records

Enerplus keeps those books and records as are necessary for the proper recording of the business transactions of the Fund. These records are, as nearly as practicable, in accordance with those required to be maintained by a distributing corporation incorporated under the *Business Corporations Act* (Alberta). Unitholders at all times have access to these records to the same extent as though they were shareholders of such a corporation. All such records are kept by Enerplus at its office in Calgary, Alberta.

Personnel

As at December 31, 2002, Enerplus (including the personnel of EGEM who devoted a significant portion of their time to the affairs of Enerplus) employed a total of 445 persons.

Description of the Trust Units and the Trust Indenture

General

The Fund was created, and the Trust Units are issued, pursuant to the Trust Indenture. The Fund is authorized to issue an unlimited number of Trust Units and each Trust Unit represents an equal undivided beneficial interest in the Fund. All Trust Units share equally in all distributions from the Fund and all Trust Units carry equal voting rights at meetings of unitholders. No unitholder will be liable to pay any further calls or assessments in respect of the Trust Units. No conversion or pre-emptive rights attach to the Trust Units.

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

The Trust Indenture, among other things, provides for the investment of the Fund's assets, the calculation and payment of distributions to unitholders, the calling of and conduct of business at meetings of unitholders, the appointment and removal of the Trustee, redemptions of Trust Units and the payment of distributions by the Fund to its unitholders. Among other things, material amendments to the Trust Indenture, the early termination of the Fund and the sale or transfer of all or substantially all of the property of the Fund require the approval by extraordinary resolution (i.e., 66 2/3% of the votes cast) of the unitholders. See "Meetings and Voting" and "Amendments to the Trust Indenture" below.

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

The Trustee

CIBC Mellon Trust Company is the trustee of the Fund. The Trustee possesses and may exercise all rights, powers and privileges pertaining to the ownership of the Fund's assets to the same extent as an individual or beneficial owner might. Additionally, the Trustee is responsible for, among other things, (i) effecting payment of distributions to the Fund's unitholders; (ii) maintaining records and providing timely reports to unitholders, and (iii) performing functions related to supervision and activities of the Fund. The Trustee may also delegate any or all of its management or administrative powers and, pursuant to the Trust Indenture and the Management Agreement, has retained EnerMark to effect the actual administration of its duties under the Trust Indenture. However, the Trustee continues to ultimately be responsible for the performance of these duties.

The Trustee shall be removed by notice in writing delivered by EnerMark to the Trustee if the Trustee fails to meet certain criteria stated within the Trust Indenture or with the approval of at least 66 2/3% of the votes cast at a meeting of unitholders called for that purpose. The Trustee or any successor may resign upon 60 days notice to EnerMark. Such resignation or removal shall become effective upon the acceptance of appointment by a successor trustee. If the Trustee is removed by EnerMark, EnerMark may appoint a successor trustee. If the Trustee resigns or is removed by unitholders, its successor must be either appointed by EnerMark or the unitholders. If a successor trustee does not accept its appointment as trustee, a court may appoint the successor trustee.

The Trust Indenture provides that the Trustee shall exercise the powers and discharge the duties of its office honestly, in good faith and in the best interests of the Fund and its unitholders and shall exercise the degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances.

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

Non-Resident Ownership Provisions

In order for the Fund to maintain its status as a mutual fund trust under the Tax Act, it may be necessary for the Fund to ensure that it has not been established or maintained primarily for the benefit of non-residents of Canada ("non-residents") within the meaning of the Tax Act. Accordingly, the Trust Indenture provides that, from time to time, EnerMark may restrict the number of Trust Units owned by non-residents and take all necessary steps to monitor the ownership of the Trust Units such that the Fund maintains the status of a unit trust and mutual fund trust for the purposes of the Tax Act. The Trust Indenture also provides that, if at any time EnerMark becomes aware that the number of Trust Units owned by non-residents exceeds the restricted number of Trust Units as determined by EnerMark, or that such a situation is imminent, the Fund will make a public announcement of the situation and will take steps to ensure no additional Trust Units are issued or transferred to non-residents, and may require non-residents (generally chosen in the inverse order of acquisition or registration of the Trust Units) to sell their Trust Units, or a portion thereof, in order to reduce the level of non-resident ownership below the determined threshold.

Investments of the Fund

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

Distributions of Distributable Income

The Fund makes distributions from its net income and net realized capital gains. It receives income from EnerMark and ERC pursuant to the royalty agreements, as well as from other sources such as principal and interest payments and dividend and distribution payments received from its operating subsidiaries. In determining what amount of its income is distributable, the Fund deducts all taxes (including withholding tax) and all expenses and liabilities of the Fund which are due or accrued and which are chargeable to income. The Trust Indenture provides that the amount of distributable income and net realized capital gains to be paid in any period, and the timing of those distributions, is within the Trustee's discretion, which has been delegated to EnerMark under the Management Agreement.

Under the Trust Indenture, the Trustee has the authority to determine the timing and the number of distribution record dates within the year. Under the Management Agreement, the Trustee has delegated this authority to EnerMark. Currently, the Fund has established a monthly distribution, with the 10th day of each calendar month as a distribution record date and the 20th day of such month as the corresponding distribution payment date. The January 20 payment date is an exception as its corresponding record date is December 31 of the immediately preceding year. Under certain circumstances, including where the Fund does not have sufficient cash to pay the full distribution to be made on a distribution payment date, the distribution payable to unitholders may, at the option of the Trustee (as delegated to EnerMark), include a distribution of Trust Units having a value equal to the cash shortfall.

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

Meetings and Voting

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

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

Under the Trust Indenture and the Governance Agreement, the Fund's unitholders are entitled to nominate the directors of EnerMark and to nominate the auditors of the Fund. Certain matters, such as the removal or appointment of the Trustee, making material amendments to the Trust Indenture, the termination of the Fund or the sale of all or substantially all of the property of the Fund, must be approved by at least 66 2/3% of the votes cast at a meeting of unitholders. Provided due and proper notice to unitholders is given in accordance with the Trust Indenture, a resolution executed by unitholders holding the requisite number of the outstanding Trust Units entitled to vote shall have the same effect as if it had been passed by that percentage of votes cast at a meeting of unitholders.

