PETROFUND ENERGY TRUST
Form F-10
May 10, 2004

As filed with the Securities and Exchange Commission on May 7, 2004.

Registration No. 333-

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM F-10

REGISTRATION STATEMENT UNDER
THE SECURITIES ACT OF 1933

Petrofund Energy Trust
(Exact name of Registrant as specified in its charter)

Ontario, Canada	1311	Not Applicable
(Province or other jurisdiction of incorporation or organization)	(Primary Standard Industrial Classification Code Number (if applicable))	(I.R.S. Employer Identificat Number (if applicable))

444-7th Avenue S.W., Suite 600, Calgary, Alberta, Canada T2P 0X8
(403) 218-8625
(Address and telephone number of Registrant's principal executive offices)

CT CORPORATION SYSTEM
111 Eighth Avenue, 13th Floor, New York, NY 10011
(212) 894-8700
(Name, address (including zip code) and telephone number (including area code) of agent for service in the United States)

Copies to:

Brice T. Voran	Keith A. Greenfield
Shearman & Sterling LLP	Burnet, Duckworth & Palmer LLP
Commerce Court West	1400, 350-7th Avenue S.W.
199 Bay Street, Suite 4405	Calgary, Alberta, Canada
Toronto, Ontario, Canada M5L 1E8	T2P 3N9
Telephone (416) 360-8484	Telephone (403) 260-0100

Approximate date of commencement of proposed sale of the securities to the public: As soon as practicable after this Registration Statement is declared effective.

Province of Alberta, Canada
(Principal jurisdiction regulating this offering)

It is proposed that this filing shall become effective (check appropriate box):

A. |X| Upon filing with the Commission, pursuant to Rule 467(a) (if in connection with an offering being made contemporaneously in the United States and Canada).

B. |_| At some future date (check the appropriate box below):

1. |_| pursuant to Rule 467(b) on ( ) at ( ) (designate a time not sooner than 7 calendar days after filing).
2. |_| pursuant to Rule 467(b) on ( ) at ( ) (designate a time 7 calendar days or sooner after filing) because the securities regulatory authority in the review jurisdiction has issued a receipt or notification of clearance on ( ).
3. |_| pursuant to Rule 467(b) as soon as practicable after notification of the Commission by the Registrant or the Canadian securities regulatory authority of the review jurisdiction that a receipt or notification of clearance has been issued with respect hereto.
4. |_| after the filing of the next amendment to this Form (if preliminary material is being filed).

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to the home jurisdiction's shelf prospectus offering procedures, check the following box. |_|

CALCULATION OF REGISTRATION FEE

Title of each class of securities to be registered	Amount to be registered(1)	Proposed maximum offering price per trust unit	Proposed maximum aggregate offering price(2)	Amount registra fee(2
Trust Units	5,866,475	N/A	U.S.$68,487,810	U.S.$8,

(1) Consists of up to 5,866,475 trust units of the Registrant issuable to United States residents upon a business combination.

(2) Estimated solely for the purpose of calculating the registration fee, and based upon the product of Cdn.$7.09 (the average of the high and low prices of Ultima Energy Trust units on May 3, 2004, on the Toronto Stock Exchange) times 13,272,569 (the approximate number of Ultima Energy Trust units outstanding and held by United States residents), divided by 1.374, the noon buying rate in New York City on May 3, 2004 for cable transfers in Canadian dollars as certified by the Federal Reserve Bank of New York.

If, as a result of stock splits, stock dividends or similar transactions, the number of securities purported to be registered on this registration statement changes, the provisions of Rule 416 shall apply to this Registration Statement.

PART I

INFORMATION REQUIRED TO BE DELIVERED TO OFFEREES OR PURCHASERS

Item 1. Home Jurisdiction Documents

Letter to Unitholders of Ultima Energy Trust
Notice of Meeting of Unitholders and Proxy Statement and

Information Circular dated April 30, 2004 together with the documents included in Appendices "A" through "E" thereto (the "Information Circular")

Item 2. Additional Information-- Reconciliation of Financial Statements to U.S. GAAP

See Comparative Audited Annual Financial Statements as at and for the years ended December 31, 2003 and 2002, included in Appendix C to the Information Circular.

Item 3. Informational Legends

See the cover page of the Information Circular.

Item 4. Incorporation of Certain Information by Reference

Not applicable.

Item 5. List of Documents Filed with the Commission

See "Documents Filed as Part of Petrofund's U.S. Registration Statement" in Part "II" of the Information Circular.

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[LOGO] [GRAPHIC OMITTED]

ULTIMA ENERGY TRUST

NOTICE OF ANNUAL AND SPECIAL
MEETING OF UNITHOLDERS

to be held on

June 4, 2004

- and -

PROXY STATEMENT AND INFORMATION CIRCULAR

with respect to a

BUSINESS COMBINATION

involving

ULTIMA ENERGY TRUST

- and -

PETROFUND ENERGY TRUST

April 30, 2004

NOTICE TO UNITED STATES HOLDERS

The proposed Merger is in respect of the securities of a foreign issuer that is permitted, under a multijurisdictional disclosure system adopted by the United States, to prepare the Information Circular in accordance with the disclosure requirements of applicable Canadian law. Holders of Ultima Units should be aware that these requirements are different from those of the United States. The financial statements included herein have been prepared in accordance with Canadian generally accepted accounting principles and are subject to Canadian auditing and auditor independence standards. They may not be comparable to financial statements of United States companies.

Acquisition of Petrofund Units pursuant to the Merger may subject holders of Ultima Units to tax consequences both in the United States and Canada. Such consequences for holders of Ultima Units who are resident in, or citizens of, the United States may not be described fully herein.

Information concerning oil and gas properties, reserves and operations of Ultima and Petrofund have been prepared in accordance with Canadian disclosure standards and are not comparable in all respects to similar information for United States companies. For example, the SEC permits oil and gas companies, in their filings with the SEC, to disclose only proved reserves (as defined in SEC rules). Canadian securities laws permit oil and gas companies, in their filings with Canadian securities regulators, to disclose proved reserves (defined differently from SEC rules) and probable reserves. Probable reserves are of higher risk and are generally believed to be less likely to be recovered than proved reserves. Moreover, "proved reserves," are calculated in accordance with Canadian practices using forecasted and constant prices and costs, whereas the SEC requires that the prices and costs be held constant at prices in effect on the date of the reserve report. In addition, under Canadian practice, reserves and production are reported using gross volumes, which are volumes prior to deduction of royalty and similar payments. The practice in the Unites States is to report reserves and production using net volumes, after deduction of applicable royalties and similar payments. As a consequence, the production volumes and reserve estimates in this Information Circular may not be comparable to those of U.S. domestic companies subject to SEC reporting and disclosure requirements.

The enforcement by investors of civil liabilities under the United States federal securities laws may be affected adversely by the fact that Ultima was created under the laws of the Province of Alberta, Canada and Petrofund was created under the laws of the Province of Ontario, Canada, that some or all of the officers, directors and trustees of Ultima, Petrofund and their respective management companies may be residents of Canada, that some or all of the experts named in the Information Circular may be residents of Canada and that all or a substantial portion of the assets of Ultima and Petrofund and of such persons may be located outside the United States.

No broker, dealer, salesperson or other person has been authorized to give any information or make any representation other than those contained in this document and, if given or made, such information or representation must not be relied upon as having been authorized by Ultima or Petrofund.

THE SECURITIES OFFERED BY PETROFUND PURSUANT TO THE MERGER HAVE NOT BEEN APPROVED OR DISAPPROVED BY THE UNITED STATES SECURITIES AND EXCHANGE COMMISSION OR ANY OTHER SECURITIES REGULATORY AUTHORITY NOR HAS THE UNITED STATES SECURITIES AND EXCHANGE COMMISSION OR ANY OTHER SECURITIES REGULATORY AUTHORITY PASSED UPON THE ACCURACY OR ADEQUACY OF THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS A CRIMINAL OFFENSE.

This Information Circular includes financial statements audited by Arthur Andersen LLP for which neither Ultima nor Petrofund obtained the consent of Arthur Andersen LLP to the use of their auditors' report. The consent of Arthur Andersen LLP was not obtained because, on June 3, 2002, Arthur Andersen LLP ceased to practice public accounting in Canada. See "Additional Information Regarding Petrofund Energy Trust - Information Relating to Arthur Andersen LLP".

[LOGO] [GRAPHIC OMITTED]

ULTIMA VENTURES CORP.

April 30, 2004

Dear Fellow Unitholder:

You are invited to attend the annual and special meeting (the "Meeting") of the holders ("Ultima Unitholders") of Trust Units ("Ultima Units") of Ultima Energy Trust ("Ultima") to be held in the Chambers Room located on the conference level at 350 - 7th Avenue S.W., Calgary, Alberta on Friday, June 4, 2004 at 10:30 a.m. (Calgary time) for the purposes set forth in the accompanying Notice of Annual and Special Meeting. At the Meeting, among other things, Ultima Unitholders will be asked to consider and vote upon a merger involving Ultima and Petrofund Energy Trust ("Petrofund"). As a result of the merger, Petrofund will acquire all of the assets and liabilities of Ultima, and Ultima Unitholders will receive, in exchange for each Ultima Unit held, 0.442 of a trust unit ("Petrofund Units") of Petrofund (the "Merger"). The merged trust will continue to be known as Petrofund Energy Trust. Ultima Unitholders will also receive, on the business day prior to completion of the Merger, an aggregate of $10 million in the form of a one-time special distribution, estimated to be $0.17 per Ultima Unit (the "Special Distribution"). Former Ultima Unitholders who are holders of record of Petrofund Units on June 16, 2004 (and any subsequent record date for distributions to Petrofund Unitholders) will also be entitled to receive distributions from Petrofund following the closing date of the Merger.

For the Special Distribution and Merger to proceed, it must be approved by at least 66 2/3% of the votes cast by Ultima Unitholders attending the Meeting and voting on the proposal in person or by proxy. If such approval is obtained and if other conditions to the Special Distribution and Merger becoming effective are satisfied or waived, it is expected that the Special Distribution and Merger will be completed on or about June 16, 2004.

The board of directors of Ultima Ventures Corp., based upon, among other things, a fairness opinion delivered by its financial advisor, CIBC World Markets Inc., that the consideration to be received by Ultima Unitholders pursuant to the Special Distribution and Merger is fair, from a financial point of view, to the Ultima Unitholders, has determined unanimously that the Special Distribution and Merger is in the best interests of Ultima and the Ultima Unitholders and has unanimously resolved to recommend that Ultima Unitholders vote in favour of the Special Distribution and Merger.

All of the directors and senior officers of Ultima Ventures Corp. have entered into Support Agreements with Petrofund agreeing to vote the Ultima Units held by them in favour of the Special Distribution and Merger.

The accompanying Information Circular provides a detailed description of the Special Distribution and Merger and certain information about Petrofund and Ultima, as well as the other matters to come before the Meeting. Please give this material your careful consideration, and, if you require assistance, consult your financial, income tax or other professional advisor.

To be represented at the Meeting, you must either be a registered Ultima Unitholder and attend the Meeting in person or complete and sign the enclosed form of proxy and forward it so that the form of proxy is received and deposited with Computershare Trust Company of Canada, by mail or facsimile to Computershare Trust Company of Canada, 100 University Avenue, 9th Floor, Toronto, Ontario M5J 2Y1, fax number: 905-771-4414, at least 24 hours (excluding Saturdays, Sundays and holidays) prior to the time of the Meeting or any adjournment thereof.

Yours very truly,

(signed) Brian Gieni

S. BRIAN GIENI
President and Chief Executive Officer
of Ultima Ventures Corp.

| Suite 1000,350 - 7th Avenue SW
| Calgary, AB Canada T2P 3N9
| ph: 403 264.5709 fx: 403 264.6103
|
| ultimatrust.com

[LOGO] [GRAPHIC OMITTED]

ULTIMA ENERGY TRUST

NOTICE OF ANNUAL AND SPECIAL MEETING OF THE UNITHOLDERS

TAKE NOTICE THAT the annual and special meeting (the "Meeting") of unitholders (the "Ultima Unitholders") of Ultima Energy Trust ("Ultima") will be held in the Chambers Room located on the conference level at 350 - 7th Avenue S.W., Calgary, Alberta on Friday, June 4, 2004 at 10:30 a.m. (Calgary time) for the following purposes:

1. to receive and consider the consolidated audited comparative financial statements of Ultima for the year ended December 31, 2003 and the report of the auditors thereon;

2. to elect the directors of Ultima Ventures Corp. ("Ultima Co") for the ensuing year;

3. to elect the directors of Ultima Acquisitions Corp. ("AcquireCo") for the ensuing year;

4. to appoint the auditors of Ultima, Ultima Ventures Trust, Ultima Co and AcquireCo for the ensuing year;

5. to consider, and if thought fit, to pass a special resolution in the form set forth in Appendix "A" to the accompanying Proxy Statement and Information Circular (the "Information Circular") to approve the merger of Ultima with Petrofund Energy Trust ("Petrofund"), on the basis that each Ultima Unitholder would receive 0.442 of a trust unit of Petrofund in exchange for each trust unit ("Ultima Units") of Ultima (the "Merger") on the terms and conditions described in the Information Circular, and to effect all other transactions ancillary to or which are necessary to implement the Merger as described in the Information Circular, including, without limitation, the payment of a one-time special distribution by Ultima in the aggregate amount of $10 million; and

6. to transact such other business as may properly come before the Meeting.

Information relating to items 1 through 5 above is set forth in the accompanying Information Circular.

An Ultima Unitholder may attend the Meeting in person or may be represented thereat by proxy. A form of proxy for use at the Meeting or any adjournment thereof is enclosed with this Notice. Ultima Unitholders who are unable to attend the Meeting are requested to date, sign and return the enclosed form of proxy to the transfer agent of Ultima, Computershare Trust Company of Canada ("Computershare"), by mail or facsimile to Computershare, 100 University Avenue, 9th Floor, Toronto, Ontario, M5J 2Y1 (a self-addressed envelope is enclosed), fax number: 905-771-4414. In order to be valid, proxies must be received by Computershare at least 24 hours, excluding Saturdays, Sundays and holidays, prior to the time of the Meeting or any adjournment thereof.

Ultima Unitholders of record as of April 19, 2004, the record date, are entitled to notice of the Meeting. Holders of Ultima Units issued subsequent to the date of this Information Circular and prior to the date of the Meeting are also entitled to attend and vote at the Meeting. If an Ultima Unitholder has transferred the ownership of any of his, her or its Ultima Units after the record date and the transferee of those Ultima Units produces properly endorsed certificates or otherwise establishes that he, she or it owns the Ultima Units and demands, not later than 10 days before the Meeting, that his or her name be included in the list before the Meeting, then the transferee shall be entitled to vote such Ultima Units at the Meeting.

DATED at Calgary, Alberta the 30th day of April, 2004.

By Order of COMPUTERSHARE TRUST COMPANY OF CANADA,
As Trustee of ULTIMA ENERGY TRUST

"Karen Biscope"
KAREN BISCOPE
Account Manager

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FORWARD-LOOKING STATEMENTS

Certain statements contained in the accompanying Information Circular under the headings "Background to the Merger", "Reasons for the Merger", "Recommendation of the Ultima Board of Directors" and "Selected Pro Forma Information Relating to Petrofund", in addition to certain statements contained elsewhere in this document, are "forward-looking statements", are prospective in nature and may be indicated by words such as "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe" and similar expressions. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. Ultima, Ultima Co, Ventures Trust, AcquireCo, the Manager and Ultima Energy believe the expectations reflected in these forward-looking statements are reasonable, but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this Information Circular should not be unduly relied upon. These statements speak only as of the date of this Information Circular or as of the date specified in this Information Circular, as the case may be.

In particular, this Information Circular contains forward-looking statements pertaining to, among other things, the following:

- oil and natural gas production levels;
- the size of the oil and natural gas reserves in which Ultima, Ventures Trust and Ultima Energy hold working interests and/or royalty interests;
- the size of the oil and natural gas reserves in which Petrofund and Petrofund Co hold working interests and/or royalty interests;
- projections of market prices, production costs and development capital;
- future currency exchange rates;
- supply and demand for oil and natural gas; and
- treatment under applicable tax laws and other governmental regulatory regimes.

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

- volatility in market prices for oil and natural gas;
- liabilities inherent in oil and natural gas operations;
- uncertainties associated with estimating reserves volumes and values;
- competition for, among other things, capital, acquisitions of reserves and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems;
- fluctuations in foreign exchange and interest rates and stock market volatility;
- changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts; and
- the other factors discussed under "Competitive Conditions and Risk Factors" in the Renewal Annual Information Form of Ultima dated April 30, 2004 attached as part of

Appendix "C" of this Information Circular and under "Risk Factors" in the Renewal Annual Information Form of Petrofund dated March 15, 2004 attached as part of Appendix "B" of this Information Circular.

These factors should not be construed as exhaustive. None of Ultima, Ventures Co, Ventures Trust, AcquireCo, the Manager and Ultima Energy undertakes any obligation to publicly update or revise any forward-looking statements.

EXCHANGE RATE OF CANADIAN DOLLAR

Except as otherwise indicated, all dollar amounts set forth in this Information Circular are in Canadian dollars. The following table sets forth: (i) the rates of exchange for Canadian dollars, expressed in United States dollars, in effect at the end of each of the periods indicated; (ii) the average of exchange rates in effect on the last day of each month during such periods; and (iii) the high and low exchange rates during each such periods, in each case based on the noon buying rate in New York City for cable transfers in Canadian dollars as certified for customs purposes by the Federal Reserve Bank of New York.

	Year ended December 31,		
	2003	2002	2001
Rate at end of period	0.7710	0.6362	0.6277
Average rate during period	0.7146	0.6369	0.6457
High	0.6382	0.6198	0.6234
Low	0.7733	0.6616	0.6697

On April 29, 2004 the noon buying rate for $1.00 Canadian was $0.7301 United States.

SUMMARY

This Summary is qualified in its entirety by the more detailed information appearing elsewhere in this Information Circular, including the Appendices hereto. Capitalized terms not otherwise defined herein have the meaning assigned thereto in the Glossary of Terms.

The Meeting

The Meeting will be held on Friday, June 4, 2004 at 10:30 a.m. (Calgary time) in the Chambers Room located on the conference level at 350 - 7th Avenue S.W., Calgary, Alberta, for the purposes set forth in the accompanying Notice of Annual and Special Meeting. The business of the Meeting will be to elect the directors of each of Ultima Co and AcquireCo (to serve only until such time as the Merger is completed), to appoint the auditors of Ultima, Ventures Trust, Ultima Co and AcquireCo (to serve only until such time as the Merger is completed), to consider and vote upon the Special Distribution and Merger (including certain ancillary matters related to the Merger) and to attend to other related business. The Merger will result in the merger of Petrofund and Ultima on the terms described herein.

Petrofund

Petrofund is a royalty trust created under the laws of the Province of Ontario in 1988. Petrofund's primary source of income is from a 99% net royalty interest granted by Petrofund Co. Petrofund Co acquires, manages, and disposes of petroleum and natural gas rights and royalties and related property rights and interests located primarily in western Canada. Petrofund makes monthly cash distributions to the Petrofund Unitholders, which are derived from Petrofund's cash flow from its properties. Certain additional information in respect of

Petrofund is set forth under the heading "Additional Information Regarding Petrofund Energy Trust" and in Appendix "B" to this Information Circular.

Ultima

Ultima is an open-end investment trust formed under the laws of the Province of Alberta in 1996. Ultima's primary source of income is from petroleum and natural gas working interests and related assets which Ultima Co, on behalf of Ventures Trust, and Ultima Energy hold and from distributions from Ventures Trust in respect of cash flow attributable to the 11.7136% net royalty interest held by Ventures Trust in the Weyburn Unit located in southeastern Saskatchewan. Ultima makes monthly cash distributions to the Ultima Unitholders, which are derived from its assets. Certain additional information in respect of Ultima is set forth under the heading "Additional Information Regarding Ultima Energy Trust" and in Appendix "C" to this Information Circular.

Effect of the Merger Upon Ultima Unitholders

General

After giving effect to the Merger, Petrofund will have acquired all of the Ultima Assets and assumed all of the Assumed Liabilities, and former Ultima Unitholders will become holders of Petrofund Units on the basis of 0.442 of a Petrofund Unit for each issued and outstanding Ultima Unit. The Merger is structured to be a tax deferred event such that the exchange of Ultima Units for Petrofund Units will not result in a taxable event to Ultima Unitholders for Canadian tax purposes. See "Canadian Income Tax Considerations".

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Assuming completion of the Merger whereby all Ultima Unitholders receive Petrofund Units for their Ultima Units, there will be approximately 99,233,252 Petrofund Units issued and outstanding, subject to changes due to the exercise of outstanding Ultima Rights and the rounding to the nearest whole number of fractional Petrofund Units and assuming that all outstanding exchangeable shares of Petrofund Co are exchanged for Petrofund Units. Immediately following the Merger and assuming that all of the outstanding exchangeable shares of Petrofund Co are exchanged for Petrofund Units, current Petrofund Unitholders will hold approximately 73,682,400 Petrofund Units, representing approximately 74% of the issued and outstanding Petrofund Units, and former holders of Ultima Units will hold approximately 25,550,852 Petrofund Units, representing approximately 26% of the issued and outstanding Petrofund Units. As of April 19, 2004, a total of approximately 2,028,639 Ultima Rights were outstanding which, based on the adjustment provisions, the Ultima Employment Agreements and the Exchange Ratio, could result in an additional 896,658 Petrofund Units being issued to former securityholders of Ultima in connection with the Merger.

See "Effect of the Merger Upon Ultima Unitholders -- General".

Special Distribution

If the Ultima Special Resolution is approved at the Meeting, a record date will be announced for the Special Distribution. Ultima Unitholders of record on the record date set for the Special Distribution will be entitled to a distribution from Ultima in the amount of $10 million divided by the number of Ultima Units outstanding on such record date (or approximately $0.17 per Ultima Unit assuming 59,835,996 Ultima Units are outstanding). The record date will be the date which is at least seven business days following approval of the Ultima

Special Resolution, but which will be not later than the business day immediately prior to the Closing Date of the Merger. Therefore, if the Meeting is held as currently proposed on June 4, 2004 and the Closing Date is held as currently proposed on June 16, 2004, the record date for the Special Distribution will be June 15, 2004. Ultima will issue a press release announcing the actual record date for the Special Distribution at least seven business days prior to the record date. It is possible that the Special Distribution is approved by the Ultima Unitholders and paid by Ultima on the business day prior to the Closing Date and that the Merger is not completed.

See "Effect of the Merger Upon Ultima Unitholders -- Special Distribution".

Effect on Distributions

Distributions paid to Ultima Unitholders for the months of April and May 2004 will not be affected by the proposed Merger and will be paid in the usual manner. Therefore, Ultima Unitholders of record on April 30, 2004 and May 31, 2004 will receive their regular monthly cash distribution from Ultima on May 17, 2004 and June 15, 2004, respectively. Assuming the Merger becomes effective on June 16, 2004, Petrofund Unitholders of record on June 16, 2004, including former Ultima Unitholders, will receive a cash distribution from Petrofund on June 30, 2004, and will receive monthly distributions from Petrofund in a similar manner in the future. Former Ultima Unitholders who are Petrofund Unitholders of record on June 16, 2004 (and any subsequent record date for distributions to Petrofund Unitholders) will be entitled to receive distributions from Petrofund following the Closing Date of the Merger without any further action required on their part provided they have exchanged their certificates representing Ultima Units for Petrofund Units on or prior to the sixth anniversary of the Closing Date.

See "Effect of the Merger Upon Ultima Unitholders -- Effect on Distributions" and "Effect of the Merger Upon Ultima Unitholders -- Exchange of Ultima Certificates".

Exchange of Ultima Certificates

After the Closing Date, certificates formerly representing Ultima Units shall only represent the right to receive Petrofund Units which a former Ultima Unitholder is, except as set forth below, entitled to receive pursuant to the Merger.

A form of letter of transmittal (printed on yellow paper) containing instructions with respect to the surrender of certificates representing Ultima Units has been forwarded to registered Ultima Unitholders for use in exchanging their certificates. Upon surrender of properly completed letters of transmittal together with certificates representing Ultima Units to Computershare Trust Company of Canada, certificates for the appropriate number of Petrofund Units will be issued, subject to any withholdings as required by law.

No fractional Petrofund Units shall be issued to former Ultima Unitholders pursuant to the Merger. In the event that the Exchange Ratio would otherwise result in an Ultima Unitholder being entitled to a fractional Petrofund Unit, an adjustment will be made to the nearest whole number of Petrofund Units and a certificate representing the resulting whole number of Petrofund Units will be issued. In calculating such fractional interests, all Ultima Units held by a registered holder of Ultima Units immediately prior to the Closing Date shall be aggregated.

The Combination Agreement provides that any certificate representing Ultima Units that is not validly deposited with Computershare Trust Company of Canada within six years of the Closing Date shall cease to represent a claim or interest of any kind or nature in Petrofund, and the Petrofund Units to which the holder of such certificate would have otherwise been entitled shall be deemed to have been surrendered to Petrofund, together with all entitlements to distributions and interest thereon held for such holder.

See "Effect of the Merger Upon Ultima Unitholders -- Exchange of Ultima Certificates".

Recommendation of the Ultima Board of Directors

The Ultima Board of Directors has determined unanimously that the Special Distribution and Merger are in the best interests of Ultima and the Ultima Unitholders and unanimously recommends that Ultima Unitholders vote in favour of the Ultima Special Resolution. In coming to its conclusion and recommendation, the Ultima Board of Directors considered a number of factors including the following:

(a) the expectation that the Merger will result in a mutual fund trust that is financially and operationally stronger than Ultima, enabling it to more effectively participate and compete in the acquisition and development of oil and natural gas and the production and marketing of oil and natural gas under a variety of economic conditions;

(b) the improved liquidity of the investment anticipated for Ultima Unitholders and the improved access to capital for the combined entity that is expected to result from the increase in the market capitalization of the combined entity;

(c) the Fairness Opinion from CIBC World Markets;

(d) the Special Distribution;

(e) the timing of the record dates for monthly distributions of each of Ultima and Petrofund and the Closing Date;

(f) the increased efficiencies that are expected to result in reduced general and administrative costs on a per BOE basis;

(g) that the Merger will enable Ultima Unitholders to continue to participate in a larger oil and gas royalty trust with a proven management team;

(h) increased diversification and property synergies that are anticipated to result from the combination of the high quality asset bases of each of Ultima and Petrofund;

(i) the increased exposure to a broader suite of internal growth opportunities through Petrofund's large undeveloped land base and prospect inventory;

(j) information concerning the financial condition, results of operations, business, plans and prospects of the Petrofund Parties and the Ultima Parties and the resulting potential for enhanced business efficiency, management, effectiveness and financial results of the combined entity; and

(k) the historical and current trading prices of the Petrofund Units and Ultima Units.

The Ultima Board of Directors believes the Special Distribution and Merger is in the best interests of Ultima and Ultima Unitholders and therefore unanimously recommends that Ultima Unitholders vote FOR the Ultima Special Resolution.

The Merger

The Combination Agreement provides for the implementation, subject to the satisfaction of certain conditions, of the Merger. See "Details of the Merger - The Combination Agreement".

On the Closing Date, each of the events set out below will occur and be deemed to occur immediately at the Effective Time in the sequence set out below:

1. the Ultima Trust Indenture and any other constating documents of the Ultima Parties will be amended to the extent necessary to facilitate the Merger;

2. Ultima will sell, transfer, convey, assign and deliver to Petrofund, and Petrofund will purchase and accept from Ultima, all of the Ultima Assets, as the same exist at the Effective Time;

3. Petrofund will (i) assume and become liable to pay, satisfy, discharge and observe, perform and fulfill the Assumed Liabilities, in accordance with their terms, and (ii) issue to Ultima an aggregate number of Petrofund Payment Units equal in number to the product of the number of Ultima Units outstanding as of the close of business on the day immediately prior to the Closing Date multiplied by the Exchange Ratio;

4. Petrofund will subscribe for the Ultima Remaining Unit for $10.00 and Ultima will issue to Petrofund the Ultima Remaining Unit;

5. the Ultima Units (other than the Ultima Remaining Unit) will be redeemed in exchange for the Petrofund Payment Units which shall be distributed to the Ultima Unitholders in accordance with the Exchange Ratio;

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6. the directors of the Ultima Parties, where applicable, will resign in favour of the nominees for election as directors of Petrofund Co; and

7. all officers of the Ultima Parties, where applicable, will resign from their offices with such Ultima Parties.

The Combination Agreement also provides that upon the occurrence or non-occurrence of certain events which result in the Merger not being completed, the party to the Combination Agreement responsible for or subject to such events will be required to pay compensation to the other party. See "Details of the

Merger - The Combination Agreement -- Termination Fees".

Procedure for the Merger to Become Effective

The following procedural steps must occur in order for the Merger to become effective:

(a) the Ultima Special Resolution must be approved by at least 66 2/3% of the votes cast by the Ultima Unitholders present in person or by proxy at the Meeting;

(b) all conditions precedent to the Merger, as set forth below under " Details of the Merger - The Combination Agreement - Conditions of the Special Distribution and Merger", must be satisfied or waived by the appropriate party; and

(c) all agreements which are required in order to implement the Merger must be executed by the appropriate parties at Closing.

Fairness Opinion

To assist in determining whether to recommend the Special Distribution and Merger to Ultima Unitholders, CIBC World Markets provided the Ultima Board of Directors with the Fairness Opinion, which concluded that the consideration to be received by Ultima Unitholders pursuant to the Special Distribution and Merger is fair, from a financial point of view, to the Ultima Unitholders. A copy of the Fairness Opinion is attached as Appendix "E" to this Information Circular. See "Fairness Opinion".

Intention of Certain Insiders

Members of the Ultima Board of Directors and senior officers of Ultima Co, who collectively own, directly or indirectly, or exercise control or direction over, an aggregate of 535,921 Ultima Units, representing approximately 1.0% of the Ultima Units outstanding on April 19, 2004, have indicated their intention to vote their Ultima Units in favour of the Ultima Special Resolution approving the Special Distribution and Merger and have entered into Support Agreements with Petrofund agreeing to vote their Ultima Units in favour of the Ultima Special Resolution.

See "Interests of Insiders in the Merger and Intentions of Certain Insiders".

Timing

The Merger will become effective at Closing. If the Ultima Special Resolution is approved at the Meeting and all other conditions specified in the Combination Agreement are satisfied or waived, Petrofund and Ultima expect the Closing Date will be on or about June 16, 2004.

See "Timing".

Canadian Income Tax Considerations

For Canadian tax purposes, Ultima Unitholders who hold their Ultima Units as capital property within the meaning of the Tax Act will not realize a capital gain (or capital loss) on the disposition of Ultima Units for Petrofund

Units pursuant to the terms of the Merger.

Ultima Unitholders (other than Exempt Plans) who are resident in Canada for the purposes of the Tax Act will generally be required to include in income their proportionate share of the Special Distribution which represents a distribution of Ultima's income in the taxation year in which the Special Distribution is paid. Exempt Plans will not generally be liable for tax with respect to the Special Distribution.

Ultima Unitholders who are not resident, or deemed to be resident, in Canada, will generally be subject to a 25% Canadian withholding tax on their proportionate share of Ultima's income which is distributed pursuant to the Special Distribution at the time such distribution is paid unless such rate is reduced under the provisions of a tax treaty between Canada and the respective Ultima Unitholder's jurisdiction of residence.

See "Canadian Federal Income Tax Considerations".

All Ultima Unitholders should consult their own legal and tax advisors as to the tax consequences of the Special Distribution and Merger.

United States Federal Income Tax Considerations

Subject to the PFIC, FIC and FPHC rules (discussed under "United States Federal Income Tax Considerations"), the gross amount of the Special Distribution (before reduction for Canadian withholding taxes) will be taxable to U.S. holders of Ultima Units as a dividend to the extent of Ultima's current and accumulated earnings and profits, as determined under U.S. federal income tax principles. Ultima stated in 2003 that it believed that it would qualify as a PFIC for the year ended December 31, 2003. If this is the case, U.S. Holders of Ultima Units would not be eligible for the reduced rate of taxation on the Special Distribution that is applicable to dividends paid by certain qualified foreign corporations.

For U.S. federal income tax purposes, the exchange of Ultima Units for Petrofund Units has been structured to qualify as a reorganization under the provisions of Section 368(a) of the U.S. Internal Revenue Code of 1986, as amended. The U.S. federal income tax treatment of the exchange to a U.S. Holder of Ultima Units, however, will depend on whether Ultima has been a PFIC at any time during which the U.S. Holder has held the Ultima Units. As discussed under "United States Federal Income Tax Considerations", Ultima believes that it should not be a PFIC for 2004. Because this conclusion is a factual determination that is made annually and is subject to change, there can be no assurances that Ultima will not be a PFIC for the current or any future taxable year.

If Ultima has been a PFIC at any time during the time during which a U.S. Holder has held Ultima Units, the exchange of Ultima Units for Petrofund Units in the Merger should be a taxable transaction to the U.S. Holder. If Ultima has not been a PFIC at any time during the time during which a U.S. Holder has held Ultima Units, the U.S. Holder of Ultima Units should not be required to recognize gain on the exchange of its Ultima Units for Petrofund Units. If, contrary to Petrofund's current belief (discussed under "United States Federal Income Tax Considerations"), Petrofund is determined to be a PFIC for 2004, and Ultima has also been a PFIC at any time during which a U.S. Holder has held Ultima Units, such a U.S. Holder of Ultima Units should not be required to recognize gain on the exchange of its Ultima Units for Petrofund Units.

U.S. holders of Ultima Units are urged to consult their own tax advisors regarding the U.S. federal income tax consequences of the Special Distribution, the Merger, and ownership of Petrofund Units, as well as any applicable state or foreign tax consequences.

See "United States Federal Income Tax Considerations".

Stock Exchange Listings

The currently outstanding Ultima Units are listed and posted for trading on the TSX and the Petrofund Units are listed and posted for trading on the TSX and the AMEX. On March 26, 2004, the last trading day prior to the date of the announcement of the Merger, the closing price of the Petrofund Units on the TSX was $17.14 per Petrofund Unit and on the AMEX was U.S.$12.97 per Petrofund Unit. On March 26, 2004, the closing price of the Ultima Units on the TSX was $7.47 per Ultima Unit. On April 29, 2004, the closing price of the Petrofund Units on the TSX was $16.42 per Petrofund Unit and on the AMEX was U.S.$11.95 per Petrofund Unit. On April 29, 2004, the closing price of the Ultima Units was $7.07 per Ultima Unit. Following the Closing Date of the Merger, the Ultima Units will be delisted from the TSX. See "Stock Exchange Listings", "Additional Information Regarding Ultima Energy Trust - Trust Unit Price Range and Trading Volumes" and "Additional Information Regarding Petrofund Energy Trust - Trust Unit Price Range and Trading Volumes"

Selected Pro Forma Information

The pro forma combined financial information set forth below and the Unaudited Pro Forma Combined Financial Statements set forth in Appendix "D" hereto are not necessarily indicative either of results of operations that would have occurred in the year ended December 31, 2003 had the proposed Merger and certain other adjustments been effected on January 1, 2003, or of the results of operations expected in 2004 and future years. In preparing the pro forma statements, no adjustments have been made to reflect the operating synergies and the resulting cost savings expected to result from combining the operations of Petrofund and Ultima.

Selected Pro Forma Combined Financial Information

The following table sets out certain financial information for Petrofund and Ultima as at and for the year ended December 31, 2003 and for Petrofund on a pro forma basis as at and for the year ended December 31, 2003 after giving effect to the Special Distribution and Merger and certain other adjustments. The following is a summary only and must be read in conjunction with the Unaudited Pro Forma Combined Financial Statements of Petrofund set forth in Appendix "D" to this Information Circular.

	As at and for the year ended December 31, 2003		
	Petrofund	Ultima	Pro Forma After Giving Effect to the Merger
		($ millions)	
Revenues	393.1	111.1	504.2
Cash flow(1)	187.6	54.9	245.8
Net income	85.8	12.3	62.0
Total assets	943.9	326.5	1,522.2
Working capital (deficiency)	(30.0)	(8.2)	(42.1)
Long term debt	110.3	73.1	193.7

Unitholders' equity...............	649.2	208.4	1,102.0

Note:

(1) Management of Ultima Co uses cash flow (before changes in non-cash working capital) to analyze financial performance, as one measure to benchmark performance against peers, and as one measure to determine distribution levels. Cash flow is calculated as net income for the period plus charges to income not requiring an outlay of funds less credits to net income not involving a source of funds. Cash flow as presented does not have any standardized meaning prescribed by Generally Accepted Accounting Principles in Canada ("GAAP") and therefore it may not be comparable with the calculation of similar measures by other entities. Cash flow as presented is not intended to represent operating cash flows or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net income or other measures of financial performance calculated in accordance with GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital.

Selected Combined Operational Information

The following table sets out certain operational information for Petrofund and Ultima on a pro forma combined basis after giving effect to the Merger. Further operational information concerning Petrofund and Ultima is set forth in their respective annual information forms which are attached as Appendices "B" and "C" to this Information Circular.

	Petrofund	Ultima	Combin After Givin to the M
Production(1)			
Natural gas (MMcf/d)	79.4	13.7	93.1
Oil and NGLs (Bbls/d)	13,448	8,065	21,51
Total (BOE/d)(3).....................	26,681	10,348	37,02
Reserves(2)(3)			
Proved (MBOE)........................	81,762	30,725	112,4
Proved plus Probable (MBOE)	102,030	41,377	143,4
Reserve Life Index(4)			
Proved...............................	8.4 years	8.1 years	8.3 ye
Proved plus Probable.................	10.5 years	11.0 years	10.6 ye
Undeveloped land (thousands of net acres)...	250,509	35,270	285,7

Notes:

(1) Based on the 2004 forecast of proved plus probable production of each of Petrofund and Ultima as estimated by the independent engineers of each of Petrofund and Ultima in their respective reports of oil and gas reserves as at December 31, 2003.

(2) Calculated on a gross basis before deducting royalties, without including royalty interests, and based on the evaluations of the independent engineers of each of Petrofund and Ultima as at December 31, 2003. The 11.7136% net royalty interest held by Ventures Trust in the Weyburn Unit is treated as a working interest as Ultima is responsible for its share of capital costs, operating costs, royalties and abandonment costs.

(3) BOEs may be misleading, particularly if used in isolation. A BOE conversion of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(4) Calculated as proved reserves or proved plus probable reserves, as the case may be, divided by 2004 forecast of proved plus probable production.

Pro Forma Combined Capitalization

The following table sets out the capitalization of Petrofund and Ultima as at December 31, 2003, together with the pro forma combined capitalization of Petrofund as at December 31, 2003 after giving effect to the Merger and certain other adjustments. The following is a summary only and, where applicable, must be read in conjunction with the Unaudited Pro Forma Combined Financial Statements of Petrofund set forth in Appendix "D" to this Information Circular.