Redemption Right

Each unitholder is entitled to require the Fund to redeem at any time or from time to time, at the demand of the unitholder, all or any part of the Trust Units registered in the name of the unitholder at a price per Trust Unit equal to the lesser of:

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

(b) the closing market price on the principal market on which the Trust Units are quoted for trading, on the date that the Trust Units were so tendered for redemption.

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

Management of the Fund

The Trust Indenture provides the Trustee with certain powers and authorities with respect to the Fund and its assets. See "Description of the Trust Units and The Trust Indenture - The Trustee" above. Additionally, the Trust Indenture provides that the Trustee may grant or delegate such authority as the Trustee may in its sole discretion deem necessary or advisable to effect the actual administration of the Fund. The Trustee has delegated to EnerMark the supervision of the management and affairs of the Fund, including the responsibility for significant administrative and operational decisions. In particular, the Trustee has delegated to EnerMark the responsibility for, among other things, all issuances and offerings of Trust Units, merger and acquisition activity relating to Enerplus, the amendment of material contracts to which the Fund is a party, borrowings by Enerplus, voting of securities held by the Fund and approval of the Fund's financial statements. Additionally, following completion of the Internalization Transaction,

EnerMark has the responsibility to manage the operations, business and affairs of Enerplus as a whole. See "Information Respecting Enerplus Resources Fund - Management and Corporate Governance".

Termination of the Fund

The unitholders may vote by extraordinary resolution (i.e., 66 2/3% of the votes cast) to terminate the Fund at any meeting of unitholders duly called for that purpose, following which the Trustee shall commence to wind up the affairs of the Fund. However, such a vote may be held only if requested in writing by the holders of at least 25% of the Trust Units or if called by the Trustee following the refusal of the Trustee to redeem Trust Units. The quorum requirement for such a meeting is at least 20% of the issued and outstanding Trust Units represented in person or by proxy.

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

After the date on which the Trustee is required to commence to wind up the affairs of the Fund, the Trustee will generally carry on no activities except for the purpose of winding up the affairs of the Fund and, for this purpose, the Trustee will continue to be vested with and may exercise all or any of the powers conferred upon the Trustee under the Trust Indenture.

Reporting to Unitholders

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

The Trust Indenture provides that a unitholder has the right, upon payment of reasonable production costs, to obtain a copy of the Trust Indenture and the right to inspect and, on payment of the reasonable charges of the registrar therefor, to obtain a list of the registered holders of the Trust Units for purposes connected with the Fund.

Auditors

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

Amendments to the Trust Indenture

The Trust Indenture may be amended from time to time by the Trustee, EnerMark and ERC. Material amendments to the Trust Indenture require approval by at least 66 2/3% of the votes cast at a meeting of the unitholders called for that purpose. However, the Trustee, EnerMark and ERC may, without the approval of the unitholders, make amendments to the Trust Indenture for the purposes of:

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

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

(c) ensuring that such additional protection is provided for the interests of unitholders as the Trustee or the board of directors of EnerMark may consider expedient;

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

(e) adding to the provisions of the Trust Indenture such additional covenants and enforcement provisions as, in the opinion of counsel, are necessary or advisable, or making such provisions not inconsistent with the Trust Indenture as may be necessary or desirable with respect to matters or questions arising under the Trust Indenture, provided that the same are not, in the opinion of the Trustee, prejudicial to the interests of the unitholders;

(f) modifying any of the provisions of the Trust Indenture, including relieving EnerMark from any of its obligations, conditions or restrictions, provided that such modification or relief shall be or become operative or effective only if, in the opinion of the Trustee, such modification or relief in no way prejudices any of the rights of the unitholders or the Trustee; and

(g) for any other purpose not inconsistent with the terms of the Trust Indenture, including the correction or rectification of any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions therein, provided that in the opinion of the Trustee the rights of the Trustee and of the unitholders are not prejudiced thereby.

Description of the Royalty Agreements and Subordinated Note

The Fund's primary sources of net cash flow are: (i) payments received from 95% and 99% net royalty interests issued to the Fund by EnerMark and ERC, respectively, on the production from their oil and natural gas properties; (ii) interest and principal payments on unsecured, subordinated debt issued to the Fund by EnerMark; and (iii) dividend and distribution payments received by the Fund from EnerMark and certain other operating subsidiaries of the Fund. Outlined below is a description of the royalties granted by EnerMark and ERC to the Fund and the subordinated debt issued by EnerMark to the Fund.

Royalty Agreements

Pursuant to separate royalty agreements between the Fund and each of EnerMark and ERC, EnerMark and ERC have granted to the Fund a 95% and 99% royalty, respectively, on the net income from their respective oil and natural gas properties and operations. The Fund pays these royalties on or about the 20th day of the second month following the month to which such income relates. The net cash flow received by the Fund from EnerMark and ERC pursuant to the royalty agreements is equal to the gross production revenue from their oil and natural gas operations, less certain permitted deductions (generally being operating costs, other third party royalties, general and administrative expenses, debt service charges, taxes on the properties and site restoration and abandonment costs). Unitholders may also receive distributions of the net proceeds received from the sale of properties, although it is anticipated that these proceeds will generally be used to repay debt or purchase additional properties and assets.

Under the royalty agreements, the properties in respect of which the Fund has been granted a royalty interest may be encumbered by security interests given to secure loans by EnerMark and ERC. Such security interests may rank ahead of the royalty interests of the Fund. Further, both EnerMark and ERC have the option at any time to apply any amount of gross production revenues to the repayment of debt. The Fund has entered into a subordination agreement pursuant to which the royalty payments to the Fund by EnerMark and ERC are subordinated and will rank junior to the indebtedness of EnerMark to its lenders and the holders of its senior unsecured notes.

Pursuant to each royalty agreement, EnerMark and ERC have the right to dispose of properties and the associated royalties if they believe that it is in the best interests of unitholders to do so. The royalty agreements continue in

force for as long as EnerMark or ERC has an interest in the properties covered by their respective agreement. The royalty agreements and the royalty indenture (described below) may be amended in writing from time to time. All decisions in respect of such amendments are made by the board of directors of EnerMark on behalf of all parties to those agreements.

The royalty from ERC is paid to the Fund as payments on royalty units issued by ERC to the Fund pursuant to an amended and restated royalty indenture dated June 21, 2001 between ERC and the Trustee. All of the royalty units are held by the Trustee on behalf of the Fund.

Subordinated Note

EnerMark has issued an unsecured, subordinated promissory note to the Fund. The subordinated note bears interest at an annual rate of 8% and the principal amount of the note varies as additional funds (generally from the issuance of Trust Units) are loaned from the Fund to EnerMark and principal repayments are made on the note. The maturity date of the note is June 21, 2015. The payment of principal and interest on the note is subordinated to the prior payment in full of all other debt of EnerMark, other than debt which, by its terms or by operation of law, ranks equal with the subordinated note. The Fund has entered into a subordination agreement pursuant to which the payment to the Fund by EnerMark of obligations under the subordinated note is subordinated and will rank junior to the indebtedness of EnerMark to its lenders and the holders of its senior unsecured notes.

Management and Corporate Governance

General

Under the terms of the Trust Indenture, the Trustee is given broad powers and authorities over the administration and management of the Fund. Pursuant to the Trust Indenture and the Management Agreement, the Trustee has delegated to EnerMark the supervision of the management of the business and affairs of the Fund. Among other things, the board of directors of EnerMark is given responsibility for all matters relating to offerings of securities of the Fund, take-over bids or similar transactions involving the Fund or its subsidiaries, the terms, amendment or execution of material contracts (including the royalty agreements, the Management Agreement and the Governance Agreement) on behalf of the Fund, the voting of securities held by the Fund (including the shares of EnerMark), the redemption of Trust Units, any borrowings or acquisitions made by the Fund or its subsidiaries and the approval of the Fund's public disclosure documents.

Pursuant to the Trust Indenture and in accordance with the Management Agreement, the Trustee has retained and delegated certain authority to EnerMark to provide comprehensive management services to and administer and manage the day to day operations of the Fund and its operating subsidiaries, including: (i) determining the total distributions owing to unitholders, (ii) providing investor relations services to the Fund; (iii) providing unitholders with financial reports and tax information relating to the Fund; (iv) calling, holding and distributing materials in respect of meetings of unitholders; and (v) determining the timing and terms of future offerings, issuances and repurchases of Trust Units or other securities of the Fund. Prior to the Internalization Transaction, EGEM provided these services to Enerplus, subject to the supervision of the board of directors of EnerMark, pursuant to the Management Agreement.

Governance Agreement

The Fund, as the sole shareholder of EnerMark, is entitled to elect the directors of EnerMark, and under the terms of the Governance Agreement, must do so in accordance with a vote of the Fund's unitholders. Following those nominations, the Fund and EnerMark will facilitate the election of those persons to EnerMark's board of directors. The Governance Agreement also provides that the boards of directors of EnerMark and its wholly-owned subsidiary, ERC, are to be identical, and that any dividends received by EnerMark from ERC must immediately be paid by EnerMark to the Fund.

Any person who subsequently becomes an owner of any shares of EnerMark or ERC will be bound by the provisions of the Governance Agreement, and the Governance Agreement may only be terminated, cancelled or amended in writing by the parties to the agreement. The Trustee is to act in accordance with the direction of the board of directors of EnerMark with respect to such matters.

Corporate Governance

Information regarding the Fund's corporate governance and the duties and procedures of the EnerMark board of directors and its committees is contained under the heading "Statement of Corporate Governance Practices" on pages 85 to 89 of the Fund's 2002 Annual Report and under the heading "Statement of Corporate Governance Practices" in the Fund's information circular and proxy statement dated March 10, 2003.

Unitholder Rights Plan

On March 5, 1999, the Fund entered into a Unitholder Rights Plan Agreement (the "Rights Plan") with CIBC Mellon Trust Company, as Rights Agent, which was approved by Enerplus' unitholders on April 23, 1999 and was renewed for an additional three years by the Enerplus unitholders at the 2002 annual general and special meeting of unitholders. The Rights Plan generally provides that following any person or entity acquiring 20% or more of the issued and outstanding Trust Units (except pursuant to certain permitted or excepted transactions) and upon the occurrence of certain other events, each holder of Trust Units, other than such person or entity, shall be entitled to acquire Trust Units at a discounted price. The Rights Plan is similar to other shareholder or unitholder rights plans adopted in the energy sector.

DISTRIBUTIONS TO UNITHOLDERS

Unitholders of record on a distribution record date are entitled to receive distributions which are paid by Enerplus to its unitholders on the corresponding distribution payment date. Enerplus has established the 10th day of each calendar month as a distribution record date with the 20th day of such month being the corresponding distribution payment date, with the exception of the January 20th payment date which is preceded by a distribution record date of December 31 of the prior year. Distributions to unitholders that are not resident in Canada may be subject to Canadian withholding tax.

Distributable Income

The amount available to the Fund to pay distributions depends on the level of net cash flow received by the Fund from its operating subsidiaries pursuant to the royalty agreements and as interest, principal, dividend and distribution payments. Distributions for a period generally represent net cash flow of the operating subsidiaries from the period approximately two months prior to the period in which the distribution is made.

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 be determined 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 expenditures plans. In the past, the level of cash retained for debt repayment has typically varied between 5% and 20% of the total annual cash flow. For the year ended December 31, 2002, approximately 15% 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. See "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 Enerplus realizes for its oil and natural gas production (after hedging contract receipts and payments), (2) the quantity of oil and natural gas that Enerplus produces, (3) the cost to produce oil and natural gas and administer the Fund and its subsidiaries, (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 Units will be affected by the number of outstanding Trust Units.

The following cash distributions have been paid by Enerplus to its unitholders since completion of the Merger on June 21, 2001.