	As at December 31, 2003		
	Petrofund	Ultima	P After G to
Net debt ($ millions)(1)....................	$140.3	$81.4	
Units outstanding ($ millions) (2)	$1,031.2 (73.6 million units)	$324.8 (57.6 million units)	(100.1

Notes:

(1) Long term debt plus working capital deficiency as at December 31, 2003. Ultima net debt also includes its deferred capital obligation relating to the 11.7136% net royalty interest held by Ventures Trust in the Weyburn Unit. Pro forma net debt reflects the payment of the Special Distribution and excludes transaction costs.

(2) Units outstanding for Petrofund includes those issuable upon conversion of outstanding exchangeable shares. Pro forma units outstanding reflects exercise of all outstanding Ultima Rights.

GLOSSARY OF TERMS

The following is a glossary of certain terms used in this Information Circular including the Summary hereof and the Appendices hereto; however, terms and abbreviations used in the Appendices to this Information Circular, to the extent that they are defined in an Appendix, shall have the meanings set forth therein.

"AcquireCo" means Ultima Acquisitions Corp., a corporation incorporated under the laws of the Province of Alberta;

"AcquireCo USA" means the amended and restated unanimous shareholder agreement dated as of June 23, 1999, and among AcquireCo, Maximize, and TCBM, for and on behalf of Ultima, as amended;

"Acquisition Proposal" has the meaning ascribed thereto in "Details of the Merger - The Combination Agreement - Acquisition Proposal and Take-Over Proposal";

"Assumed Liabilities" means the liabilities and obligations of Ultima, whether or not reflected on the books of Ultima;

"AMEX" means the American Stock Exchange;

"CIBC World Markets" means CIBC World Markets Inc., financial advisor to Ultima and Ultima Co;

"Closing" means closing of the transactions contemplated by the Combination Agreement, anticipated to be on or about June 16, 2004;

"Closing Date" means the date upon which the Merger becomes effective, anticipated to be on or about June 16, 2004, provided that, in the event any of the conditions of closing contained in the Combination Agreement in favour of Ultima or Petrofund have not been fulfilled or waived by such date, the Closing Date shall be extended to a date mutually agreed by Ultima and Petrofund, provided (i) the Merger shall become effective on a date which follows a record date for the payment of a regular monthly cash distribution by Ultima to the Ultima Unitholders and which precedes the next following record date for the payment of a regular monthly cash distribution by Petrofund to the Petrofund Unitholders and (ii) the date is no later than July 16, 2004, unless otherwise agreed to by Ultima and Petrofund;

"Combination Agreement" means the combination agreement dated March 29, 2004, as amended April 30, 2004, including any subsequent amendments thereto, between Ultima, Ultima Co, Petrofund and Petrofund Co;

"Commissioner" means the Commissioner of Competition appointed pursuant to the provisions of the Competition Act;

"Competition Act" means the Competition Act (Canada), as amended;

"Effective Time" means the effective time of the Merger;

"Exchange Ratio" means the ratio of 0.442 Petrofund Units for each Ultima Unit;

"Exempt Plans" means trusts governed by registered retirement savings plans, registered retirement income funds, registered education savings plans and deferred profit sharing plans as defined in the Tax Act;

"Fairness Opinion" means the opinion of CIBC World Markets dated April 30, 2004 that the consideration to be received by Ultima Unitholders in connection with the Special Distribution and Merger is fair, from a financial point of view, to the Ultima Unitholders. A copy of the Fairness Opinion is attached to this Information Circular as Appendix "E";

"Information Circular" means this proxy statement and information circular dated April 30, 2004, together with all Appendices hereto and including the Summary hereof, distributed by Ultima in connection with the Meeting;

"Management Agreement" means the amended and restated management agreement dated as of August 31, 1997 among Maximize, Ultima Co, on its own behalf and on behalf of Ventures Trust, AcquireCo, TCBM, for and on behalf of Ultima, and Maximum Energy Corp. (as it existed at the time), as amended;

"Manager" means Ultima Management Inc., a corporation incorporated under the laws of the Province of Alberta, which is the manager of Ultima, Ultima Co, Ventures Trust and AcquireCo;

"Material Adverse Change" or "Material Adverse Effect" means, with respect to any person, any matter or action that has an effect or change that is, or would reasonably be expected to be, material and adverse to the business, operations, assets, capitalization, financial condition or prospects of such person and its subsidiaries, taken as a whole, other than any matter, action, effect or change relating to or resulting from: (i) general economic, financial, currency exchange, securities or commodity prices in Canada or elsewhere, (ii) conditions affecting the oil and gas exploration, exploitation, development and production industry as a whole, and not specifically relating to any person and/or its subsidiaries or (iii) any decline in crude oil or natural gas prices on a current or forward basis;

"Maximize" means Maximize Management Corp., a corporation incorporated under the laws of the Province of Alberta, and the former manager of Ultima, Ultima Co, Ventures Trust and AcquireCo;

"Meeting" means the special meeting of Ultima Unitholders to be held on June 4, 2004, and any adjournment thereof, at which, among other things, the Ultima Unitholders will consider the Ultima Special Resolution;

"Merger" means the business combination of Ultima and Petrofund which will provide for, inter alia, the transfer of all the Ultima Assets to Petrofund in consideration of the Petrofund Payment Units and the assumption of the Assumed Liabilities by Petrofund and the distribution of all Petrofund Payment Units to the Ultima Unitholders as of the Effective Time upon, and as consideration for, the redemption of all of the Ultima Units (other than the Ultima Remaining Unit), all as contemplated in Section 132.2 of the Tax Act;

"person" includes any individual, firm, partnership, joint venture, venture capital fund, association, trust, trustee, executor, administrator, legal personal representative, estate group, body corporate, corporation, unincorporated association or organization, governmental entity, syndicate or other entity, whether or not having legal status;

"Petrofund" means Petrofund Energy Trust, a trust created under the laws of the Province of Ontario;

"Petrofund Board of Directors" means the board of directors of Petrofund Co as it may be comprised from time to time;

"Petrofund Co" means Petrofund Corp., a corporation incorporated under the laws of the Province of Alberta;

"Petrofund Parties" means Petrofund, Petrofund Co, 1518274 Ontario Limited, NCE Petrofund Management Corp. and NCE Management Services Inc. and "Petrofund Party" means any of them unless the context otherwise requires;

"Petrofund Payment Units" means the Petrofund Units issued to Ultima in consideration of the sale and transfer of the Ultima Assets and the assumption of the Assumed Liabilities by Petrofund;

"Petrofund Royalty" means the royalty granted by Petrofund Co to Petrofund pursuant to the terms of the amended and restated royalty agreement dated as of April 16, 2003 between Petrofund Co and Petrofund;

"Petrofund Unit" means a trust unit issued by Petrofund;

"Petrofund Unitholders" means, at the relevant time, the holders of Petrofund Units;

"Record Date" means the record date set for the Meeting, being the close of business on April 19, 2004;

"SEC" means the United States Securities and Exchange Commission;

"Special Distribution" means the one-time special cash distribution to Ultima Unitholders in the aggregate amount of $10 million payable to holders of record of Ultima Units on the business day immediately preceding the Closing Date;

"Support Agreements" means the agreements entered into between Petrofund and each member of the Ultima Board of Directors and the senior officers of Ultima Co, pursuant to which such directors and officers have agreed to vote the Ultima Units held by them in favour of the Ultima Special Resolution;

"Take-Over Proposal" has the meaning ascribed thereto in "Details of the Merger - The Combination Agreement - Acquisition Proposal and Take-Over Proposal";

"Tax Act" means the Income Tax Act (Canada) and the Income Tax Regulations, all as amended from time to time;

"TCBM" means The Trust Company of Bank of Montreal;

"TSX" means the Toronto Stock Exchange;

"Ultima" means Ultima Energy Trust, a trust created under the laws of the Province of Alberta;

"Ultima Assets" means all the property, assets and undertaking of Ultima of whatsoever nature or kind, present and future, and wheresoever located, including the shares, units, royalties, notes or other interests in the capital of or granted by Ultima's direct subsidiaries and any rights to purchase assets, properties or undertakings of third parties under agreements to purchase that have not yet closed, if any, and whether or not reflected on the books of Ultima (other than $10.00);

"Ultima Board of Directors" means the board of directors of Ultima Co as it may be comprised from time to time;

"Ultima Co" means Ultima Ventures Corp., a corporation incorporated under the laws of the Province of Alberta;

"Ultima Co USA" means the unanimous shareholder agreement dated as of August 31, 1997 among Ultima Co, on its own behalf and for and on behalf of Ventures Trust, Maximize, and TCBM, for and on behalf of Ultima, as amended;

"Ultima Employment Agreements" means the employment agreements, as amended, between Ultima, Ultima Management Inc. and each of S. Brian Gieni, Ken G. Pinsky and Michael P. Wihak;

"Ultima Energy" means Ultima Energy Inc., a corporation incorporated under the laws of the Province of Alberta;

"Ultima Parties" means Ultima, Ultima Co, Ventures Trust, Ultima Energy, AcquireCo and the Manager and "Ultima Party" means any of them unless the context otherwise requires;

"Ultima Remaining Unit" means one Ultima Unit issued to Petrofund immediately prior to the Effective Time of the Merger;

"Ultima Rights" means the rights to acquire Ultima Units granted under the Ultima TURIP and pursuant to the Ultima Employment Agreements;

"Ultima Royalties" means the royalty granted by Ventures Trust to Ultima pursuant to the terms of the amended and restated royalty agreement dated June 23, 1999, between Ultima Co and The Trust Company of Bank of Montreal in its capacity as trustee of Ultima, as amended, and the royalty granted by Ultima Energy to Ultima pursuant to the terms of the royalty agreement dated June 26, 2003, between Ultima Energy and Ultima Co on behalf of Ultima;

"Ultima Special Resolution" means the special resolution of Ultima Unitholders to approve the Special Distribution and Merger;

"Ultima Trustee" means Computershare Trust Company of Canada, in its capacity as the trustee under the Ultima Trust Indenture;

"Ultima Trust Indenture" means the amended and restated trust indenture governing Ultima dated as of August 31, 1997, between Ultima Co, AcquireCo, The Trust Company of Bank of Montreal, Maximum Energy Corp. and Glenn C. Proudfoot, as amended;

"Ultima Unit" means a trust unit issued by Ultima;

"Ultima TURIP" means the Trust Unit Rights Incentive Plan of Ultima;

"Ultima Unitholders" means, at the relevant time, the holders of Ultima Units other than Petrofund;

"Unitholder Indemnity Agreement" means the agreement between Ultima and Petrofund to be entered into on the date of the payment of the Special Distribution by Ultima pursuant to which Petrofund shall indemnify and save Ultima Unitholders and annuitants under a plan of which a unitholder acts as a trustee or carrier harmless from all and any costs, damages or expenses that may be paid or incurred following any claim, suit or action taken by any other party because of the failure of Petrofund to discharge and perform all or any of the obligations, covenants, agreements and obligations forming part of the Assumed Liabilities;

"Ventures Trust" means Ultima Ventures Trust, a trust formed under the laws of the Province of Alberta;

"Ventures Trust Indenture" means the trust indenture governing Ventures Trust dated as of August 31, 1997 between Ultima Co in its capacity as trustee of Ventures Trust and TCBM in its capacity as trustee of Ultima, as amended; and

"1933 Act" means the United States Securities Act of 1933, as amended.

ABBREVIATIONS

The following abbreviations are used in this Information Circular to represent the following terms:

"API" means American Petroleum Institute;
"Bbl" means barrel and "Bbls" means barrels;
"Bbls/d" means barrels per day;
"Bcf" means 1,000,000,000 cubic feet;
"BOE" means barrels of oil equivalent, with natural gas converted at 6 Mcf of natural gas per Bbl of oil, unless otherwise stated;
"BOE/d" means barrels of oil equivalent per day, with natural gas converted at 6 Mcf of gas per Bbl of oil, unless otherwise stated;
"GJ" means gigajoule;
"m3" means cubic metre;
"Mbbls" means 1,000 barrels;
"MBOE" means 1,000 barrels of oil equivalent, with natural gas converted at 6 Mcf of gas per Bbl of oil, unless otherwise stated;
"Mcf" means 1,000 cubic feet;
"Mcf/d" means 1,000 cubic feet per day;
"Mlt" means one thousand long tons or 2,240,000 pounds;
"MMbbls" means, 1,000,000 barrels;
"MMBTU" means 1,000,000 British Thermal Units;
"MMcf" means 1,000,000 cubic feet;
"MMcf/d" means 1,000,000 cubic feet per day;
"NGLs" or "liquids" means natural gas liquids;
"WI" means working interest;
"WTI" means West Texas Intermediate, the benchmark crude for pricing purposes; and
"000s" means thousands of dollars;

BOE's may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf: 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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	6.289
feet	metres	0.305
metres	feet	3.281
miles	kilometers	1.609
kilometers	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

PART I - GENERAL PROXY MATERIALS
AND ANNUAL AND SPECIAL MEETING MATTERS

SOLICITATION OF PROXIES

This Information Circular is furnished in connection with the solicitation of proxies on behalf of Ultima by the management of the Manager for use at the Meeting. The Meeting will be held in the Chambers Room located on the conference level at 350 - 7th Avenue S.W., Calgary, Alberta on Friday, June 4, 2004 at 10:30 a.m. (Calgary time) for the purposes set forth in the Notice of Annual and Special Meeting of the Ultima Unitholders accompanying this Information Circular. It is expected that such solicitation will be primarily by mail. Proxies may also be solicited personally by officers of the Manager at nominal cost. The cost of solicitation on behalf of Ultima will be borne by the Manager and reimbursed by Ultima. The information contained in this Information Circular is given as of April 30, 2004 except where otherwise indicated.

In addition, Ultima has retained Georgeson Shareholder Communications Canada Inc. ("Georgeson Shareholder"), 66 Wellington Street West, TD Tower, Suite 5210, Toronto Dominion Centre, P.O. Box 240, Toronto, Ontario, M5K 1J3 at a fee of approximately $40,000 plus out-of-pocket expenses to aid in the solicitation of proxies from individual and institutional investors in Canada and the United States. If you have questions about the information contained in this Information Circular or require assistance in completing your form of proxy (printed on blue paper) or letter of transmittal (printed on yellow paper), please call Georgeson Shareholder at 1-866-800-4722.

APPOINTMENT OF PROXIES

Those Ultima Unitholders who wish to be represented at the Meeting by proxy must complete and deliver a proper form of proxy to Computershare Trust Company of Canada by mail or facsimile to Computershare Trust Company of Canada, 100 University Avenue, 9th Floor, Toronto, Ontario, M5J 2Y1 (a self-addressed envelope is enclosed), fax number: 905-771-4414. In order to be valid, proxies must be received by the Ultima Trustee at least 24 hours, excluding Saturdays, Sundays and holidays, prior to the time of the Meeting or any adjournment thereof.

The document appointing a proxy must be in writing and completed and signed by the Ultima Unitholder or his or her attorney authorized in writing or, if the Unitholder is a corporation, under its corporate seal or by an officer or attorney thereof duly authorized. Persons signing as officers, attorneys, executors, administrators, trustees, etc. should so indicate and provide satisfactory evidence of such authority.

The persons named as proxyholders in the enclosed form of proxy, S. Brian Gieni and Gary Lee, are directors of Ultima Co, Ultima Energy, AcquireCo and the Manager. Mr. Gieni is also the President and Chief Executive Officer of Ultima Co, Ultima Energy, AcquireCo and the Manager. An Ultima Unitholder desiring to appoint some other person as his or her representative at the Meeting may do so by either: (i) crossing out the names of the management nominees AND legibly printing the other person's name (who need not be an Ultima Unitholder) in the blank space provided in the enclosed form of proxy; or (ii) completing another valid form of proxy. In either case, the completed proxy must be delivered to the Ultima Trustee at the place and within the time specified above for the deposit of proxies.

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REVOCATION OF PROXIES

An Ultima Unitholder who has given a proxy has the power to revoke it before the proxy is exercised. In addition to revocation in any other manner permitted by law, an Ultima Unitholder may revoke the proxy with an instrument in writing signed and delivered to the Ultima Trustee at any time up to and including the last business day preceding the date of the Meeting or any adjournment thereof or deposited with the Chairman of the Meeting on the day of the Meeting or any adjournment thereof prior to the commencement of the Meeting. The document used to revoke a proxy must be in writing and completed and signed by the Ultima Unitholder or his or her attorney authorized in writing or, if the Ultima Unitholder is a corporation, under its corporate seal or by an officer or duly authorized attorney thereof. As well, an Ultima Unitholder who has given a proxy may attend the Meeting in person (or where the Ultima Unitholder is a corporation, its authorized representative may attend), revoke the proxy (by indicating such intention to the Chairman of the Meeting before the proxy is exercised) and vote in person (or abstain from voting).

EXERCISE OF DISCRETION WITH RESPECT TO PROXIES

The Ultima Units represented by the enclosed proxy will be voted or withheld from voting on any motion, by ballot or otherwise, in accordance with any indicated instructions. In the absence of such direction, such Ultima Units will be voted FOR the resolutions referred to in the proxy. If any amendment or variation to the matters identified in the Notice is proposed at the Meeting or any adjournment thereof, or if any other matters properly come before the Meeting or any adjournment thereof, the enclosed proxy confers discretionary authority to vote on such amendments or variations or such other matters according to the best judgment of the appointed proxyholder. As at the date of this Information Circular, none of the Ultima Trustee, in its capacity as trustee of Ultima, Ultima Co, Ultima Energy, AcquireCo or the Manager is aware of any other amendments or variations or other matters to come before the Meeting.

ADVICE TO BENEFICIAL HOLDERS OF ULTIMA UNITS

The information set forth in this section is of significant importance to many holders of Ultima Units, as a substantial number of Ultima Unitholders do not hold their Ultima Units in their own name. Ultima Unitholders who do not hold their Ultima Units in their own name (referred to herein as "Beneficial Unitholders") should note that only proxies deposited by Ultima Unitholders whose names appear on the records of Ultima as the registered holders of Ultima Units can be recognized and acted upon at the Meeting. If Ultima Units are listed in an account statement provided to an Ultima Unitholder by a broker, then, in almost all cases, those Ultima Units will not be registered in the Ultima Unitholder's name on the records of the Ultima. Such Ultima Units will more likely be registered under the name of the Ultima Unitholder's broker or an agent of that broker. In Canada, the vast majority of such Ultima Units are registered under the name of CDS & Co. (the registration name for The Canadian Depository for Securities, which acts as nominee for many Canadian brokerage firms). Ultima Units held by brokers or their agents or nominees can only be voted (for or against resolutions) upon the instructions of the Beneficial Unitholder. Without specific instructions, a broker and its agents and nominees are prohibited from voting Ultima Units for the broker's clients. Therefore, Beneficial Unitholders should ensure that instructions respecting the voting of their Ultima Units are communicated to the appropriate person or that the Ultima Units are duly registered in their name.

Applicable Canadian regulatory policy requires intermediaries/brokers to seek voting instructions from Beneficial Unitholders in advance of meetings. Every intermediary/broker has its own mailing procedures and provides its own return instructions to clients, which should be carefully followed by Beneficial Unitholders in order to ensure that their Ultima Units are voted at the Meeting. Often, the form of proxy supplied to a Beneficial Unitholder by its broker (or the agent of the broker) is identical to the form of proxy provided to registered Ultima Unitholders. However, its purpose is limited to instructing the registered Ultima Unitholder (the broker or agent of the broker) how to vote on behalf of the Beneficial Unitholder. In Canada, the majority of brokers now delegate responsibility for obtaining instructions from clients to the ADP Investor Communications Corporation ("ADP"). In most cases, ADP mails a scannable voting instruction form in lieu of the form of proxy provided by Ultima, and asks Beneficial Unitholders to return the voting instruction form to ADP. Alternatively, Beneficial Unitholders can either call their toll-free telephone number to vote their Ultima Units, or access ADP's dedicated voting website at www.proxyvotecanada.com to deliver their voting instructions. ADP then tabulates the results of all instructions received and provides appropriate instructions respecting the voting of Ultima Units to be represented at the Meeting. A Beneficial Unitholder receiving a voting instruction form from ADP cannot use that form to vote Ultima Units directly at the Meeting - the voting instruction form must be returned to ADP or, alternatively, instructions must be received by ADP well in advance of the Meeting in order to have such Ultima Units voted.

Although a Beneficial Unitholder may not be recognized directly at the Meeting for the purposes of voting Ultima Units registered in the name of his broker (or an agent of the broker), a Beneficial Unitholder may attend the Meeting as proxyholder for the registered Ultima Unitholder and vote the Ultima Units in that capacity. A Beneficial Unitholder who wishes to attend the Meeting and indirectly vote his Ultima Units as proxyholder for the registered Ultima Unitholder, should enter his own name in the blank space on the form of proxy provided to him and return the same to his broker (or broker's agent) in accordance with the instructions provided by such broker (or agent), well in advance of the Meeting.

VOTING SECURITIES AND PRINCIPAL HOLDERS OF VOTING SECURITIES

The Ultima Unitholders are the sole beneficiaries of Ultima. On a show of hands, every Ultima Unitholder present in person or represented by proxy (and entitled to vote) has one vote. On a poll or ballot, every Ultima Unitholder present in person or by proxy has one vote for each Ultima Unit held. All votes on special resolutions will be conducted by a poll and no demand for a poll is required. As at April 19, 2004 (the "Record Date"), Ultima had 57,807,357 issued and outstanding Ultima Units. Ultima Unitholders of record as of the Record Date are entitled to receive the Notice and attend and vote at the Meeting.

Holders of Ultima Units issued subsequent to the date of this Information Circular and prior to the date of the Meeting are also entitled to attend and vote at the Meeting. If an Ultima Unitholder has transferred the ownership of any of his, her or its Ultima Units after the Record Date and the transferee of those Ultima Units produces properly endorsed certificates or otherwise establishes that he, she or it owns the Ultima Units and demands, not later than 10 days before the Meeting, that his or her name be included in the list before the Meeting, then the transferee shall be entitled to vote such Ultima Units at the Meeting.

As at the date of this Information Circular and to the best of the knowledge of the directors and senior officers of Ultima Co, AcquireCo and the Manager, no person or company beneficially owns, directly or indirectly, or exercises control or direction over, more than 10% of the issued and outstanding Ultima Units.

ANNUAL MEETING MATTERS

The election of the directors of each of Ultima Co and AcquireCo in this "Annual Meeting Matters" section will be effective until such time as the Merger is approved and completed, after which time the nominees of Petrofund shall form the board of directors of each of Ultima Co and AcquireCo. If the Merger is not completed, the matters acted upon in this "Annual Meeting Matters" section shall be effective until the next annual meeting of Ultima Unitholders or otherwise as described below.

Consideration of Financial Statements

The consolidated financial statements of Ultima for the year ended December 31, 2003, together with the auditors' report thereon, have been mailed to Ultima Unitholders as part of this Information Circular. See "Comparative Audited Consolidated Financial Statements as at and for the years ended December 31, 2003 and 2002, together with the auditors' report thereon" in Appendix "C" of this Information Circular.

Election of Directors Until Completion to the Merger

The persons named as proxyholders in the enclosed form of proxy intend to vote FOR the election of the persons listed in the following table as directors of each of Ultima Co and AcquireCo. Each such director will hold office until the next annual meeting of the Ultima Unitholders or until his successor is duly elected or appointed in accordance with: (i) in the case of Ultima Co, the by-laws of Ultima Co and the Ultima Co USA; or (ii) in the case of AcquireCo, the by-laws of AcquireCo and the AcquireCo USA. If the proposed Merger is completed in accordance with its terms, the directors of Ultima Co and AcquireCo named below will resign and cease to hold office on the Closing Date.

The following table and notes thereto state the names of the persons to be nominated for election by the Ultima Unitholders as directors of each of Ultima Co and AcquireCo, their current principal occupations, the periods during which they have served as directors, and the number of Ultima Units owned beneficially or subject to each of their control or direction as at April 19, 2004.

Name and Municipality of Residence	Principal Occupation	Director Since	Trust U or Bene
Marshall M. Williams(1) Calgary, Alberta	Businessman; Chairman of the Boards of directors of Ultima Co and AcquireCo	August 1997(2)	
Arthur E. Dumont(3) Calgary, Alberta	Chairman and Chief Executive Officer of Technicoil Corporation	June 2001	
S. Brian Gieni(4) Calgary, Alberta	President and Chief Executive Officer of the Manager, Ultima Co, Ultima Energy and AcquireCo	December 2000	
John M. Gunn(5) Calgary, Alberta	Chief Executive Officer and Chief Financial Officer of Tango Energy Inc.	November 1999	
Henry R. Lawrie(6) Calgary, Alberta	Businessman	May 2003	
Gary Lee(7) Calgary, Alberta	Director of North West Capital Inc.	December 2000	
David Tuer(9) Calgary, Alberta	Chairman and Chief Executive Officer of Hawker Resources Inc.	May 2003	

Notes:

(1) Mr. Williams is a former Chairman of Alberta Treasury Branches. He has also served as Chairman of the Board and as a director of TransAlta Corporation, and as a director of Stelco Inc. from 1984 to 1996 and Sun Life Assurance from 1978 to 1995.

(2) Mr. Williams was appointed to the Boards of directors of Ultima Co and AcquireCo in August 1997 in connection with a reorganization of Ultima. Prior thereto, Mr. Williams had been elected as a director of Maximum Energy Corp., the corporate entity which held the initial properties presently held by Ventures Trust.

(3) Mr. Dumont has been the President and Chief Executive Officer of Technicoil Corporation since October 2000. Prior thereto, Mr. Dumont was President and Chief Executive Officer of CenAlta Energy Services and its predecessor companies from November 1998 until October 2000. He has also worked in senior roles at Western Rock Bit Company, Precision Drilling Corporation, Kenting Energy Services Inc. and Trimac Limited.

(4) Mr. Gieni is a finance and accounting professional who was employed in various senior management capacities at PanCanadian Petroleum Limited between 1997 and 2000. Prior to that, he was President and Chief Executive Officer and a director of Grantham Resources Inc., a junior

resource company listed on the Alberta Stock Exchange.

(5) Mr. Gunn has been the Chief Executive Officer and Chief Financial Officer of Tango Energy Inc. (a TSX-listed oil and gas company) since March 2002. Prior thereto, Mr. Gunn was the Chairman of Renata Resources Inc., formerly a TSX-listed oil and gas company, from 1996 until it was acquired in 2000. Prior thereto, Mr. Gunn was President and Chief Executive Officer of Ballistic Energy Corporation (formerly a TSX-listed oil and gas company).

(6) Mr. Lawrie is a Chartered Accountant - FCA. From July 1997 to February 2001 Mr. Lawrie was the Chief Accountant of the Alberta Securities Commission. Prior to that, Mr. Lawrie spent 35 years as a Chartered Accountant with PricewaterhouseCoopers and acted as managing partner of the Calgary office before retiring in 1997.

(7) Mr. Lee is a director and officer of North West Capital Inc. Prior to that, he was a partner with Hoar, Lee, Boers, Barristers and Solicitors, until December 1998.

(8) The Ultima Units are held by a company of which Mr. Lee is the sole director and a shareholder.

(9) Mr. Tuer has been Chairman and Chief Executive Officer of Hawker Resources Inc. since January 2003 and Chairman of the Calgary Health Region since October 2001. From December 1994 until October 2001, Mr. Tuer was President and Chief Executive Officer of PanCanadian Energy Corporation. Prior thereto, he worked in various senior roles at PanCanadian Petroleum Limited and for the Alberta Government.

Each of the Ultima Board of Directors and the board of directors of AcquireCo has appointed a compensation committee, reserves committee, audit committee and corporate governance committee. See "Additional Information Regarding Ultima Energy Trust - Statement of Corporate Governance Practices - Committees of the Boards" for a description of such committees. Neither board of directors has appointed an executive committee.

Appointment of Auditors Until Completion of the Merger

The Ultima Trust Indenture provides that the Ultima Unitholders shall appoint the auditors of Ultima at each annual meeting of Ultima Unitholders. Both the Ultima Co USA and the AcquireCo USA provide that the Unitholders shall likewise appoint the auditors of Ultima Co and AcquireCo, respectively, at each annual meeting of Unitholders. The Ventures Trust Indenture provides that the Ultima Unitholders shall also appoint auditors of Ventures Trust at each annual meeting of Ultima Unitholders. Deloitte & Touche LLP was appointed as auditors of Ultima, Ventures Trust, Ultima Co and AcquireCo on May 27, 2002.

The persons named in the enclosed form of proxy intend to vote FOR the re-appointment of Deloitte & Touche LLP as auditors of Ultima, Ventures Trust, Ultima Co and AcquireCo, respectively, to hold such office until the next annual meeting of the Ultima Unitholders and at a remuneration to be fixed by the directors of Ultima Co and AcquireCo.

PART II - THE MERGER

Background to the Merger

In the normal course, Ultima continually examines opportunities to advance the interests of its unitholders and to advance unitholder value. In January 2004, the Ultima Board of Directors, after considering the business and operations of Ultima, on both a historical and prospective basis, the current industry, economic and market conditions, including an anticipated consolidation in the oil and gas trust market, commenced a strategic analysis of Ultima's position and the alternatives available to Ultima.

In assessing the alternatives available to Ultima, Ultima retained CIBC World Markets effective January 19, 2004. CIBC World Markets presented the Ultima Board of Directors with a list of industry participants which, by virtue of their objectives, goals, valuation, market trading levels and corporate governance policies were most likely to have the ability and interest to enter into a favourable strategic transaction with Ultima. The Ultima Board of Directors and CIBC World Markets reviewed, discussed and agreed upon the list of likely industry participants. A number of these industry participants were approached and were provided with access to certain non-public information relating to Ultima and its business and affairs under the terms of a confidentiality agreement.

Discussions took place with the potential candidates during late February and early March. Certain of the potential candidates, including Petrofund, were provided with access to a confidential data room established by Ultima. As a result of this process, a written, non-binding proposal was received from Petrofund. On March 18, 2004, the Ultima Board of Directors met with CIBC World Markets and its legal advisors, Bennett Jones LLP, and reviewed Petrofund's proposal in detail. Up to this date, the Ultima Board of Directors had met on numerous occasions, both formally and informally, to receive updates from Bennett Jones LLP and CIBC World Markets, and to review the process.

The Ultima Board of Directors received financial advice from CIBC World Markets on the proposal by Petrofund and reviewed with them and Bennett Jones LLP the structure and terms of the proposal. The Ultima Board of Directors authorized management to continue to negotiate the terms of the non-binding proposal with Petrofund and, subject to certain terms and provisions being included in the proposal, authorized the entering into of the proposal on behalf of Ultima. The proposal was entered into on March 19, 2004. The proposal provided for a period of exclusivity to March 30, 2004, indicated preliminary terms of a combination and outlined certain outstanding due diligence procedures. The terms of any combination were subject to completion of due diligence by Ultima and Petrofund, final negotiations and the approval of each of the Ultima Board of Directors and Petrofund Board of Directors.

Between March 22, 2004 and March 28, 2004, discussions and negotiations continued between representatives of Ultima and representatives of Petrofund with respect to price, conditions to the Merger and the terms of the Combination Agreement.

The Ultima Board of Directors met during the afternoon of March 28, 2004. CIBC World Markets provided the Ultima Board of Directors with financial advice regarding the proposed Merger and the Special Distribution, including its view as to the fairness, from a financial point of view, of the consideration to be received by the Ultima Unitholders under the proposal. Bennett Jones LLP provided advice on the structure of the transaction and the terms of the draft Combination Agreement. The Ultima Board of Directors reviewed the terms of the draft Combination Agreement, discussed with its counsel a number of issues arising in respect of the Combination Agreement and fully considered its duties and responsibilities to holders of Ultima Units. The Ultima Board of Directors approved the Combination Agreement and unanimously determined that the Special

Distribution and Merger are in the best interest of Ultima and Ultima Unitholders and resolved to unanimously recommend that the Ultima Unitholders vote in favour of the Special Distribution and Merger.

The Combination Agreement was executed in the morning of March 29, 2004, and the transaction was publicly announced before markets opened on March 29, 2004. Thereafter, the Support Agreements were executed by each member of the Ultima Board of Directors and each senior officer of Ultima.

On April 30, 2004, the Ultima Board of Directors met again, approved an amending agreement to the Combination Agreement, reconfirmed its recommendation respecting the Special Distribution and Merger and approved the contents of this Information Circular.

Reasons for the Merger

The Ultima Board of Directors believes that the principal advantages of the Merger to Ultima Unitholders are as follows:

1. the Merger will improve access of the combined entity to capital markets in both Canada and the United States due to the increased size and liquidity of the combined entity which should provide the combined entity a more competitive cost of capital and an improved ability to compete for and finance future acquisitions;

2. after giving effect to the Merger, former holders of Ultima Units will hold interests in a much broader and more diversified group of properties and product mix;

3. the Merger will permit Ultima Unitholders to benefit from Petrofund's broader suite of internal growth opportunities through Petrofund's large undeveloped land base and prospect inventory;

4. the Merger will create a trust with larger market capitalization on two stock exchanges that should result in increased market liquidity for Ultima Unitholders; and

5. the Merger is expected to eliminate the duplication of costs and services which arises from administering two separate trusts.

The Merger will result in a combined entity with a larger market capitalization (approximately four times the current market capitalization of Ultima) which is expected to improve access of the combined entity to capital markets at a more competitive cost of capital. As a result, it is anticipated that the ability to compete for and finance future acquisitions will be strengthened.

As a result of the Merger, Ultima Unitholders will hold Petrofund Units with a market capitalization, based on current prices, of an aggregate of approximately $1.64 billion. Proved plus probable reserves (calculated on a gross basis before deducting royalties and without including royalty interests) attributable to Petrofund following the Merger will be approximately 143,400 MBOE. Total production attributable to Petrofund following the Merger is expected to be approximately 21,500 Bbls/d of crude oil and NGLs and 93.1 MMcf/d of natural gas, for total gross production of approximately 37,000 BOE/d. Management of Ultima also anticipates that a larger and more diversified group of properties will reduce the production risk to which Ultima, as a smaller producer, is currently exposed.

The Merger, if approved, is expected to enhance the liquidity to the former holders of Ultima Units as the Merger will result in approximately 100,129,910 Petrofund Units (assuming that all outstanding exchangeable shares of Petrofund Co are exchanged for Petrofund Units) being issued and outstanding and listed for trading on the TSX and the AMEX with a larger investor base, which management of Ultima anticipates will result in a more efficient market for the former holders of Ultima Units.

Administrative cost savings will be realized by eliminating the duplication of certain third party costs, as well as internal administrative costs, arising from managing and reporting for two separate trusts. Costs such as trustee and transfer agency fees, audit fees, mailing and reporting costs and exchange listing fees are higher for the two separate entities than are expected for one consolidated entity. The Merger

will eliminate the internal costs associated with segregating and maintaining separate books and records, bank accounts and property interests for the two separate entities.

Recommendation of the Ultima Board of Directors

The Ultima Board of Directors has determined unanimously that the Special Distribution and Merger are in the best interests of Ultima and the Ultima Unitholders and unanimously recommends that Ultima Unitholders vote in favour of the Ultima Special Resolution. In coming to its conclusion and recommendation, the Ultima Board of Directors considered a number of factors including the following:

(a) the expectation that the Merger will result in a mutual fund trust that is financially and operationally stronger than Ultima, enabling it to more effectively participate and compete in the acquisition and development of oil and natural gas properties and the production and marketing of oil and natural gas under a variety of economic conditions;

(b) the improved liquidity of the investment anticipated for Ultima Unitholders and the improved access to capital for the combined entity that is expected to result from the increase in the market capitalization of the combined entity;

(c) the Fairness Opinion from CIBC World Markets;

(d) the Special Distribution;

(e) the timing of the record dates for monthly distributions of each of Ultima and Petrofund and the Closing Date;

(f) the increased efficiencies that are expected to result in reduced general and administrative costs on a per BOE basis;

(g) that the Merger will enable Ultima Unitholders to continue to participate in a larger oil and gas royalty trust with a proven management team;

(h) increased diversification and property synergies that are anticipated to result from the combination of the high quality asset bases of each of Ultima and Petrofund;

(i) the increased exposure to a broader suite of internal growth opportunities through Petrofund's large undeveloped land base and prospect inventory;

(j) information concerning the financial condition, results of operations, business, plans and prospects of the Petrofund Parties and the Ultima Parties and the resulting potential for enhanced business efficiency, management, effectiveness and financial results of the combined entity; and

(k) the historical and current trading prices of the Petrofund Units and Ultima Units.

The Ultima Board of Directors believes the Special Distribution and Merger is in the best interests of Ultima and Ultima Unitholders and therefore unanimously recommends that Ultima Unitholders vote FOR the Ultima Special Resolution.

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The Ultima Special Resolution requires the approval of holders of not less than 66 2/3% of the Ultima Units represented at the Meeting which are voted in respect of the resolution in person or by proxy. See "Interests of Insiders in the Merger and Intentions of Certain Insiders".

It is the intention of the persons named in the enclosed Form of Proxy, if not expressly directed to the contrary in such Form of Proxy, to vote such proxy in favour of the Ultima Special Resolution set forth in the attached Appendix "A".

EFFECT OF THE MERGER UPON ULTIMA UNITHOLDERS

General

After giving effect to the Merger, Petrofund will have acquired all of the Ultima Assets and assumed all of the Assumed Liabilities, and former Ultima Unitholders will become holders of Petrofund Units on the basis of 0.442 of a Petrofund Unit for each issued and outstanding Ultima Unit. The Merger is structured to be a tax deferred event such that the exchange of Ultima Units for Petrofund Units will not result in a taxable event to Ultima Unitholders for Canadian tax purposes. See "Canadian Income Tax Considerations".

Assuming completion of the Merger whereby all Ultima Unitholders receive Petrofund Units for their Ultima Units, there will be approximately 99,233,252 Petrofund Units issued and outstanding, subject to changes due to the exercise of outstanding Ultima Rights and the rounding to the nearest whole number of fractional Petrofund Units and assuming that all outstanding exchangeable shares of Petrofund Co are exchanged for Petrofund Units. Immediately following the Merger and assuming that all of the outstanding exchangeable shares of Petrofund Co are exchanged for Petrofund Units, current Petrofund Unitholders will hold approximately 73,682,400 Petrofund Units, representing approximately 74% of the issued and outstanding Petrofund Units, and former holders of Ultima Units will hold approximately 25,550,852 Petrofund Units, representing approximately 26% of the issued and outstanding Petrofund Units. As of April 19, 2004, a total of approximately 2,028,639 Ultima Rights were outstanding which, based on the adjustment provisions, the Ultima

Employment Agreements and the Exchange Ratio, could result in an additional 896,658 Petrofund Units being issued to former securityholders of Ultima in connection with the Merger.

Special Distribution

If the Ultima Special Resolution is approved at the Meeting, a record date will be announced for the Special Distribution. Ultima Unitholders of record on the record date set for the Special Distribution will be entitled to a distribution from Ultima in the amount of $10 million divided by the number of Ultima Units outstanding on such record date (or approximately $0.17 per Ultima Unit assuming 59,835,996 Ultima Units are outstanding). The record date will be the date which is at least seven business days following approval of the Ultima Special Resolution, but which will be not later than the business day immediately prior to the Closing Date of the Merger. Therefore, if the Meeting is held as currently proposed on June 4, 2004 and the Closing Date is held as currently proposed on June 16, 2004, the record date for the Special Distribution will be June 15, 2004. Ultima will issue a press release announcing the actual record date for the Special Distribution at least seven business days prior to the record date. It is possible that the Special Distribution is approved by the Ultima Unitholders and paid by Ultima on the business day prior to the Closing Date and that the Merger is not completed.