Month of Record and Payment Date	Cash Distribution Per Trust Unit		
	2003	2002	2001
January[(1)]	$0.30	$0.30	N/A
February	$0.32	$0.25	N/A
March	$0.35	$0.20	N/A
April	$0.35	$0.20	N/A
May	$0.37	$0.28	N/A
June		$0.28	N/A
July		$0.28	$0.48
August		$0.28	$0.50
September		$0.28	$0.45
October		$0.30	$0.40
November		$0.30	$0.40
December		$0.30	$0.35

Note:

(1) The record date for the distribution was December 31 of the prior year.

The historical distribution payments described above may not be reflective of future distribution payments, which will be subject to review by the board of directors of EnerMark taking into account the prevailing financial circumstances of the Fund at the relevant time. See "Risk Factors".

INDUSTRY CONDITIONS

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

Pricing and Marketing - Oil

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

Pricing and Marketing - Natural Gas

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

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

The North American Free Trade Agreement

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

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

Provincial Royalties and Incentives

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

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

On October 13, 1992, the government of Alberta implemented major changes to its royalty structure and created incentives for exploring and developing oil and natural gas reserves. The incentives created include: (i) a one year

royalty holiday on new oil discovered on or after October 1, 1992; (ii) incentives by way of royalty holidays and reduced royalties on reactivated, low productivity, vertical re-entry and horizontal wells; (iii) introduction of separate par pricing for light/medium and heavy oil; and (iv) a modification of the royalty formula structure through the implementation of a third tier royalty with a base rate of 10% and a rate cap of 25% for oil pools discovered after September 30, 1992. The new oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 30%. The old oil royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%.

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

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

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

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

The new fiscal regime for the Saskatchewan oil and gas industry provides an incentive to encourage exploration and development through a revised royalty/tax structure for oil and natural gas wells with a finished drilling date on or after October 1, 2002 or incremental oil production due to a new or expanded waterflood project with a commencement date on or after October 1, 2002. This "fourth tier" Crown royalty rate, applicable to both oil and natural gas, is price sensitive and ranges from a minimum 5% at a base price to a maximum of 30% at a price above the base price. A fourth tier freehold tax structure, calculated by subtracting a production tax factor of 12.5 percentage points from the corresponding Crown royalty rates, has also been created which is applicable to conventional oil, incremental oil from new or expanded waterfloods and natural gas. The fourth tier royalty/tax structure is also applicable in respect of associated natural gas that is gathered for use or sale which is produced either from oil wells with a finished drilling date on or after October 1, 2002 and oil wells with a finished drilling date prior to October 1, 2002, where the individual oil well has a gas-oil production ratio in any month of more than 3,500 cubic metres of natural gas per cubic metre of oil. In addition, volume-based royalty/tax reduction incentives have been changed such that a maximum royalty of 2.5% now applies to various volumes of both oil and natural gas, depending on the depth and nature of the well (up to 16,000 cubic metres of oil in the case of deep exploratory wells and 25,000 cubic metres of natural gas produced from exploratory wells). The royalty/tax category with respect to re-entry and short sectional horizontal oil wells has been eliminated such that all horizontal oil wells with a finished drilling date on or after October 1, 2002 will receive fourth tier royalty/tax rates and incentive volumes. Further

changes include the reduction of the corporation capital tax resource surcharge rate from 3.6% to 2.0% and the expansion of the deep oil well definition to include oil wells producing from a zone deeper than 1,700 meters provided that the zone is within a geological system deposited during the Mississippian Period or earlier or from a zone that was deposited before the Bakken zone regardless of depth.

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

Environmental Regulation

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

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

In 1994, the United Nations' Framework Convention on Climate Change came into force and three years later led to the Kyoto Protocol which will require participating countries, upon ratification, to reduce their emissions of carbon dioxide and other greenhouse gases. Canada ratified the Kyoto Protocol in late 2002. Although the federal government has not released details of any implementation plan which could result in increased operating costs and capital expenditures, it has stated that it intends to limit the emission reduction targets for the industry.

Enerplus believes that it is in material compliance with applicable environmental laws and regulations and is committed to meeting its responsibilities to protect the environment wherever it operates. Enerplus intends to continue to take all steps necessary to comply with applicable environmental laws, including the *Alberta Environmental Protection and Enhancement Act*, the *Environmental Management and Protection Act* (Saskatchewan), the *Environmental Assessment Act* (British Columbia) and similar legislation or requirements in other jurisdictions in which it operates. Enerplus anticipates that this compliance may result in increased expenditures of both a capital and expense nature in order to comply with increasingly stringent laws relating to the protection of the environment.

RISK FACTORS

Trust Units are inherently different from capital stock of a corporation, although many of the business risks to which Enerplus is subject are similar to those that would be faced by a corporation engaged in the same business. Prospective investors should carefully consider the following risk factors, together with other information contained in this Renewal Annual Information Form and the information incorporated by reference, before investing in the Trust Units.

Risks Related to Enerplus' Business

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

Enerplus' results of operations and financial condition are dependent on the prices it receives for the oil and natural gas it sells. 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 Enerplus' 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 liquefied 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 world-wide energy conservation measures; and
- government regulations.

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

Enerplus uses 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 Enerplus hedges its commodity price exposure, it foregoes the benefits it would otherwise experience if commodity prices were to increase. In addition, Enerplus' commodity hedging activities could expose it to losses. These losses could occur under various circumstances, including if the other party to Enerplus' hedge does not perform its obligations under the hedge agreement or if hedging policies and procedures are not followed.

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

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

The level of production from Enerplus' existing properties may decline at rates greater than anticipated due to unforeseen circumstances, many of which are beyond Enerplus' 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 unitholders.

Enerplus' distributions may be reduced during periods in which it makes capital expenditures or debt repayments using cash flow.

To the extent that Enerplus uses cash flow to finance acquisitions, development costs and other significant capital expenditures, the net cash flow that the Fund receives 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 Enerplus' unitholders. To the extent that external sources of capital, including the issuance of additional Trust Units, becomes limited or unavailable, Enerplus' ability to make the necessary capital investments to maintain or expand its oil and gas reserves and to invest in assets, as the case may be, will be impaired. To the extent that Enerplus is required to use distributable cash flow to finance capital expenditures, property acquisitions or asset acquisitions, as the case may be, the level of its distributable income will be reduced or even eliminated.