Treatment of Ultima Rights

In connection with the Merger, the Ultima Board of Directors, on behalf of Ultima, resolved to accelerate the vesting of the Ultima Rights immediately prior to the record date of the Special Distribution so that Ultima Rights may be exercised prior to the payment of the Special Distribution. Subject to the pre-existing rights of certain executive officers of Ultima Co as set forth in their respective Ultima Employment Agreements, Ultima has agreed to use its reasonable commercial efforts to ensure that any Ultima Rights that are not exercised on or prior to the Effective Time are terminated or surrendered without the payment of any consideration therefor unless consented to by Petrofund, acting reasonably. In order to facilitate the exercise of Ultima Rights prior to the Effective Time, Ultima and Petrofund have agreed to implement such policies and procedures (including the lending of sufficient funds for an agreed upon limited period to the holders of Ultima Rights to allow for the exercise of the Ultima Rights by such holders prior to the Effective Time provided the person providing the funds required to exercise such Ultima Rights is granted sufficient security in exchange therefor) to allow for the due exercise of Ultima Rights on or prior to the record date of the Special Distribution.

Effect on Distributions

Distributions paid to Ultima Unitholders for the months of April and May 2004 will not be affected by the proposed Merger and will be paid in the usual manner. Therefore, Ultima Unitholders of record on April 30, 2004 and May 31, 2004 will receive their regular monthly cash distribution from Ultima on May 17, 2004 and June 15, 2004, respectively. Assuming the Merger becomes effective on June 16, 2004, Petrofund Unitholders of record on June 16, 2004, including former Ultima Unitholders, will receive a cash distribution from Petrofund on June 30, 2004, and will receive monthly distributions from Petrofund in a similar manner in the future. Former Ultima Unitholders who are Petrofund Unitholders of record on June 16, 2004 (and any subsequent record date for distributions to Petrofund Unitholders) will be entitled to receive distributions from Petrofund following the Closing Date of the Merger without any further action required on their part provided they have exchanged their certificates representing Ultima Units for Petrofund Units on or prior to the sixth anniversary of the Closing Date. See "Exchange of Ultima Certificates" below.

Exchange of Ultima Certificates

After the Closing Date, certificates formerly representing Ultima Units shall only represent the right to receive Petrofund Units which a former Ultima Unitholder is, except as set forth below, entitled to receive pursuant to the Merger.

A form of letter of transmittal (printed on yellow paper) containing instructions with respect to the surrender of certificates representing Ultima Units has been forwarded to registered Ultima Unitholders for use in exchanging their certificates. Upon surrender of properly completed letters of transmittal together with certificates representing Ultima Units to Computershare Trust Company of Canada, certificates for the appropriate number of Petrofund Units will be issued, subject to any withholdings as required by law.

No fractional Petrofund Units shall be issued to former Ultima Unitholders pursuant to the Merger. In the event that the Exchange Ratio would otherwise result in an Ultima Unitholder being entitled to a fractional Petrofund Unit, an adjustment will be made to the nearest whole number of Petrofund Units and a certificate representing the resulting whole number of Petrofund Units will be issued. In calculating such fractional interests, all Ultima Units held by a registered holder of Ultima Units immediately prior to the Closing Date shall be aggregated.

The Combination Agreement provides that any certificate representing Ultima Units that is not validly deposited with Computershare Trust Company of Canada within six years of the Closing Date shall cease to represent a claim or interest of any kind or nature in Petrofund, and the Petrofund Units to which the holder of such certificate would have otherwise been entitled shall be deemed to have been surrendered to Petrofund, together with all entitlements to distributions and interest thereon held for such holder.

DETAILS OF THE MERGER

On March 29, 2004, Ultima, Ultima Co, Petrofund and Petrofund Co, entered into the Combination Agreement whereby they agreed to combine the operations of Ultima and Petrofund. See "The Combination Agreement". The Merger will become effective on the Closing Date which is expected to be on or about June 16, 2004. The following procedural steps must occur in order for the Merger to become effective:

(a) the Merger must be approved by the Ultima Unitholders in the manner described below under "The Combination Agreement - Unitholder Approval";

(b) all conditions precedent to the Merger, as set forth below under "The Combination Agreement - Conditions of the Special Distribution and Merger", must be satisfied or waived by the appropriate party; and

(c) all agreements which are required in order to implement the Merger must be executed by the appropriate parties at Closing.

On the Closing Date, each of the events set out below shall occur and be deemed to occur immediately at the Effective Time in the sequence set out below:

1. the Ultima Trust Indenture and any other constating documents of the Ultima Parties will be amended to the extent necessary to facilitate the Merger;

2. Ultima will sell, transfer, convey, assign and deliver to Petrofund, and Petrofund will purchase and accept from Ultima, all of the Ultima Assets, as the same exist at the Effective Time;

3. Petrofund will (i) assume and become liable to pay, satisfy, discharge and observe, perform and fulfill the Assumed Liabilities, in accordance with their terms, and (ii) issue to Ultima an aggregate number of Petrofund Payment Units equal in number to the product of the number of Ultima Units outstanding as of the close of business on the day immediately prior to the Closing Date multiplied by the Exchange Ratio;

4. Petrofund will subscribe for the Ultima Remaining Unit for $10.00 and Ultima will issue to Petrofund the Ultima Remaining Unit;

5. the Ultima Units (other than the Ultima Remaining Unit) will be redeemed in exchange for the Petrofund Payment Units which shall be distributed to the Ultima Unitholders in accordance with the Exchange Ratio;

6. the directors of the Ultima Parties, where applicable, will resign in favour of the nominees for election as directors of Petrofund Co; and

7. all officers of the Ultima Parties, where applicable, will resign from their offices with such Ultima Parties.

No fractional Petrofund Units shall be issued to former Ultima Unitholders pursuant to the Merger and no distribution, dividend or other change in the structure of Petrofund shall relate to any such fractional security and such fractional interest shall not entitle the owner thereof to exercise any rights as a securityholder of Petrofund. In the event that the Merger would otherwise result in an Ultima Unitholder being entitled to a fractional Petrofund Unit, an adjustment will be made to the nearest whole number of Petrofund Units and a certificate representing the resulting whole number of Petrofund Units will be issued. In calculating such fractional interests, all Ultima Units held by a registered holder of Ultima Units immediately prior to the Effective Time will be aggregated.

Special Distribution and Unitholder Indemnity Agreement

In connection with the Merger and conditional on approval of the Ultima Special Resolution (i) Ultima will declare the Special Distribution payable to Ultima Unitholders of record on the business day immediately preceding the Closing Date, payable on the business day immediately preceding the Closing Date, and (ii) Ultima and Petrofund will execute the Unitholder Indemnity Agreement. The amount of the Special Distribution payable to each Ultima Unitholder will be equal to such unitholder's pro rata share, on the basis of their holdings of Ultima Units, of $10 million (expected to be approximately

$0.17 per Ultima Unit) and all rights Ultima Unitholders are entitled to under the Unitholder Indemnity Agreement. It is possible that the Special Distribution is approved by the Ultima Unitholders and paid by Ultima on the business day prior to the Closing Date and that the Merger is not completed.

The Combination Agreement

On March 29, 2004, Ultima, Ultima Co, Petrofund and Petrofund Co, entered into the Combination Agreement whereby they agreed to combine the operations of Ultima and Petrofund. The Combination Agreement sets forth a number of conditions to be satisfied or waived in order for the Special Distribution and Merger to become effective (see "Conditions of the Special Distribution and Merger") and provides the right of the parties thereto to terminate the Combination Agreement on the occurrence or non-occurrence of certain events within specific time frames (see "Termination"). The Combination Agreement also sets forth a number of covenants on behalf of the parties thereto, including prescribing the manner of operation of the business and operations of the parties and precluding the parties from entering into certain new agreements or commitments with respect to their capitalization or assets during the term of the Combination Agreement (see "Covenants").

Unitholder Approval

The Ultima Special Resolution must be approved by at least 66 2/3% of the votes cast by the Ultima Unitholders present in person or by proxy at the Meeting. In order for the Meeting to be duly constituted for the transaction of business, at least two Ultima Unitholders (represented in person or by proxy) must be present at the Meeting, representing not less than 5% of the outstanding Ultima Units entitled to vote at the Meeting.

Conditions of the Special Distribution and Merger

The obligations of the parties to the Combination Agreement to complete the Merger are subject to the fulfillment or waiver of a number of significant conditions which must be satisfied on or before the Closing Date or be waived to the extent they are capable of being waived by the party benefiting from such condition. There is no assurance that the conditions will be satisfied or waived on a timely basis, if

at all. The following is a summary of the material conditions other than those which have been satisfied as at the date hereof:

(a) the Ultima Special Resolution shall have been passed by the Ultima Unitholders at the Meeting by the level of approval set forth under "Unitholder Approval";

(b) the documents by which the Special Distribution and Merger are to be effected shall be in form and substance satisfactory to the parties, acting reasonably;

(c) all approvals and consents, regulatory or otherwise, including those summarized under "Regulatory and Third Party Approvals" shall have been obtained;

(d) Ultima shall have received an opinion of counsel to Petrofund, in form and substance satisfactory to Ultima, as to such matters as Ultima and Ultima Co, acting reasonably, may require, including with respect to the status of Petrofund as a "mutual fund trust" under Section 132 of the Tax Act, the application of the federal budget of March 23, 2004 to such status as a mutual fund trust and that the Petrofund Units to be distributed to Ultima Unitholders pursuant to the Merger will not constitute "foreign property" for the purposes of Part XI of the Tax Act;

(e) Petrofund shall have received an opinion of counsel to Ultima, in form and substance satisfactory to Petrofund, as to such matters as Petrofund, acting reasonably, may require;

(f) no act, action, suit or proceeding shall have been threatened or taken before or by any domestic or foreign court or tribunal or governmental entity or person in Canada or elsewhere, whether or not having the force of law, and no law, regulation or policy shall have been proposed, enacted, promulgated or applied which has the effect to cease trade or enjoin, prohibit or impose material limitations on the Special Distribution and Merger or which would have a Material Adverse Effect with respect to Petrofund or Ultima;

(g) there shall not exist any prohibition at law against Ultima making the Special Distribution or against Petrofund and Ultima completing the Merger;

(h) the representations, warranties and covenants of each of the parties to the Combination Agreement shall be true and correct or complied with, as applicable, in all material respects as of the Effective Time;

(i) all outstanding Ultima Rights shall have been exercised, terminated or surrendered for cancellation; and

(j) there shall not have occurred or arisen after March 29, 2004, any change (or any condition, event or development involving a prospective change) which involves a Material Adverse Effect with respect to either Ultima or Petrofund.

In the event that the Merger does not become effective on or before July 16, 2004, or such other date as Petrofund and Ultima may agree, Ultima or Petrofund may terminate its obligations under the Combination Agreement.

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Regulatory and Third Party Approvals

The Combination Agreement provides that receipt of all required regulatory and third party approvals is a condition precedent to the Special Distribution and Merger becoming effective, including:

(a) any rulings required under the securities regulatory authorities in Canada to permit the issuance of the Petrofund Payment Units on a prospectus and registration exempt basis to residents of the provinces of Canada and to permit such Petrofund Payment Units to be issued as freely tradable subject to restrictions imposed upon trades by control persons;

(b) a registration statement on Form F-10, which includes the Information Circular as a prospectus, and an appointment of agent for service of process and undertaking on Form F-X, each of which complies in all material respects with the requirements of the 1933 Act at the time it became effective and at the Closing Date, shall have been filed by Petrofund with the SEC and declared effective by the SEC under the 1933 Act, and no stop order suspending the effectiveness of the registration statement shall have been issued by the SEC and no proceeding for that purpose shall have been initiated by the SEC;

(c) the Commissioner or any person authorized to exercise the powers and perform the duties of the Commissioner shall have issued an advance ruling certificate under Section 102 of the Competition Act to the effect that he is satisfied that he would not have sufficient ground on which to apply to the Competition Tribunal under Section 92 of the Competition Act in respect of the Merger, or the appropriate time period specified in Section 123 of the Competition Act shall have expired and neither the Commissioner, nor the Competition Tribunal as authorized under the Competition Act shall have taken, or have indicated their intention to take, any action under such Act, whether before or after the completion of the Merger, which could have a materially adverse effect on the Merger;

(d) the Minister under the Investment Canada Act (Canada) is satisfied or deemed to be satisfied that the consummation of the Special Distribution and Merger are likely to be of net benefit to Canada;

(e) the Petrofund Units issuable pursuant to the Merger shall have been conditionally approved for listing on the TSX and the AMEX, subject to the filing of required documentation;

(f) the lenders to each of Ultima Co and Petrofund Co, to the extent required, shall have consented to the Special Distribution and Merger, or shall continue to make financing available to Ultima Co and Petrofund Co subsequent to the Special Distribution and Merger on conditions acceptable to Ultima Co and Petrofund Co, acting reasonably; and

(g) such other sanctions, rulings, consents, orders, exemptions, permits and other approvals as may be necessary for the Merger and the other transactions contemplated by the Combination Agreement to be effected in compliance with applicable laws.

Representations and Warranties

The Combination Agreement includes a number of representations and warranties on behalf of the Ultima Parties and the Petrofund Parties, including representations and warranties as to:

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(a) the existence of those entities, their power and authority to enter into the Combination Agreement, the due execution and delivery of the Combination Agreement and the enforceability of the Combination Agreement;

(b) the capitalization of the respective parties;

(c) the accuracy of certain financial statements of Ultima and

Petrofund;

(d) the absence of any Material Adverse Changes since specified dates in the business or affairs of the respective parties;

(e) the absence of any violation of governing documents and agreements to which the respective parties are subject; and

(f) various other matters intended to establish the condition of the respective parties in connection with the Special Distribution and Merger;

which representations and warranties are required to be true and correct at the Effective Time in all material respects.

Covenants

The Combination Agreement includes a number of covenants given by the Ultima Parties and the Petrofund Parties. The following is a summary of some of the material covenants:

(a) each of the Ultima Parties and the Petrofund Parties, prior to termination of the Combination Agreement, shall conduct its undertaking and businesses only in, and not take any action except in, the usual, ordinary and regular course of business and consistent with past practice except as necessary to comply with applicable laws or to complete the transactions contemplated by the Combination Agreement or any transactions entered into prior to the date of the Combination Agreement;

(b) each of Ultima and Petrofund have agreed to restrictions on certain interim operations including the issuance of securities, the sale of assets exceeding certain threshold amounts and the acquisition of assets exceeding certain threshold amounts;

(c) each of the Ultima Parties and Petrofund Parties shall use their reasonable best efforts to take, or cause to be taken, all appropriate action, and to do or cause to be done all things necessary, proper or advisable under applicable laws and regulations to consummate and give effect to the transactions contemplated by the Combination Agreement;

(d) within the prescribed time period and in the prescribed form provided for in section 132.2 of the Tax Act, Petrofund and Ultima shall jointly elect to have section 132.2 of the Tax Act apply with respect to the Merger; and

(e) if the Merger is completed, Petrofund has agreed to arrange for and/or maintain directors' and officers' insurance coverage for the directors and officers of Ultima's subsidiaries substantially equivalent in scope and coverage as the directors' and officers' coverage in place for the benefit of the directors and officers of Petrofund's subsidiaries on a "trailing" or "run-off" basis covering claims made prior to or within five years of the Closing Date.

Composition of Board of Directors of Petrofund Co

Pursuant to the Combination Agreement, Petrofund has agreed to use its reasonable commercial efforts such that, effective as at the Effective Time, the Petrofund Board of Directors shall be varied to be comprised of two members mutually agreed to by Ultima and Petrofund, acting reasonably, from among the individuals presently serving on the Ultima Board of Directors.

Acquisition Proposal and Take-Over Proposal

The Combination Agreement defines "Acquisition Proposal" to mean any take-over bid, tender offer or exchange offer, merger, amalgamation, plan of arrangement, reorganization, consolidation, business combination, reverse take-over, sale of material assets, issuance or sale of securities without the consent of the other party (other than, in the case of Ultima, pursuant to the exercise of securities outstanding on the date of execution of the Combination Agreement and, in the case of Petrofund, pursuant to the exercise of securities outstanding on the date of execution of the Combination Agreement and securities issuable pursuant to compensation arrangements of Petrofund to be considered at the Annual and Special Meeting of Petrofund Unitholders on April 14, 2004), re-capitalization, liquidation, dissolution, winding-up or similar transaction, other than the Merger and the other transactions contemplated by the Combination Agreement.

The Combination Agreement defines "Take-Over Proposal" to mean a bid, proposal or offer, whether or not subject to conditions, to acquire in any manner, directly or indirectly, beneficial ownership or control or direction over 20% or more of the outstanding Ultima Units or Petrofund Units, as the case may be, whether by way of an arrangement, amalgamation, merger, consolidation, recapitalization, liquidation, dissolution, reorganization or similar transaction or other business combination involving Ultima or Petrofund or any of their respective subsidiaries, as the case may be (and whether in a single or multi-step transaction or a series of related transactions) or any proposal, offer or agreement to acquire 20% or more of the assets of Ultima or its subsidiaries (taken as a whole) or Petrofund or its subsidiaries (taken as a whole) as the case may be.

Cease Negotiations

Pursuant to the Combination Agreement and subject to the matters set forth under "Non-Solicitation", each of Ultima and Ultima Co and Petrofund and Petrofund Co have agreed to, and to direct and use reasonable efforts to cause their respective trustees, directors, officers, employees, representatives and agents to, immediately cease and cause to be terminated any discussions or negotiations with any person, other than the Ultima Parties and the Petrofund Parties, as the case may be, with respect to any actual, future or potential Acquisition Proposal. The parties to the Combination Agreement have also agreed not to release any third party from or forebear in the enforcement of any confidentiality or standstill agreement to which the Ultima Parties or the Petrofund Parties and any such third party is a party.

Non-Solicitation

The Combination Agreement also provides that Ultima and Ultima Co and Petrofund and Petrofund Co shall not, directly or indirectly, through any trustee, officer, director, employee, financial advisor or other representative or agent of the Ultima Parties or the Petrofund Parties, as the case may be, (i) solicit, initiate or encourage (including by way of furnishing information or entering into any form of agreement, arrangement or understanding) any inquiries or proposals regarding any Acquisition Proposal involving it or its subsidiaries or unitholders or participate in or take any other action to facilitate any inquiries or the making of any proposal which constitutes or may reasonably be expected to lead to such an Acquisition Proposal, or (ii) provide any confidential information to, participate in any discussions or negotiations relating to any such transactions with, or otherwise cooperate with or assist or participate in any effort to take such action by, any person; provided that nothing shall prevent the Ultima Board of Directors or the Petrofund Board of Directors, as the case may be, from responding or acting in any manner (including considering, negotiating, approving and recommending to their respective unitholders (provided that prior to furnishing information or entering into negotiations with any person, Ultima and Ultima Co or Petrofund and Petrofund Co, as applicable, shall have complied with the matters set forth under "Notice of Request for Information", prior to providing any non-public information to any such person, Ultima and Ultima Co or Petrofund and Petrofund Co, as applicable, shall have complied with the matters set forth under "Provision of Information to Requesting Party" and prior to entering into any Proposed Agreement, Ultima and Ultima Co. shall have complied with the matters set forth under "Right to Match")) to an unsolicited bona fide written Acquisition Proposal (i) in respect of which any funds or other consideration necessary for such Acquisition Proposal has been demonstrated to the satisfaction of the Ultima Board of Directors or the Petrofund Board of Directors, as the case may be, to be reasonably likely to be obtained, and (ii) in respect of which the Ultima Board of Directors or the Petrofund Board of Directors, as the case may be, determines in good faith would, if consummated in accordance with its terms, result in a transaction financially more favourable to Ultima or the Ultima Unitholders or a transaction financially more favourable to Petrofund or the Petrofund Unitholders, as the case may be, than the transactions contemplated by the Combination Agreement (any such Acquisition Proposal being referred to herein as a "Superior Proposal"). Any good faith determination as aforesaid shall only be made by duly passed resolutions of the Ultima Board of Directors or the Petrofund Board of Directors, as the case may be, after consultation with its financial advisors and receipt by such Board of the advice of counsel reflected in the minutes of its board of directors to the effect that entertaining or negotiating such Acquisition Proposal or the furnishing of information concerning the Ultima Parties or the Petrofund Parties, as applicable, is necessary for such board to satisfy its fiduciary duties under applicable laws.

Notice of Request for Information

Prior to furnishing any information to, or entering into any negotiations with, any person in respect of an Acquisition Proposal, each of Ultima and Ultima Co and Petrofund and Petrofund Co, as the case may be, shall notify the other party of any Acquisition Proposal received by it or any request received by it following March 29, 2004 for non-public information relating to the Ultima Parties or the Petrofund Parties in connection with an Acquisition Proposal or for access to the properties, books or records of the Ultima Parties or the Petrofund Parties by any person that informs the Ultima Parties or the Petrofund Parties that it is considering making, or has made, an Acquisition Proposal. Such notice shall be made, from time to time, orally and in writing and shall indicate such details of the proposal, inquiry or contact known to the Ultima Parties or the Petrofund Parties as the other party may reasonably request, having regard to the fiduciary obligations of the Ultima Board of Directors or the Petrofund Board of Directors, as the case may be, and the identity of the person making such proposal, inquiry or contact.

Provision of Information to Requesting Party

Subject to the matters set forth under "Non-Solicitation", if any of the Ultima Parties or the Petrofund Parties receives a request for material non-public information from a person who proposes to the Ultima Parties or the Petrofund Parties a bona fide Acquisition Proposal and the Ultima Board of Directors or the Petrofund Board of Directors, as the case may be, determines that such proposal is a Superior Proposal pursuant to the matters set forth under "Non-Solicitation", the Ultima Party or the Petrofund Party, as the case may be, may, subject to the execution of a confidentiality agreement containing customary terms, conditions and restrictions substantially similar to the confidentiality agreement entered into between Ultima and Petrofund, provide such person with access to information regarding the Ultima Party or the Petrofund Party, as the case may be. To the extent not previously done,

the party receiving the request from a third party shall provide to the other party a copy of all information provided to the third party forthwith after the information is provided to the third party.

Right to Match

Ultima and Ultima Co have agreed not to enter into any agreement (other than any confidentiality agreement contemplated under "Provision of Information to Requesting Party") to propose, pursue, support or recommend any Acquisition Proposal (a "Proposed Agreement") or change their recommendation of the transactions contemplated by the Combination Agreement except in compliance with the Combination Agreement and only after providing Petrofund with an opportunity to amend the Combination Agreement to provide for at least equivalent financial terms to those included in the Proposed Agreement as determined by the Ultima Board of Directors, acting reasonably and in good faith and in accordance with its fiduciary duties, after consultation with Ultima's financial advisors and Ultima and Ultima Co have agreed to negotiate in good faith with Petrofund in respect of any such amendment. In particular, in such circumstance Ultima Co has agreed to provide Petrofund Co with a copy of any Proposed Agreement as executed or submitted by the party making such Acquisition Proposal, not less than two business days prior to its proposed execution. In the event that Petrofund and Petrofund Co agree to amend the Combination Agreement as provided above and within the two business day period, neither Ultima nor Ultima Co shall enter into the Proposed Agreement.

Termination Fees

The Combination Agreement provides that if at any time after the execution of the Combination Agreement and prior to the termination thereof:

(a) the Ultima Board of Directors or the Petrofund Board of Directors (in such case the Ultima Parties or the Petrofund Parties, respectively, being the "Non-Completing Party") has withdrawn, changed or modified in a manner adverse to the other party, or failed to reaffirm upon request (other than as a result of and in direct response to a material breach by the other party of their obligations under the Combination Agreement that would or reasonably could result in the non-satisfaction of the conditions precedent to the closing of the transactions contemplated by the Combination Agreement or a material misrepresentation by the other party or a Material Adverse Change to the other party) any of (i) its determination or its recommendations to Ultima Unitholders or Petrofund Unitholders, as the case may be, to vote in favour of the Special Distribution and/or the Merger, as applicable, or (ii) its authorization to complete the Merger as contemplated by its representation and warranties in the Combination Agreement, or resolved to take any of the foregoing actions prior to the completion of the Merger; or

(b) the Ultima Board of Directors or the Petrofund Board of Directors (in such case the Ultima Parties or the Petrofund Parties, respectively, being the "Non-Completing Party") has recommended that, in the case of the Ultima Board of Directors, the Ultima Unitholders deposit their Ultima Units under, vote in favour of, or otherwise accept a Take-Over Proposal and, in the case of the Petrofund Board of Directors, the Petrofund Unitholders deposit their Petrofund Units under, vote in favour of, or otherwise accept a Take-Over Proposal; or

(c) prior to the date of the Meeting, a bona fide Take-Over Proposal is publicly announced, proposed, offered or made to any of the Ultima Parties or the Petrofund Parties (in such case the Ultima Parties or the Petrofund Parties, respectively, being the "Non-Completing Party") or their respective unitholders, the Merger is not completed and the

transactions contemplated by any Take-Over Proposal is completed within 180 days of July 16, 2004; or

(d) any of the Ultima Parties enters into a Proposed Agreement or any of the Petrofund Parties enters into any agreement to propose, pursue, support or recommend any Take-Over Proposal (other than a confidentiality agreement contemplated under "Provision of Information to Requesting Party") (in such case the Ultima Parties or the Petrofund Parties, respectively being the "Non-Completing Party"); or

(e) any of the Ultima Parties or the Petrofund Parties (in such case the Ultima Parties or the Petrofund Parties, respectively, being the "Non-Completing Party") breaches any of its representations or warranties or covenants contained in the Combination Agreement which breach individually or in the aggregate would or would reasonably be expected to have a Material Adverse Effect upon the Non-Completing Party, or would materially impede completion of the transactions contemplated by the Combination Agreement, and which the Non-Completing Party fails to cure within five business days after receipt of written notice thereof from the other party (except that no cure period shall be provided for a breach by a Non-Completing Party which by its nature cannot be cured and in no event shall any cure period extend beyond the Effective Time);

then if the Ultima Parties are the Non-Completing Party, Ultima shall pay to Petrofund, or if the Petrofund Parties are the Non-Completing Party, Petrofund shall pay to Ultima, within three business days, an aggregate of $10 million as liquidated damages in immediately available funds.

Notwithstanding the foregoing, in the event there is a breach in a representation or warranty or covenant as contemplated in (e) above, and whether or not the $10 million termination fee is also payable pursuant to any of (a) through (d) above, the party (not being the Non-Completing Party) shall have the right at its sole option to either be paid the $10 million termination fee as liquidated damages or to be paid $1 million and retain the right to pursue any rights or remedies available to such party as a result of any breach of the Combination Agreement.

Termination

The Combination Agreement may be terminated prior to the completion of the Merger:

(a) by mutual written consent of the parties to the Combination Agreement;

(b) by Ultima and Ultima Co or Petrofund and Petrofund Co if the closing date of the Merger shall not have occurred on or before July 16, 2004;

(c) by Ultima and Ultima Co or Petrofund and Petrofund Co if certain conditions to the Special Distribution and Merger (including those described above under (a), (b), (c), (f) and (g) under "Conditions of the Special Distribution and Merger") have not been satisfied or waived on or before the date required for the performance thereof unless the failure of any such condition shall be due to the failure of the party seeking to terminate the Combination Agreement to perform the obligations required to be performed by it under the Combination Agreement;

(d) by Ultima and Ultima Co or Petrofund and Petrofund Co if any of the conditions (other than those described under (c) above) which are for the benefit of such parties and which

are contained in the Combination Agreement have not been satisfied or waived on or before the date required for the performance thereof; or

(e) by any of Ultima and Ultima Co or Petrofund and Petrofund Co, as the case may be, if the other party becomes a Non-Completing Party (as defined under "Termination Fees").

FAIRNESS OPINION

The following summary of the Fairness Opinion is qualified in its entirety by reference to the full text of the Fairness Opinion, which is attached and contained herein in Appendix "E" - Fairness Opinion of CIBC World Markets Inc. Ultima Unitholders are urged to read the Fairness Opinion in its entirety.

CIBC World Markets was retained by the Ultima Board of Directors, on its behalf and on behalf of Ultima, effective January 19, 2004 as financial advisor in connection with the Ultima Board of Directors' consideration and evaluation of a number of potential strategic transactions involving Ultima. As discussions and negotiations between Ultima and Petrofund progressed, CIBC World Markets was, among other things, requested to consider the Special Distribution and Merger and related matters and make such recommendations relating to financial matters as it considered appropriate, including the preparation and delivery to the Ultima Board of Directors of the Fairness Opinion.

In preparing the Fairness Opinion, CIBC World Markets has assumed and relied on the accuracy and completeness of all information supplied or otherwise made available to CIBC World Markets, discussed with or reviewed by or for CIBC World Markets, or publicly available, and CIBC World Markets has not assumed any responsibility for independently verifying such information nor undertaken an independent formal valuation or appraisal of any of the Ultima Parties or the Petrofund Parties or their assets or securities or been furnished with any such formal valuation or appraisal. The Fairness Opinion is based upon securities market, economic and general business and financial conditions as they existed on, and on the information made available to CIBC World Markets as of, April 30, 2004.

Based upon the assumptions and its review of the information described in the Fairness Opinion, and subject to the limitations contained in the Fairness Opinion, it is the opinion of CIBC World Markets that the consideration to be received by Ultima Unitholders pursuant to the Special Distribution and Merger is fair, from a financial point of view, to the Ultima Unitholders. The Fairness Opinion was prepared at the request of and for the information of the Ultima Board of Directors and does not constitute a recommendation to any Ultima Unitholder as to how any such unitholder should vote with respect to the Merger.

CIBC World Markets will receive fees for its services in connection with the Merger, some of which are contingent upon the consummation of the Merger. In addition, Ultima has agreed to reimburse CIBC World Markets for its reasonable expenses incurred in performance of such services and to indemnify it in respect of certain liabilities as may be incurred by it in connection with its engagement.

INTERESTS OF INSIDERS IN THE MERGER AND INTENTIONS OF CERTAIN INSIDERS

Members of the Ultima Board of Directors and senior officers of Ultima Co, who collectively own, directly or indirectly, or exercise control or direction over, an aggregate of 535,921 Ultima Units, representing approximately 1.0% of the Ultima Units outstanding on April 19, 2004, have indicated their intention to vote their Ultima Units in favour of the Ultima Special Resolution approving the Special

Distribution and Merger and have entered into Support Agreements with Petrofund agreeing to vote their Ultima Units in favour of the Ultima Special Resolution.

Neither the Manager, nor any person who has been a director or senior officer of Ultima Co, AcquireCo or the Manager at any time since January 1, 2003, the beginning of the most recently completed financial year of Ultima, nor any proposed nominee for election as a director, nor any associate or affiliate of any one of them, has any material interest, direct or indirect, by way of beneficial ownership of securities or otherwise, in any matter to be acted on at the Meeting except as disclosed in this Information Circular.

CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Bennett Jones LLP ("counsel"), the following summary describes the principal Canadian federal income tax considerations pursuant to the Tax Act generally applicable to an Ultima Unitholder who is entitled to receive a proportionate amount of the Special Distribution and acquires Petrofund Units pursuant to the Merger and who, for purposes of the Tax Act, holds the Ultima Units disposed of and the Petrofund Units acquired as capital property and deals at arm's length with each of Ultima and Petrofund. Generally, the Ultima Units or Petrofund Units, as the case may be, will be considered to be capital property to an Ultima Unitholder provided such Ultima Unitholder does not hold such Ultima Units in the course of carrying on a business and has not acquired them in one or more transactions considered to be an adventure or concern in the nature of trade. Certain Ultima Unitholders who are resident in Canada and who might not otherwise be considered to hold their Ultima Units or Petrofund Units as capital property may, in certain circumstances, be entitled to have them treated as capital property by making the irrevocable election permitted by subsection 39(4) of the Tax Act. This summary is not applicable to an Ultima Unitholder that is a "financial institution", as defined in the Tax Act, for purposes of the mark-to-market rules or an interest in which would be a "tax shelter investment" as defined in the Tax Act. Any such Ultima Unitholder should consult its own tax advisor with respect to the Merger.

This summary is based upon the provisions of the Tax Act in force as of the date hereof, all specific proposals to amend the Tax Act that have been publicly announced by or on behalf of the Minister of Finance (Canada) prior to the date hereof (the "Proposed Amendments") including the March 23, 2004 Canadian federal budget (the "budget"), counsel's understanding of the current published administrative and assessing policies of the Canada Revenue Agency (the "CRA") and representations of Ultima and Petrofund as to certain factual matters.

This summary is not exhaustive of all possible Canadian federal income tax considerations and, except for the Proposed Amendments and the budget, does not take into account any changes in the law, whether by legislative, regulatory or judicial action, nor does it take into account provincial, territorial or foreign tax considerations, which may differ significantly from those discussed herein.

This summary is of a general nature only and is not intended to be legal or tax advice to any particular Ultima Unitholder. Consequently, Ultima Unitholders should consult their own tax advisors having regard to their own particular circumstances.

Special Distribution

On the last business day immediately prior to the Closing Date of the Merger, Ultima Unitholders of record will, subject to approving the Ultima Special Resolution, receive the Special Distribution consisting of an aggregate cash payment of $10 million and the rights under the Unitholder Indemnity Agreement which management of Ultima believes has a nominal value. For the purposes of the Tax Act,

the Special Distribution will be treated like all other Ultima distributions and is not conditional on the closing of the Merger.

An Ultima Unitholder resident in Canada for the purposes of the Tax Act (other than an Exempt Plan) will be required to include in income such proportionate share of the Special Distribution which represents a distribution of Ultima's income to the Ultima Unitholder in the taxation year in which the Special Distribution is paid. Exempt Plans will not generally be liable for any tax with respect to the Special Distribution. The proportionate share of the Special Distribution distributed to an Ultima Unitholder in excess of such Unitholder's share of Ultima's income will generally not be included in the Ultima Unitholder's income but will reduce the adjusted cost base of the Ultima Units held by the Ultima Unitholder. To the extent that the adjusted cost base of Ultima Units would be less than nil, an Ultima Unitholder will be deemed to have realized a capital gain equal to such negative amount. The taxation of capital gains is discussed below under "Taxation of Unitholders who are Residents of Canada".

An Ultima Unitholder who is not resident, or deemed to be resident, in Canada, will be subject to a 25% Canadian withholding tax on the proportionate share of Ultima's income which is distributed pursuant to the Special Distribution at the time the Special Distribution is paid unless such rate is reduced under the provisions of a tax treaty between Canada and the Ultima Unitholder's jurisdiction of residence. For example, an Ultima Unitholder resident in the United States for purposes of the Canada-United States Income Tax Convention, 1980 (the "Canada-U.S. Treaty") will be entitled to have the rate of withholding reduced to 15% of the amount of any income distributed. The proposals under the budget to apply a new 15% Canadian withholding tax on the non-taxable portion of a distribution should not apply to any non-taxable portion of the Special Distribution.

The Merger

The Merger will be structured as a "qualifying exchange" pursuant to section 132.2 of the Tax Act. Accordingly, the disposition by Ultima Unitholders of Ultima Units in exchange for Petrofund Units pursuant to the terms of the Merger will not result in a capital gain or capital loss to Ultima Unitholders. The year end of each of Petrofund and Ultima will be deemed to end in the course of the Merger and any income of Petrofund or Ultima for such year will be paid or payable to their respective Unitholders in accordance with the terms of their respective trust indentures. Ultima and Petrofund have advised counsel that they will file an election with the CRA in respect of the Merger with the result that no taxable income will arise in Ultima as a result of the Merger. The aggregate initial cost of Petrofund Units received by each Ultima Unitholder in exchange for Ultima Units pursuant to the Merger will be equal to the aggregate adjusted cost base to such holder of the Ultima Units which are cancelled on the Merger. This cost will be averaged with the cost of all other Petrofund Units held by Ultima Unitholders to determine the adjusted cost base of each Petrofund Unit held.

Status of Combined Trust

Counsel has been advised that Ultima and Petrofund each qualify as a "unit trust" and a "mutual fund trust" as defined by the Tax Act at all relevant times. The trust remaining after the Merger will be Petrofund (referred to hereinafter on or after the Merger as the "Combined Trust") and this summary assumes that the Combined Trust will also qualify as a mutual fund trust on the date of the Merger, and will continue to so qualify thereafter for the duration of its existence. In order to so qualify, there must be at least 150 unitholders of the Combined Trust ("Unitholders") each of whom owns not less than one "block" of units of the Combined Trust ("Units") having an aggregate fair market value of not less than $500. A "block" of Units means 100 Units if the fair market value of one Unit is less than $25 and 25 Units if the fair market value of one Unit is greater than $25 and less than $100. In order to qualify as a mutual fund trust, the Combined Trust cannot, and may not at any time, reasonably be considered to be

established or maintained primarily for the benefit of non-resident persons unless at all times since February 21, 1990, all or substantially all of its property has consisted of property other than "taxable Canadian property" (as defined in the Tax Act) (the "property exception"). In addition, the undertaking of the Combined Trust must be restricted to the investing of its funds in property (other than real property or an interest in real property), the acquiring, holding, maintaining, improving, leasing or managing of any real property (or interest in real property) that is capital property of the Combined Trust, or a combination of these activities.

Subject to certain transitional relief available until December 31, 2006, the budget proposes that Canadian resource property (which includes the Ultima Royalties and the Petrofund Royalty) be considered taxable Canadian property for the purposes of the property exception after March 22, 2004. The transitional relief contained in the budget is available to those trusts that on March 23, 2004 (i) were maintained primarily for the benefit of non-resident persons and (ii) satisfied the property exception. Counsel has been advised by Petrofund Co that Petrofund satisfied the forgoing requirements on March 23, 2004 and is entitled to rely on the transitional relief contained in the budget. Accordingly, subsequent to the Merger, the Combined Trust will have until December 31, 2006 to ensure that it is not maintained primarily for the benefit of non-resident persons. If the Combined Trust is maintained primarily for the benefit of non-resident persons on or after January 1, 2007, the Combined Trust would permanently lose its status as a mutual fund trust.

It is intended, and this summary assumes, that all the forgoing requirements, including the transitional relief set out in the budget, will be satisfied so that Ultima, Petrofund and the Combined Trust will each qualify as a mutual fund trust at all relevant times. In the event that Ultima, Petrofund or the Combined Trust were not to qualify as a mutual fund trust at the relevant times, the income tax considerations would in some respects be materially different from those described herein.

The budget proposes to restrict direct and indirect holdings by registered pension plans and tax exempt registered pension plan corporations (together referred to as "pension funds") in certain "business income trusts" after 2004 through the imposition of certain taxes which are similar to the tax on foreign property held by pension plans. A "business income trust" does not include certain "exempt trusts" which includes most real estate investment trusts and royalty trusts. It is expected that the Combined Trust will be an exempt trust and that these proposed amendments contained in the budget should not apply to pension funds investing in units of the Combined Trust.

Taxation of the Combined Trust

The Combined Trust is subject to taxation in each taxation year on its income for the year, including net realized taxable capital gains, less the portion thereof that is paid or payable in the year to its Unitholders and which is deducted by the Combined Trust in computing its income for purposes of the Tax Act. An amount will be considered to be payable to a Unitholder in a taxation year if it is paid in the year by the Combined Trust or the Unitholder is entitled in that year to enforce payment of the amount. Losses incurred by the Combined Trust cannot be allocated to Unitholders but may be deducted by the Combined Trust in future years in accordance with the Tax Act. The taxation year of the Combined Trust is the calendar year.

The Combined Trust will be required to include in its income amounts computed in accordance with the Ultima Royalties and the Petrofund Royalty held by the Combined Trust on an accrual basis. The Combined Trust will also be required to include in its income interest on its investments that accrues to the Combined Trust to the end of the year, or becomes receivable or is received by the Combined Trust before the end of the year, except to the extent that such interest was included in computing its income for a preceding taxation year, and any dividends received or deemed to be received on shares owned by the Combined Trust. Provided that appropriate designations are made by the Combined Trust, all dividends which would otherwise be included in its income as dividends received on shares held by the Combined Trust will be deemed to have been received by Unitholders and not to have been received by the Combined Trust.

Generally, the Combined Trust may deduct, in computing its income from all sources for a taxation year, an amount not exceeding 10% of its cumulative Canadian oil and gas property expense ("COGPE") account at the end of that year, on a declining balance basis, pro-rated for short taxation years. In addition to annual deductions in respect of its cumulative COGPE account, the Combined Trust will be entitled to deduct in computing its income on an annual basis reasonable administrative expenses incurred for the purpose of earning income from the Ultima Royalties, the Petrofund Royalty and its other investments, 20% of the total costs related to the issuance of Petrofund Units on the Merger and on the issuance of Petrofund Units on prior offerings (pro-rated for short taxation years) to the extent such issue expenses were not deductible in a previous taxation year and amounts in respect of a resource allowance and/or deductible Crown charges computed in accordance with the rules contained in the Tax Act.

The terms of the Combined Trust's trust indenture generally provide that all income of the Combined Trust for each taxation year be paid or be made payable to its Unitholders in the taxation year. Counsel has been advised that the Combined Trust intends to deduct the amount of its income paid or payable to its Unitholders in computing its income for each taxation year and, therefore, the Combined Trust should not be liable for any material income tax for each taxation year.

Taxation of Unitholders who are Residents of Canada

A Unitholder will generally be required to include in computing income for a particular taxation year of such Unitholder the portion of the net income of the Combined Trust for a taxation year, including taxable dividends and net realized taxable capital gains determined for the purposes of the Tax Act, that is paid or becomes payable to such Unitholder in that particular taxation year whether paid in cash or property of the Combined Trust. An amount will be considered payable to a Unitholder in a taxation year if such Unitholder is entitled in the year to enforce payment of the amount. For the purposes of the Tax Act, income of a Unitholder from the Combined Trust Units will generally be considered to be income from property and not resource income. Any deduction or loss of the Combined Trust for purposes of the Tax Act cannot be allocated to, or treated as a deduction or loss, of a Unitholder.

Provided that appropriate designations are made by the Combined Trust, such portions of its net taxable capital gains and taxable dividends as are paid or payable to a Unitholder will effectively retain their character as taxable capital gains and taxable dividends, respectively, and shall be treated as such in the hands of the Unitholder for purposes of the Tax Act. Such dividends will be subject, among other things, to the gross-up and dividend tax credit provisions in respect of Unitholders who are individuals, the refundable tax under Part IV of the Tax Act in respect of certain Unitholders who are corporations, and the deduction in computing taxable income in respect of dividends received by taxable Canadian corporations for Unitholders who are corporations.

Any amount paid or payable by the Combined Trust to a Unitholder in excess of the net income of the Combined Trust that is paid or payable to such Unitholder in a taxation year should not generally be included in such

Unitholder's income for the year. However, the proportionate amount of such excess will reduce the adjusted cost base of each Unit held by the Unitholder. To the extent that the adjusted cost base of a Unit to a Unitholder would otherwise be less than nil, the negative amount will be deemed to be a capital gain realized by the Unitholder from the disposition of the Unit in the year in which the negative amount arises.

Upon the disposition or deemed disposition of a Unit by a Unitholder, whether on redemption or otherwise, the Unitholder will generally realize a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition (excluding any amount payable by the Combined Trust which represents an amount that must otherwise be included in income) are greater (or less) than the aggregate of the Unitholder's adjusted cost base of the Unit and any reasonable costs of the disposition. Where, in accordance with the trust indenture of the Combined Trust, a Unitholder redeems Units and notes held by the Combined Trust (the "notes") are distributed or debt securities are issued by the Combined Trust (the "Repurchase Notes"), as the case may be, in satisfaction of the aggregate redemption price, the proceeds of disposition to the Unitholder will generally be equal to the fair market value of the notes distributed or the Repurchase Notes so issued, as the case may be.

One-half of any capital gain realized by a Unitholder on a disposition or deemed disposition of Units, and the amount of any net taxable capital gains designated by the Combined Trust in respect of the Unitholder, will be included in the Unitholder's income under the Tax Act in the year of disposition or designation, as the case may be, as a taxable capital gain. One-half of any capital loss (an "allowable capital loss") realized by a Unitholder upon a disposition of Units may be deducted against any taxable capital gains realized by the Unitholder in the year of disposition, in any of the three preceding taxation years or in any subsequent taxation year, to the extent and under the circumstances described in the Tax Act.

The cost of any note distributed by the Combined Trust to a Unitholder or Repurchase Note issued to a Unitholder by the Combined Trust upon a redemption of Units will generally be equal to the fair market value of the note or Repurchase Note, as the case may be, at the time of distribution or issuance, respectively, less any accrued interest thereon. Such a Unitholder will be required to include in income interest paid or accrued on the note or Repurchase Note, as the case may be, in accordance with the provisions of the Tax Act. To the extent that a Unitholder is required to include in income any interest that had accrued to the date of the acquisition of the note, an offsetting deduction may be available. For purposes of computing the adjusted cost base to a holder of notes or Repurchase Notes, the respective costs must be averaged with the adjusted cost base to the holder of all notes or Repurchase Notes, as the case may be, held at that time by the holder as capital property. Unitholders who receive a note or a Repurchase Note should consult their own tax advisors, having regard to their own particular circumstances.

Taxable capital gains realized by a Unitholder that is an individual may give rise to alternative minimum tax depending on such Unitholder's circumstances. A Unitholder that is a "Canadian-controlled private corporation" as defined in the Tax Act may be liable to pay additional refundable tax on certain investment income, including taxable capital gains, but excluding certain income distributed from the Combined Trust which is deemed to be income from property.

Taxation of Tax Exempt Unitholders

Subject to the specific provisions of any particular plan, the Units will be qualified investments for Exempt Plans. Such Exempt Plans will generally not be liable for tax in respect of any distributions received from the Combined Trust or any capital gain realized on the disposition of any Units of the Combined Trust.

Exempt Plans should contact their own tax advisors with regard to the acquisition of notes or Repurchase Notes on the redemption of Units to determine whether such indebtedness constitutes a qualified investment for such Exempt Plan, having regard to their own particular circumstances. Certain negative tax consequences may arise where an Exempt Plan acquires or holds a non-qualified investment.

The manager to the Combined Trust has advised counsel that, at all relevant times, the cost amount of foreign property of the Combined Trust, if any, was, or will be, less than 30% of the cost amount of all property of the Combined Trust and, accordingly, the Units will not constitute foreign property for registered retirement savings plans, registered retirement income funds, deferred profit sharing plans, registered pension plans or other persons subject to tax under Part XI of the Tax Act.

Taxation of Unitholders who are Non-Residents of Canada

Where the Combined Trust makes distributions to a Unitholder who is not resident in Canada for purposes of the Tax Act, the same general considerations as those discussed above with respect to a Unitholder who is resident in Canada will apply, except that any distribution of income of the Combined Trust to a Unitholder not resident in Canada will be subject to Canadian withholding tax at the rate of 25% unless such rate is reduced under the provisions of a tax treaty between Canada and the Unitholder's jurisdiction of residence. For example, Unitholders resident in the United States for purposes of the Canada-U.S. Treaty will generally be entitled to have the rate of withholding reduced to 15% of the amount of any income distributed.

The budget proposes a new 15% Canadian withholding tax on the non-taxable portion of the Combined Trust's distributions, which, under the current provisions of the Tax Act, are not subject to any Canadian withholding tax. The budget proposes that the new 15% Canadian withholding tax be applicable to distributions made by the Combined Trust after 2004. The new 15% Canadian withholding tax will only apply if, at the time of the distribution, Units of the Combined Trust are listed on a prescribed stock exchange (which includes the TSX) and the value of the Combined Trust's Units is primarily attributable to real property situated in Canada, Canadian resource property (which includes the Ultima Royalties and the Petrofund Royalty) or a timber resource property. If a subsequent disposition of a Unit results in a capital loss to a non-resident Unitholder, a refund of the new 15% Canadian withholding tax is available in limited circumstances, subject to the filing of a special Canadian tax return.

The budget also proposes a 25% withholding tax on distributions made to non-residents of Canada which are attributable to capital gains realized by the Combined Trust after March 22, 2004 on the disposition of taxable Canadian property where the Combined Trust has made certain designations on such capital gains with respect to its Unitholders. The 25% rate of Canadian withholding tax may be reduced pursuant to the terms of an applicable income tax treaty between Canada and the Unitholder's jurisdiction of residence.

A disposition or deemed disposition of Units of the Combined Trust, whether on redemption, by virtue of capital distributions in excess of a Unitholder's adjusted cost base or otherwise, will not give rise to any capital gains subject to tax under the Tax Act to a Unitholder who is not resident nor deemed to be a resident in Canada provided that the Units of the Combined Trust held by the Unitholder are not "taxable Canadian property" for the purposes of the Tax Act. Units of the Combined Trust will not constitute taxable Canadian property to a non-resident Unitholder unless: (i) the Unitholder holds or uses, or is deemed to hold or use the Units in the course of carrying on business in Canada; (ii) the Units are "designated insurance property" of the Unitholder as defined for purposes of the Tax Act; (iii) at any time during the period of five years immediately preceding the disposition of the Units the Unitholder or persons with whom the Unitholder did not deal at arm's length or any combination thereof, held more than 25% of the issued Units of the Combined Trust or, either alone or together persons with whom the Unitholder did not deal at arm's length, held options or rights to acquire more than 25% of the issued Units of the Combined Trust; or (iv), the Combined Trust is not a mutual fund trust on the date of disposition.

Subject to proposals to amend the Tax Act contained in the budget, a Unitholder who is not resident in Canada will generally compute the adjusted cost base of a Unit pursuant to the same rules as apply to residents of Canada. For the purposes of computing a non-resident Unitholder's adjusted cost base of a Unit after 2004, the budget proposes that a distribution paid in respect of a Unit which is subject to the new 15% Canadian withholding tax will not reduce the adjusted cost base of such Unit to a non-resident Unitholder.

Non-resident Unitholders are urged to consult their own tax advisors on the application of the budget to the ownership of Units of the Combined Trust, having regard to their own particular circumstances.

UNITED STATES FEDERAL INCOME TAX CONSIDERATIONS

The following summary describes the U.S. federal income tax considerations generally applicable to U.S. Holders (as defined below) of Ultima Units who receive a proportionate amount of the Special Distribution and who exchange their Ultima Units for Petrofund Units in the Merger. This summary is based upon the Internal Revenue Code of 1986, as amended (the "Code"), proposed, temporary and final U.S. Treasury regulations under the Code, administrative rulings and judicial decisions, all as in effect as of the date of this document and all of which are subject to change (possibly with retroactive effect) or to differing interpretations. This summary applies only to holders of Ultima Units that hold their Ultima Units, and will hold the Petrofund Units that they receive in the Merger, as capital assets within the meaning of Section 1221 of the Code. This summary does not discuss all aspects of U.S. federal income taxation that may be relevant to a particular holder of Ultima Units in light of its particular circumstances or to holders of Ultima Units subject to special treatment under the U.S. federal income tax laws, including:

- banks, insurance companies, trusts and financial institutions;
- tax-exempt organizations;
- mutual funds;
- persons that have a functional currency other than the U.S. dollar;

- traders in securities who elect to apply a mark-to-market method of accounting;
- dealers in securities or foreign currency;
- holders of Ultima Units who received their units in compensatory transactions; and
- holders of Ultima Units who hold their units as part of a hedge, straddle, constructive sale, conversion transaction or other integrated investment

For purposes of this summary, a U.S. Holder is:

- an individual who is a U.S. citizen or resident alien for U.S. federal income tax purposes;
- a corporation, or entity taxable as a corporation, created or organized under the laws of the United States, any state thereof, or the District of Columbia;
- an estate that is subject to U.S. federal income tax on its worldwide income; or

- a trust if (i) a U.S. court is able to exercise supervision over the administration of the trust and one or more U.S. persons have the authority to control all substantial decisions of the trust or (ii) the trust has a valid election in effect to be treated as a U.S. person for U.S. federal income tax purposes.

If a partnership holds Ultima Units, the U.S. federal income tax treatment of a partner in the partnership generally will depend upon the status of the partner and the activities of the partnership. Partners of partnerships that hold Ultima Units should consult their tax advisors regarding the U.S. federal income tax consequences to them of the Merger.

Classification of Ultima and Petrofund as Non-U.S. Corporations

Although Ultima and Petrofund are organized as trusts under Canadian law, this summary is based on the assumption that both Ultima and Petrofund are classified as non-U.S. corporations for U.S. federal income tax purposes under current U.S. Treasury regulations. Accordingly, Ultima and Petrofund Units are treated as shares of stock of non-U.S. corporations for U.S. federal income tax purposes. This summary reflects this classification and uses terminology consistent with this classification, including references to "dividends" and "earnings and profits".

The Special Distribution

Subject to the passive foreign investment company ("PFIC"), foreign investment company ("FIC"), and foreign personal holding company ("FPHC") rules discussed below, the gross amount of the Special Distribution (before reduction for Canadian withholding taxes) will be taxable to holders of Ultima Units as a dividend to the extent of Ultima's current and accumulated earnings and profits, as determined under U.S. federal income tax principles. To the extent that the amount of the Special Distribution exceeds Ultima's current and accumulated earnings and profits, as determined under U.S. federal income tax principles, the Special Distribution will be treated as a tax-free return of capital, causing a reduction in the adjusted basis of the Ultima Units. Any balance in excess of adjusted basis will be subject to tax as capital gain.

Subject to certain limitations, dividends paid to noncorporate U.S. Holders, including individuals, may be eligible for a reduced rate of taxation if Ultima is deemed to be a "qualified foreign corporation" for U.S. federal income tax purposes. A qualified foreign corporation includes a non-U.S. corporation that is eligible for the benefits of a comprehensive income tax treaty with the United States that includes an exchange of information program and that the U.S. Treasury Department has determined to be satisfactory for purposes of the qualified dividend provisions of the Code. The U.S. Treasury Department has determined that the income tax treaty between the United States and Canada is satisfactory for purposes of the qualified dividend provisions of the Code. A qualified foreign corporation does not include a non-U.S. corporation that is a PFIC, a FIC, or a FPHC for the taxable year in which a dividend is paid or for the preceding taxable year. Ultima stated in 2003 that it believed that it would qualify as a PFIC for the year ended December 31, 2003. If this is the case, U.S. Holders of Ultima Units would not be eligible for the reduced rate of taxation on the Special Distribution. U.S. Holders are urged to consult their tax advisors regarding the application of the reduced rate of taxation to the Special Distribution.

Exchange of Ultima Units for Petrofund Units

For U.S. federal income tax purposes, the exchange of Ultima Units for Petrofund Units in the Merger has been structured to qualify as a reorganization under the provisions of Section 368(a) of the Code. The U.S. federal income tax treatment of the exchange to a U.S. Holder of Ultima Units, however,

generally will depend on whether Ultima has been a PFIC at any time during which the U.S. Holder has held the Ultima Units.

Passive Foreign Investment Company Rules

Special U.S. federal income tax rules apply to U.S. Holders if Ultima currently is or has been a PFIC at any time during which the U.S. Holder has held Ultima Units. A non-U.S. corporation generally is classified as a PFIC for U.S. federal income tax purposes in any taxable year if, either (i) at least 75% of its gross income is "passive" income (the "income test"), or (ii) on average at least 50% of the gross value of its assets is attributable to assets that produce passive income or are held for the production of passive income (the "asset test"). For purposes of the income test and the asset test, if a non-U.S. corporation owns directly or indirectly at least 25% (by value) of the stock of another corporation, the non-U.S. corporation will be treated as if it held its proportionate share of the assets of the latter corporation and received directly its proportionate share of the income of that latter corporation.

Passive income generally includes dividends, interest, royalties, rents (other than rents and royalties derived in the active conduct of a trade or business and not derived from a related person), certain net gains from the sales of commodities such as oil and natural gas, annuities and gains from assets that produce passive income. Passive income does not include, however, any income that is interest, a dividend or a rent or royalty received or accrued from a related person to the extent that the amount is properly allocable to income of the related person that is not passive income. For these purposes, a related person includes a subsidiary controlled by the non-U.S. corporation, where control means ownership, directly or indirectly, of stock possessing more than 50% of the total voting power of all classes of stock entitled to vote or of the total value of the stock of a corporation.

The Code and applicable U.S. Treasury regulations exclude gains from transactions in commodities from the definition of passive income if (i) the gains arise from the sale of the commodity in the active conduct of a commodities business as a producer, processor, merchant or handler of the commodity and (ii) substantially all of the non-U.S. corporation's business is as an active producer, processor, merchant or handler of the commodity.

Ultima believes that it should be considered to be engaged in the active conduct of a commodities business, and thus should not be a PFIC for 2004. Because this conclusion is a factual determination that is made annually and is subject to change, there can be no assurances that Ultima will not be a PFIC for the current or any future taxable year. Ultima stated in 2003 that it had qualified as a PFIC for taxable years prior to 2003 and that it believed that it would qualify as a PFIC for the year ended December 31, 2003.

Treatment if Ultima is a PFIC with respect to a U.S. Holder

If Ultima has been a PFIC at any time during the time during which a U.S. Holder has held Ultima Units, the exchange of Ultima Units for Petrofund Units in the Merger should be a taxable transaction to the U.S. Holder. In such case, a U.S. Holder should recognize gain upon exchanging its Ultima Units for Petrofund Units. Such gain should be equal to the difference between the fair market value of the Petrofund Units received and the U.S. Holder's adjusted tax basis in the Ultima Units exchanged. Such gain should be recognized on a share-by-share basis and should be taxable as an "excess distribution" under the PFIC rules. An excess distribution should be allocated ratably to each day that the U.S. Holder held Ultima Units. Amounts allocated to the current taxable year and to years before Ultima became a PFIC should be treated as ordinary income. In addition, amounts allocated to each taxable year beginning with the year Ultima first became a PFIC should be taxed at the highest rate in

effect for that year on ordinary income. The tax should be subject to an interest charge at the rate applicable to deficiencies for income tax.

A U.S. Holder generally should not be permitted to recognize a loss on the exchange of Ultima Units for Petrofund Units. The U.S. Holder's basis in the Petrofund Units received should be adjusted to reflect the gain realized. The U.S. Holder's holding period in the Petrofund Units received should begin on the day after the Merger.

Treatment if Ultima is not a PFIC with respect to a U.S. Holder

If Ultima has not been a PFIC at any time during the time during which a U.S. Holder has held Ultima Units, the U.S. Holder of Ultima Units should not be required to recognize gain on the exchange of its Ultima Units for Petrofund Units. The aggregate adjusted tax basis of the Petrofund Units received in the Merger should be equal to the aggregate adjusted tax basis of the Ultima Units surrendered for the Petrofund Units. The holding period of the Petrofund Units received should include the period during which the U.S. Holder held the Ultima Units.

Treatment if Ultima is a PFIC with respect to a U.S.

Holder and Petrofund is a PFIC

If, contrary to Petrofund's current belief (discussed below), Petrofund is determined to be a PFIC for 2004, and Ultima has also been a PFIC at any time during which a U.S. Holder has held Ultima Units, such a U.S. Holder of Ultima Units should not be required to recognize gain on the exchange of its Ultima Units for Petrofund Units. The aggregate adjusted tax basis of the Petrofund Units received in the Merger should be equal to the aggregate adjusted tax basis of the Ultima Units surrendered for the Petrofund Units. The holding period of the Petrofund Units received should include the period during which the U.S. Holder held the Ultima Units.

Recordkeeping Requirements

Each U.S. Holder of Ultima Units that receives Petrofund Units in the Merger will be required to file a statement with its U.S. federal income tax return providing its basis in the Ultima Units surrendered and the fair market value of the Petrofund Units received, and to retain permanent records of this information relating to the Merger.

Ownership of Petrofund Units

Distributions on Petrofund Units

Subject to the PFIC, FIC, and FPHC rules discussed below, the gross amount of any cash distributions on the Petrofund Units (before reduction for Canadian withholding taxes) will be taxable to a U.S. Holder as dividends to the extent of Petrofund's current and accumulated earnings and profits, as determined under U.S. federal income tax principles. As discussed above under "The Special Distribution", dividends paid to noncorporate U.S. Holders, including individuals, by a qualified foreign corporation may be eligible for a reduced rate of taxation. Distributions on the Petrofund Units should be eligible for this reduced rate of taxation as long as Petrofund is not a PFIC, a FIC, or a FPHC and is eligible for the benefits of the income tax treaty between the United States and Canada.

Distributions will be includable in a U.S. Holder's gross income on the date actually or constructively received by the U.S. Holder. These dividends will not be eligible for the dividends-received deduction generally allowed to U.S. corporations in respect of dividends received from other U.S. corporations. To the extent that the amount of any cash distribution exceeds Petrofund's current and

accumulated earnings and profits, as determined under U.S. federal income tax principles, the distribution will first be treated as a tax-free return of capital, causing a reduction in the adjusted basis of the Petrofund Units (thereby increasing the amount of gain or decreasing the amount of loss that a U.S. Holder would recognize on a subsequent disposition of the Petrofund Units), and the balance in excess of adjusted basis will be subject to tax as capital gain.

To the extent Petrofund pays dividends on the Petrofund Units in Canadian dollars, the U.S. dollar value of such dividends should be calculated by reference to the exchange rate prevailing on the date of actual or constructive receipt of the dividend, regardless of whether the Canadian dollars are converted into U.S. dollars at that time. If Canadian dollars are converted into U.S. dollars on the date of actual or constructive receipt of such dividends, a U.S. Holder's tax basis in such Canadian dollars will be equal to their U.S. dollar value on that date and, as a result, the U.S. Holder generally should not be required to recognize any foreign currency exchange gain or loss. Any gain or loss recognized on a subsequent conversion or other disposition of the Canadian dollars generally will be treated as U.S. source ordinary income or loss.

A U.S. Holder may be entitled to deduct, or claim a U.S. foreign tax credit for, Canadian taxes that are withheld on dividends received by the U.S. Holder, subject to applicable limitations in the Code. Dividends paid on the Petrofund Units generally will constitute "passive income" or, in the case of certain U.S. Holders, "financial services income" and will be treated as income from sources without the United States for U.S. foreign tax credit limitation purposes. The amount of foreign income taxes that may be claimed as a credit in any year is subject to complex limitations and restrictions, which must be determined on an individual basis by each holder. U.S. Holders are urged to consult their tax advisors regarding the availability of the U.S. foreign tax credit in their particular circumstances.

Sale, Exchange or Other Disposition of Petrofund Units

Subject to the PFIC and FIC rules discussed below, upon the sale, exchange or other disposition of common shares, a U.S. Holder generally will recognize capital gain or loss equal to the difference between the amount realized upon the sale, exchange or other disposition of Petrofund Units and the U.S. Holder's adjusted tax basis in the Petrofund Units. The capital gain or loss generally will be long-term capital gain or loss if, at the time of sale, exchange or other disposition, the U.S. Holder has held the Petrofund Unit for more than one year. Net long-term capital gains of noncorporate U.S. Holders, including individuals, are eligible for reduced rates of taxation. The deductibility of capital losses is subject to limitations. Any gain or loss that a U.S. Holder recognizes generally will be treated as gain or loss from sources within the United States for U.S. foreign tax credit limitation purposes.

Passive Foreign Investment Company Rules

As discussed under "Exchange of Ultima Units for Petrofund Units - Passive Foreign Investment Company Rules", above, special rules apply in determining whether a non-U.S. corporation is a PFIC. Petrofund believes that it should be considered to be engaged in the active conduct of a commodities business, and thus should not be a PFIC for 2004. Because this conclusion is a factual determination that is made annually and is subject to change, there can be no assurances that Petrofund will not be a PFIC for the current or any future taxable year. Under the Code, if Petrofund were considered to be a PFIC in any taxable year that a U.S. Holder held Petrofund Units, Petrofund generally would be considered a PFIC for all taxable years that such U.S. Holder held Petrofund Units after the first taxable year that Petrofund was considered to be a PFIC.

In general, if Petrofund were a PFIC, a U.S. Holder would be taxed at ordinary income tax rates on any gain realized on the sale or exchange of the Petrofund Units and on any "excess distributions"

received. Excess distributions are amounts received by a U.S. Holder with respect to Petrofund Units in any taxable year that exceed 125% of the average distributions received by the U.S. Holder in the shorter of either the three previous years or the U.S. Holder's holding period for the Petrofund Units before the current taxable year. Gain and excess distributions would be allocated ratably to each day that that U.S. Holder held Petrofund Units. Amounts allocated to the current taxable year and to years before Petrofund became a PFIC would be treated as ordinary income. In addition, amounts allocated to each taxable year beginning with the year Petrofund first became a PFIC would be taxed at the highest rate in effect for that year on ordinary income. The tax would be subject to an interest charge at the rate applicable to deficiencies for income tax.

Rather than being subject to this tax regime, a U.S. Holder could:

- make a qualified electing fund ("QEF") election to be taxed currently on its pro rata portion of Petrofund's income and gain, whether or not such income or gain were distributed in the form of dividends or otherwise; or

- make a "mark-to-market" election and thereby agree, for the year of the election and each subsequent tax year, to recognize ordinary gain or, to the extent of any prior ordinary gain, ordinary loss based on the increase or decrease in market value for such taxable year. A U.S. Holder's basis in its shares would be adjusted to reflect any such income or loss amounts.

A QEF election generally should be made for the first taxable year in which a corporation is a PFIC.

If Petrofund were a PFIC, a U.S. Holder would be required to file Internal Revenue Service Form 8621 for each year in which the U.S. Holder held Petrofund Units.

U.S. Holders are strongly urged to consult their own tax advisors regarding possible classification of Petrofund as a PFIC and the adverse tax consequences that would result from such classification.

Foreign Investment Company Rules

Special U.S. federal income tax rules would apply to U.S. Holders if Petrofund were a FIC. A non-U.S. corporation generally is classified as a FIC for U.S. federal income tax purposes in any taxable year if it is (i) engaged primarily in the business of investing, reinvesting, or trading in securities, commodities, or interests in securities or commodities (ii) at a time when 50% or more of the total combined voting power of all classes of stock entitled to vote, or the total value of all classes of stock, is held, directly or indirectly, by U.S. persons. After the Merger, U.S. persons may own 50% or more of Petrofund's voting power or value. As discussed above, however, Petrofund believes that it is engaged in the active conduct of a commodities business and thus is not the type of investment company intended to be covered by the FIC rules.

Foreign Personal Holding Company Rules

Special U.S. federal income tax rules would apply to U.S. Holders if Petrofund were a FPHC. A non-U.S. corporation generally is classified as a FPHC for U.S. federal income tax purposes in any taxable year if both (i) five or fewer individuals who are U.S. citizens or residents actually or constructively own more than 50% of all classes of the corporation's stock by vote or value at any time during the corporation's taxable year and (ii) at least 60% of the corporation's income is passive income, as described above with respect to the PFIC rules. Petrofund believes that it should not currently be a FPHC. Because this conclusion is a factual determination that is made annually and is subject to change, there can be no assurances that Petrofund will not be a FPHC for the current or any future taxable year.

Information Reporting and Backup Withholding

In general, unless a U.S. Holder belongs to a category of certain exempt recipients (such as corporations), information reporting requirements will apply to dividends as well as proceeds of sales of Petrofund Units that are effected through the U.S. office of a broker or the non-U.S. office of a broker that has certain connections with the United States. Backup withholding may apply to these payments if a U.S. Holder fails to provide a correct taxpayer identification number or certification of exempt status, fails to report in full dividend and interest income or, in certain circumstances, fails to comply with applicable certification requirements. Any amounts withheld under the backup withholding rules will be allowed as a refund or credit against a U.S. Holder's U.S. federal income tax, provided the U.S. Holder furnishes the required information to the Internal Revenue Service in a timely manner.

SELECTED PRO FORMA INFORMATION RELATING TO PETROFUND

The following sets forth selected information relating to Petrofund and Ultima together with pro forma information of Petrofund after giving effect to the Special Distribution and Merger and certain other adjustments. Additional information concerning Petrofund and Ultima is set forth in Appendices "B" and "C" to this Information Circular. In addition, attached as Appendix "D" to this Information Circular are Unaudited Pro Forma Combined Financial Statements of Petrofund giving effect to the Special Distribution and Merger and certain other adjustments.

The pro forma combined financial information set forth below and the Unaudited Pro Forma Combined Financial Statements set forth in Appendix "D" hereto are not necessarily indicative either of results of operations that would have occurred in the year ended December 31, 2003 had the proposed Merger and certain other adjustments been effected on January 1, 2003, or of the results of operations expected in 2004 and future years. In preparing the pro forma statements, no adjustments have been made to reflect the operating synergies and the resulting cost savings expected to result from combining the operations of Petrofund and Ultima.

Selected Pro Forma Combined Financial Information

The following table sets out certain financial information for Petrofund and Ultima as at and for the year ended December 31, 2003 and for Petrofund on a pro forma basis as at and for the year ended December 31, 2003 after giving effect to the Special Distribution and Merger and certain other adjustments. The following is a summary only and must be read in conjunction with the Unaudited Pro Forma Combined Financial Statements of Petrofund set forth in Appendix "D" to this Information Circular.

	As at and for the year ended December 31, 2003
	Pro Forma After Giving Effect

	Petrofund	Ultima	to the Merger
		($ millions)	
Revenues.......................	393.1	111.1	504.2
Cash flow(1)...................	187.6	54.9	245.8
Net income.....................	85.8	12.3	62.0
Total assets...................	943.9	326.5	1,522.2
Working capital (deficiency)...	(30.0)	(8.2)	(42.1)
Long term debt.................	110.3	73.1	193.7
Unitholders' equity............	649.2	208.4	1,102.0

Note:

(1) Management of Ultima Co uses cash flow (before changes in non-cash working capital) to analyze financial performance, as one measure to benchmark performance against peers, and as one measure to determine distribution levels. Cash flow is calculated as net income for the period plus charges to income not requiring an outlay of funds less credits to net income not involving a source of funds. Cash flow as presented does not have any standardized meaning prescribed by Generally Accepted Accounting Principles in Canada ("GAAP") and therefore it may not be comparable with the calculation of similar measures by other entities. Cash flow as presented is not intended to represent operating cash flows or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net income or other measures of financial performance calculated in accordance with GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital.

Selected Combined Operational Information

The following table sets out certain operational information for Petrofund and Ultima on a pro forma combined basis after giving effect to the Merger. Further operational information concerning Petrofund and Ultima is set forth in their respective annual information forms which are attached as Appendices "B" and "C" to this Information Circular.

	Petrofund	Ultima	Combin After Givin to the M
Production(1)			
Natural gas (MMcf/d)	79.4	13.7	93.1
Oil and NGLs (Bbls/d)	13,448	8,065	21,51
Total (BOE/d)(3).....................	26,681	10,348	37,02
Reserves(2)(3)			
Proved (MBOE)........................	81,762	30,725	112,4
Proved plus Probable (MBOE)	102,030	41,377	143,4
Reserve Life Index(4)			
Proved...............................	8.4 years	8.1 years	8.3 ye
Proved plus Probable.................	10.5 years	11.0 years	10.6 ye
Undeveloped land (thousands of net acres)...	250,509	35,270	285,7

Notes:

(1) Based on the 2004 forecast of proved plus probable production of each of Petrofund and Ultima as estimated by the independent engineers of each of Petrofund and Ultima in their respective reports of oil and gas reserves as at December 31, 2003.

(2) Calculated on a gross basis before deducting royalties, without including royalty interests, and based on the evaluations of the independent engineers of each of Petrofund and Ultima as at December 31, 2003. The 11.7136% net royalty interest held by Ventures Trust in the Weyburn Unit is treated as a working interest as Ultima is responsible for its share of capital costs, operating costs, royalties and abandonment costs.

(3) BOEs may be misleading, particularly if used in isolation. A BOE conversion of 6 mcf:1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

(4) Calculated as proved reserves or proved plus probable reserves, as the case may be, divided by 2004 forecast of proved plus probable production.

Pro Forma Combined Capitalization

The following table sets out the capitalization of Petrofund and Ultima as at December 31, 2003, together with the pro forma combined capitalization of Petrofund as at December 31, 2003 after giving effect to the Merger and certain other adjustments. The following is a summary only and, where applicable, must be read in conjunction with the Unaudited Pro Forma Combined Financial Statements of Petrofund set forth in Appendix "D" to this Information Circular.

	As at December 31, 2003		
	Petrofund	Ultima	Aft
Net debt ($ millions)(1)	$140.3	$81.4	
Units outstanding ($ millions) (2)	$1,031.2 (73.6 million units)	$324.8 (57.6 million units)	(100

Notes:

(1) Long term debt plus working capital deficiency as at December 31, 2003. Ultima net debt also includes its deferred capital obligation relating to the 11.7136% net royalty interest held by Ventures Trust in the Weyburn Unit. Pro forma net debt reflects the payment of the Special Distribution and excludes transaction costs.

(2) Units outstanding for Petrofund includes those issuable upon conversion of outstanding exchangeable shares. Pro forma units outstanding reflects exercise of all outstanding Ultima Rights.

RISK FACTORS

Ultima Unitholders should carefully consider the information described under the heading "Competitive Conditions and Risk Factors" in the Renewal Annual Information Form of Ultima dated April 30, 2004 set forth in Appendix "C" of this Information Circular and under the heading "Risk Factors" in the Renewal Annual Information Form of Petrofund dated March 15, 2004 set forth in Appendix "B" of this Information Circular, as well as the other information set forth elsewhere in this Information Circular.

In addition to the foregoing, 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 Petrofund and the Petrofund Unitholders. For instance, certain proposed amendments to the Tax Act announced in the Canadian federal government's 2004 budget may affect the permitted amount of non-Canadian resident ownership of the Petrofund Units and may result in increased withholding tax on Petrofund's cash distributions paid to non-residents of Canada. In particular, the proposed transition period within which Petrofund may be required to take certain steps to ensure that it "not be maintained primarily for the benefit of non-residents" of Canada (as defined in the Tax Act), currently proposed to end on January 1, 2007, may be shortened or eliminated. Whether or not the transition period is shortened or eliminated, Petrofund may not be able to take steps necessary to ensure that Petrofund "not be maintained primarily for the benefit of non-residents" within the prescribed transition period, if any, and to ensure that Petrofund maintains its mutual fund trust status. Even if Petrofund is successful in taking such measures, there can be no assurance that such measures will be completed in a manner that is not detrimental to Petrofund Unitholders, including both non-resident Petrofund Unitholders and the Petrofund Unitholders as a whole. Additionally, legislation may be implemented to limit the investment in income funds and royalty trusts by certain investors or to change the manner in which these entities are taxed. Tax authorities having jurisdiction over Petrofund or the Petrofund Unitholders may disagree with how

Petrofund calculates its income for tax purposes or could change administrative practices to the detriment of Petrofund or the detriment of the Petrofund Unitholders.

STOCK EXCHANGE LISTINGS

The currently outstanding Ultima Units are listed and posted for trading on the TSX and the Petrofund Units are listed and posted for trading on the TSX and the AMEX. Following the Closing Date of the Merger, the Ultima Units will be delisted from the TSX. Information with respect to the trading history of the Petrofund Units is contained under the heading "Additional Information Regarding Petrofund Energy Trust - Trust Unit Price Range and Trading Volumes" and the Ultima Units is contained under the heading "Additional Information Regarding Ultima Energy Trust - Trust Unit Price Range and Trading Volumes".

TIMING

The Merger will become effective at Closing. If the Ultima Special Resolution is approved at the Meeting and all other conditions specified in the Combination Agreement are satisfied or waived, Petrofund and Ultima expect the

Closing Date will be on or about June 16, 2004.

EXPENSES OF THE MERGER

The costs to be incurred by Ultima relating to the Merger including, without limitation, accounting and legal fees, financial advisor fees, contractual severance obligations, the preparation and printing of this Information Circular and other out-of-pocket costs associated with the Meeting, but excluding retention payments and statutory severance obligations, are estimated to be approximately $6.6 million.

INTERESTS OF EXPERTS

As of the date hereof, the partners and associates of each of Bennett Jones LLP, considered as a group, beneficially own, directly or indirectly, less than 1% of the issued and outstanding Ultima Units. Mr. John H. Kousinioris, a partner with Bennett Jones LLP, is the Corporate Secretary of Ultima Co, Ultima Energy, AcquireCo and the Manager. As of the date hereof, the partners of Deloitte & Touche LLP do not beneficially own, directly or indirectly, any of the issued and outstanding Ultima Units. As of the date hereof, the partners of Collins Barrow Calgary LLP do not beneficially own, directly or indirectly, any of the issued and outstanding Ultima Units. As of the date hereof, each of Gilbert Laustsen Jung Associates Ltd. and McDaniel & Associates Consultants Ltd., considered as a group, beneficially own, directly or indirectly, less than 1% of the issued and outstanding Ultima Units.

OTHER LEGAL MATTERS

Resale of Petrofund Securities

The Petrofund Units to be issued to Ultima Unitholders pursuant to the Merger will be issued in reliance on exemptions from prospectus and registration requirements of applicable securities laws of the various applicable provinces and territories in Canada and (other than in Quebec and New Brunswick as described below) will generally be "freely tradeable" (and not subject to any "restricted period" or "hold period") if the following conditions are met: (i) the trade is not a control distribution (as defined in applicable securities legislation); (ii) no unusual effort is made to prepare the market or to create a demand for the securities that are the subject of the trade; (iii) no extraordinary commission or consideration is paid to a person or company in respect of the trade; and (iv) if the selling securityholder

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is an insider or an officer of the issuer, the selling securityholder has no reasonable grounds to believe that the issuer is in default of securities legislation.