The board of directors of EnerMark has the discretion to determine the extent to which cash flow from the Fund's operating subsidiaries 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 Fund's operating subsidiaries to pay debt service charges or reduce debt will reduce the amount of cash distributed to the Fund's unitholders during those periods in which funds are so retained. In addition, variations in interest rates and scheduled principal repayments, if required under the terms of banking agreements, could result in significant changes in the amount required to be applied to debt service before payment of any amounts by the operating subsidiaries to the Fund. Certain covenants in agreements with lenders may also limit payments by these subsidiaries to the Fund. Although lines of credit are believed to be sufficient, there can be no assurance that the amount will be adequate for the financial obligations of Enerplus or that additional funds can be obtained. Furthermore, if the Fund's operating subsidiaries are unable to pay their debt service charges or otherwise commit an event of default such as bankruptcy, lenders may rank senior to securities or royalties of the operating companies which are held by the Fund.

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

Enerplus' business depends in part upon the availability, proximity and capacity of natural 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 Enerplus' ability to produce and market oil and natural gas. If market factors change and inhibit the marketing of Enerplus' production, overall production or realized prices may decline, which could reduce distributions to unitholders.

Fluctuations in foreign currency exchange rates could adversely affect Enerplus' business.

The price that Enerplus receives for a majority of its oil and natural gas is based on United States dollar denominated benchmarks, and therefore the price that Enerplus receives 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 Enerplus' net production revenue by decreasing the Canadian dollars Enerplus receives for a given United States dollar price. Currently, Enerplus does 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 issued by EnerMark.

If Enerplus is unable to acquire additional reserves, the value of the Trust Units and the Fund's distributions to unitholders may decline.

Enerplus does not directly explore for oil and natural gas reserves. Instead Enerplus adds to its oil and natural gas reserves primarily through acquisitions. As a result, Enerplus' future oil and natural gas reserves are highly dependent on its success in exploiting its reserve base and acquiring additional reserves. Enerplus also distributes the majority of its net cash flow to unitholders rather than reinvest it in reserve additions. Therefore, if capital from external sources is not available on commercially reasonable terms, Enerplus' ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. Even if the necessary capital is available, Enerplus cannot assure prospective investors that it will be successful in acquiring additional reserves on terms that meet its investment objectives. Without these reserve additions, Enerplus' reserves will deplete and, as a consequence, either its production or the average reserve life of its reserves will decline. Either decline may result in a reduction in the value of the Trust Units and in a reduction in cash available for distribution to the Fund's unitholders.

Acquisitions are subject to exploitation and development risks which may affect the value of the Trust Units and distributions to unitholders.

Exploitation and development risks arise for Enerplus and, as a result, may affect the value of the Trust Units and distributions to unitholders due to the uncertain results of searching for and producing oil and natural gas using imperfect scientific methods. Exploitation and development risks are mitigated by using highly skilled staff, focusing exploitation efforts in areas in which Enerplus has existing knowledge and expertise or access to such expertise, using up-to-date technology to enhance methods and controlling costs to maximize returns. Advanced oil and natural gas related technologies such as three dimensional seismography, reservoir simulation studies and horizontal drilling are also used by Enerplus to improve its ability to find, develop and produce oil and natural gas.

Enerplus' actual reserves will vary from its reserve estimates, and those variations could be material.

The value of the Trust Units depends upon, among other things, the reserves attributable to Enerplus' properties. Estimating reserves is inherently uncertain. Ultimately, actual reserves attributable to Enerplus' properties will vary from estimates, and those variations may be material. The reserve information contained in this Renewal Annual Information Form is only an estimate. 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 Enerplus' control. If these factors, assumptions and prices prove to be inaccurate, Enerplus' actual reserves could vary materially from its reserve estimates.

If Enerplus expands operations beyond oil and natural gas production in western Canada, Enerplus may face new challenges and risks. If Enerplus is unsuccessful in managing these challenges and risks, its results of operations and financial condition could be adversely affected.

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

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

The price that Enerplus is willing to pay for reserve acquisitions is based largely on its estimates of the reserves to be acquired. Actual reserves could vary materially from these estimates. Consequently, the reserves that Enerplus acquires may be less than it expected, which could adversely impact its cash flows and distributions to its 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 Enerplus' engineers, and these initial assessments may differ significantly from Enerplus' subsequent assessments.

Since many of Enerplus' properties are not operated by Enerplus, 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 Enerplus' properties. Approximately 40% of Enerplus' daily production is from properties operated by third parties. To the extent a third-party operator fails to perform these duties properly or becomes insolvent, Enerplus' cash flow may be reduced. Third party operators also make estimates of future capital expenditures more difficult.

Further, the operating agreements governing the properties not operated by Enerplus 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 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 the Fund's distributions to unitholders.

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of Enerplus' properties, and the delays of those operators in remitting payment to Enerplus, 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 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 Enerplus' unitholders in a given period and expose Enerplus to additional third party credit risks.

Enerplus' indebtedness many limit the timing or amount of the distributions that the Fund pays to unitholders.

The payments of interest and principal with respect to Enerplus' indebtedness reduces amounts available for distribution to unitholders. Enerplus has an unsecured credit facility available to it at variable interest rates. In addition, Enerplus swapped its U.S. dollar denominated senior unsecured notes with fixed interest rates into Canadian dollar denominated floating rate debt. Variations in interest rates and scheduled principal repayments could result in significant changes to the amount of the cash flows required to be applied by the operating subsidiaries 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 Enerplus is in default, exceeds certain borrowing thresholds or fails to comply with certain covenants, the Fund's ability to make distributions to unitholders may be restricted. In addition, the Fund's right to receive payments from its operating subsidiaries is expressly subordinated to the rights of the lenders under the credit facility and the holders of the senior unsecured notes.

Enerplus' credit facility and any replacement credit facility may not provide sufficient liquidity.

The amounts available under Enerplus' credit facility may not be sufficient for future operations, or Enerplus may not be able to obtain additional financing on attractive economic terms, if at all. Enerplus' 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, Enerplus may need to obtain alternate financing. Any failure to obtain suitable replacement financing may have a material adverse effect on Enerplus' business, and distributions to unitholders may be materially reduced.