Notice of the Merger and of the issuance of the Petrofund Units pursuant thereto will be submitted to the Autorite des marches financiers (the "Autorite") on behalf of Petrofund which, if accepted by, or if no objection is received within 15 days from, the Autorite, will result in the Petrofund Units received by Ultima Unitholders resident in the Province of Quebec not being subject to the registration and prospectus requirements of such province to permit such securities to be freely tradeable under the applicable securities laws of such province. In addition, an application will be made to the Office of the Administrator for the Province of New Brunswick to provide that Petrofund Units received by Ultima Unitholders resident in such province will not be subject to the registration and prospectus requirements of such province and to permit such securities to be freely tradeable (other than as a result of any "control block" restrictions which may arise by virtue of the ownership thereof) under applicable securities laws of such province.

It is a condition of the Combination Agreement and the completion of the Merger that all approvals, regulatory or otherwise, necessary in respect of the Special Distribution and Merger be obtained. See "Details of the Merger -- The Combination Agreement - Conditions of the Special Distribution and Merger".

Information for United States Holders

This Information Circular has been prepared in accordance with Canadian disclosure requirements, which differ from those in the United States. The financial statements and other financial information herein have been prepared in accordance with Canadian generally accepted accounting principles that are subject to Canadian auditing and auditor independent standards and thus may not be comparable to financial statements and other financial information of United States companies. Information concerning oil and gas operations and reserves have been prepared in accordance with Canadian requirements, which differ significantly from those of the SEC.

The Petrofund Units to be issued to United States holders of Ultima Units pursuant to the Merger will be registered under the 1933 Act, and such securities will be freely tradeable under applicable United States securities laws except for any securities acquired by an affiliate of Ultima or Petrofund.

Unitholders are urged to consult their legal advisers to determine the extent of all applicable resale provisions.

DOCUMENTS FILED AS PART OF PETROFUND'S U.S. REGISTRATION STATEMENT

A registration statement on Form F-10 has been filed by Petrofund with the SEC under the 1933 Act relating to the Merger. The following documents have been or will be filed with the SEC as part of the Registration Statement of which this Information Circular is a part, insofar as called for by the SEC's Form F-10: (i) the Form of Proxy accompanying this Information Circular; (ii) the Combination Agreement; (iii) consents of independent auditors, counsel, engineers and the financial advisor; and (iv) powers of attorney pursuant to which the amendments to the Registration Statement may be signed.

AVAILABILITY OF DISCLOSURE DOCUMENTS

In the United States, Petrofund is subject to the informational requirements of the United States Securities Exchange Act of 1934, as amended, and in accordance therewith must file reports and other information with the SEC. Under a multijurisdictional disclosure system adopted by the SEC, such

reports and other information may be prepared in accordance with the disclosure requirements of Canada, which requirements are different from those in the United States. Such reports and other information filed by Petrofund are available for inspection and copying at the public reference facilities maintained by the SEC at Room 1024, 450 Fifth Street, NW, Judiciary Plaza, Washington, DC 20549.

PART III - ADDITIONAL INFORMATION
REGARDING ULTIMA ENERGY TRUST

General

Information with respect to Ultima and its business, operations and affairs are included in the following (which are attached as Appendix "C" and form an integral part of this Information Circular):

1. Ultima Energy Trust Renewal Annual Information Form dated April 30, 2004 for the year ended December 31, 2003, including the Compilation Report and the Unaudited Pro Forma Combined Financial Statements of Ultima Energy Trust after giving effect to the acquisition of all of the issued and outstanding shares in the capital of Trioco Resources Inc.;

2. Ultima Energy Trust Management's Discussion and Analysis for the year ended December 31, 2003 compared to the year ended December 31, 2002; and

3. Ultima Energy Trust comparative audited consolidated financial statements as at and for the years ended December 31, 2003 and 2002 and the auditors' report thereon.

Distributions

Income of Ultima that is distributed to the Ultima Unitholders pursuant to the Ultima Trust Indenture is calculated by the Manager and is approved by the Ultima Board of Directors and the board of directors of AcquireCo. The Ultima Trustee distributes the income to Ultima Unitholders of record on the last day of each month on the 15th day of the following month, or if such day does not fall on a business day, the next business day following the 15th day of the month. The following cash distributions per Ultima Unit have been made to Ultima Unitholders during the periods indicated below:

	2002	2003	2004
First Quarter...........	$0.19	$0.27	$0.255
Second Quarter..........	0.23	0.27	N/A
Third Quarter...........	0.24	0.285	N/A
Fourth Quarter..........	0.24	0.265	N/A
Total Annual............	$0.90	$1.09	$0.255

Trust Unit Price Range and Trading Volumes

The currently outstanding Ultima Units are listed on the TSX. The following table shows the high, low and closing prices and volume of trading of the Ultima Units on the TSX, as reported by such exchange, for the periods indicated.

	Unit Price Range($)			
	High	Low	Close	Trading Volume
2002				
First Quarter........................	5.45	4.12	5.25	2,012,668
Second Quarter.......................	6.06	5.05	5.91	4,929,460

Third Quarter........................	5.95	5.30	5.84	8,103,931
Fourth Quarter.......................	5.89	4.90	5.15	7,993,507
2003				
First Quarter........................	5.68	5.05	5.30	9,596,702
Second Quarter.......................	5.53	5.07	5.42	12,860,905
Third Quarter........................	6.25	5.22	6.13	24,868,329
Fourth Quarter.......................	6.36	5.69	6.24	16,758,872
2004				
January..............................	7.04	6.20	6.89	5,945,912
February.............................	7.07	6.16	7.03	7,688,115
March................................	7.73	6.96	7.62	5,864,881
April (through April 29).............	7.62	7.05	7.07	6,694,800

On March 26, 2004, the last trading day prior to the announcement of the Merger, the closing price of the Ultima Units on the TSX was $7.47. On April 29, 2004, the closing price of the Ultima Units on the TSX was $7.07.

Executive Compensation

Compensation of the Ultima Trustee

The Ultima Trustee was reimbursed for costs and expenses it incurred as trustee of Ultima for the year ended December 31, 2003. Compensation is paid to the Ultima Trustee for the services it provides as trustee and as transfer agent and registrar of Ultima. The Ultima Trustee was paid $16,512 as compensation for the services it provided as trustee of Ultima for the year ended December 31, 2003. The Ultima Trustee was paid $44,932 for the services it provided as transfer agent and registrar of Ultima for the year ended December 31, 2003.

Compensation of the Manager

Pursuant to the terms of the Management Agreement, the Manager provides services in connection with the management and administration of Ultima, Ventures Trust, Ultima Co and AcquireCo, and in connection with the operation of the properties and assets owned, or which may be acquired, by Ventures Trust and/or AcquireCo. The delegation of authority to the Manager is subject to the supervision of, and restrictions imposed from time to time by, the Ultima Board of Directors and the board of directors of AcquireCo, and the provisions of the Management Agreement. In particular, the Ultima Board of Directors and the board of directors of AcquireCo have exclusive authority over matters such as the annual operating budget, acquisitions and dispositions of properties, capital expenditures and acquisitions in excess of $2,000,000, borrowing limits and policies, equity financing approval and Ultima's cash distribution policy. The Manager also provides services to Ultima Energy.

On March 26, 2003, Ultima, through 1032213 Alberta Ltd. ("1032213") (a wholly-owned subsidiary of Ultima), acquired all of the issued and outstanding common shares of the Manager for a total cash payment of $3,800,000, plus management and retention obligations of $1,500,000 (the "Management Internalization Transaction"). Prior to the Management Internalization Transaction,

Ultima Co, for and on behalf of Ventures Trust, AcquireCo and the Ultima

Trustee, for and on behalf of Ultima, paid the Manager certain management fees (the "Management Fees"), administration fees (the "Administration Fees") and acquisition fees (the "Acquisition Fees"). Management Fees of $487,000 were paid to the Manager for the period commencing January 1, 2003 and ending on March 26, 2003. No Acquisition Fee or Administration Fee was payable for that period. As a result of the Management Internalization Transaction, the Manager is now a wholly-owned subsidiary of Ultima. Consequently, any fees paid to the Manager are now effectively for the account of Ultima as they remain within the trust structure.

Compensation of Executive Officers of Ultima Co, AcquireCo and Ultima Energy

The officers of each of Ultima Co, AcquireCo and Ultima Energy receive no direct compensation from those companies.

Pursuant to the terms of the Management Agreement, Ultima Co, AcquireCo and the Ultima Trustee, for and on behalf of Ultima, reimburse the Manager for the costs and expenses incurred by the Manager in the management and administration of Ultima, Ventures Trust, Ultima Co and AcquireCo. The Manager is also reimbursed for the costs and expenses it incurs for services it provides to Ultima Energy. The Ultima Board of Directors and the board of directors of AcquireCo, having regard to industry salaries, approve the amounts paid in respect of salaries and benefits as part of their approval of the general and administrative budget of the Manager.

The following table details the total compensation paid, during each of the last three financial years, to the President and Chief Executive Officer of the Manager and each of the executive officers of the Manager whose total salary and bonus exceeded $100,000 during the financial year ended December 31, 2003 (collectively, the "Named Executive Officers").

		Annual Compensation			Long Term Compensatio
Name and Principal Position	Year	Salary(1) ($)	Bonus ($)	Other Annual Compensation ($)	Securities Un Rights Grant (#)
S. Brian Gieni	2003	$200,000	$100,000	Nil	70,000
President and	2002	$127,500	$75,000	Nil	Nil
Chief Executive Officer	2001	$93,125	$75,000	Nil	200,000
Kenneth G. Pinsky	2003	$170,000	$85,000	Nil	60,000
Chief Financial Officer	2002	$106,250	$65,000	Nil	Nil
	2001	$67,904	$55,000	Nil	175,000
Michael P. Wihak	2003	$170,000	$85,000	Nil	60,000
Chief Operating Officer	2002	$110,500	$51,500	Nil	Nil
	2001	$49,563	$50,000	Nil	175,000

Notes:

(1) The amounts set forth under these columns for the financial years ended December 31, 2002 and 2001 do not include the portion of salary and other compensation paid by the Weyburn Limited Partnership to the Named Executive Officer. No salary or other compensation was paid by the Weyburn Limited Partnership to the Named Executive Officer for the

financial year ended December 31, 2003.

(2) In connection with the Management Internalization Transaction and pursuant to the Ultima Employment Agreements, each of Messrs. Gieni, Pinsky and Wihak also received $125,000 in cash and 11,200 Ultima Units at closing. Each of Messrs. Gieni, Pinsky and Wihak also received $83,333 (paid by the issuance of 11,462 Ultima Units) on the first anniversary of the closing of the Management Internalization Transaction and, pursuant to the Ultima Employment Agreement, are entitled to receive an additional $83,333 on each of the second and third anniversary dates of the closing of the Management Internalization Transaction, in each instance paid by the issuance of Ultima Units based on the weighted average price of the Ultima Units on the TSX during the 20 consecutive trading days preceding the date of payment. In connection with the Merger, the Ultima Board of Directors, on behalf of Ultima, resolved to accelerate the timing of the payments pursuant to the Ultima Employment Agreements to immediately prior to the record date of the

Special Distribution so that the right to acquire Ultima Units pursuant to the Ultima Employment Agreements is received immediately prior to the payment of the Special Distribution.

(3) The Manager has a company-sponsored savings plan (the "Savings Plan") pursuant to which the Manager contributes up to 6% of an employee's salary to the Savings Plan if the employee contributes up to 4% of his or her salary to the Savings Plan. The amounts paid to the Named Executive Officers pursuant to the Savings Plan are included in this column.

Employment Agreements

Pursuant to the terms of the Ultima Employment Agreements, Messrs. Gieni, Wihak and Pinsky are entitled to annual salaries of $200,000, $170,000 and $170,000, respectively, subject to annual review. Further, upon the occurrence of a termination event, including the sale of all or substantially all of the assets of Ultima, each of Messrs. Gieni, Wihak and Pinsky is entitled to receive: (i) a sum equal to his salary for the month immediately preceding termination, multiplied by 18, in the case of Mr. Gieni, or 12, in the case of Messrs. Wihak and Pinsky, plus the number of full or partial years of service to a maximum of 24 months, in the case of Mr. Gieni, or 18 months, in the case of Messrs. Wihak and Pinsky; and (ii) the simple average of the largest annual bonuses and other compensation paid to the Named Executive Officer during two of the three years immediately preceding termination, multiplied by 1.5, in the case of Mr. Gieni, or 1.0, in the case of Messrs. Wihak and Pinsky, plus the number of full or partial years of service divided by 12.

The Ultima Employment Agreements also provide that upon the occurrence of a termination event, including the sale of all or substantially all of the assets of Ultima, each of Messrs. Gieni, Wihak and Pinsky may elect, by written notice to Ultima, to receive a cash payment in respect of his vested Ultima Rights equal to the number of such vested Ultima Rights multiplied by the amount by which the market price for the Ultima Units (determined in accordance with the Ultima Employment Agreement) exceeds the exercise price for such Ultima Rights.

Ultima TURIP

Ultima currently has a Trust Unit Rights Incentive Plan, the purpose of which is to:

1. develop the interest of directors, officers, employees and key consultants of Ultima and its affiliates in the growth and development of Ultima by providing such persons with the opportunity to acquire a proprietary interest in Ultima;

2. provide a compensation mechanism for persons who provide a service to Ultima and its affiliates on an ongoing basis, or who have provided, or are expected to provide, a service of value to Ultima; and

3. align the interests of directors, officers, employees and key consultants with those of Ultima Unitholders by devising a compensation mechanism which encourages the prudent maximization of distributions to Ultima Unitholders and long-term value growth of the Ultima Units.

The Ultima TURIP permits the Ultima Board of Directors and the board of directors of AcquireCo to grant rights to acquire Ultima Units to those persons eligible to participate in the Ultima TURIP. Rights to acquire Ultima Units may only be granted with the approval of the Ultima Board of Directors and the board of directors of AcquireCo. As at December 31, 2003, rights to acquire 2,007,669 Ultima Units pursuant to the Ultima TURIP were outstanding. Rights to acquire an aggregate of 512,998 Ultima Units pursuant to the Ultima TURIP were exercised during the financial year ended December 31, 2003.

In the event that the amount of distributions to Ultima Unitholders in any calendar quarter is greater than 2.5% of the book value of the oil and natural gas properties and other assets of Ultima, the book value of which is reflected in the "Capital assets, net" account appearing on the most recent annual or quarterly, as the case may be, balance sheet of Ultima (the "Capital Assets"), then the exercise price of each right to acquire Ultima Units pursuant to the Ultima TURIP then outstanding shall, at the election of the holder thereof on the date of exercise of such rights, be reduced by an amount equal to the distributions for the calendar quarter calculated on a per Ultima Unit basis, less 2.5% of the book value of the Capital Assets at the end of such calendar quarter calculated on a per Ultima Unit basis. For purposes of the Ultima TURIP, distributions in any calendar quarter shall be deemed to consist of the aggregate distributable income declared by Ultima in such calendar quarter.

Ultima Rights Grants During the Year Ended December 31, 2003

The following table provides details of rights to acquire Ultima Units granted pursuant to the Ultima TURIP to the Named Executive Officers during the year ended December 31, 2003:

Name	Ultima Units under Ultima Rights Granted	% of Total Ultima Rights Granted to Employees and Directors in Financial Year	Exercise Price ($/Unit)	Market Value of Securities Underlying Ultima Rights on the Date of Grant ($/Units)

S. Brian Gieni	70,000	6.1%	5.27	5.27
Kenneth G. Pinsky	60,000	5.2%	5.27	5.27
Michael P. Wihak	60,000	5.2%	5.27	5.27

Note:
(1) As at December 31, 2003, the average exercise price of each right to acquire an Ultima Unit pursuant to the Ultima TURIP was subject to a downward adjustment of $0.63 per Ultima Unit, at the holder's discretion, in accordance with the adjustment provisions of the Ultima TURIP. To date no Named Executive Officer has elected to utilize the downward adjustment when exercising such rights.

Aggregated Ultima Rights Exercised During the Year Ended December 31, 2003

The following table sets forth certain information respecting the number and accrued value of unexercised rights to acquire Ultima Units granted pursuant to the Ultima TURIP as at December 31, 2003 and rights to acquire Ultima Units granted pursuant to the Ultima TURIP exercised by the Named Executive Officers during the financial year ended December 31, 2003:

			Unexercised Ultima Rights at December 31, 2003		Valu In- Righ
Name	Securities Acquired on Exercise	Aggregate Value Realized ($)(1)(2)	Vested	Not Vested	Veste
S. Brian Gieni	133,333	42,668	-	136,667	-
Kenneth G. Pinsky	58,333	99,999	58,333	118,334	107,333
Michael P. Wihak	60,000	86,400	56,666	118,334	104,265

Notes:
(1) The aggregate value realized represents the dollar value equal to the difference between the exercise price of the rights exercised and the market value of the Ultima Units on the TSX on the date the rights were exercised, multiplied by the number of rights exercised.

(2) Excluding the downward adjustment, which to date no Named Executive Officer has elected to receive.

(3) The value of the unexercised "in-the-money" rights has been determined by subtracting the exercise price of the rights from the closing Ultima Unit price of $6.24 on December 31, 2003, as reported by the TSX, and multiplying by the number of Ultima Units that may be acquired upon the exercise of the rights.

The balance of the rights to acquire Ultima Units granted pursuant to the Ultima TURIP during the year ended December 31, 2003 were granted to employees of the Manager and to directors of Ultima Co and AcquireCo.

Trust Unit Option Agreements

In July 2000, options to purchase Ultima Units (the "Options") were issued to certain directors of Ultima Co and AcquireCo, at a fixed price, in order to encourage ownership of Ultima Units by such directors. All of such Options had been exercised prior to the commencement of the current financial year.

The following table summarizes the number of Ultima Units acquired pursuant to the exercise of the Options during the financial year ended December 31, 2003 and the aggregate value realized upon exercise. Value realized upon exercise is the difference between the market value of the Ultima Units on the exercise date and the exercise price of the Options.

			Unexercised Options at December 31, 2003		V in- De
Name	Securities Acquired on Exercise	Aggregate Value Realized ($)	Vested	Not Vested	Ve
Marshall M. Williams	50,000	109,000	Nil	Nil	

Compensation of Directors

The directors of each of Ultima Co and AcquireCo are paid an annual retainer and meeting fees. However, directors who are also officers of the Manager receive no consideration for also serving as a director of Ultima Co or AcquireCo.

The directors of Ultima Co and AcquireCo, other than the chairman (the "Chairman") of the Ultima Board of Directors and the board of directors of AcquireCo and those directors who are also officers of the Manager, each received an annual retainer of $10,000 and $750 per joint meeting of the boards of directors of Ultima Co and AcquireCo or committees of Ultima Co and AcquireCo attended in 2003. The Chairman received an annual retainer of $16,875 and $750 per joint meeting of the boards of directors of Ultima Co and AcquireCo or committees of Ultima Co and AcquireCo attended in 2003. For the year ended December 31, 2003, a total of $63,125 was paid in annual retainers and $92,500 was paid for attendance at meetings to the directors of Ultima Co and AcquireCo.

Report on Executive Compensation

The Human Resources Committee is responsible for developing the approach of the Ultima Board of Directors and the board of directors of AcquireCo in establishing and implementing appropriate compensation and human resource strategies, policies and practices in order to attract, motivate and retain the quality of personnel required to meet the business objectives of Ultima. Within the scope of the Human Resources Committee's mandate, it assesses the performance of senior management of Ultima Co, AcquireCo, Ultima Energy and the Manager, and reviews and approves the form and amount of compensation that they receive including short and long-term incentive plans.

In carrying out its mandate and formulating its recommendations, the Human Resources Committee takes into consideration a number of factors including the education and experience of each individual, such individual's performance, the value of such individual to Ultima, the financial

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performance of Ultima and the relative competitiveness of the overall compensation of such individual within the industry.

Salary

The salaries of the Named Executive Officers are reviewed annually having regard to a number of factors including the expertise, experience and performance of each individual and the comparative levels of compensation paid to executives of other industry participants of comparable size. In respect of the salary levels established for the Named Executive Officers for 2003, the Human Resources Committee did not specifically retain the advice of independent consultants but rather relied on public disclosure by comparable companies and knowledge obtained from other sources regarding competitive compensation packages within the industry. The current view of the Human Resources Committee is that the salaries paid to the Named Executive Officers is appropriate having regard to a number of factors including Ultima's relative size.

Ultima Rights

Directors, officers, employees and consultants are eligible to participate in the Ultima TURIP. Awards of rights to acquire Ultima Units are made from time to time to participants at varying levels having regard to each individual's level of responsibility. The term and certain other provisions of the rights to acquire Ultima Units granted under the Ultima TURIP, including the vesting period, are at the discretion of the Ultima Board of Directors and the board of directors of AcquireCo. The outstanding rights to acquire Ultima Units granted to the Named Executive Officers to date have been made to align their interests with those of Ultima Unitholders on a long-term basis with a view to encouraging the prudent maximization of distributions to Ultima Unitholders and the growth in long-term value of Ultima Units.

Discretionary Bonus

The Ultima Board of Directors and the board of directors of AcquireCo have discretion from time to time to grant bonuses to reward exceptional individual performance and the achievement of short term goals. In respect of the 2003 financial year, an aggregate of $698,000 was awarded as bonuses to officers and employees of the Manager in recognition of the superior financial and operating performance attained by Ultima during 2003.

Compensation of the Chief Executive Officer

Mr. Gieni received the base salary, bonus and rights to acquire Ultima Units outlined in this Information Circular for the calendar year 2003. See

"Executive Compensation - Compensation of Executive Officers of Ultima Co, AcquireCo and Ultima Energy". These levels were established and approved by the Ultima Board of Directors and the board of directors of AcquireCo having regard to the foregoing considerations.

The foregoing report has been furnished by the Human Resources Committee consisting of Messrs. Lee (Chairman), Dumont and Williams.

Performance Table

The following table and graph illustrates changes in cumulative Ultima Unitholder return on Ultima Units from December 31, 1998 to December 31, 2003, assuming an initial $100 investment in Ultima Units on December 31, 1998 and the reinvestment of cash distributions, compared to the

cumulative return of the S&P/TSX Composite Index and the TSX Oil and Gas Producers Index for the comparable period.

Cumulative Value of $100 Investment

	December 31				
	1998	1999	2000	2001	200
Ultima Energy Trust............................	$100	$136	$238	$318	$46
S&P/TSX Composite Index........................	$100	$132	$141	$123	$10
TSX Oil & Gas Producers Index..................	$100	$122	$179	$185	$21

Ultima Energy Trust
Relative Total Return History
December 31, 1998 to December 31, 2003

[ATTORNEY TO PROVIDE TABLE]

Statement of Corporate Governance Practices

In December 1994, the TSX Committee on Corporate Governance in Canada issued a report setting out a series of guidelines for effective corporate governance which were subsequently incorporated into the TSX's Company Manual as formal disclosure policies (the "TSX Guidelines"). The TSX Guidelines address matters such as the constitution and independence of corporate boards of directors, the functions to be performed by boards of directors and their committees, and the effectiveness and education of board members. The TSX requires a listed issuer to disclose, on an annual basis, its approach to corporate governance with specific reference to the TSX Guidelines. Set out below are the 14 TSX Guidelines and a brief description of Ultima's compliance with those guidelines in light of its existing governance practices, which have been established by the terms of the Ultima Trust Indenture, the Ventures USA, the AcquireCo USA, and the Management Agreement. The Ultima Board of Directors and the boards of directors of AcquireCo, Ultima Energy and the Manager, all of which are comprised of the same members, are collectively referred to below as the "Boards of Ultima".

1. The boards should explicitly assume responsibility for stewardship of Ultima, and specifically for adoption of a strategic planning process, identification of principal risks, succession planning and monitoring, communications policy and integrity of internal control and management information systems.

The directors of Ultima Co and AcquireCo have, pursuant to the Ultima Trust Indenture, the authority and responsibility to make or approve most significant decisions affecting Ultima. Each of the Ultima Co USA and AcquireCo USA provides that the Ultima Board of Directors and the board of directors of AcquireCo may give special, but not exclusive, consideration to the interests of the Ultima Unitholders in determining whether a matter under its consideration is in the best interests of Ultima Co and AcquireCo, respectively. While day-to-day management of Ultima, Ventures Trust, Ultima Co, AcquireCo and Ultima Energy has been delegated to the Manager (largely pursuant to the Management Agreement), the directors fulfill their responsibility for the broader stewardship of the business and affairs of Ultima, Ventures Trust, Ultima Co, AcquireCo, Ultima Energy and the Manager through the activities and procedures set forth below:

- While management is directly involved with, and often initiates the strategic planning process for, Ultima, the Boards of Ultima remain integral to the implementation of strategic business decisions through their review of matters at board meetings and through the involvement of directors, individually, with management in the analysis and assessment of strategic business alternatives for Ultima. The Boards of Ultima approve all significant decisions affecting Ultima, Ventures Trust, Ultima Co, AcquireCo, Ultima Energy and the Manager.

- The Boards of Ultima participate in strategic planning through the review of annual forecasts, the approval of annual operating and capital budgets and by providing advice to management. Other strategic issues, such as acquisition or disposition transactions or financings, are addressed at meetings of the Boards of Ultima with members of senior management. The Boards of Ultima have set strategic objectives to maximize distributions to Ultima Unitholders, maintain a prudent capital structure, and pursue appropriate acquisition and disposition opportunities, all with a view to maximizing Ultima Unitholder value.

- The duties and limitations of the Manager are generally contained in the Management Agreement. The day-to-day management of the business and affairs of Ultima, Ventures Trust, Ultima Co, AcquireCo and Ultima Energy is undertaken by the Manager, subject to overview by the Boards of Ultima. As a result of the Management Internalization Transaction, the Manager is now a wholly-owned subsidiary of Ultima.

- The Boards of Ultima have assigned responsibility for senior management succession planning to the Human Resources Committee of the Ultima Board of Directors and the President and Chief Executive Officer of Ultima Co, AcquireCo, Ultima Energy and the Manager. The Human Resources Committee and the President and Chief Executive Officer consult with, and seek approval from, the Boards of Ultima with respect to senior management appointments. The appointment of officers of Ultima Co, AcquireCo, Ultima Energy and the Manager are made by their respective board of directors.

- Management has implemented internal control and information systems including systems for compiling and processing accounting and production information as part of the day-to-day management of the business and affairs of Ultima, Ventures Trust, Ultima Co, AcquireCo and Ultima Energy. The Boards of Ultima monitor the effectiveness of

these systems by reviewing operational and financial status reports presented at board meetings. As well, the Audit Committee of the Boards of Ultima meets independently with the auditors to receive reports on the adequacy of such systems.

- The Boards of Ultima establish parameters within which management may conduct certain activities such as those related to risk management. The Boards of Ultima rely on management, in the day-to-day management of the business and affairs of Ultima, Ventures Trust, Ultima Co, AcquireCo and Ultima Energy, to identify any significant business risks outside those parameters and review such risks with individual directors, as circumstances dictate, and thereafter with the full Boards of Ultima.

- Management has, with the approval of the Boards of Ultima, assumed primary responsibility for communications with Ultima Unitholders. Senior management attempts to respond to inquiries by individual Ultima Unitholders in a timely fashion. The President and Chief Executive Officer and the Chief Financial Officer of the Manager also meet with interested Ultima Unitholders from time to time and report to the Boards of Ultima on feedback that they have received from Ultima Unitholders.

2. A majority of directors should be "unrelated" (free from conflicting interest).

The Boards of Ultima are currently comprised of seven members, all of whom have extensive and varied business experience. An "unrelated" director for the purposes of the TSX Guidelines is one who is independent of management and is free from any interest and any business or other relationship that could, or could reasonably be perceived to, materially interfere with the director's ability to act with a view to the best interests of Ultima, Ventures Trust, Ultima Co, AcquireCo and Ultima Energy, other than interests and relationships arising from shareholdings. In defining an unrelated director, the TSX Guidelines place emphasis on the ability of a director to exercise objective judgment, independent of management. Alternatively, a related director is a director who is not an unrelated director. The TSX Guidelines also make an informal distinction between inside and outside directors. The TSX Guidelines consider an inside director to be one who is an officer or employee of the corporation or any of its affiliates. The majority of the members of the Boards of Ultima are "unrelated directors", as defined in the TSX Guidelines. Each of the Ultima Co USA and AcquireCo USA provides that all of the members of each board of directors be elected by the Ultima Unitholders. Ultima does not have a significant unitholder with the ability to exercise a majority of the votes for the election of directors.

3. Disclose for each director whether he or she is related, and how that conclusion was reached.

The Boards of Ultima are of the view that Mr. Brian Gieni is a related director as he is the President and Chief Executive Officer of Ultima Co, AcquireCo, Ultima Energy and the Manager. The Boards of Ultima are of the view that all of the remaining directors of Ultima Co, AcquireCo, Ultima Energy and the Manager are unrelated to Ultima, Ventures Trust, Ultima Co, AcquireCo, Ultima Energy and the Manager in that they do not form part of the management team and are free from any interest or other relationship that could, or could reasonably be perceived to, materially interfere with their ability to act with a view to the best interests of Ultima, Ventures Trust or the respective corporations.

4. Appointment of a Committee responsible for appointment/assessment of directors.

Given the relatively small size of the Boards of Ultima, it has been determined that the establishment of a nominating committee whose responsibility would be to propose new

nominees to the Boards of Ultima is unnecessary. New nominees to the Boards of Ultima are reviewed by the Boards of Ultima. Assessment of individual director's performance and the effectiveness of the Boards of Ultima, as a whole, are considered to be of significant importance and are undertaken by the Boards of Ultima and the Governance Committee of the Ultima Board of Directors, which consists of Messrs. Art Dumont (Chairman), David Tuer and Marshall Williams, all of which are "unrelated directors".

5. Implement a process for assessing the effectiveness of the Board, its Committees and individual directors.

Responsibility for the assessment of the effectiveness of the Boards of Ultima, as a whole, the committees of the Boards of Ultima and the contribution of individual directors rests with the Boards of Ultima and the recently appointed Governance Committee. The Governance Committee has been charged with developing and reviewing the approach of Ultima to governance matters and was in the process of developing a more formal process for assessing the effectiveness of the Boards of Ultima and individual directors prior to the announcement of the Merger.

6. Provide orientation and education programs for new directors.

To date, the directors of Ultima Co, AcquireCo, Ultima Energy and the Manager have been persons with extensive and varied business experience. Accordingly, Ultima Co, AcquireCo, Ultima Energy and the Manager have not established a formal orientation and education program for new directors. Ultima Co, AcquireCo, Ultima Energy and the Manager would, however, provide orientation to new directors on an informal basis as required depending on their background and knowledge of Ultima's business and operations.

7. Consider reducing size of Board, with a view to improving effectiveness.

The Ventures USA and the AcquireCo USA require the Ultima Board of Directors and the board of directors of AcquireCo to consist of seven members. The Boards of Ultima believe that this number of directors promotes efficiency and effectiveness. There is no intention to increase or reduce the number of directors further.

8. Review the compensation of directors in light of risks and responsibilities.

The Ultima Board of Directors has established a Human Resources Committee consisting of Messrs. Gary Lee (Chairman), Henry Lawrie and Marshall Williams, all of which are "unrelated directors". One of the functions of the Human Resources Committee is to review the adequacy and form of directors' compensation and make recommendations designed to ensure the directors' compensation realistically reflects the responsibilities of the Boards of Ultima. It is also responsible for the overall approval of the compensation policies and levels of compensation for Ultima Co, AcquireCo, Ultima Energy and the Manager.

9. Committees should generally be composed of outside directors, a majority of whom are unrelated.

The Boards of Ultima have established a Human Resources Committee, a Reserves Committee, a Governance Committee and an Audit Committee.

- The Human Resources Committee consists of Messrs. Gary Lee (Chairman), Henry Lawrie and Marshall Williams, all of which are "unrelated" and "outside" directors. This Committee assesses the performance of senior management of Ultima Co, AcquireCo, Ultima Energy and the Manager and reviews and approves the form and amount of compensation that they receive including short and long-term incentive plans. The Committee also evaluates the fees that directors receive.

- The Reserves Committee consists of Messrs. John Gunn (Chairman), David Tuer and Art Dumont, all of which are "unrelated" and "outside" directors. This Committee is responsible for reviewing, approving and reporting annually on the independent engineers' reserve reports.

- The Audit Committee consists of Messrs. Henry Lawrie (Chairman), John Gunn and Gary Lee, all of which are "unrelated" and "outside" directors. The Audit Committee reviews the quarterly and annual consolidated financial statements of Ultima and the systems of internal control for Ultima, Ventures Trust, Ultima Co, AcquireCo, Ultima Energy and the Manager. The Audit Committee meets periodically with the Chief Financial Officer of Ultima Co, AcquireCo, Ultima Energy and the Manager, and with the auditors of Ultima, Ventures Trust, Ultima Co, AcquireCo and Ultima Energy, as necessary, to review the audit process independently of management.

- The Governance Committee consists of Messrs. Art Dumont (Chairman), David Tuer and Marshall Williams, all of which are "unrelated" and "outside" directors. The Committee is responsible for developing and reviewing the approach of Ultima to corporate governance matters.

10. Appoint a Committee responsible for Ultima's approach to corporate governance issues.

The Ultima Board of Directors has appointed a Governance Committee, which has been mandated to assume responsibility for developing Ultima's approach to governance issues.

11. The Board should develop position descriptions for the Board and for the Chief Executive Officer, and the Board should approve or develop corporate objectives, which the Chief Executive Officer is responsible for meeting.

The President and Chief Executive Officer is accountable to the Boards of Ultima for meeting corporate objectives. The Boards of Ultima has delegated to the President and Chief Executive Officer the responsibility for the day-to-day management of Ultima's business subject to compliance with plans and objectives approved from time to time by the Boards of Ultima. A written position description has been prepared for the President and Chief Executive Officer. Any responsibility that is not delegated to the President and Chief Executive Officer or a Committee remains with the Boards of Ultima, who have not yet developed formal position descriptions. The Boards of Ultima have set the strategic objectives for Ultima, Ventures Trust, Ultima Co, AcquireCo and Ultima Energy and have approved all operating and capital budgets.

12. Establish procedures to enable the Board to function independently of management.

The Boards of Ultima have functioned, and are of the view that they can continue to function, independently of management. The Chairman of each of the Boards of Ultima, Mr. Marshall Williams, is not a member of management and is an "outside" and "unrelated" director. The Chairman is responsible for ensuring that the directors discharge their responsibilities effectively.

The Boards of Ultima and any Committee of the Boards of Ultima can meet without management whenever appropriate or deemed necessary.

13. Establish an Audit Committee with a specifically defined mandate (all members should be non-management directors).

The Ultima Board of Directors has established an Audit Committee. The Ultima Board of Directors has determined that all members of this committee are financially literate and that at least one member has accounting or related financial expertise. The Audit Committee communicates directly with Ultima's external auditors, both with management and independent of management, and is responsible for monitoring the preparation and audit of Ultima's financial statements and the establishment of appropriate internal controls. The Audit Committee and the Ultima Board of Directors has adopted "Terms of Reference" which outlines the purpose of the Audit Committee, its composition, procedures, organization, role and responsibilities.

14. Implement a system to enable individual directors to engage outside advisors, at Corporation's expense.

The Boards of Ultima support the engagement of separate professional advisors (e.g., financial, legal or other advisors) by an individual director or a Committee of directors, at the expense of Ultima, Ultima Co, AcquireCo or Ultima Energy, as the case may be, in appropriate circumstances.

PART IV - ADDITIONAL INFORMATION REGARDING PETROFUND ENERGY TRUST

General

Information with respect to Petrofund and its business, operations and affairs are included in the following (which are attached as Appendix "B" and form an integral part of this Information Circular):

1. Petrofund Energy Trust Renewal Annual Information Form dated March 15, 2004 for the year ended December 31, 2003 (the "Petrofund AIF");

2. Petrofund Energy Trust Management's Discussion and Analysis for the year ended December 31, 2003 compared to the year ended December 31, 2002;

3. Petrofund Energy Trust comparative audited consolidated financial statements as at December 31, 2003 and 2002 and for the years ended December 31, 2003, 2002 and 2001 and the auditors' reports thereon; and

4. additional information relating to Petrofund.

Petrofund's syndicated facility of $240 million as described in the Petrofund AIF under "Selected Financial and Operating Information - Credit Facility" has been extended to May 28, 2005, unless further extended.

Distributions

The following cash distributions per Petrofund Unit have been made to Petrofund Unitholders during the periods indicated below:

	2000	2001	2002	2003	2004
First Quarter..................	$0.90	$1.26	$0.43	$0.48	$0.48
Second Quarter.................	0.99	1.32	0.41	0.53	$0.48(1)
Third Quarter..................	1.02	0.93	0.42	0.54	N/A
Fourth Quarter.................	1.08	0.73	0.45	0.54	N/A
Total Annual...................	$3.99	$4.24	$1.71	$2.09	$0.96

Note:

(1) A distribution of $0.16 per Petrofund Unit was paid to Petrofund Unitholders of record on April 30, 2004. Based on current commodity prices, Petrofund expects to maintain the $0.16 distribution per Petrofund Unit for both the May and June distribution periods, which distributions reflect Petrofund's current expectation with regard to

its near term performance and are subject to change based on actual market conditions.

Cash distributions by Petrofund are payable on the last business day of each month to Petrofund Unitholders of record on the tenth business day preceding the end of such month. Former Ultima Unitholders who are Petrofund Unitholders of record on June 16, 2004 (and any subsequent record date for distributions to Petrofund Unitholders) will be entitled to receive distributions from Petrofund following the Closing Date of the Merger without any further action required on their part provided they have exchanged their certificates representing Ultima Units for Petrofund Units on or prior to the sixth anniversary of the Closing Date.

Distributions may vary significantly from period to period based on, among other things, commodity prices and production levels of Petrofund. The acquisition and development activity of Petrofund will also impact the level of distributions. Petrofund has historically been engaged in an active program of acquiring producing oil and gas properties with a view to replacing exploited reserves and increasing production per Petrofund Unit in order to enhance distributions; however, there can be no assurance that such acquisitions will continue in the foreseeable future. Distributions for any given period will also vary to the extent cash flow is utilized for debt repayment, reserved for purposes of funding future operating costs, capital expenditures, reclamation obligations, general and administrative costs or debt service charges or to the extent such reserve is utilized in a particular period. Distributions per Petrofund Unit will also vary based on the number of outstanding Petrofund Units. There is no minimum distribution payable in any period.

The twelve month trailing distributions (including April, 2004) are $2.08 per Petrofund Unit. Average prices received by Petrofund for the twelve months ended February 29, 2004 were $37.94 per Bbl before hedging ($36.79 per Bbl net of hedging) for crude oil, $6.45 per Mcf before hedging ($6.33 per Mcf net of hedging) for natural gas and $33.67 per Bbl for NGL's.

The Petrofund Board of Directors on behalf of Petrofund reviews the distribution policy from time to time. The current distribution policy allows for the payment into a reserve of a portion of the amounts that would otherwise be available for distribution to provide greater stability to distributions. Over a twelve month period, Petrofund intends to distribute the majority of its cash flow.

Trust Unit Price Range and Trading Volumes

The Petrofund Units are listed on the TSX and the AMEX. The following table shows the high, low and closing prices and volume of trading of the Petrofund Units on the TSX and the AMEX, as reported by such exchanges, for the periods indicated.

Toronto Stock Exchange				Ameri	
Unit Price Range ($)				Unit Price R	
High	Low	Close	Trading Volume	High	Lo

2002						
First Quarter...............................	14.01	11.42	13.17	8,253,120	8.86	7.
Second Quarter..............................	13.55	11.50	12.06	6,382,746	8.55	7.
Third Quarter...............................	12.70	10.01	11.80	4,617,459	8.63	6.
Fourth Quarter..............................	11.95	10.10	10.85	6,566,922	7.50	6.
2003						
First Quarter...............................	12.54	10.30	11.47	6,536,345	8.55	6.
Second Quarter..............................	13.59	10.69	13.15	15,649,323	10.06	7.
Third Quarter...............................	16.70	13.01	16.00	16,214,493	12.24	9.
Fourth Quarter..............................	19.15	15.89	18.79	14,730,252	14.73	11.
2004						
January.....................................	19.24	14.56	16.80	4,339,354	15.01	10.
February....................................	17.50	14.67	17.45	4,477,979	13.13	11.
March.......................................	18.00	15.12	17.35	4,259,182	13.65	11.
April (through April 29)....................	18.08	16.36	16.42	3,282,500	13.54	11.

On March 26, 2004, the last trading day prior to the announcement of the Merger, the closing price of the Petrofund Units on the TSX was $17.14 and on the AMEX was U.S.$12.97. On April 29, 2004, the closing price of the Petrofund Units on the TSX was $16.42 and on the AMEX was U.S.$11.95.

Information Relating to Arthur Andersen LLP

In connection with the filing of this Information Circular, Ultima would normally be required to obtain written consent from Arthur Andersen LLP, independent auditors, to the filing of their audit report on the consolidated financial statements of Petrofund for the year ended December 31, 2001 and to file that consent with this Information Circular. In addition, Petrofund would normally be required to obtain written consent from Arthur Andersen LLP, to the filing of their audit report on the consolidated financial statements of Petrofund for the year ended December 31, 2001 and to file that consent with the SEC as an exhibit to the registration statement. However, on June 3, 2002, Arthur Andersen LLP, which was an Ontario limited liability partnership, separate from Arthur Andersen LLP in the United States, ceased to practice public accounting in Canada, including at its Calgary, Alberta, Canada office, from which Petrofund was primarily serviced. As a consequence, representatives of Arthur Andersen LLP are no longer available to provide consent in connection with the filing of this Information Circular with the Canadian securities commissions and similar regulatory authorities and the filing of the registration statement with the SEC. Ultima is filing this Information Circular in Canada in reliance on a staff notice of the Canadian Securities Administrators and Petrofund has filed the registration statement with the SEC in reliance on an SEC rule, each of which relieves an issuer from the obligation to obtain the consent of Arthur Andersen LLP in certain cases.

CONSENTS

Consent of Bennett Jones LLP

TO: The Trustee of Ultima Energy Trust
The Board of Directors of Ultima Ventures Corp.
The securities commission or similar regulatory authority in each of the provinces of Canada

We hereby consent to the inclusion of and reference to our opinion contained under "Canadian Federal Income Tax Considerations" in the Proxy Statement and Information Circular of Ultima Energy Trust dated April 30, 2004 with respect to the proposed merger of Petrofund Energy Trust and Ultima Energy Trust.

Calgary, Alberta
April 30, 2004

(Signed) BENNETT JONES LLP
Bennett Jones LLP

Consent of Gilbert Laustsen Jung Associates Ltd.

TO: The Trustee of Ultima Energy Trust
The Board of Directors of Ultima Ventures Corp.
The securities commission or similar regulatory authority in each of the provinces of Canada

We hereby consent to the inclusion of and reference to our reports in the Proxy Statement and Information Circular of Ultima Energy Trust dated April 30, 2004 with respect to the proposed merger of Petrofund Energy Trust and Ultima Energy Trust.

Calgary, Alberta
April 30, 2004

(Signed) Dana B. Laustsen, P. Eng.
Gilbert Laustsen Jung Associates Ltd.

Consent of McDaniel & Associates Consultants Ltd.

TO: The Trustee of Ultima Energy Trust
The Board of Directors of Ultima Ventures Corp.
The securities commission or similar regulatory authority in each of the provinces of Canada

We hereby consent to the inclusion of and reference to our reports in the Proxy Statement and Information Circular of Ultima Energy Trust dated April 30, 2004 with respect to the proposed merger of Petrofund Energy Trust and Ultima Energy Trust.

Calgary, Alberta
April 30, 2004

(Signed) P.A. Welch, P. Eng.
McDaniel & Associates Consultants Ltd.

Consent of Collins Barrow Calgary LLP

TO: The Trustee of Ultima Energy Trust
The Board of Directors of Ultima Ventures Corp.
The securities commission or similar regulatory authority in each of the provinces of Canada

We refer to the Proxy Statement and Information Circular of Ultima Energy Trust (the "Circular") dated April 30, 2004 with respect to the proposed merger of Petrofund Energy Trust and Ultima Energy Trust.

We consent to the inclusion in the Circular of our report to the Directors of Trioco Resources Inc. ("Trioco") on the balance sheets of Trioco as at December 31, 2002 and 2001 and the statements of income and retained earnings and cashflow for each of the years then ended. Our report is dated March 31, 2003 (except for Note 9 which is dated June 20, 2003).

Calgary, Alberta	(Signed) Collins Barrow Calgary LLP
April 30, 2004	Chartered Accountants

Consent of CIBC World Markets Inc.

TO: The Trustee of Ultima Energy Trust
The Board of Directors of Ultima Ventures Corp.
The securities commission or similar regulatory authority in each of the provinces of Canada

Dear Sirs:

We refer to the Proxy Statement and Information Circular of Ultima Energy Trust (the "Circular") dated April 30, 2004 with respect to the proposed merger of Petrofund Energy Trust and Ultima Energy Trust.

We consent to the inclusion in, and the references contained in, the Circular of our fairness opinion dated April 30, 2004 to the Board of Directors of Ultima Ventures Corp. with respect to the proposed merger of Petrofund Energy Trust and Ultima Energy Trust.

Calgary, Alberta	(Signed) CIBC WORLD MARKETS INC.
April 30, 2004	CIBC World Markets Inc.

Consent of Deloitte & Touche LLP

We have read the Proxy Statement and Information Circular of Ultima Energy Trust (the "Circular") dated April 30, 2004 with respect to the proposed transaction between Petrofund Energy Trust ("Petrofund") and Ultima Energy Trust ("Ultima"). We have complied with Canadian generally accepted standards for an auditor's involvement with offering documents.

We consent to the use in the Circular of our report dated February 6, 2004 (except as to Note 19 which is as of April 30, 2004) to the Board of Directors of Petrofund Corp. on the following financial statements:

- Consolidated balance sheet of Petrofund as at December 31, 2003 and 2002; and

- Consolidated statements of operations, unitholders' equity and cash flows of Petrofund for the years ended December 31, 2003 and 2002.

We consent to the use in the Circular of our report dated February 24, 2004 (except as to Notes 14 and 15 which are as of April 30, 2004) to the Board of Directors of Ultima Ventures Corp. and Ultima Acquisitions Corp. on the following financial statements:

- Consolidated balance sheet of Ultima as at December 31, 2003 and 2002; and
- Consolidated statements of income and deficit and cash flows of Ultima for the years ended December 31, 2003 and 2002.

Calgary, Alberta (Signed) DELOITTE & TOUCHE LLP
April 30, 2004 Chartered Accountants

Disclosure in Lieu of Consent of Arthur Andersen LLP

The consolidated financial statements of Petrofund for the year ended December 31, 2001 were audited by Arthur Andersen LLP. Arthur Andersen LLP expressed an opinion without reservation on those financial statements in their report dated February 14, 2002 which is attached as part of Appendix "B" of this Information Circular. Neither Ultima nor Petrofund obtained the consent of Arthur Andersen LLP to the use of their auditors' report. The consent of Arthur Andersen LLP was not obtained because, on June 3, 2002, Arthur Andersen LLP ceased to practice public accounting in Canada. See "Additional Information Regarding Petrofund Energy Trust - Information Relating to Arthur Andersen LLP".

INTEREST OF INSIDERS IN MATERIAL TRANSACTIONS

Except as disclosed in this Information Circular, neither the Manager, nor any director or officer of Ultima Co, Ultima Energy, the Manager or AcquireCo, nor any other insider of Ultima, Ultima Co, Ultima Energy or AcquireCo, nor any proposed nominee for election as a director of Ultima Co or AcquireCo, nor any associate or affiliate of any one of them, has or has had, at any time since January 1, 2003, the beginning of the most recently completed financial year of Ultima, any material interest, direct or indirect, in any transaction or proposed transaction that has materially affected or would materially affect Ultima, Ventures Trust, Ultima Co, Ultima Energy, the Manager or AcquireCo.

INDEBTEDNESS OF DIRECTORS, EXECUTIVE OFFICERS AND SENIOR OFFICERS

None of the directors, executive officers or senior officers of Ultima Co, AcquireCo, Ultima Energy or the Manager, nor any proposed nominee for election as a director, nor any associate or affiliate of any one of them, is or has been indebted, directly or indirectly, to Ultima, Ventures Trust, Ultima Co, AcquireCo, Ultima Energy or the Manager at any time since January 1, 2003, the beginning of the most recently completed financial year of Ultima.

OTHER MATTERS

As of the date of this Information Circular, neither the Ultima Board of Directors nor management of Ultima Co knows of any amendment, variation or other matter to come before the Meeting other than the matters referred to in the Notice of Annual and Special Meeting. If any other matter properly comes before the Meeting, however, the accompanying proxies will be voted on such matter in accordance with the best judgment of the person or persons voting the proxies.

QUESTIONS AND OTHER ASSISTANCE

If you have any questions about the information contained in this Information Circular or require assistance in completing your form of proxy (printed on blue paper) or letter of transmittal (printed on yellow paper), please contact Georgeson Shareholder, the Corporation's proxy solicitation agent, at:

66 Wellington Street West
TD Tower - Suite 5210
Toronto Dominion Centre
P.O. Box 240
Toronto, Ontario, Canada M5K 1J3
Toll Free Number in Canada and U.S.A.:
1-866-800-4722

APPROVAL AND CERTIFICATION

The contents and sending of this Information Circular have been approved by the Ultima Board of Directors, for and on behalf of Ultima.

The foregoing contains no untrue statement of a material fact and does not omit to state a material fact that is required to be stated or that is necessary to make a statement not misleading in the light of the circumstances in which it was made.

DATED at Calgary, Alberta this 30th day of April, 2004.

ULTIMA ENERGY TRUST
by ULTIMA VENTURES CORP.

"S. Brian Gieni"	"Kenneth G. Pinsky"
S. Brian Gieni	Kenneth G. Pinsky
President and Chief Executive Officer	Chief Financial Officer

APPENDIX "A"

TEXT OF SPECIAL RESOLUTION OF UNITHOLDERS
OF ULTIMA ENERGY TRUST

BE IT RESOLVED AS A SPECIAL RESOLUTION THAT:

1. the Special Distribution and Merger of Petrofund and Ultima as described in the Information Circular which accompanies the Notice of

Annual and Special Meeting dated April 30, 2004 (the "Information Circular"), and upon the terms and conditions set out in the Combination Agreement, be and is hereby authorized and approved and, in order to give effect thereto, the following events are hereby authorized and shall occur and be deemed to occur in the sequence set out below without further act or formality:

(a) the Ultima Trust Indenture and other constating documents of the Ultima Parties shall be amended to the extent necessary to permit the completion of the transactions contemplated in the Combination Agreement, including, without limitation, to provide for the right of Ultima to declare and pay the Special Distribution, distribute the rights pursuant to the Unitholder Indemnity Agreement and redeem any or all outstanding Ultima Units (other than the Ultima Remaining Unit) in exchange for consideration consisting of Petrofund Units, without further notice to, agreement of, or act by, any holder of Ultima Units;

(b) all of the Ultima Assets shall be transferred to Petrofund in exchange for the assumption by Petrofund of all of the Assumed Liabilities and for the issuance by Petrofund of the Petrofund Payment Units to Ultima, with the number of such Petrofund Payment Units to be based upon the Exchange Ratio multiplied by the number of Ultima Units issued and outstanding as of the Closing Date, all as described in the Information Circular;

(c) Petrofund shall subscribe for the Ultima Payment Unit upon payment of $10.00 and Ultima shall issue to Petrofund the Ultima Remaining Unit; and

(d) the Ultima Units (other than the Ultima Remaining Unit) shall be redeemed and, upon the redemption of the Ultima Units (other than the Ultima Remaining Unit), the Petrofund Units which are issuable as contemplated by paragraph (b) above shall be distributed to Ultima Unitholders (other than Petrofund) on a proportionate basis in accordance with the Exchange Ratio, all as described in the Information Circular;

2. the directors of Ultima Co and any officer of Ultima Co be and is hereby authorized and directed to execute on behalf of Ultima, Ultima Co, AcquireCo, Ventures Trust, Ultima Energy or the Manager and to deliver and to cause and be delivered, all such documents, agreements and instruments and to do or cause to be done all such other acts and things as they shall determine to be necessary or desirable in order to carry out the intent of the foregoing resolutions and the matters authorized thereby, such determination to be conclusively evidenced by the execution and delivery of such document, agreement or instrument or the doing of any such act or thing;

3. the Ultima Board of Directors is authorized to revoke this resolution for any reason whatsoever in its sole and absolute discretion, without further approval of the Ultima Unitholders at any time prior to the completion of the Merger; and

4. all capitalized terms not otherwise defined in this Ultima Special Resolution have the meanings ascribed thereto in the Information Circular.

APPENDIX "B"

INFORMATION RELATING TO PETROFUND ENERGY TRUST

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PETROFUND ENERGY TRUST

RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2003

March 15, 2004

TABLE OF CONTENTS

INFORMATION PREPARED BY PETROFUND CORP.

The information contained in this annual information form has been prepared by Petrofund Corp., who manages the Trust.

FORWARD-LOOKING STATEMENTS

Some of the statements contained herein including, without limitation, financial and business prospects and financial outlooks, may be forward-looking statements which reflect management's expectations regarding future plans and intentions, growth, results of operations, performance and business prospects and opportunities. Words such as "may", "will" "should", "could", "anticipate", "believe", "expect", "intend", "plan", "potential", "continue" and similar expressions have been used to identify these forward-looking statements. These statements reflect management's current beliefs and are based on information currently available to management. Forward-looking statements involve significant risk and uncertainties. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements including, but not limited to, changes in general economic and market conditions and other risk factors. Although the forward-looking statements contained herein are based upon what management believes to be reasonable assumptions, we cannot assure that actual results will be consistent with these forward looking statements. Investors should not place undue reliance on forward-looking statements. These forward-looking statements are made as of the date hereof and we assume no obligation to update or revise them to reflect new events or circumstances.

Forward-looking statements and other information contained herein concerning the oil and gas industry and our general expectations concerning this industry is based on estimates prepared by us using data from publicly available industry sources as well as from reserve reports, market research and industry analysis and on assumptions based on data and knowledge of this industry which we believe to be reasonable. However, this data is inherently imprecise, although generally indicative of relative market positions, market shares and performance characteristics. While we are not aware of any misstatements regarding any industry data presented herein, the industry involves risks and uncertainties and is subject to change based on various factors.

DOLLAR AMOUNTS

Unless otherwise specified, all dollar amounts set out in this annual information form are in Canadian dollars.

GLOSSARY OF TERMS

The following terms used herein have the meanings set out below:

AECO: The regional pricing hub for natural gas located at the storage facilities of Alberta Energy Company near Medicine Hat, Alberta.

Aggregate Equivalent Vote Amount: With respect to any matter, proposition or question on which Unitholders are entitled to

	vote, consent or otherwise act, the number of votes that the holder of a Special Voting Unit would be entitled to had the holder exchanged all of the Exchangeable Shares held by the holder for Petrofund Units immediately prior to the record date set for any such meeting.
bbl:	Barrel.
bcf:	Billions of cubic feet.
Board or Board of Directors:	The board of directors of PC.
boe:	Barrels of oil equivalent, using a conversion factor of 6 mcf of gas being equivalent to one bbl of oil and one bbl of NGLs being equivalent to one bbl of oil.
boepd:	Barrels of oil equivalent per day.
bpd:	Barrels of oil or NGLs per day.
Cash Retraction Notice:	A notice to redeem PC Exchangeable Shares exercisable for a period of 5 business days from the date of expiry of the subject Dividend Period.
Current Market Price:	In respect of a Unit on any date, the weighted average trading price of a Unit on the TSX for the 10 trading days preceding that date.
Distribution Payment Date:	Each date from and after the effective date on which a distribution is paid to Unitholders.
Distribution Record Date:	In respect of any distribution, the day on which Unitholders are identified for purposes of determining entitlement to such distribution.
Dividend Period:	A period within two business days of a Distribution Payment Date.
Drip Price:	In respect of a Unit on any Valuation Date, the most recently applicable price at which a holder of a Unit is entitled to purchase a Unit in respect of the Distribution to which the subject Valuation Date relates pursuant to any distribution re-investment plan which Petrofund may have in effect on such Valuation Date and which is available to the holders of Units generally.
Established Reserves:	Company interest reserves (proved plus 50% probable) prior to royalties that conform to National Policy Statement 2-B.
Exchange Ratio:	At any time and in respect of each PC Exchangeable Share, shall initially be equal to one, and provided that PC shall not have declared a dividend in respect of the subject Dividend Period, shall be cumulatively increased on the expiry date of each Dividend Period by an

amount equal to the (i) fraction having as its numerator the Per Share Dividend Amount relating to the subject expired Dividend Period, and having as its denominator the Current Market Price on the Valuation Date, or (ii) in the event that: (a) as at the subject Valuation Date, the Trust has in place a distribution re-investment plan which is available to the holders of Units generally, and (b) the holder has not delivered a Cash

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Retraction Notice in respect of the Distribution to which the expired Dividend Period relates within the time period provided for, the fraction having as its numerator the Per Share Dividend Amount relating to the subject expired Dividend Period, and having as its denominator the Drip Price in effect as at the Valuation Date.

gj:	Gigajoule.
GLJ:	Gilbert Laustsen Jung Associates Ltd., independent oil and gas reservoir engineers of Calgary, Alberta.
GLJ Report:	The report prepared by GLJ dated February 17 2004 with respect to the petroleum, natural gas and NGL reserves of PC effective as at December 31, 2003.
Internalization Transaction:	The transaction approved at the annual and special meeting of Unitholders held on April 16, 2003 under which management of the Trust was internalized through the acquisition by PC of all of the issued and outstanding shares of NCEP Management and the consequent elimination of all management, acquisition and disposition fees payable to NCEP Management.
Management Agreement:	The amended and restated management, advisory and administration agreement made as of January 1, 2002 among PC, the Trust and NCEP Management.
mbbls:	Thousands of barrels.
mboe:	Thousands of barrels of oil equivalent.
mcf:	Thousands of cubic feet.
mcfe:	Thousands of cubic feet of natural gas equivalent, using a conversion factor of one barrel of oil and one barrel of NGL's being equivalent to 6 mcf of gas.

mcfepd:	Thousands of cubic feet of natural gas equivalent per day.
mcfpd:	Thousands of cubic feet per day.
mlt:	Thousand long tons.
mmboe:	Millions of barrels of oil equivalent.
MMBtu:	Millions of British Thermal Units
mmcf:	Millions of cubic feet.
mmcfpd:	Millions of cubic feet per day.
M$:	Thousands of dollars.
MM$:	Millions of dollars.
NCEP Management:	NCE Petrofund Management Corp., the previous manager.
NCE Services or NMSI:	NCE Management Services Inc.
netback:	The amount received from the sale of a barrel of oil or barrel of oil equivalent after deduction of operating costs and royalty payments.
NGL or NGLs:	Natural gas liquids.
PC:	Petrofund Corp.
PC Exchangeable Share Provisions:	The rights, privileges and conditions attaching to the PC Exchangeable Shares set forth in the Articles of PC.

PC Exchangeable Shares:	Non voting exchangeable shares in the capital of PC.
PC Support Voting and Exchange Agreement:	The agreement dated April 29, 2003 between PC, the Trust, 1518274 Ontario Limited ("Exchangeco."), and Petro Assets Inc. ("Petro Assets") whereby PC will take certain actions and make certain payments and deliveries necessary to ensure that the Trust and Exchangeco. will be able to make certain payments and to deliver or cause to be delivered Units in satisfaction of the obligations of the Trust and Exchangeco under the PC Exchangeable Share Provisions and the Unanimous Shareholders Agreement.
Per Share Dividend Amount:	A distribution relating to the subject Distribution Payment Date multiplied by the Exchange Ratio.

Petro Assets:	Petro Assets Inc.
Petrofund or the Trust:	Petrofund Energy Trust.
Properties:	The interests, including working interests and unit interests, in petroleum and natural gas rights held by PC.
Redemption Date:	The date which is 60 days after the date of delivery of a Redemption Notice.
Redemption Price:	A price per PC Exchangeable Share equal to the amount determined by multiplying the Exchange Ratio on the last business day prior to the applicable Redemption Date by the current market price on the last Business Day prior to such Redemption Date.
Retracted Shares:	Means the number of Exchangeable Shares redeemed in accordance with a Cash Retraction Notice.
Retraction Date:	The date that is 5 Business days after the date on which PC receives a retraction request in respect of the Retracted Shares.
Royalty Agreement:	The amended and restated royalty agreement dated as of April 16, 2003 between PC and the Trust.
Special Resolution:	A resolution approved in writing by Unitholders holding not less than 66 2/3% of the outstanding Trust Units or passed by a majority of not less than 66 2/3% of the votes cast, either in person or by proxy, at a meeting of the Unitholders called for the purpose of approving such resolution.
Tax Act:	Income Tax Act (Canada), as amended.
TSX:	Toronto Stock Exchange.
Trustee:	Computershare Trust Company of Canada, as trustee of the Trust.
Trust Indenture:	The amended and restated trust indenture made as of April 16, 2003 between PC and the Trustee.
Trust Unit or Unit:	A trust unit created pursuant to the Trust Indenture and representing a fractional undivided interest in the Trust.
Unanimous Shareholder Agreement:	The unanimous shareholder agreement made as of November 1, 2000 among PC, the Trust and NCEP Management.
Unitholder:	A holder from time to time of Trust Units.
Valuation Date:	The first Business Day following the Distribution Record Date in respect of the Distribution to which the expired Dividend Period relates.

PETROFUND ENERGY TRUST
RENEWAL ANNUAL INFORMATION FORM
FOR THE YEAR ENDED DECEMBER 31, 2003
DATED March 15, 2004

PETROFUND ENERGY TRUST

The Trust

The Trust is an open-ended investment trust created under the laws of the Province of Ontario on December 18, 1988 under the name "NCE Petrofund I". Active operations commenced March 3, 1989. On July 4, 1996, the name of the Trust was changed to "NCE Petrofund" and on November 1, 2003 the name was changed to its present name of "Petrofund Energy Trust". Effective September 7, 2001, the Trustee became the trustee of the Trust. The Trust is currently governed by the Trust Indenture.

The executive office was relocated from 130 King Street West, Suite 2850, Toronto, Ontario, M5X 1A4 in conjunction with the internalization of management. The executive office, head office and operations of the Trust are now located at Suite 600, 444 - 7th Avenue S.W., Calgary, Alberta, T2P 0X8.

The Trust's primary source of income is from 99% net royalty interests granted by PC, its wholly-owned subsidiary. PC is a corporation incorporated under the laws of Alberta. PC acquires, manages and disposes of petroleum and natural gas rights and royalties and related property rights and interests located primarily in western Canada. In addition, PC may acquire royalties or other property interests or securities of other resource issuers. The Trust may also purchase directly or indirectly securities of oil and gas companies, oil and gas properties and other related assets.

The following chart shows the structure of the Trust at the date hereof:

```
                             UNITHOLDERS
                                  |
                                  |    Trust Units
                                  |
                           ---------------
                              PETROFUND
                           ---------------
                                  |
           99% Net Royalty Interests   |    100% of Capital Stock
                            |     |
                            |     |
                           ---------------
                           PETROFUND CORP.
                           ---------------
                                  |
                                  |    Working Interests
                                  |
                           ---------------
                             OIL AND GAS
                              PROPERTIES
                           ---------------
```

Each Trust Unit represents an equal undivided beneficial interest in the assets of the Trust. Historically, the Trust's activities have been focused on the acquisition of net royalties from PC. For each property for which a net royalty is granted by PC, the Trust receives 99% of the revenue generated by the property net of operating costs, management fees (prior to 2003), debt service charges, general and administrative costs and certain other taxes and charges. The Trust distributes to its Unitholders a majority of its cash flow in the form of monthly distributions, part of which is on a tax-advantaged basis. Cash flow includes royalty income and may include cash flow generated by properties and interests not currently subject to the Trust's net royalty interests.

The Trust was initially formed as a closed-end royalty trust for the purposes of acquiring royalty interests from PC. Effective February 2, 1999, the Trust was converted to an open-ended investment trust. The Trust Indenture, Royalty Agreement and related agreements were amended to: (i) permit the Trust and PC to acquire, directly or indirectly, interests in resource issuers and/or resource properties and other related assets; (ii) remove certain financing restrictions applicable to the Trust and PC to permit the Trust and PC, subject to certain limitations, to raise or issue capital in connection with, or to finance, such acquisitions, either through the issuance of Trust Units or other equity or debt securities of the Trust or PC or through borrowing; and (iii) provide that Unitholders have the right to cause the Trust to redeem their Trust Units in certain circumstances.

Effective November 1, 2000, the Trust acquired all of the issued and outstanding shares of PC from a subsidiary of NCEP Management for nominal consideration, resulting in PC becoming a wholly-owned direct subsidiary of the Trust. This change simplified the structure of the Trust and related entities and allows the Trust to present consolidated financial statements which fully reflect the assets and liabilities of the Trust and PC.

In conjunction with PC becoming a wholly-owned subsidiary of the Trust, the corporate governance of the Trust was changed so that the stewardship of the Trust and PC was undertaken by the Board of Directors of PC.

Management of the Trust

On January 1, 1990 PC entered into the Management Agreement, under which it retained the services of NCEP Management to identify, assess and assist in the acquisition, disposition and ongoing management of the Trust's properties and to administer its net royalties and other assets. Management of the Trust is now carried out directly by directors, officers and other employees of PC, see "Governance of the Trust and PC - Management Agreement" and "Internalization of Management".

Employees and Consultants

As at December 31, 2003 PC had 90 office employees and 18 full time consultants. PC also has 31 direct field employees and a number of contractors to manage its field operations.

Internalization of Management

On March 10, 2003, the Trust entered into an agreement to internalize its management structure such that NCEP Management, the then manager of the Trust, became a wholly owned subsidiary of PC. Unitholder and regulatory approval of the Internalization Transaction was received at the annual and special meeting of Unitholders held on April 16, 2003. As a result of the

Internalization Transaction, all management, acquisition and disposition fees payable to NCEP Management were eliminated effective January 1, 2003. The cost of the Internalization Transaction was $30.9 million including $2.5 million of transaction costs, all of which was expensed to the income statement. The transaction was effected in the following manner:

- Prior to the closing, NCEP Management acquired NMSI (which employed all of the Calgary-based personnel who provided services to the Trust and PC on behalf of NCEP Management).

- At the closing, PC purchased all of the issued shares of NCEP Management from Petro Assets Inc. for $21.7 million. Petro Assets Inc. is owned by the Driscoll Family Trust (a trust established for the family of John F. Driscoll). John Driscoll was Chairman and Chief Executive Officer of PC at closing.

- The purchase price for the shares of NCEP Management was satisfied by the issuance of 1,939,147 PC Exchangeable Shares, plus a cash amount per PC Exchangeable Share equal to the distributions paid or payable per Trust Unit by the Trust to Unitholders of record from and after January 1, 2003 up to and including the closing date. Initially each PC Exchangeable Share was exchangeable into one Trust Unit. The exchange rate is adjusted from time to time to reflect distributions paid on each Trust Unit after the closing date. Each PC Exchangeable Share was initially ascribed a value of $12.1703, representing the weighted average trading price of the Trust Units over the 10 trading days, ending on March 4, 2003 on the TSX. For accounting purposes the PC Exchangeable Shares were deemed to be issued at a value of $11.20 per share being the average trading value of the Trust Units for the last ten days prior to the closing date.

- At closing, PC paid $3.4 million in cash to fund the repayment of indebtedness owing by NCEP Management. In addition, as part of the Internalization Transaction NMSI paid certain senior executives of NCEP Management $780,000 in cash and issued 100,244 Trust Units plus an amount per Trust Unit equal to the distributions per Trust Unit paid to holders of record of Trust Units during the period commencing on January 1, 2003 and ending on the closing date.

Subsequent to the closing of the Internalization Transaction, the Trust proceeded to consolidate all activities in PC's offices in Calgary, Alberta. To ensure an orderly transition of the services then provided by NCEP Management through its office in Toronto, Ontario, Sentry Select Capital Corp. ("Sentry") entered into an agreement on closing, which was effective January 1, 2003, with the Trust, PC and NCEP Management to provide certain of these services to the Trust and PC at Sentry's cost until December 31, 2003, subject to a maximum cost of $2 million. After December 31, 2003, Sentry no longer provides any services. At closing Sentry was an affiliate of NCEP Management and is a company in which John F. Driscoll owns a controlling interest.

As part of the agreement, all management fees and acquisition and disposition fees were eliminated retroactive to January 1, 2003.

Strategy

The Trust's objective is to maximize cash flow for distribution to its Unitholders. The Trust intends to execute its business strategy by:

- continuing to pursue selected acquisitions that meet its portfolio acquisition criteria;
- continuing to develop its existing properties to enhance production and increase reserves;
- maintaining a balanced portfolio of geographically and geologically diversified oil and gas properties;
- controlling costs through efficient operation of existing and acquired properties;
- maintaining a capital structure that provides flexibility in accessing debt and capital markets;
- and managing commodity price risk when appropriate through hedging agreements that will increase the level of predictability in prices for its oil and gas production.

Acquisition Criteria

The Royalty Agreement requires PC to comply with the following criteria and procedures before purchasing a property:

- Properties will be acquired with the objective of providing Unitholders with an average annual net yield after all costs but before income taxes of at least 15% over the first five years from the date of acquisition and at least a 15% internal rate of return over the life of the reserves after all costs but before income taxes.
- At least 70% of the purchase price of all gas and oil properties must be represented by proved reserves.
- At least 50% of the properties purchased will be estimated to be producing for 20 years following their acquisition, based on independent engineering reports.
- Generally accepted industry practices and procedures will be employed in investigating title to the properties.
- No property having an acquisition cost of $10 million or more will be acquired unless a report has been obtained from an independent engineering consultant.
- Where the acquisition price of a property has not been determined by arm's length negotiations, the price will be no greater than the fair market value of the property at the time of acquisition as determined by an independent engineering consultant.
- The amount of anticipated future capital expenditures for a property will not be significant and such expenditures will be of the type which are intended to maintain, realize or improve production from the properties.

In addition to the above, the Trust's properties, in aggregate, must be geographically and geologically diversified. Not more than 25% of the asset value of all the Trust's properties may be attributable to a single reservoir. The Trust's properties will be located primarily in western Canada (namely, British Columbia, Alberta, Saskatchewan and Manitoba). At the time of each acquisition, after giving effect to the proposed acquisition, not more than 10% of the asset value of the Trust's properties may be represented by properties located outside of western Canada. All of the Trust's properties must be located in Canada. Asset value is the fair market value of the property as estimated by the Board of Directors based on the most recent independent engineering report respecting such property. If there is a material change to such property, a new report will be prepared and used to determine the fair market value of such property.

The foregoing acquisition criteria apply only to the Trust's property acquisitions. The foregoing criteria may only be amended by Special Resolution. Although the Trust is not required to apply these criteria when it acquires oil and gas companies, as a matter of policy, the Trust is generally guided by the same criteria. In addition, the Trust Indenture requires that any such acquisition will be subject to standard industry due diligence procedures and a favourable valuation report.

In the event of a sale of a property, the Board of Directors must make a determination as to whether the proceeds of the sale will be reinvested in additional properties or assets or will be distributed to the Unitholders, in each case after repayment of such portion of the outstanding indebtedness as PC may determine. A sale involving more than 35% of the asset value of all properties requires the approval of the Unitholders by Special Resolution.

Key Factors for Success

The success of the Trust in meeting its objectives lies in management's ability to positively influence three main factors:

1) Identify, pursue and acquire oil and gas properties and/or companies at prices which meet the acquisition criteria previously mentioned and add value to the Trust;

2) Cost effectively add or extend reserves with farmouts and internal development and drilling; and,

3) Manage and contain costs.

PC's ability to achieve these three factors depends mainly on the experience, knowledge, and capability of the management team. In addition to the factors over which management has influence, there are numerous other factors beyond management's control which will influence the success of the organization. These other potential risks are identified in the Risk Factors section of this document.

GENERAL DEVELOPMENT OF THE BUSINESS OF THE TRUST

Financings

The Trust was established in 1988 to raise funds for the purposes of acquiring royalties from PC. On July 6, 2001, the Trust Units were consolidated on a one-for-three basis. All relevant figures, including Trust Units outstanding, net income per Trust Unit and distributions per Trust Unit, have been restated to reflect this consolidation.

During the last three years, the Trust completed the following public offerings of Trust Units:

Date	Trust Units	Price	Gross Proceeds
April, 2001	13,600,000*	$ 5.50*	$ 74,800,000*
August, 2001	3,450,000	15.00	51,750,000
November, 2001	3,200,000	12.75	40,800,000
March, 2002	4,600,000	13.00	59,800,000
May, 2003	9,200,000	10.60	97,520,000
December, 2003	6,600,000	$16.20	$ 106,920,000

*Prior to the 3 for 1 consolidation of the units on July 6, 2001.

Acquisitions

2001

Apache Properties

Effective January 1, 2001, PC purchased a 50% interest in a diverse group of oil and gas producing properties from a major oil and gas company for $23.8 million. The acquisition added 3.7 mmboe of Established Reserves, at a cost of $6.40 per boe, and 702 boepd of production. The reserves and production were 57% gas.

Strachan

On March 6, 2001, PC closed the purchase of an interest in a gas producing property in Strachan, Alberta from a major Canadian oil and gas producer. The purchase price was $9.5 million. The acquisition added approximately 1.2 million boe of Established Reserves and 270 boepd of production.

Magin Energy Inc.

In July 2001, PC completed the acquisition of Magin Energy Inc., a company listed on the TSX. The purchase price consisted of $58.6 million in cash and 8.5 million Trust Units. PC also assumed $43.7 million of debt, including negative working capital, the outstanding bank loan and capital leases, and incurred other transaction costs of $11.8 million (comprised principally of brokers' fees, severance costs and an acquisition fee of $4.4 million paid to NCEP Management) and received net stock option proceeds of $6.9 million. In consideration for the delivery of such Trust Units, the Trust received promissory notes of PC in the aggregate amount of $157.1 million. Magin Energy was amalgamated into PC and a royalty was granted in the Magin Energy properties in favour of the Trust. Cash flow from the Magin Energy properties is paid to the Trust as royalty income and as payment on the promissory notes.

Magin Energy was a Canadian oil and gas exploration and production company whose principal areas of operation were Alberta and Saskatchewan. Prior to the completion of the acquisition of Magin Energy, Magin Energy sold its interest in a property known as the Copton property.

As a result of the acquisition, PC acquired Established Reserves of 29 mmboe and production of 9,000 boepd at the time of the acquisition at an effective purchase price of $9.17 per Established Reserves boe. The reserves and production were 50% gas. The reserve life index for the Magin Energy properties at December 31, 2000 was 7.5 years. Over 90% of the Magin Energy properties were operated by Magin Energy, and are now operated by PC. The Magin Energy properties are located in areas with year round road access and this, along with the multiple geological zone potential, is expected to help keep development costs at or below the average for the area. As a result of the Magin Energy acquisition, PC also acquired undeveloped land of 345,080 net (460,287 gross) acres.

Swan Hills

Effective November 1, 2001, PC acquired a 1.2% interest in the Swan Hills Unit #1 along with other minor interests in the Swan Hills area from a Large independent U.S. oil and gas company. The transaction closed on February 26, 2002. The purchase price was $12.3 million. The acquisition added approximately 2.5 million boe of Established Reserves and 400 boepd of production.

On December 31, 2001, PC acquired a 1.4% interest in the Swan Hills Unit #1 in north central Alberta from a large independent U.S. oil and gas company for $7.5 million. The acquisition added approximately 2.2 million boe of Established Reserves and 300 boepd of production.

2002

Central Alberta

Effective March 2002, PC acquired two gas properties and two oil properties in Central Alberta for $40.2 million. Three of the properties are unitized and one is operated. Net Established Reserves acquired were estimated at 8.8 million boe and net production at date of acquisition was approximately 1,800 boepd consisting of 67% oil. The properties had a reserve life index in excess of 13 years.

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NCE Energy Trust

On May 30, 2002, PC completed the acquisition of NCE Energy Trust, a royalty trust listed on the TSX. The acquisition was completed through the exchange of 0.2325 of a unit of PC for each unit of NCE Energy Trust. The total price of the transaction was $140.1 million comprised of 7.6 million Trust Units with an assigned value of $98.6 million, the assumption of $39.5 million of debt and negative working capital, and transaction costs of $2.0 million. A non-cash amount of $27.1 million was added to oil and gas properties to reflect the difference between the cost and the tax basis of the properties acquired.

As a result of the acquisition, PC acquired Established Reserves of 13.9 mmboe and production of 5,300 boepd at an effective purchase price of $10.08 per boe and $26,400 per boepd. The reserves and production were approximately 50% gas and the reserve life index for these properties was 7.2

years. The NCE Energy Trust properties are located in British Columbia, Alberta and Saskatchewan. Over 50% of the production was operated by NCE Energy Trust and is now operated by PC. Approximately 30% of the production and reserves in NCE Energy Trust were common with or adjacent to PC properties.

The Trust and NCE Energy Trust were managed by affiliated management companies. Although it was concluded that the acquisition was not a "related party transaction" within the meaning of certain Canadian securities laws, because of the fact that the Trust and NCE Energy Trust were managed by management companies that were under common control, the acquisition was effectively treated as a related party transaction. As such, certain valuation, disclosure and minority approval requirements were complied with. A valuation of each of the Trust and NCE Energy Trust was completed by Sayer Securities Limited. The valuation report, dated April 19, 2002, concluded that a reasonable range of the fair market value for the units of the Trust was a low of $11.39 and a high of $14.29 and that a reasonable range of the fair market value for the units of NCE Energy Trust was a low of $2.59 and a high of $3.29. The acquisition was negotiated on an arm's length basis on behalf of the Trust and NCE Energy Trust by a special committee of the board responsible for each respective entity.

ATCO

On December 31, 2002, PC acquired producing gas properties in the Fort Saskatchewan, Alberta area from ATCO Gas for $31.5 million. PC now operates the properties and holds an average 95% working interest. Production net to PC was approximately 6 mmcfpd and the Established Reserves acquired were approximately 19 bcf.