Enerplus may be unable to compete successfully with other organizations in the oil and natural gas industry.

The oil and natural gas industry is highly competitive. Enerplus competes 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 Enerplus. Some of these organizations not only explore for, develop and produce oil and natural gas but also conduct refining operations and market oil and other products on a world-wide basis. As a result of these complementary activities, some of Enerplus' competitors may have greater and more diverse competitive resources to draw upon.

The industry in which Enerplus operates exposes Enerplus to potential liabilities that may not be covered by insurance.

Enerplus' 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 Enerplus' property and the property of others. Enerplus cannot fully protect against all of these risks, nor are all of these risks insurable. Enerplus may become liable for damages arising from these events against which it cannot insure or against which it may elect not to insure because of high premium costs or other reasons. While Enerplus has both safety and environmental policies in place to protect its operators and employees and to meet regulatory requirements in areas where they operate, any costs incurred to repair damages or pay liabilities would reduce funds available for distribution to the Fund's unitholders.

Enerplus' operation of oil and natural gas wells could subject it 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 Enerplus' 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 gas emissions, was ratified by Canada in late 2002. Although the implications are unknown at this time as specified measures for meeting Canada's commitments have not yet been developed, the Kyoto Protocol may result in additional costs for oil and natural gas producers such as Enerplus.

Enerplus is 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, Enerplus' 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.

Enerplus does not establish a separate reclamation fund for the purpose of funding its estimated future environmental and reclamation obligations. Enerplus cannot assure prospective investors that it will be able to satisfy its future environmental and reclamation obligations. 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 unitholders. Should Enerplus be unable to fully fund the cost of remedying an environmental claim, Enerplus 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 Enerplus' 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, Enerplus must charge the amount of the excess against earnings. If oil and natural gas prices decline, Enerplus' net capitalized cost may exceed this cost ceiling, ultimately resulting in a charge against its earnings. Under United States generally accepted accounting principles ("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, Enerplus would have more risk of a ceiling test write-down in a declining price environment if Enerplus 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.

Enerplus conducts 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 Enerplus' title to the purchased assets. If this type of defect were to occur, Enerplus' entitlement to the production and reserves from the purchased assets could be jeopardized and, as a result, distributions to unitholders may be reduced.

Risks Related to Enerplus' Structure and the Ownership of the Trust Units

Changes in tax and other laws may adversely affect unitholders.

Income tax laws, or 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 its unitholders. Tax authorities having jurisdiction over Enerplus or the unitholders may disagree with how Enerplus calculates its income for tax purposes or could change administrative practices to Enerplus' detriment or the detriment of its unitholders.

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

Enerplus intends that the Fund will continue to qualify as a mutual fund trust for purposes of the Tax Act. 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 its 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.

- Trust Units would not constitute qualified investments for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESPs") or deferred profit sharing plans ("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, Enerplus may take certain measures in the future to the extent it believes necessary to ensure that the Fund maintains its status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada (as defined in the Tax Act). See "Description of the Trust Units and the Trust Indenture - Non-Resident Ownership Provisions."

The rights of an Enerplus 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 Enerplus. 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 the Fund's unitholders to seek legal remedies against other parties on Enerplus' behalf.

The Trust Units are also unlike conventional debt instruments in that there is no principal amount owing directly to unitholders. The Trust Units will have no value when reserves from Enerplus' 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 unitholders receive over the life of an investment may not meet or exceed the initial capital investment.

Changes in market-based factors may adversely affect the trading price of the Trust Units.

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

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

Unitholders are entirely dependent on the management of Enerplus with respect to the acquisition of oil and natural gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters relating to Enerplus' properties and the administration of the Fund. The loss of the services of key individuals could have a detrimental effect on the Fund. Investors should carefully consider whether they are willing to rely on the management of Enerplus before investing in the Trust Units.

Conflicts of interest may arise between Enerplus and its directors and officers.

Circumstances may arise where directors and officers of Enerplus are directors or officers of corporations or other entities involved in the oil and gas industry which are in competition to the interests of Enerplus. No assurances can be given that opportunities identified by such persons will be provided to Enerplus.

The limited liability of the Fund's 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 it is intended that every written contract or commitment of the Fund will 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 Enerplus' 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 a unitholder resulting from or arising out of the unitholder not having limited liability, Enerplus cannot assure prospective investors that any assets would be available in these circumstances to reimburse unitholders for any such liability. However, personal liability to unitholders of a trust in Canada is minimal where the beneficiaries are not controlling the day-to-day activities of the trust and there is no direct contact between the beneficiaries of the trust and parties who contract with the trust, each of which conditions is satisfied in the case of the Fund and its unitholders.

The redemption rights of unitholders is limited.

Unitholders have a limited right to require the Fund to repurchase Trust Units, which is referred to as a redemption right. See "Description of the Trust Units and the Trust Indenture - Redemption Right". It is anticipated that the redemption right will not be the primary mechanism for unitholders to liquidate their investment. The Fund's 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.

Risks Particular to United States Unitholders

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

The Fund may be a passive foreign investment company for United States federal income tax purposes for the 2003 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 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 Trust Units. The amount allocated to the current taxable year and any year prior to the first year in which Enerplus was 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 Enerplus 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 Enerplus' possible classification as a passive foreign investment company and the consequences of such classification.

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

The Fund is a trust organized under the laws of Alberta, Canada, and Enerplus' principal place of business is in Canada. Most of the directors and all of the officers of Enerplus are residents of Canada and most of the experts who provide services to Enerplus (such as its auditors and independent reserve engineers) are residents of Canada, and all or a substantial portion of their assets and Enerplus' 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 Enerplus or any of its 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.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The following tables set forth selected consolidated financial information of Enerplus for the past three years.