2003

Solaris

Effective January 1, 2003, PC acquired 100% of the outstanding common share of Solaris Oil & Gas Inc. ("Solaris"), and on February 7, 2003, amalgamated Solaris in PC. PC paid $7.4 million in cash, and assumed debt and negative working capital of $1.2 million, for a total cost of the oil and gas properties of $8.6 million. The acquisition added 720,000 boe of Established Reserves and approximately 200 boepd of production.

Property Package

In the second quarter of 2003, PC closed the acquisition of a diverse group of oil and gas properties for $61.7 million after adjustment. The purchase was accretive to distributable cash flow, production from the properties was approximately 2,300 boepd of which 42% was gas. Production and cash flow for the month of June has been included in this report. Net revenue of $4.3 million from the effective date to May 31, 2003 was applied against the purchase price. The properties contain a large percentage of unit production, and have an RLI of 11.6 years.

Swan Hills

On August 21, 2003, PC purchased a 7.22% interest in Swan Hills Unit #1 for $37.1 million from a private Canadian company. This acquisition increased the Trust's interest in the Unit, bringing the Trust's total interest in the

Unit to 9.87%. This acquisition added 8.5 mmboe of Established Reserves and approximately 1,100 boepd of production. The property's RLI was over 20 years.

BUSINESS AND PROPERTIES

PC acquires, manages and disposes of petroleum and natural gas property rights and interests. As of December 31, 2003, PC's principal properties were located in Alberta, British Columbia, Manitoba and Saskatchewan. PC primarily produces light and medium oil, natural gas and natural gas liquids. As at December 31, 2003, PC's asset base included proved plus probable reserves (before deduction of royalties) of 53.4 mbbls of oil, 248.7 bcf of natural gas and 7.2 mbbls of natural gas liquids based on forecast prices and cost assumptions, and an inventory of undeveloped land totaling 534,589 gross acres and 250,509 net acres. See "Statement of Reserves Data and Other Oil and Gas Information - Disclosure of Reserves Data" and "Statement of Reserves Data and Other Oil and Gas Information - Properties With No Attributed Reserves".

One of PC's ongoing objectives is to enhance reserves and production through acquisitions. With respect to acquisitions, PC operates in a competitive environment with both large and small competitors.

In 2003, PC acquired new properties for a total purchase price of $58.4 million and expended approximately $57.2 million to increase interests in existing properties. PC disposed of properties for total proceeds of $33.5 million. In addition, PC incurred approximately $71.4 million mainly for drilling, well equipment and facility costs.

The following is a summary of PC's properties as at December 31, 2003. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2003. Reserve amounts are stated, before deduction of royalties, as at December 31, 2003 based on forecast costs and price assumptions as evaluated in the GLJ Report. The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Property Name	Operator	Average Working Interest	Major Product	2003 Average Production (boepd)	Prov P R
Swan Hills	Various		Oil	2,300	
Weyburn	PanCanadian	9.3%	Oil	2,000	
Pembina	Various		Oil & Gas	1,200	
Hatton	Apache	95.0%	Gas	1,100	
Strachan	Various		Oil & Gas	1,225	
Ring Border	Burlington Resources	9.4%	Gas	750	
July Lake	Canadian Natural Resources	35.0%	Gas	1,200	
Fort St. John	Petrofund and Others		Oil & Gas	775	
Fort Saskatchewan	Petrofund	97.0%	Gas	850	
Minehead	Shiningbank Energy	35.0%	Gas	500	
Others	Various	Various	Oil & Gas	16,518	
				28,418	

Weyburn, Saskatchewan

The Weyburn Unit, operated by EnCana Oil & Gas Partnership, is located 30 kilometres south of the city of Weyburn in southeastern Saskatchewan. Petrofund owns a 9.3% interest in the Weyburn Unit following the acquisition of an additional 2.3% unit interest in 2003. This unit has an especially long reserves life index (20+ years) due to ongoing enhanced recovery operations by water and CO2 flooding. The unit's 2003 performance exceeded budget expectations. 2003 development activity included further expansion of the CO2 flood, horizontal drilling (10 producers within the waterflood area and 2 injectors within the CO2 flood area) and the commencement of pre-engineering work on Phase 4 of the CO2 flood. Petrofund's unit working interest production averaged 2,000 boepd in 2003. Petrofund's total proved plus probable reserves as of December 31, 2003, amounted to 14,012 mboe consisting of 13,655 mbbl of oil and 357 mbbl of NGL.

Swan Hills, Alberta

Petrofund's Swan Hills (including Swan Hills North) property is located approximately 200 kilometres northwest of Edmonton, Alberta and includes significant ownership in such major oil units as Swan Hills Unit #1, Judy Creek West Beaverhill Lake Unit, South Swan Hills Unit and House Mountain Unit #1. Each of these units has long life reserves due to enhanced recovery through water flooding and/or miscible hydrocarbon flooding. Early in 2003, Petrofund significantly increased its Swan Hills Unit #1 ownership from 2.6% to 9.9% through an acquisition. In addition, 6 horizontal wells were drilled in House Mountain Unit #1 and 2 verticals wells in Swan Hills Unit #1. The Swan Hills Unit #1 owners agreed to implement a pilot CO2 enhanced recovery project that's expected to start up in early 2004. At yearend, Petrofund's working interest Swan Hills production was 2,300 boepd. Petrofund's total proved plus probable reserves as of December 31, 2003, totaled 14,424 mboe, consisting of 12,654 mbbl of oil, 4.2 bcf of gas and 1,074 mbbl of NGL.

Pembina, Alberta

Petrofund's extensive Pembina holdings are situated 100 kilometres southwest of Edmonton, Alberta. Petrofund operates several Pembina properties, including Alder Flats, Cynthia, Lodgepole, Pembina, Rose Creek and Warburg. Partner operated properties include North Pembina Cardium Unit, Berrymoor Cardium Unit, Pembina Cardium Unit #7, Pembina Easyford Cardium Unit #1, Lobstick Cardium Unit and Pembina Knobhill Belly River Unit #2. Development activity in 2003 included the drilling of approximately 40 gross wells and continued optimization/reactivation of several unit waterfloods. Petrofund anticipates a similar number of wells being drilled on its properties next year. Petrofund's working interest Pembina averaged 1,200 boepd during 2003. Petrofund's total proved plus probable reserves as of December 31, 2003, totaled 8,815 mboe, comprising of 6,753 mbbl of oil, 8.9 bcf of gas and 576 mbbl of NGL.

Hatton, Saskatchewan

Petrofund's Hatton gas property is located approximately 140 kilometres west of Swift Current, Saskatchewan. Petrofund operates 265 shallow gas wells, including 74 new 100% working interest wells drilled in late 2003. Petrofund's production originates from the shallow (500 metres) commingled Medicine Hat and Milk River sand zones. At yearend, Petrofund's working interest production was 1,100 boepd. Petrofund's total proved plus probable reserves as of December 31, 2003, were 4,100 mboe, comprising of 24.6 bcf of gas.

Strachan-Caroline, Alberta

Petrofund's Strachan-Caroline property is located approximately 160 kilometres northwest of Calgary and consists of a combination of operated and non-operated producing entities. Petrofund operates approximately

85% of its Strachan-Caroline production. This area is well-known for its multiple targets as evidenced by Petrofund's production coming from a variety of zones such as the Leduc, Beaverhill Lake, Cardium, Viking, Ostracod, Glauconite and Lower Mannville. In 2003, Petrofund successfully completed, equipped and tied in 2 operated gas wells that had been drilled in late 2002. Petrofund's working interest production averaged 1,225 boepd in 2003. Petrofund's total proved plus probable reserves as of December 31, 2003, were 3,963 mboe, made up of 67 mbbl of oil, 17.8 bcf of gas and 924 mbbl of NGL.

Border Bluesky, British Columbia

Petrofund's Border Bluesky gas property is located 190 kilometres northeast of Fort St. John in northeastern British Columbia and is operated by Burlington Resources Canada. Petrofund owns a 9.4% interest in the Border Bluesky-Gething-Montney Unit "B" and a similar interest in certain surrounding non-unit lands. Petrofund also has ownership in the Border gas plant. Sixteen unit and non-unit wells were drilled and equipped in early 2003. A similar infill drilling program is planned for early 2004 (winter access only). Petrofund's 2003 working interest production averaged 750 boepd. Petrofund's total proved plus probable reserves as of December 31, 2003, were 3,941 mboe, comprising of 20.9 bcf of gas and 450 mbbl of NGL.

July Lake, British Columbia

Petrofund's July Lake property is situated approximately 160 kilometres northeast of Fort Nelson in northeastern British Columbia. Petrofund holds an average 34% working interest in 19 producing gas wells, several of which are horizontals, within a Production Sharing Area operated by Canadian Natural Resources Limited. Petrofund also owns 100% working interest in nine additional gas wells. All gas production comes from the Jean Marie formation and is processed at Duke's Fort Nelson gas plant. No wells were drilled on Petrofund lands in 2003 but as many as 8 wells could be drilled in 2004. Petrofund's working interest production averaged 1,200 boepd during 2003. Petrofund's total proved plus probable reserves as of December 31, 2003, were 3,175 mboe, consisting of 19.0 bcf of gas and 8 mbbl of NGL.

Fort St. John, British Columbia

Petrofund's Fort St. John property is located close by the city of the Fort St. John in northeastern British Columbia. Petrofund's operated entities include Boundary Lake, Cecil Lake, Fort St. John and Wilder, while non-operated entities include West Eagle and Stoddart. During 2003, Petrofund successfully drilled 2 operated Boundary Lake wells, plus completed, equipped and tied in 2 operated Cecil Lake oil wells that had been drilled late in 2002. Petrofund is moving ahead with plans to waterflood its Cecil Lake property in 2004. Petrofund is also contemplating follow-up drilling on its Boundary Lake and Cecil Lake oil properties in 2004. Petrofund's working interest production from this property averaged 775 boepd during 2003. Petrofund's total proved plus probable reserves as of December 31, 2003, totaled 3,031 mboe, containing 1,417 mbbl of oil, 8.1 bcf of gas and 267 mbbl of NGL.

Minehead, Alberta

Minehead is a gas property located approximately 120 kilometres southwest of Edmonton, Alberta. Shiningbank Energy and Calpine Canada operate Petrofund's Minehead production. Petrofund's working interests vary from 27.8 per cent to 40 per cent. Producing zones include the Cardium and Belly River. Cardium production is characterized by low decline and high NGL recovery. During 2003, Petrofund participated for its 40% working interest in drilling 2 successful Cardium gas wells which came on stream in the 4th quarter. Petrofund anticipates as many as 8 gross wells being drilled on its Minehead acreage in 2004. Petrofund's working interest production from this property averaged 500 boepd in 2003. Petrofund's total proved plus probable reserves as of December 31, 2003, were 2,838 mboe, comprising of 12.8 bcf of gas and 712 mbbl of NGL.

Fort Saskatchewan, Alberta

Petrofund operates its Fort Saskatchewan gas property located immediately east of Edmonton, Alberta. Petrofund's Fort Saskatchewan property includes the Beaverhill Lake Viking Gas Unit #1 along with the nearby Partridge Hill and Bremner producing fields. Petrofund's average working interest for this area is nearly 100%. Besides the wells, Petrofund owns and operates 3 associated compression-dehydration facilities. Production is predominantly gas from the Viking zone. During 2003, Petrofund aggressively recompleted and reactivated several wells with mixed success. In 2004, Petrofund will continue to evaluate its lands and wells for development opportunities. Petrofund's working interest production averaged 850 boepd during 2003. Petrofund's total proved plus probable reserves as of December 31, 2003, amounted to 3,015 mboe, consisting of 18.1 bcf of gas.

The above 10 properties account for about 60% of PC's total proved plus probable reserves as at December 31, 2003.

Other Properties

PC has various interests in numerous other properties located in Alberta, British Columbia, Manitoba and Saskatchewan. PC's proved plus probable reserves for these other properties as at December 31, 2003 amounted to approximately 40,700 mboe. In total, these properties represent approximately 40% of PC's proved plus probable reserves as at December 31, 2003.

A map which illustrates the approximate locations of PC's principal properties is set out below:

[GRAPHIC OF MAP OMITTED]

REPORT OF MANAGEMENT AND DIRECTORS ON RESERVES DATA AND OTHER INFORMATION

Management of Petrofund Corp. (the "Company") are responsible for the preparation and disclosure of information with respect to the Company's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated the Company's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Company has:

(a) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(b) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(c) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Audit Committee, approved:

(a) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(b) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(signed) "Jeffery E. Errico"
Jeffery E. Errico
President and Chief Executive Officer

(signed) "Glen C. Fischer"
Glen C. Fischer
Senior Vice President, Operations

(signed) "Wayne M. Newhouse"
Wayne M. Newhouse
Director and Chairman of the
Reserves Audit Committee

(signed) "James E. Allard"
James E. Allard
Director and Member of the
Reserves Audit Committee

March 1, 2004

REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR OR AUDITOR

To the board of directors of Petrofund Corp. (the "Company"):

1. We have evaluated the Company's reserves data as at February 17, 2004. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us for the year ended December 31, 2003, and identifies the respective portions thereof that we have audited, evaluated and reviewed and reported on to the Company's board of directors:

Description and Preparation Date of Report	Location of Reserves (County or Reserves Foreign Geographic Area)	Net Present Value of Future Net Revenue (M$ before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total

February 4, 2004	Canada	nil	678,788	nil	678,788

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook.

6. We have no responsibility to update this evaluation for events and circumstances occurring after the preparation date.

7. Because the reserves data are based on judgements regarding future events, actual results will vary and the variations may be material.

(signed) "Wayne Chow, P.Eng"
Vice President
Gilbert Laustsen Jung Associates Ltd.

Calgary, Alberta
February 17, 2004

STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The statement of reserves data and other oil and gas information set forth below (the "Statement") is dated February 17, 2004. The effective date of the Statement is December 31, 2003 and the preparation date of the Statement is February 4, 2004.

Disclosure of Reserves Data

The reserves data set forth below (the "Reserves Data") is based upon an evaluation by GLJ with an effective date of December 31, 2003 contained in the GLJ Report dated February 17, 2004. The Reserves Data summarizes the oil, liquids and natural gas reserves of PC and the net present values of future net revenue for these reserves using constant prices and costs and forecast prices and costs. The Reserves Data conforms with the requirements of National Instrument 51-101 Standards of Disclosure for Oil and Gas Activities ("NI 51-101"). Additional information not required by NI 51-101 has been presented to provide continuity and additional information which we believe is important to the readers of this information. PC engaged GLJ to provide an evaluation of proved and proved plus probable reserves and no attempt was made to evaluate possible reserves.

All of PC's reserves are in Canada and, specifically, in the provinces of Alberta, British Columbia, Manitoba and Saskatchewan.

PC is not taxable under the existing trust structure. The Alberta Securities Commission has advised that PC will be exempt from disclosing after tax future net revenues from its reserves.

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Reserves Data (Constant Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2003
CONSTANT PRICES AND COSTS

	RESERVES						
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURA LIQU
RESERVES CATEGORY	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)
PROVED							
Developed Producing	33,914	29,686	853	750	196,898	155,614	5,213
Developed Non-Producing	310	292	0	0	5,903	4,488	148
Undeveloped	8,671	7,815	0	0	5,402	4,170	376
TOTAL PROVED	42,895	37,793	853	750	208,203	164,271	5,738
PROBABLE	11,240	9,677	205	183	45,680	36,115	1,584
TOTAL PROVED PLUS PROBABLE	54,135	47,471	1,058	933	253,883	200,386	7,323

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	12 (MM$)	15 (MM$)
PROVED					
Developed Producing	1,214	902	728	678	616
Developed Non-Producing	32	24	19	18	16
Undeveloped	174	105	67	57	44
TOTAL PROVED	1,419	1,031	814	753	677

PROBABLE	429	239	155	134	110	--
TOTAL PROVED PLUS PROBABLE	1,848	1,270	970	887	787	==

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2003
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTUR NET REVEN BEFO INCO TAXE (M$
Proved Reserves	3,122,731	591,013	942,158	116,124	54,124	1,419,
Proved Plus Probable Reserves	3,886,979	730,689	1,105,367	147,279	55,609	1,848,

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2003
CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET BEFORE INCO (discounted at (M$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	394,
	Heavy Oil (including solution gas and other by-products)	9,
	Natural Gas (including by-products but excluding	

	solution gas from oil wells)	411,
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	487,
	Heavy Oil (including solution gas and other by-products)	10,
	Natural Gas (including by-products but excluding solution gas from oil wells)	471,

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of December 31, 2003
FORECAST PRICES AND COSTS

	RESERVES						
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURA LIQU
RESERVES CATEGORY	Gross (mbbl)	Net (mbbl)	Gross (mbbl)	Net (mbbl)	Gross (mmcf)	Net (mmcf)	Gross (mbbl)
PROVED							
Developed Producing	32,512	28,565	848	750	191,682	151,527	5,060
Developed Non-Producing	276	260	0	0	6,071	4,616	154
Undeveloped	8,675	8,196	0	0	5,408	4,177	377
TOTAL PROVED	41,463	37,021	848	750	203,161	160,320	5,591
PROBABLE	10,889	9,458	203	182	45,605	36,114	1,575
TOTAL PROVED PLUS PROBABLE	52,352	46,479	1,051	932	248,766	196,434	7,166

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)				
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)	12 (MM$)	15 (MM$)

PROVED					
Developed Producing	790	615	513	483	446
Developed Non-Producing	24	18	15	14	12
Undeveloped	111	63	37	30	21
TOTAL PROVED	925	696	565	527	479
PROBABLE	320	177	114	98	81
TOTAL PROVED PLUS PROBABLE	1,245	873	679	625	560

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of December 31, 2003
FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE REVEN BEFO INCO TAXE (M$
Proved Reserves	2,590,205	473,795	1,003,268	123,226	64,581	925,
Proved Plus Probable Reserves	3,267,061	589,762	1,206,744	156,876	68,834	1,244,

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of December 31, 2003
FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET BEFORE INCO (discounted at (M$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	241,
	Heavy Oil (including solution gas and other by-products)	6,

	Natural Gas (including by-products but excluding solution gas from oil wells)	316,
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	309,
	Heavy Oil (including solution gas and other by-products)	7,
	Natural Gas (including by-products but excluding solution gas from oil wells)	361,

Definitions and Other Notes

In the tables set forth above in "Disclosure of Reserves Data" and elsewhere in this Annual Information Form the following definitions and other notes are applicable:

1. "Gross" means:

   (a) in relation to PC's interest in production and reserves, its "PC gross reserves", which are PC's interest (operating and non-operating) share before deduction of royalties and without including any royalty interest of PC;

   (b) in relation to wells, the total number of wells in which PC has an interest; and

   (c) in relation to properties, the total area of properties in which PC has an interest.

2. "Net" means:

   (a) in relation to PC's interest in production and reserves, its "PC net reserves", which are PC's interest (operating and non-operating) share after deduction of royalties obligations, plus PC's royalty interest in production or reserves.

   (b) in relation to wells, the number of wells obtained by aggregating PC's working interest in each of its gross wells; and

   (c) in relation to PC's interest in a property, the total area in which PC has an interest multiplied by the working interest owned by PC.

3. Definitions used for reserve categories are as follows:

   Reserve Categories

   Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

   o analysis of drilling, geological, geophysical and engineering data;

- the use of established technology; and

- specified economic conditions (see the discussion of "Economic Assumptions" below).

Reserves are classified according to the degree of certainty associated with the estimates.

(a) Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

(b) Probable reserves are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved plus probable reserves.

"Economic Assumptions" will be the prices and costs used in the estimate, namely:

- constant prices and costs as at the last day of PC's financial year

- forecast prices and costs

Development and Production Status

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) Developed reserves are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.

    (i) Developed producing reserves are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently

producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

    (ii) Developed non-producing reserves are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(b) Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

In multi-well pools it may be appropriate to allocate total pool reserves between the developed and undeveloped categories or to subdivide the developed reserves for the pool between developed producing and developed non-producing. This allocation should be based on the estimator's assessment as to the reserves that will be recovered from specific wells, facilities and completion intervals in the pool and their respective development and production status.

Levels of Certainty for Reported Reserves

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

- At least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves;

- At least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves.

A qualitative measure of the certainty levels pertaining to estimates prepared for the various reserves categories is desirable to provide a clearer understanding of the associated risks and uncertainties. However, the majority of reserves estimates will be prepared using deterministic methods that do not provide a mathematically derived quantitative measure of probability. In principle, there should be no difference between estimates prepared using probabilistic or deterministic methods.

4. Forecast prices and costs Future prices and costs that are:

(a) Generally acceptable as being a reasonable outlook of the future; and

(b) If and only to the extent that, there are fixed or presently determinable future prices or costs to which PC is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

The forecast summary table under "Pricing Assumptions" identifies benchmark reference pricing that apply to PC.

5. Constant prices and costs

Prices and costs used in an estimate that are:

(a) PC's prices and costs as at the effective date of the estimation, held constant throughout the estimated lives of the properties to which the estimate applies; and

(b) If, and only to the extent that, there are fixed or presently determinable future prices or costs to which PC is legally bound by a contractual or other obligation to supply a physical product, including those for an extension period of a contract that is likely to be extended, those prices or costs rather than the prices and costs referred to in paragraph (a).

For the purposes of paragraph (a), PC prices are the posted prices for oil and the spot price for gas, after historical adjustments for transportation, gravity and other factors.

6. The Alberta royalty tax credit ("ARTC") is included in the cumulative cash flow amounts. ARTC is based on the program announced November 1989 by the Alberta government with modifications effective January 1, 1995. PC qualifies for the maximum ARTC.

7. Future income tax expense

` Future income tax expenses estimate:

(a) Making appropriate allocations of estimated unclaimed costs and losses carried forward for tax purposes;

(b) Without deducting estimated future costs that are not deductible in computing taxable income;

(c) Taking into account estimated tax credits and allowances; and

(d) Applying to the future pre-tax net cash flows relating to PC's oil and gas activities the appropriate year-end statutory rates, taking into account future tax rates already legislated.

8. "Development well" means a well drilled inside the established limits of an oil and gas reservoir, or in close proximity to the edge of the reservoir, to the depth of a stratigraphic horizon known to be productive.

9. "Development costs" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) Gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground draining, road building, and relocating public roads, gas lines and power lines, pumping equipment and wellhead assembly;

(b) Drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) Acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) Provide improved recovery systems.

10. "Exploration well" means a well that is not a development well, a service well or a stratigraphic test well.

11. "Exploration costs" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) Costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) Costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;

(c) Dry hole contributions and bottom hole contributions;

(d) Costs of drilling and equipping exploratory wells; and

(e) Costs of drilling exploratory type stratigraphic test wells.

12. "Service well" means a well drilled or completed for the purpose of supporting production in an existing field. Wells in this class are drilled for the following specific purposes: gas injection (natural gas, propane, butane or flue gas), water injection, steam injection, air injection, salt water disposal, water supply for injection, observation or injection for combustion.

13. Numbers may not add due to rounding.

14. The estimates of future net revenue presented in the tables above do not represent fair market value.

15. Disclosure provided herein in respect of boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf : 1 bbls is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

16. Estimated further abandonment and reclamation costs related to a

property have been taken into account by GLJ in determining reserves that should be attributable to a property and in determining the aggregate future net revenue therefrom, there was deducted the reasonable estimated further well abandonment costs.

17. Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

18. The extended character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

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Pricing Assumptions

The following sets out the benchmark reference prices, as at December 31, 2003, reflected in the Reserves Data. These price assumptions were provided to PC by GLJ, PC's independent qualified evaluator.

SUMMARY OF PRICING ASSUMPTIONS
as of December 31, 2003
CONSTANT PRICES AND COSTS
OIL

	OIL						
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40(degree) API ($Cdn/bbl)	Hardisty Heavy 12(degree) API ($Cdn/bbl)	Cromer Medium 29.3(degree) API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMBtu)	Edmonton Propane ($Cdn/bbl)	Edm ($
Historical							
As at December 31, 2003	32.52	40.81	23.31	34.81	6.09	29.81	

Notes:
(1) The exchange rate used to generate the benchmark reference prices in this table.

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of December 31, 2003
FORECAST PRICES AND COSTS

OIL

Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40(degree) API ($Cdn/bbl)	Hardisty Heavy 12(degree) API) ($Cdn/bbl	Cromer Medium 29.3(degree) API ($Cdn/bbl)	NATURAL GAS AECO Gas Price ($Cdn/MMBtu)	Edmonton Propane ($Cdn/bbl)	Edmonton Butane ($Cdn/bb
Forecast:							
2004	29.00	37.75	20.25	31.75	5.85	26.75	28.75
2005	26.00	33.75	20.25	28.75	5.15	21.75	23.75
2006	25.00	32.50	21.00	28.50	5.00	20.50	22.50
2007	25.00	32.50	21.00	28.50	5.00	20.50	22.50
2008	25.00	32.50	21.00	28.50	5.00	20.50	22.50

Notes:
(1) Inflation rates for forecasting prices and costs.

(2) Exchange rates used to generate the benchmark reference prices in this table.

PC's weighted average prices received in 2003 after transportation and quality differentials were $37.91/bbl for oil, $6.30/mcf for natural gas and $34.66/bbl for natural gas liquids.

Reconciliations of Changes in Reserves and Future Net Revenue

RECONCILIATION OF
COMPANY NET RESERVES
BY PRINCIPAL PRODUCT TYPE
CONSTANT PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL			ASSOCIAT NON-ASSOCI	
FACTORS	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	Net Proved (bcf)	Net Proba (bcf
December 31 2002(1)	34,834	6,758	41,592	553	40	593	181	32
Extensions	159	23	182	0	0	0	1	0
Improved Recovery	681	(492)	189	0	0	0	0	0
Technical Revisions	(1,303)	2,478	1,175	318	143	461	(8)	3
Discoveries	79	21	100	0	0	0	0	0
Acquisitions	9,319	2,348	11,667	0	0	0	15	2
Dispositions	(2,186)	(1,520)	(3,705)	0	0	0	(2)	(1
Economic Factors	(102)	62	(39)	0	0	0	1	1
Production	(3,689)		(3,689)	(121)		(121)	(23)	

December 31, 2003	37,793	9,678	47,471	750	183	933	164	36

FACTORS	NATURAL GAS LIQUIDS Net Proved (mbbl)	Net Probable (mbbl)	Net Proved Plus Probable (mbbl)	BARRELS OF OIL EQUIVALENT Net Proved (mboe)	Net Probable (mboe)	Net Proved Plus Probable (mboe)
December 31 2002(1)	4,175	762	4,937	69,753	12,850	82,602
Extensions	30	4	34	332	53	385
Improved Recovery	11	1	13	757	(478)	280
Technical Revisions	(1,007)	294	(713)	(3,391)	3,365	(27)
Discoveries	0	0	0	79	21	100
Acquisitions	1,367	129	1,496	13,201	2,820	16,020
Dispositions	(13)	(8)	(22)	(2,537)	(1,750)	(4,287)
Economic Factors	17	29	45	11	211	222
Production	(545)		(545)	(8,248)		(8,248)
December 31, 2003	4,036	1,211	5,247	69,957	17,091	87,048

Note:

(1) The evaluation as at December 31, 2002 was prepared using National Policy Statement 2-B reserves definitions. Under those definitions, probable reserves were adjusted by a factor to account for the risk associated with their recovery. PC previously applied a risk factor of 50% in reporting probable reserves. Under current NI 51-101 reserves definitions, estimates are prepared such that the full proved plus probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "best estimate"). The above reconciliation reflects current probable reserves versus previous risk adjusted (50%) probable reserves reported by PC.

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RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR
PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR	20 (M
Estimated Net Present Value Before Tax at Beginning of Year	1,0

Oil and Gas Sales During the Period(1)	(2
Changes due to Prices, Production Costs and Royalties Related to Forecast Production(2)	(1
Development Costs During the Period(3)	(
Changes in Forecast Development Costs(4)	
Changes Resulting from Extensions and Improved Recovery(5)	
Changes Resulting from Discoveries(5)	
Changes Resulting from Acquisitions of Reserves(5)	1
Changes Resulting from Dispositions of Reserves(5)	(
Accretion of Discount(6)	1
Net Change in Income Taxes(7)	
Changes Resulting from Technical Reserves Revisions Plus All Other Changes	(
Estimated Net Present Value Before Tax at End of Period	8

Notes:
(1) Net of production costs and royalties, before income taxes
(2) The impact of changes in prices and other economic factors on future net revenue
(3) Actual capital expenditures relating to the exploration and development and production of oil and gas reserves
(4) Includes the difference between actual and forecast development costs during the period
(5) Production and capital costs associated with recovery of the related reserves are included in this category
(6) 10% of after adjustments for dispositions
(7) Includes the difference between actual and forecast income taxes during the period

Additional Information Relating to Reserves Data

Undeveloped Reserves

Proved and probable undeveloped reserves have been estimated in accordance with procedures and standards contained in the COGE Handbook. In general, undeveloped reserves are scheduled to be developed within the next two years of the effective date. Capital expenditures to develop proved undeveloped reserves are estimated at $15.8 million in 2004 and $11.4 million in 2005.

Significant Factors or Uncertainties

For details of important economic factors or significant uncertainties that affect particular components of the Reserves Data, see "Management's Discussion And Analysis" and "Risk Factors - Business-Related Risks".

Future Development Costs

The following table sets forth development costs deducted in the estimation of PC's future net revenue attributable to the reserve categories noted below.

Constant Prices

	Forecast Prices and Costs (M$)		and Costs (M$)
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves
2004	24,634	29,548	24,634
2005	17,535	24,829	17,446
2006	14,504	18,473	14,209
2007	13,975	16,194	13,487
2008	7,383	12,280	7,049
Remainder	45,195	55,552	39,299
Total Undiscounted	123,226	156,876	116,124
Total Discounted at 10%	83,033	106,285	80,566

The source of funding for future development costs will be internally generated cash flow, debt or a combination of both. Disclosed reserves and future net revenue will not be materially affected by the costs of funding the future development expenditures.

Other Oil and Gas Information

Oil And Gas Wells

The following table sets forth the number and status of wells in which PC has a working interest as at December 31, 2003.

	Oil Wells				Natural Gas Wells		
	Producing		Non-Producing		Producing		Non-P
	Gross	Net	Gross	Net	Gross	Net	Gross
Alberta	2,618	392.4	762	172.5	845	256.1	187
British Columbia	88	23.2	69	11.0	244	37.8	71
Manitoba	121	114.8	51	49.1	0	0.0	0
Saskatchewan	1,592	525.1	237	34.2	341	298.5	16
Total	4,419	1,055.5	1,119	266.8	1,430	592.4	274

Properties with no Attributable Reserves

The following table sets out PC's undeveloped land holdings as at December 31, 2003.

	Undeveloped Acres	
	Gross	Net
Alberta	311,218	150,319
British Columbia	132,701	44,346
Manitoba	1,201	1,181

Saskatchewan	89,469	54,663
Total	534,589	250,509

There are no material work commitments on the undeveloped land holdings.

PC expects that rights to explore, develop and exploit 48,680 net acres of its undeveloped land holdings will expire by December 31, 2004.

Additional Information Concerning Abandonment and Reclamation Costs

Future abandonment and reclamation costs have been estimated based on actual costs incurred to date by PC for abandonment and reclamation activities. Costs to abandon and reclaim approximately 2,040 net wells totaling $61.6 million net of salvage value ($26.0 million discounted at 10%) are included in the estimate of future net revenue. Facility abandonment costs of $20.7 million ($3.1 million discounted at 10%) are not included in the estimate of future net revenue. Abandonment and reclamation costs estimated for the next three years are $4.3 million in 2004, $4.1 million in 2005 and $3.3 million in 2006.

Forward Contracts

For details of material commitments to sell natural gas and crude oil which were outstanding at December 31, 2003, see Note 14 to the Trust's audited consolidated financial statement for the year ended December 31, 2003, which Note is incorporated herein by reference.

Tax Horizon

Under its existing trust structure, PC does not pay income tax because the tax liability is transferred to the individual Unitholders.

Capital Expenditures

The following tables summarize capital expenditures (net of incentives and net of certain proceeds and including capitalized general and administrative expenses) related to PC's activities for the year ended December 31, 2003:

	(M$)
Property acquisition costs	
Proved properties	$82,100
Undeveloped properties	1,700
Exploration costs	5,700
Development costs	64,000
Total	$153,500

Exploration and Development Activities

The following tables sets forth the gross and net exploratory and development wells in which PC participated during the year ended December 31, 2003:

Working Interest Wells

	Development Wells		Exploration Wells	
	Gross	Net	Gross	Net
Oil	74	7.9	6	1.5
Gas	110	80.2	5	1.9
Service	4	2.2	0	0
Dry	7	1.5	8	3.7
Total:	195	91.8	19	7.1

Farm-out Wells

	Development Wells	Exploration Wells
Oil	2	1
Gas	10	22
Service	0	0
Dry	1	4
Total:	13	27

PC's most important current and likely exploration and development activities are described under "Business and Properties".

Production Estimates

The following table sets out the gross volume of PC's production estimated for the year ended December 31, 2004 which is reflected in the estimate of future net revenue disclosed in the tables contained under "Disclosure of Reserves Data" using constant prices and costs.

	Light and Medium Oil (bpd)	Heavy Oil (bpd)	Natural Gas (mcfpd)	Natural Gas Liquids (bpd)	BOE (boepd)
Proved Producing	10,381	333	74,091	2,020	25,083
Total Proved	10,745	333	76,739	1,899	25,767
Proved plus Probable	11,088	340	78,077	1,921	26,361

Production History

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netbacks of PC for the periods indicated below:

	Quarter Ended 2003 Dec. 31	Sept. 30	June 30	Mar. 31
Oil Wells(1)				
Average Daily Production (boepd)	15,111	14,297	13,005	12,847
Revenue ($/boe)	33.72	36.50	37.32	44.04
Royalties ($/boe)	5.87	6.62	6.55	8.36
Production Costs ($/boe)	11.06	12.85	12.22	10.49
Netback ($/boe)	16.79	17.03	18.55	25.19
Gas Wells(1)				
Average Daily Production (mcfepd)	85,660	85,099	84,866	87,384
Revenue ($/mcfe)	5.63	5.77	6.26	7.46
Royalties ($/mcfe)	1.33	1.37	1.51	1.91
Production Costs ($/mcfe)	0.91	1.10	0.97	0.89
Netback ($/mcfe)	3.39	3.30	3.78	4.66

Note:
(1) Principal product type attributable to the wells

SELECTED FINANCIAL AND OPERATING INFORMATION

Consolidated Financial Information

The following is a summary of selected consolidated financial information of the Trust for the years indicated.

December 31,	2003	2002	2
	(MM$, except per unit amounts)		
Total revenues................................	$393.1	$270.7	
Royalties, net of incentives..................	$ 84.8	$ 50.4	
Lease operating costs.........................	$ 91.3	$ 74.8	

Proceeds on disposition of property interests..	$ 33.5	$ 30.0
Cash flow from operations.....................	$187.6	$112.6
Cash flow available for distribution...........	$150.7	$103.1
per Unit - basic.....................	$ 2.47	$ 2.07
per Unit - diluted...................	$ 2.46	$ 2.06
Net income....................................	$ 85.8	$ 24.4
Per Unit - basic.....................	$ 1.41	$ 0.49
Per Unit - diluted	$ 1.40	$ 0.49
Working Capital (deficit)......................	$(30.0)	$(6.9)
Total assets..................................	$943.9	$890.6
Total long-term debt(1).......................	$110.3	$219.2
Unitholders' equity...........................	$649.2	$480.1
Weighted average number of Units outstanding		
Basic	61.0	49.9
Diluted..............................	61.2	49.9

Note:

(1) Although the Trust does not have any long term indebtedness, PC does have long term indebtedness, which is secured against all of PC's assets. The loan is the legal obligation of PC. While principal and interest payments are allowable deductions in the calculation of royalty income, the Unitholders of the Trust have no direct liability to PC's lenders or to PC should the assets securing the loan generate insufficient cash flow to repay the obligations.

(2) On July 6, 2001, the Trust Units were consolidated on a one-for-three basis. All relevant figures, including Trust Units, outstanding net income per Trust Unit and distributions per Trust Unit have been restated to reflect this consolidation.

Sensitivity Analysis

In 2003, PC's cash flow from operating activities was $187.6 million, and net income was $85.8 million. The sensitivity of PC's cash flow and net income before income taxes to oil price, gas price, $US/$CAN exchange rate, and the prime interest rate is listed below.

The table below shows sensitivities to pre-hedging cash flow as a result of product price and operational changes. The table is based on actual 2003 prices received and production volumes of 27,000 boepd. These sensitivities are approximations only and are not necessarily valid at other price and production levels. As well, hedging activities can significantly affect these sensitivities.

	Change	M$	$/unit per year
Price per barrel of oil	$ 1.00US	$ 5,331	$ 0.072
Price per mcf of natural gas	$ 0.25Cdn	$ 5,585	$ 0.076
US/Cdn exchange rate	$ 0.01	$ 2,650	$ 0.036
Interest rate on debt ($125 million)	1%	$ 1,250	$ 0.017
Oil production volumes -	100 bpd	1,131	$ 0.015
Gas production volumes -	1 mmcfpd	1,784	$ 0.024
*After adjustment for estimated royalties			

Distribution Policy

A major objective of the Trust's distribution policy is to provide unitholders with relatively stable and predictable monthly distributions despite potentially significant variations in product prices. A second objective is to retain a portion of cash flow to fund ongoing development and optimization projects designed to enhance the sustainability of cash flow.

The percentage of cash flow from operations paid to unitholders each quarter will vary according to a number of factors assessed by management including:

- Fluctuations in oil and gas prices
- Changes in the $Canadian/$US exchange rate
- The size of the development drilling programs and the portion funded from cash flow
- The level of debt within PC.

Although the payout ratio will vary significantly from quarter to quarter, the objective is to pay to unitholders 80% of cash flow over the long term. The payout ratio was 70% in 2003 and 75% in 2002. The payout ratio in 2003 ranged between 45% in the first quarter to 92% in the third quarter.

Distributions

The following cash distributions per Trust Unit in respect of the quarters indicated have been made to Unitholders since 2001:

Cash Distributions

	2003	2002	2001
First Quarter	$0.48	$0.43	$1.26
Second Quarter	0.53	0.41	1.32
Third Quarter	0.54	0.42	0.93
Fourth Quarter	0.54	0.45	0.73
Total Annual	$2.09	$1.71	$4.24

Product Marketing

Petrofund markets its products to a diverse group of buyers with a variety of contract terms and lengths as a way to help stabilize distributions and mitigate the effect of price fluctuations. Forward selling instruments such as swaps, collars, and floors are used for up to 50 percent of its production, with the remainder subject to market prices. This marketing strategy is not intended to make money as a speculation on future commodity prices. The goal of this hedging program is to improve financial protection and help sustain cash flow should prices drop.

During 2003, product prices were impacted by commodity price fluctuations and the rising value of the Canadian dollar. Crude oil prices were robust throughout 2003 with West Texas Intermediate (WTI) averaging US$ 31.04/bbl in the fourth quarter, up US$ 2.89/bbl from the same period in 2002. WTI for the year returned the highest average annual price of US$ 31.04/bbl since 1982. So far in 2004, product prices have exceeded those realized in the fourth quarter 2003 levels and are following early 2003 levels in the mid-thirty dollar per barrel range.