Three Year Detailed Statistical Review

	Year Ended December 31,		
	2002	2001	2000
	(in thousands, except per Trust Unit amounts)		
Financial			
Gross oil and gas sales	$ 621,450	$ 639,397	$ 343,182
Funds flow from operations	289,852	340,246	176,366
Per Trust Unit	4.03	6.20	6.57
Net income	115,876	180,269	82,150
Per Trust Unit – Basic	1.61	3.28	3.06
Per Trust Unit – Diluted	1.61	3.28	3.05
Capital expenditures (net)	203,639	152,216	65,844
Total assets	2,471,631	2,284,253	1,567,952
Long term debt	361,729	412,589	275,944
Cash available for distribution			
Funds flow from operations	289,852	340,246	176,366
Site restoration and abandonment costs incurred	-	2,628	1,471
Cash withheld for debt reduction	(46,344)	(48,850)	(11,746)
Enerplus Resources Fund (pre-Merger) cash flows	-	16,870	-
Accruals	3,279	5,560	-
Pursuit Resources Corp. operating cash flows net of cash withheld for debt reduction	-	-	2,090
Cash available for distribution	$246,787	$ 316,454	$ 168,181
Per Trust Unit	$3.32	$ 5.67	$ 5.49

The above financial data has been taken from the audited consolidated financial statements of Enerplus for the years ended December 31, 2002, 2001 and 2000. The audited consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles. See Note 1 to Enerplus' audited annual consolidated financial statements of the year ended December 31, 2002 for a description of the significant accounting policies of Enerplus.

Cash Distributions to Unitholders

Reference is made to the information under the heading "Distributions to Unitholders" in this Renewal Annual Information Form.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's discussion and analysis of financial results for the year ended December 31, 2002, as contained on pages 39 to 56 of the Fund's Annual Report for the year ended December 31, 2002, is incorporated by reference in this Renewal Annual Information Form.

MARKET FOR SECURITIES

The Trust Units are listed and posted for trading on the Toronto Stock Exchange (the "TSX") and the New York Stock Exchange (the "NYSE"). The trading symbol for the Trust Units on the TSX is "ERF.UN" and on the NYSE is "ERF".

DIRECTORS AND OFFICERS

Directors of EnerMark

The directors of EnerMark are nominated by the unitholders of the Fund at each annual meeting of unitholders. Prior to the Internalization Transaction (but including the nomination of directors of EnerMark at the 2003 annual meeting of Unitholders), EGEM was entitled to nominate three of the directors of EnerMark pursuant to the Management Agreement at the Governance Agreement. All directors, including the Nominees of EGEM, serve until the next annual meeting or until a successor is elected or appointed. The name, municipality of residence, principal occupation for the past five years and year of appointment as a director of EnerMark for each director of EnerMark are set forth below:

Name and Municipality of Residence	Director Since	Principal Occupation for Past Five Years[9]
André Bineau [2] Montréal, Québec	February 1996	Vice President of Association de bienfaisance et de retraite des policiers et policières de la Ville de Montréal (a municipal pension plan).
Derek J.M. Fortune[4][5] Ottawa, Ontario	June 2001	Secretary/Manager, City of Ottawa Superannuation Fund (a municipal pension plan).
Gordon J. Kerr[6][9] Calgary, Alberta	May 2001	President and Chief Executive Officer of Enerplus since May 2001 (and Chief Financial Officer of Enerplus until December 2001). Executive Vice President and Chief Financial Officer of Enerplus since January 2001. Prior thereto, Senior Vice President, Financial Services of Enerplus since September 2000. Prior thereto, Vice President, Finance and Chief Financial Officer of Enerplus since 1998.
Douglas R. Martin[1][4][7] Calgary, Alberta	July 2000	President of Charles Avenue Capital Corp. (a private merchant banking company) since April, 2000. Chairman of the Board of Pursuit Resources Corp. (an oil and natural gas exploration and production company).
Robert Normand[2][4][5] Rosemere, Québec	June 2001	Businessman.
Eric P. Tremblay[3][6][9] Calgary, Alberta	January 2001	Senior Vice President, Capital Markets of Enerplus since September 2000. Prior thereto, Senior Vice President, Corporate Development of Enerplus since January, 2000. Prior thereto, Vice President, Corporate Development of Enerplus since 1996.
Donald T. West[3] Calgary, Alberta	April 2003	Businessman since October 1999. Prior thereto, President and Chief Executive Officer of Rigel Energy Corporation.
Harry B. Wheeler[2][3] Calgary, Alberta	January 2001	President of Colchester Investments Ltd. (a private investment firm) since January 2001. Prior thereto, Chairman of the Board of Cabre Exploration Ltd. (an oil and natural gas exploration and production company).
Robert L. Zorich[6][8] Houston, Texas	January 2001	Managing Director of EnCap Investments L.L.C. (a wholly owned subsidiary of El Paso Corporation, which provides private equity financing to the oil and gas industry).

Notes:

(1) Chairman of the Board of Directors.
(2) The Audit and Risk Management Committee is comprised of Robert Normand as Chairman, André Bineau and Harry B. Wheeler.
(3) The Environment, Safety and Reserves Committee is comprised of Harry B. Wheeler as Chairman, Donald T. West and Eric P. Tremblay.

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

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

(6) Nominee of EGEM pursuant to the Management Agreement and the Governance Agreement

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

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

(9) Prior to the completion of the Internalization Transaction on April 23, 2003, the executive services of Enerplus Resources Fund were provided by EGEM (and its predecessor, Enerplus Energy Services Ltd. ("EES")), pursuant to the Management Agreement. All references to Enerplus in the above table prior to April 23, 2003 should be construed as references to EGEM or EES, but for simplicity, Enerplus has been utilized throughout the above table.

Officers of EnerMark

The name, municipality of residence, position held and principal occupation for the past five years for each officer of EnerMark are set out below:

Name and Municipality of Residence	Office	Principal Occupation for Past Five Years[1]
Gordon J. Kerr Calgary, Alberta	President & Chief Executive Officer	President and Chief Executive Officer of Enerplus since May 2001 (and Chief Financial Officer of Enerplus until December 2001). Prior thereto, Executive Vice President and Chief Financial Officer of Enerplus since January 2001. Prior thereto, Senior Vice President, Financial Services of Enerplus since September 2000. Prior thereto, Vice President, Finance and Chief Financial Officer of Enerplus since 1998.
Heather J. Culbert Calgary, Alberta	Senior Vice President, Corporate Services	Senior Vice President, Corporate Services of Enerplus since March 2001. Prior thereto, Vice President, Management Information Systems & Administration of Enerplus since 1996.
Garry A. Tanner Calgary, Alberta	Senior Vice President & Chief Operating Officer	Senior Vice President and Chief Operating Officer of Enerplus since February 2003. Prior thereto, Senior Vice President, New Business Development of EGEM since August 2001 (in addition to Senior Vice President of El Paso Merchant Energy (a merchant trading company) since October 2000). Prior thereto, Senior Vice President of EnCap Investments L.L.C. (a wholly owned subsidiary of El Paso Corporation which provides private equity financing to the oil and gas industry) since 1997.
Eric P. Tremblay Calgary, Alberta	Senior Vice President, Capital Markets	Senior Vice President, Capital Markets of Enerplus since September 2000. Prior thereto, Senior Vice President, Corporate Development of Enerplus since January 2000. Prior thereto, Vice President, Corporate Development of Enerplus since 1996.
Robert J. Waters Calgary, Alberta	Senior Vice President & Chief Financial Officer	Senior Vice President and Chief Financial Officer of Enerplus since December 2001. Prior thereto, Vice President, Finance and Chief Financial Officer of Pengrowth Corporation since June 1998.
Jo-Anne M. Caza Calgary, Alberta	Vice President, Investor Relations	Vice President of Investor Relations of Enerplus since September 2000. Prior thereto, Manager, Investor Relations of Enerplus since 1998.

Name and Municipality of Residence	Office	Principal Occupation for Past Five Years[1]
Daryl W. Cook Calgary, Alberta	Vice President, Operations	Vice President, Operations of Enerplus since 1997.
Ian C. Dundas Calgary, Alberta	Vice President & Director, Business Development	Vice President and Director, Business Development of Enerplus since February 2003. Prior thereto, Vice President of EGEM since August 2001. Prior thereto, Chief Financial Officer of Medmira Inc., (a public biotechnology company) since 1999. Prior thereto, Director of Enron Canada Corp. merchant banking group since 1996.
Wayne T. Foch Calgary, Alberta	Vice President, Finance	Vice President, Finance of Enerplus since February 2001. Prior thereto, Treasurer of EMR Resource Management Ltd. (the management company of EnerMark Income Fund) since April 1996.
David A. McCoy Calgary, Alberta	General Counsel & Corporate Secretary	General Counsel & Corporate Secretary of Enerplus since December 2002. Prior thereto, Consultant, Offshore & International Operations, with EnCana Corporation since 2002. Prior thereto, Vice President, General Counsel & Governmental Affairs with Conoco Canada Limited since 2000. Prior thereto, Alberta Counsel with Westcoast Energy Inc. since 1998.
Daniel M. Stevens Calgary, Alberta	Vice President, Development Services	Vice President, Development Services of Enerplus since February 2003. Prior thereto, Manager, Drilling and Completions of Enerplus since 1996.
Wayne G. Ford Calgary, Alberta	Controller, Operations	Controller of Enerplus since August 2001. Prior thereto, Controller of Argonauts Group Ltd. (an oil and gas exploration and production company) since January 2000. Prior thereto, Operations Accounting Consultants with Enerplus since September 1998. Prior thereto, Client Service Manager with Applied Terravision Systems Inc. (a software company) since October 1996.
Rodney D. Gray Calgary, Alberta	Controller, Finance	Controller, Finance of Enerplus since June 2002. Prior thereto, independent consultant since September 2001. Prior thereto, Controller (since 1999) and Manager, Financial Reporting (since 1998) with Berkley Petroleum Corp.
Christina S. Meeuwsen Calgary, Alberta	Assistant Corporate Secretary	Assistant Corporate Secretary of Enerplus since December 2002. Prior thereto, Corporate Secretary of Enerplus since 1996.

Note:

(1) Prior to the completion of the Internalization Transaction on April 23, 2003, the executive services of Enerplus Resources Fund were provided by EGEM (and its predecessor, Enerplus Energy Services Ltd. ("EES")), pursuant to the Management Agreement. All references to Enerplus in the above table prior to April 23, 2003 should be construed as references to EGEM or EES, but for simplicity, Enerplus has been utilized throughout the above table. Where an individual's principal occupation has been disclosed as being with EGEM, that individual undertook significant activities on behalf of EGEM other than the management of Enerplus Resources Fund.

The directors and officers named above beneficially own, directly or indirectly, an aggregate of 415,326 Trust Units, representing approximately 0.5% of the Trust Units outstanding on May 1, 2003.

Certain of the directors and officers named above may be directors or officers of issuers which are in competition to Enerplus, and as such may encounter conflicts of interests in the administration of their duties with respect to Enerplus. See "Risk Factors - Potential Conflicts of Interest".

ADDITIONAL INFORMATION

Enerplus will provide to any person, upon request to the Corporate Secretary of Enerplus:

(a) when the securities of the Fund are in the course of a distribution under a preliminary short form prospectus or a short form prospectus:

(i) one copy of this Renewal Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in this Renewal Annual Information Form;

(ii) one copy of the Fund's comparative financial statements for its most recently completed financial year for which financial statements have been filed together with the accompanying report of the auditors and one copy of the most recent interim financial statements of the Fund that have been filed, if any, for any period after the end of its most recently completed financial year;

(iii) one copy of the information circular of the Fund in respect of its most recent annual meeting of unitholders that involved the election of directors of EnerMark or one copy of any annual filing prepared instead of that information circular, as appropriate; and

(iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or short form prospectus and are not required to be provided under (i) to (iii) above; or

(b) at any other time, one copy of any other documents referred to in clauses (a)(i), (ii) and (iii) above, provided that Enerplus may require the payment of a reasonable charge if the request is made by a person who is not a securityholder of the Fund.

Additional information regarding directors' and certain officers' remuneration and indebtedness, principal holders of Trust Units, options and rights to purchase Trust Units and interests of insiders in material transactions is contained in the Fund's information circular for its most recent annual meeting of unitholders that involved the election of directors of EnerMark. Additional information is provided in Enerplus' comparative consolidated financial statements for the year ended December 31, 2002.

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