Market fundamentals remain strong as US commercial crude inventories decreased in 2003 to 29-year lows, while the US remains committed to filling the US Strategic Petroleum Reserve by 2005. Supply additions from OPEC and non-OPEC were strong in 2003 but incremental demand from the US and China offset the new supply. Petrofund expects supply growth from non-OPEC and Iraq arising late in 2004 will exceed demand although it should be noted that re-building crude inventories takes several years to complete. Strong oil prices are also broadly supported by long-term geopolitical risks that can affect supply and demand.

Petrofund continues to believe that OPEC and other large crude suppliers will manage supplies to meet demand and that the low inventory levels actually provide a substantial cushion for any overproduction that might occur in the short run.

AECO spot natural gas prices were also at record high levels, ending the year on a strong note closely following US natural gas prices. For the year, AECO prices averaged $6.70/mcf, up 65 percent from 2002. AECO prices were strongest early in the year but fourth quarter 2003 prices averaging $5.59/mcf still exceeded fourth quarter 2002 levels by $.34/mcf, or 6.5 percent. December 2003 AECO gas prices were markedly higher than October and November, and natural gas prices are tracking rising oil prices in the first quarter of 2004. Basis differentials between AECO and the Henry Hub widened by $0.05/mcf, to approximately $0.70/mcf over the year. This level is expected to remain constant over 2004.

Petrofund believes the fundamentals underpinning natural gas markets will continue to support attractive price levels for the commodity in North America. Gas-directed drilling recovered in 2003 as rig counts rose 34 percent in the US year-over-year to 959 rigs. Canadian gas directed rig counts were only up 20 percent over the same period. The increased drilling will increase supplies after the first quarter of 2004; however, growth in the US economy and natural production declines are expected to absorb the new supply. Liquefied Natural Gas (LNG) imports to the US increased by upwards of one bcf/d in 2003, but large scale increases in imports with the potential to impact prices are not expected until 2005-2007.

Credit Facility

PC has a revolving working capital operating facility of $25 million and a syndicated facility of $240 million. Interest on the working capital loan is at prime and interest on the syndicated facility depends on PC's debt to cash flow ratio and varies from prime to prime plus 75 basis points or, at the Trust's option, bankers acceptance plus a stamping fee. Substantially all of the credit facility is financed with banker's acceptances, resulting in an average reduction in interest rates of 0.50% per annum.

The limit of the syndicated facility is subject to adjustment from time to time to reflect changes in PC's asset base. PC had long-term debt outstanding of $110 million at December 31, 2003, compared to $212 million at the end of the prior year.

The revolving period on the syndicated facility ends on May 28, 2004, unless extended for a further 364 day period. There are no principal repayments required during the revolving period. PC may request the facility be extended no earlier than 90 days and no later than 60 days prior to the end of the revolving period at which time lenders may extend the facility for an additional one year period. If the revolving period is not extended, the loan will convert to a one year term with payments due in three consecutive quarterly amounts equal to one-

twentieth of the loan amount with an additional payment due on the last day of the term period equal to the remaining balance outstanding. In the event that the revolving period is not extended, the Trust will prepay the required quarterly instalments into a reserve account.

The credit facility is secured by a debenture in the amount of $350 million under which a Canadian chartered bank, as principal and as agent for the other lenders, received a first ranking security interest on all of PC's assets. The loan is the legal obligation of PC. Unitholders have no direct liability to the lenders or to PC should the assets securing the loan generate insufficient cash flow to repay the obligation.

Outlook for Next Year

The level of cash flow for 2004 will be affected by oil and gas prices, the $US/$CAN exchange rate and the Trust's ability to add reserves and production in a cost effective manner. Both product prices and the exchange rate showed significant volatility in 2003 and this trend is expected to continue in 2004. The acquisition market is expected to continue to be active and supply should increase with the recent announcement by three large producers of their intention to dispose of their Canadian properties in 2004. Nevertheless, competition for these assets is expected to be fierce due to increased demand resulting from the increasing number of oil and gas companies that have converted to a trust structure. We expect prices for quality, long life assets to be at or near record levels. Petrofund expects to be an active participant in this market but success will be tempered by commitment to maintain historic discipline and bid only at levels consistent with the best long term interest of our unitholders.

Acquisition activities will be complemented by an extensive drilling and farmout program that will be conducted on our existing land base.

Although product prices have remained at high levels, the strengthening of the Canadian dollar in the second half of 2003 significantly moderated the net effect of these prices on Petrofund's cash flow. We expect the Canadian dollar to remain very strong in the short term with a possible decrease toward the end of 2004.

Petrofund pursues a well defined risk management program to help offset the effect of price fluctuations. This program utilizes collars as the main hedging tool but Petrofund also enters into fixed price transactions when commodity prices approach historic highs. To date, the Trust has not entered into any currency related transactions.

ENVIRONMENT, HEALTH AND SAFETY

Petrofund recognizes that our efforts to protect the environment and the health and safety of our workers and the public are essential to our continuing success. The Environment, Health and Safety program is designed to meet four objectives:

- Provide our workers with the tools and training needed to complete work assignments safely and effectively;

- Identify and manage environmental, health and safety risks as an integral part of every business activity;

- Monitor performance to ensure that Petrofund operations comply with our legal obligations and the standards we set for ourselves, and;

- Identify and manage environmental liabilities associated with our existing asset base and potential acquisitions.

All employees of Petrofund are responsible and accountable for ensuring that we manage environmental protection and health and safety responsibilities properly. Senior Management ensures work places are healthy and safe and workers know and understand Petrofund's environment, health and safety operating standards and expectations. Supervisors ensure that activities at our workplaces meet or exceed our standards and regulatory

requirements. Each employee is responsible for working safely, maintaining a healthy workplace and conducting their activities with respect for other people and the environment. Collectively, we strive to continually improve our performance and reduce the potential risks of our operations to people and the environment.

Managing Liabilities

Liability management is a cornerstone of Petrofund's environmental protection and restoration activities. We closely monitor our site abandonment and reclamation liabilities. We have taken steps to properly abandon well sites and facilities and restore the land at locations that have reached the end of their economic life. In 2003, Petrofund abandoned 70 wells and continued restoration work at over 350 sites across Western Canada. By the end of 2003, Petrofund successfully completed restoration work at over 80 sites and began the process of submitting the necessary documentation to our regulators to obtain reclamation certificates. In order to eliminate the environmental and financial liabilities of non-producing assets, Petrofund actively manages its abandonment and site restoration program. The goal is to minimize the cycle time between the initial abandonment and the final restoration.

Petrofund is also committed to fully assessing potential environmental liabilities associated with wells and facilities that may be candidates for acquisition. We review records held by governments and owners, and conduct inspections of the assets to assure ourselves that we are aware of the conditions at each site and the costs to restore these locations to meet government imposed environmental standards. The objective is to provide a realistic assessment of the liabilities associated with potential asset acquisition candidates and provide management with a factual basis to negotiate purchase terms and conditions. In 2003, Petrofund conducted 2 major and 2 minor reviews of potential acquisition opportunities as part of our due diligence process.

Stewardship

In 2003, Petrofund initiated a formal third party environmental compliance and best practices audit program to assure management and unitholders that our field operations meet or exceed regulatory requirements and our internal operating standards. We will conduct formal assessments of compliance with regulations and operating standards at our major properties every three years. Assessments were completed at 85 active sites in 13 producing fields in Alberta this past year. Our insurer conducts a safety audit/risk survey of our operations and a cross section of our field facilities each year. In 2003, seven facilities in three fields in Alberta were included in the safety audit program.

The results of these audits have confirmed that our facilities are operated and maintained at or above industry standards and that our field staff are knowledgeable and give workplace health and safety, and environmental protection a high priority in their operations. The audit findings have been incorporated into our on-going environment, health and safety program planning to better manage potential risks to people and the environment.

These external audits complement Petrofund's long standing site inspection program where field operating staff formally inspect each producing well and facility twice per year. These inspections not only identify real or potential environmental and safety risks at each location but they also serve to remind workers of the importance placed on these aspects of our business.

Corporate Citizenship

In 2003, Petrofund embarked on major projects to identify the sources and volumes of greenhouse gas emissions and other air contaminants from producing facilities. These studies will be used to confirm compliance with provincial and federal air quality guidelines, contaminant emission regulations, and possible requirements to meet Canada's potential greenhouse gas emission reduction commitments under the Kyoto protocol. These investigations will also assist us in establishing priorities for planning upgrades to our facilities to improve energy efficiency across operations.

Petrofund continues to review environmental, health and safety programs and commitments to ensure that we are positioned to address the increasing public expectation of higher levels of performance. We understand and accept our responsibility for developing and maintaining superior environment, health and safety standards and performance levels to sustain public trust and the confidence of regulators everywhere we operate.

CORPORATE GOVERNANCE

The relationship between the Board and the management of Petrofund is grounded in a mutual understanding of respective roles and the ability of the Board to act independently while fulfilling its responsibilities. Further, the Board's involvement in strategic planning recognizes that the role of directors is not to manage but to guide management. The board oversees and monitors systems for managing business risk and regularly reviews strategic plans with management. Petrofund is in full compliance with the corporate governance standards outlined by the TSX.

Petrofund has actively sought men and women with a diversity of experience and competencies to add value to boardroom deliberations. In 2003, the Board increased in size by one directorship with a view to increase overall effectiveness and improve decision making. In keeping with best practices, the Board separated the role of Chairman and Chief Executive Officer in early 2003. The Board acknowledges the critical role they must play in choosing the Chief Executive Officer and in contributing to and continually assessing Petrofund's strategic direction. All directors are elected by unitholders. Voting for directors is conducted during Petrofund's annual general meeting.

In addition to those matters which must be approved by the Board of Directors by law, significant business activities and actions proposed to be undertaken by Petrofund are subject to Board approval. The Board of Directors approves appropriate corporate objectives and recommended courses of action which have been brought forward by the Chief Executive Officer and management

Independence of the Board

The Board currently comprises seven members. Five of the seven are unrelated directors within the context and meaning outlined within TSX Guidelines. The responsibility for ensuring that individual directors are unrelated rests with the Board of Directors. The Board will ensure that Petrofund discloses on an annual basis the number of related and unrelated directors.

Petrofund has instituted a formal orientation program intended to further assist new Board members in familiarizing themselves with Petrofund's field operations, management, administration, policies and plans.

All members of the Board of Directors, with the exception of Mr. Errico and Mr. Driscoll, are unrelated. All Board committees consist entirely of unrelated directors.

Committees

The Board has four committees; the Governance Committee, the Human Resources & Compensation Committee, the Reserves Audit Committee and the Audit Committee. The committees have formal written mandates based on the council of outside advisors and approved by the Board of Directors. These mandates reflect current 'best practices' concerning committee mandates. The committees review these mandates and work processes at least annually; taking into account changes in regulatory and other appropriate requirements or practices, and propose changes as appropriate to the Board of Directors for its approval. All committees have the right to retain independent advisors at the expense of Petrofund.

Governance Committee

The Governance Committee comprises Sandra S. Cowan (Chairman), Frank Potter and Peter N. Thomson. The Committee has the responsibility of reviewing the Board's size, composition and working processes and proposing changes to the Board for its consideration. It has the responsibility for assessing the performance of the Board, its committees, and individual directors. It recommends to the Board at least annually and at such other times as it sees fit, the composition of board committees and the chairmanship of such committees. A component of the Committee's mandate is the responsibility for considering and proposing nominations to the Board, should such nominations be required. It reviews director compensation at least annually, and recommends changes as it sees fit to the Board for its approval.

Human Resources and Compensation Committee

The Human Resources and Compensation Committee comprises Frank Potter (Chairman), Sandra S. Cowan and Wayne M. Newhouse. The Committee is responsible to the Board for overseeing the development and administration of competitive policies designed to attract, develop and retain employees of the highest standards at all levels. It recommends to the Board appropriate policies dealing with recruitment, compensation, benefits and training, and oversees the administration of succession planning. It is responsible for recommending to the Board the compensation arrangements for individual senior officers, in consultation with the Chief Executive Officer.

Reserves Audit Committee

The Reserves Audit Committee comprises Wayne M. Newhouse (Chairman), James E. Allard and Peter N. Thomson. The Committee oversees the integrity of Petrofund's reserve estimates. Contained within the Committee mandate is the responsibility to ascertain those procedures and policies which minimize environmental, occupational and safety risks to asset value thereby mitigating any potential damage to or deterioration of asset value. It meets at least annually, and such other times as it sees fit. It meets with Petrofund's independent engineering consultants, and does so at least once per year.

Audit Committee

The Audit Committee comprises James E. Allard (Chairman), Frank Potter and Peter N. Thomson. All listed committee members possess the requisite financial skills necessary to qualify them as committee directors. Additionally, Mr. Allard fulfills the requirement for financial sophistication, having served as Chief Executive Officer and Chief Financial Officer for several private and publicly traded companies throughout a lengthy career.

SHARE CAPITAL OF PC

PC's authorized capital is comprised of an unlimited number of common shares and an unlimited number of PC Exchangeable Shares.

Common Shares

PC has authorized for issuance an unlimited number of common shares of which, as at February 27, 2004, two common shares are issued and outstanding and held by Computershare Trust Company of Canada, as trustee of the Trust. The holders of common shares are entitled to notice of, to attend and to one vote per share held at any meeting of the shareholders of PC (other than meetings of a class or series of shares of PC other than the common shares as such). The holders of common shares are entitled to receive dividends as and when declared

by the Board of Directors of PC on the common shares as a class, and subject to prior satisfaction of all preferential rights to dividends attached to all shares of other classes of shares of PC ranking in priority to the common shares in respect of dividends, to share rateably, together with the shares of any other class of shares of PC ranking equally with the common shares in respect of dividends. The holders of common shares are entitled to in the event of any liquidation, dissolution or winding up of PC, whether voluntary or involuntary, or any other distribution of the assets of PC among its shareholders for the purpose of winding up its affairs, and subject to prior satisfaction of all preferential rights to return of capital on dissolution attached to all shares of other classes of shares of PC ranking in priority to the common shares in respect of return of capital on dissolution, to share rateably, together with the shares of any other class of shares of PC ranking equally with the common shares in respect of return of capital on dissolution, in such assets of PC as are available for distribution.

Exchangeable Shares

PC has authorized to issue an unlimited number of PC Exchangeable Shares, of which, as at February 27, 2004, 851,471 PC Exchangeable Shares are issued and outstanding. The PC Exchangeable Shares rank prior to the common shares of PC and any other shares ranking junior to the PC Exchangeable Shares with respect to the payment of dividends and the distribution of assets in the event of the liquidation, dissolution or winding up of PC, whether voluntary or involuntary, or any other distribution of the assets of PC among its shareholders for the purpose of winding up its affairs. Provided that same is declared during the Dividend Period, holders of PC Exchangeable Shares are entitled to receive, as and when declared by the board of directors of PC in its sole discretion, from time to time, non cumulative preferential cash dividends in an amount per share equal to the amount of the Distribution relating to the subject Distribution Payment Date multiplied by the Exchange Ratio as at the subject Distribution Payment Date. It is not anticipated that dividends will be declared or paid on the PC Exchangeable Shares; however, the board of directors of PC has the right in its sole discretion to do so.

PC will not, without obtaining the approval of the holders of the PC Exchangeable Shares as set forth below:

(a) pay any dividend on the common shares of PC or any other shares ranking junior to the PC Exchangeable Shares, other than stock dividends payable in common shares of PC or any such other shares ranking junior to the PC Exchangeable Shares;

(b) redeem, purchase or make any capital distribution in respect of the common share of PC or any other shares ranking junior to the PC Exchangeable Shares;

(c) redeem or purchase any other shares of PC ranking equally with the PC Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution; or

(d) issue any shares, other than PC Exchangeable Shares or common shares of PC, which rank superior to the PC Exchangeable Shares with respect to the payment of dividends or on any liquidation distribution.

In the event that a dividend is not declared by PC prior to the expiry of a Dividend Period, each holder of PC Exchangeable Shares shall have the right, exercisable for a period of 5 business days from the date of expiry of the subject Dividend Period, to redeem such number of PC Exchangeable Shares (the "Cash Retracted Shares") as have a value (calculated as the amount equal to the Exchange Ratio as at the date of delivery of the notice of the holder to retract multiplied by the Current Market Price) equal to the aggregate amount of the dividend which would have been paid to the holder had a dividend been declared and paid in respect of the subject Dividend Period (the "Aggregate Dividend Amount") for an amount in cash equal to the Aggregate Dividend Amount.

A holder of PC Exchangeable Shares is entitled at any time to exchange each PC Exchangeable Share into the number of Trust Units equal to the Exchange Ratio then in effect.

The PC Exchangeable Shares provide holders with a security having economic, ownership and voting rights which are substantially equivalent to those of Trust Units. The PC Exchangeable Shares are maintained economically equivalent to the Trust Units by the progressive increase in the Exchange Ratio to reflect distributions paid by the Trust to Unitholders. The PC Exchangeable Shares are provided equivalent voting rights as unitholders through the PC Support Voting and Exchange Agreement. Pursuant to the PC Support Voting and Exchange Agreement, the Trust has issued a Special Voting Unit to Petro Assets, the holder of the PC Exchangeable Shares. The Special Voting Unit entitles Petro Assets to such number of votes, exerciseable at any meeting at which unitholders are entitled to vote, equal to the Aggregate Equivalent Vote Amount.

At any time on or after April 29, 2010, or at any time on or after the date when the aggregate number of issued and outstanding PC Exchangeable Shares is less than 100,000, holders of PC Exchangeable Shares may be required by PC to sell all of the then outstanding PC Exchangeable Shares in exchange for the payment of either cash, PC Exchangeable Shares or that number of Trust Units determined by multiplying the number of PC Exchangeable Shares by the Exchange Ratio then in effect.

The PC Exchangeable Shares are convertible, at the option of the holder thereof, into common shares of PC, on a one for one basis (the "Conversion Right"). Pursuant to the provisions of the Unanimous Shareholders Agreement, Petro Assets has agreed never to exercise the Conversion Right in respect of any PC Exchangeable Shares held thereby.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The Trust's Management's Discussion and Analysis, filed with the Trust's audited consolidated financial statements for the year ended December 31, 2003, is incorporated by reference herein.

RISK FACTORS

The following are certain risk factors relating to the business of the Trust which prospective investors should carefully consider before deciding whether to purchase Trust Units.

Industry-Related Risks

Oil and Natural Gas Prices

The monthly cash distributions the Trust pays to Unitholders are highly dependent on the prices received for PC's oil and natural gas production. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond the control of the Trust and PC. These factors include, among others:

- political conditions throughout the world;
- worldwide economic conditions;
- weather conditions;
- the supply and price of foreign oil and natural gas;
- the level of consumer demand;
- the price and availability of alternative fuels;
- the proximity to, and capacity of, transportation facilities;
- the effect of worldwide energy conservation measures; and
- government regulations.

Declines in oil or natural gas prices will have an adverse effect on the Trust's operations, financial condition, reserves and ultimately on its ability to pay distributions to Unitholders.

Oil prices were fairly strong throughout 2003 averaging US$31.04 WTI as compared to and average of US$26.08 WTI in 2002. The only quarter in the last two years that saw relatively low prices was the first quarter of 2002 when oil prices averaged US$21.64 WTI.

Monthly AECO prices averaged $6.71/mcf in 2003 as compared to $4.07/mcf in 2002, an increase of 65%. The AECO gas price was weak throughout the first nine months of 2002 averaging $3.67/mcf; however, increased significantly to $5.26/mcf in the fourth quarter. The monthly AECO price in 2003 ranged from a high of $10.13/mcf in March to a low of $5.48/mcf in November.

Foreign Currency Exchange Rates and Interest Rates

World oil prices are quoted in United States dollars and the price received by Canadian producers is therefore affected by the $US/$CAN exchange rate that may fluctuate over time. A material increase in the value of the Canadian dollar, which occurred in 2003, negatively impacted PC's net production revenue and may affect the future value of the Trust's reserves as determined by independent evaluations at this time. The impact is reduced to the extent that PC has engaged in, or in the future will engage in risk management activities related to commodity prices and foreign exchange rates. PC will be subject to unfavourable price changes and credit risks associated with the counterparties with which it contracts. PC has not entered into any foreign exchange contracts at this time.

Variations in interest rates could result in a significant increase in the amount the Trust pays to service debt which may result in a decrease in distributions to Unitholders.

Operations

PC's operations are subject to all of the risks normally associated with drilling for and the production and transportation of oil and gas. Such 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, property damage and environmental damage. Although PC has safety and environmental policies in place to protect operators and employees, as well as to meet regulatory requirements, and although PC has liability insurance policies in place, PC cannot fully insure against all such risks, nor are all such risks insurable. PC may become liable for damages arising from such events against which it cannot insure or against which we may elect not to insure because of high premium costs or other reasons. Costs incurred to repair such damage or pay such liabilities will reduce payments made by PC to the Trust.

Competition

There is strong competition relating to all aspects of the oil and gas industry. The Trust 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 the Trust. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market oil and other products on a world wide basis and as such have greater and more diverse resources to draw on.

Environmental Concerns

The oil and natural gas industry is subject to extensive environmental regulation pursuant to local, provincial and federal legislation. A breach of such legislation may result in the imposition of fines or issuance of clean up orders. Such legislation may be changed to impose higher standards and potentially more costly obligations. Although PC has established a reclamation fund for the purpose of funding its estimated future environmental and reclamation obligations based on its current knowledge, there can be no assurance that PC will be able to satisfy its actual future environmental and reclamation obligations.

While PC has established a reserve for extraordinary and significant site reclamation or abandonment costs, actual abandonment costs incurred in the ordinary course of business during a specific period will reduce the amounts available for distribution to Unitholders.

Although PC maintains insurance coverage considered to be customary in the industry, it 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 (compared to sudden and catastrophic damages) is not available. Accordingly, PC's properties may be subject to liability due to hazards which cannot be insured against, or have not been insured against due to prohibitive premium costs or for other reasons. In such an event, these environmental obligations will be funded out of PC's cash flow and could therefore reduce distributable income payable to Unitholders.

Business-Related Risks

Reserves

The value of the Trust Units will depend upon, among other things, the reserves attributable to PC's properties. Estimating reserves is inherently uncertain. Ultimately, actual production, revenues and expenditures for PC's properties will vary from estimates and those variations could be material. The reserve and cash flow information contained in this annual information form represent estimates only. Reserves and estimated future net cash flow from PC's properties have been independently evaluated at the dates indicated by independent firms of oil and gas reservoir engineers. These firms consider a number of factors and make assumptions when estimating reserves. These factors and assumptions include, among others:

- historical production in the area compared with production rates from similar producing areas;
- the assumed effect of governmental regulation;
- assumptions about future commodity prices, production and development costs, severance and excise taxes, and capital expenditures;
- initial production rates;
- production decline rates;
- ultimate recovery of reserves;
- timing and amount of capital expenditures;
- marketability of production;
- future prices of oil and natural gas;
- operating costs and royalties; and
- other government levies that may be imposed over the producing life of reserves.

These factors and assumptions were based on prices at the date the relevant evaluations were prepared. If these factors and assumptions prove to be inaccurate, the actual results may vary materially from the reserve estimates. Many of these factors are subject to change and are beyond the Trust's control. For example, evaluations are based in part on the assumed success of exploitation activities intended to be undertaken in future years. Actual reserves and estimated cash flows will be less than those contained in the evaluations to the extent that such exploitation activities do not achieve the level of success assumed in the evaluations. Furthermore, cash flows may differ from those contained in the evaluations depending upon whether capital expenditures and operating costs differ from those estimated in the evaluations.

Depletion of Reserves

The Trust has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions by the Trust, absent commodity price increases or cost effective acquisition and development activities, will decline. The Trust will not be reinvesting cash flow in the same manner as other industry participants. Accordingly, absent capital injections and acquisition and development activities, the Trust's production levels and reserves will decline.

PC's reserves and production, and therefore its cash flows, will be highly dependent upon its success in exploiting its reserve base and acquiring additional reserves. Without reserve additions through acquisition or development activities, PC's reserves and production will decline over time as reserves are exploited.

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, the Trust's ability to make the necessary capital investments to maintain or expand reserves will be impaired.

Even if the Trust does obtain the necessary capital, there is no assurance of success in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

Marketability of Production

The marketability of PC's production depends in part upon the availability, proximity and capacity of gas gathering systems, pipelines and processing facilities. Canadian federal and provincial, as well as U.S. federal and state, regulation of oil and gas production and transportation, tax and energy policies, general economic conditions, and changes in supply and demand all could adversely affect PC's ability to produce and market oil and natural gas. If market factors dramatically change, the financial impact on the Trust's business could be substantial. The availability of markets is beyond PC's control.

Assessments of Value of Acquisitions

Acquisitions of resource issuers and resource assets will be based in large part on engineering and economic assessments made by independent engineers. These assessments will include a series of assumptions regarding such factors as recoverability and marketability of oil and gas, future prices of oil and gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond PC's control. In particular, the prices of and markets for resource products may change from those anticipated at the time of making such assessment. In addition, all such assessments involve a measure of geologic and engineering uncertainty which could result in lower production and reserves than anticipated. Initial assessments of acquisitions may be based on reports by a firm of independent engineers that are not the same as the firm that PC uses for its year end reserve evaluations. Because each of these firms may have different evaluation methods and approaches, these initial assessments may differ significantly from the assessments of the firm used by PC. Any such instance may offset the return on and value of the Trust Units.

Reliance on Third Party Operators

Continuing production from a property and marketing of product produced from the property are dependent to a large extent on the ability of the operator of the property. PC currently operates properties that represent approximately 50% of its total daily production. To the extent the operator fails to perform these functions properly or becomes insolvent, revenue may be reduced.

Enforcement of Operating Agreements

Operations of the wells on properties not operated by PC are generally governed by operating agreements, which typically require the operator to conduct operations in a good and workmanlike manner. Operating agreements generally provide, however, that the operator will have no liability to the other non-operating working interest owners for losses sustained or liabilities incurred, except such as may result from gross negligence or wilful misconduct. In addition, third-party operators are generally not fiduciaries with respect to PC, the Trust or the Unitholders. PC, as owner of working interests in properties not operated by it, will generally have a cause of action for damages arising from a breach of such duty. Although not established by definitive legal precedent, it is unlikely that the Trust or Unitholders would be entitled to bring suit against third-party operators to enforce the terms of the operating agreements; thus, Unitholders will be dependent on PC, as owner of the working interest, to enforce such rights.

Borrowing

PC has secured credit facilities with variable interest rates. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount of PC's revenues required to be applied to its debt service before payment of any amounts to the Trust. Certain covenants contained in PC's agreements with its lenders may also limit the amounts paid to the Trust and the distributions paid by the Trust to Unitholders.

PC's lenders have been provided with security over substantially all of the assets of PC. If PC becomes unable to pay its debt service charges or otherwise commits an event of default, such as bankruptcy, these lenders may foreclose on or sell PC's properties. The proceeds of any such sale would be applied to satisfy amounts owed to PC's lenders and other creditors and only the remainder, if any, would be available to the Trust.

Although PC believes that the credit facilities are sufficient, there is no assurance that the amounts available thereunder will be adequate for its future obligations or that additional funds can be obtained. The syndicated facility is available on a one year revolving basis. If the revolving period at which the lenders may extend the facility is not renewed for an additional one year period, the loan will convert to a one year term with payments due in three consecutive quarterly amounts equal to one-twentieth of the loan amount with an additional payment due on the last day of the term equal to the balance outstanding. If this occurs, PC will have to arrange alternate financing. There is no assurance that such financing will be available or be available on favourable terms. Trust distributions may be materially reduced in these circumstances and the failure to obtain suitable replacement financing may have a material adverse effect on the Trust.

Delays in Distributions

In addition to the usual delays in payment by purchasers of oil and natural gas to the operators of PC's properties, and by those operators to PC, payments between any of these parties may also be delayed by restrictions imposed by lenders, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, recovery by the operator of expenses incurred in the operation of the properties or the establishment by the operator of reserves for such expenses. Any of these delays could adversely affect Trust distributions.

Unforeseen Title Defects

Although title reviews are conducted prior to any purchase of resource issuers or resource assets, such reviews do not guarantee that an unforeseen defect in the chain of title will not arise to defeat PC's title to certain assets. A reduction of the distributable cash flow of the Trust and possible reduction of capital could result from such defects.

Accounting Write-Downs as a Result of GAAP

Canadian Generally Accepted Accounting Principles ("GAAP") requires that management apply certain accounting policies and make certain estimates and assumptions which affect reported amounts in the consolidated financial statements of the trust. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the trust unit price.

Under GAAP, the net amounts at which petroleum and natural gas costs on a property or project basis are carried are subject to a cost-recovery test which is based in part upon estimated future net cash flow from reserves. If net capitalized costs exceed the estimated recoverable amounts, PC will have to charge the amounts of the excess to earnings. A decline in the net value of oil and natural gas properties could cause capitalized costs to exceed the cost ceiling, resulting in a charge against earnings.

Emerging GAAP surrounding hedge accounting may result in non-cash charges against net income as a result of changes in the fair market value of hedging instruments. A decrease in the fair market value of the hedging instruments as the result of fluctuations in commodity prices and foreign exchange rates may result in a write-down of net assets and a non-cash charge against net income. Such write-downs and non-cash charges may be temporary in nature if the fair market value subsequently increases.

Risks Related to the Securities Markets and the Ownership of Trust Units

Nature of Trust Units

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 PC. The Trust Units are also dissimilar to conventional debt instruments in that there is no principal amount owing directly to Unitholders. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders do not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions.

Trading Price of Trust Units

The price per Trust Unit is a function of anticipated Trust Unit distributions, the properties acquired by the Trust and its ability to effect long-term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire suitable oil and natural gas properties. Changes in market conditions may adversely affect the trading price of the Trust Units.

Trust Units will have no value when reserves from the properties can no longer be economically produced or marketed and, as a result, cash distributions do not represent a "yield" in the traditional sense as they represent both return of capital and return on investment. Investors in Trust Units will have to obtain the return of capital invested out of cash flow derived from their investments in the Trust Units during the period when reserves can be

economically recovered. Accordingly, there is no assurance that the distributions Unitholders receive over the life of their investment will meet or exceed their initial capital investment.

Reliance on Petrofund Corp. and Others

Unitholders are entirely dependent on the management of PC with respect to the acquisition of oil and gas properties and assets, the development and acquisition of additional reserves, the management and administration of all matters relating to properties and the administration of the Trust. The loss of the services of key individuals who currently comprise the management team of PC could have a detrimental effect on the Trust. PC currently operates properties that represent approximately 50% of its total daily production. Investors who are not willing to rely on the management of PC should not invest in the Trust Units.

Unitholder Limited Liability

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 Trust (to the extent that claims are not satisfied by the Trust) in respect of contracts or undertakings which the Trust enters into and for certain liabilities arising otherwise than out of contract including claims in tort, claims for taxes and possibly certain other statutory liabilities. The Trust Indenture requires that the operations of the Trust be conducted in such a way as to minimize any such risk and, in particular, where feasible, every written contract or commitment of the Trust must contain an express disavowal of liability upon the Unitholders and a limitation of liability to Trust property.

Notwithstanding the terms of the Trust Indenture, Unitholders may not be protected from liabilities of the Trust to the same extent as a shareholder is protected from the liabilities of a corporation. It is unlikely, however, that personal liability will attach in Canada to the holders of Trust Units for claims arising out of any agreement or contract containing such a disavowal and limitation of liability. It is also considered unlikely that personal liability will attach in Canada to the holders of Trust Units for claims in tort, claims for taxes and possibly certain other statutory liabilities. In the event that a Unitholder is required to satisfy any obligation of the Trust, such Unitholder will be entitled to reimbursement from any available assets in the Trust.

Retraction Right

Cash payments for Trust Units surrendered for retraction are subject to limitations and any notes issued in lieu of a cash payment will not be listed on any stock exchange and no market is expected to develop for such notes.

Future Dilution

An objective of the Trust is to continually add to its reserves through acquisitions and through development, and because the Trust does not reinvest its cash flow, the success of the Trust is in part dependent on its ability to raise capital from time to time. Holders of Trust Units may also suffer dilution in connection with future issuances of Trust Units, whether issued pursuant to a financing or acquisition or otherwise.

Changes in Legislation

There can be no assurance that income tax laws, other laws or government incentive programs relating to the oil and gas industry, such as the status of mutual fund trusts and resource allowance, will not be changed in a manner which will adversely affect the Trust and Unitholders. There can be no assurance that tax authorities having jurisdiction will agree with how the Trust calculates its income for tax purposes or that such tax authorities will not change their administrative practices to the detriment of the Trust or the Unitholders.

Changes in the Trust's Status under Tax Laws

Legislative or regulatory changes remain an ongoing risk associated with the trust units and there can be no assurance that the provisions of the Tax Act relating to the qualification of the trust as a mutual fund trust will be maintained in their current form or if changes are implemented how the new provisions may affect the trust.

Under the trust indenture of the Trust, PC may require declarations as to the jurisdictions in which beneficial holders of trust units are resident. It may also make a public announcement advising that it will not accept a subscription for trust units from, or issue or register a transfer of trust units to, a person unless the person provides a declaration that the person is a not a non-resident of Canada. If, notwithstanding the foregoing, PC determines that a majority of the trust units are held by non-residents, PC may send a notice to non-resident holders of trust units, chosen in inverse order to the order of acquisition or registration or in such other manner as PC may consider equitable and practicable, requiring them to sell their trust units or a specified portion thereof within a specified period of not less than 60 days. If the unitholders receiving such notice have not sold the specified number of trust units or provided PC with satisfactory evidence that they are not non-residents within such period, PC may on behalf of such unitholders sell such trust units and in the interim, may suspend the voting and distribution rights attached to such trust units. Any such sale shall be made on any stock exchange on which the trust units are listed and, upon such sale, the affected holders shall cease to be holders of trust units and their rights shall be limited to receiving the net proceeds of sale upon surrender of the certificates representing such trust units.

Should the status of the trust as a mutual fund trust be lost, certain adverse consequences may arise. The material consequences of losing mutual fund status are as follows: (1) trust units would not constitute qualified investments for Exempt Plans upon the trust ceasing to be a mutual fund trust. Where at the end of any month an Exempt Plan holds trust units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the tax Act equal to 1% of the fair market value of the trust units at the time such trust units were acquired by the Exempt Plan. An RRSP or RRIF holding trust units that are not qualified investments would become taxable on the income attributable to the trust units while they are not qualified investments. RESPs which hold trust units that are not qualified investments may have their registration revoked by the Canada Customs and Revenue Agency; (2) the trust would be required to pay a tax under Part XII.2 of the Tax Act in respect of amounts distributed to non-resident persons if it ceases to be a mutual fund trust. The payment of Part XII.2 tax by the trust may have adverse income tax consequences for certain unitholders, since the amount of cash available for distribution would be reduced by the amount of the tax; (3) the trust would cease being eligible for the capital gains refund mechanism available under the tax Act upon ceasing to be a mutual fund trust; (4) units held by unitholders that are not residents of Canada would become taxable Canadian property upon the trust ceasing to be a mutual fund trust. Such holders would be subject to Canadian income tax on any gains realized on a disposition of units constituting taxable Canadian property; and (5) the trust would be subject to alternative minimum tax under Part 1 of the Tax Act.

GOVERNANCE OF THE TRUST AND PC

Trust Indenture

General

The Trust is an investment trust created pursuant to the Trust Indenture and governed by the laws of the Province of Ontario. The Trust has been established for the purpose of holding royalties granted by PC and acquiring, directly and indirectly, securities and royalties of oil and gas companies, oil and gas properties and other related assets.

An unlimited number of Trust Units are issuable pursuant to the Trust Indenture. As at December 31, 2003, 73.6 million Trust Units and Trust Units issuable for PC Exchangeable Shares were issued and outstanding. Each Trust Unit represents an equal undivided beneficial interest in the assets of the Trust. Each outstanding Trust Unit is entitled to an equal share of distributions by the Trust and, in the event of termination of the Trust, the net assets of the Trust. All Trust Units rank equally. Each Trust Unit entitles the holder thereof to one vote at all meetings of Unitholders.

An unlimited number of Special Voting Units are also issuable pursuant to the Trust Indenture. Special Voting Units may only be issued by the Trust in conjunction with the issuance by the Corporation or an affiliate of exchangeable shares. Each holder of a Special Voting Unit of record is entitled to vote at all meetings of Unitholders. The maximum number of votes attached to each Special Voting Unit shall be that number of Trust Units into which the exchangeable shares issued in conjunction with the Special Voting Unit and at that time outstanding are then exchangeable. The holders of Trust Units and the holder of Special Voting Units vote together as a single class on all matters. Special Voting Units have the foregoing rights in respect of voting at all meetings of unitholders but have no other rights and, for greater certainty, Special Voting Units do not represent a beneficial interest in the Trust. In the event that exchangeable shares issued in conjunction with a Special Voting Unit cease to be outstanding, such Special Voting Unit shall be deemed to be cancelled.

A Special Voting Unit was issued in connection with the Internalization Transaction to Petro Assets, which company was issued PC Exchangeable Shares pursuant to the Internalization Transaction.

Trustee

The Trust Indenture provides that the Trustee is required to exercise its powers and carry out its functions thereunder as trustee honestly, in good faith and in the best interests of the Trust and the Unitholders and, in connection therewith, will exercise that degree of care, diligence and skill that a reasonably prudent trustee would exercise in comparable circumstances.

The Trustee, where it has met its standard of care, will be indemnified out of the assets of the Trust for any actions, suits or proceedings commenced against the Trustee in respect of the Trust and for costs, taxes and other liabilities incurred by the Trustee in respect of the administration or termination of the Trust but will have no additional recourse against Unitholders. In addition, the Trust Indenture contains other customary provisions limiting the liability of the Trustee.

Issuance of Trust Units

The Trust Indenture provides that Trust Units may be issued whether fully paid or in the context of an offering, on an instalment basis, subject to the approval of the PC Board of Directors, for the purposes of, among other things, acquiring, or raising capital to acquire, net royalty interests, securities of oil and gas companies and oil and gas properties and related assets. The Trust Indenture also provides that the PC Board of Directors may also authorize the creation and issuance from time to time of rights, warrants or options to subscribe for Trust Units or other securities convertible or exchangeable into Trust Units.

Distributions

The Trust makes monthly cash distributions of the distributable cash flow received by the Trust in each month. Distributions are made on the last business day of each month to Unitholders of record as at the close of business on the tenth business day preceding each such distribution date.

Retraction Right in Respect of Trust Units

Trust Units are retractable at any time on demand by the holders thereof upon delivery to the Trust of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requesting retraction. Upon receipt of the retraction request by the Trust, all rights to and under the Trust Units tendered for retraction shall be surrendered and the holder thereof shall be entitled to receive a price per Trust Unit (the "Retraction Price") equal to the lesser of: (i) 85% of the "market price" of the Trust Units on the principal market on which the Trust Units are quoted for trading during the 10 trading day period commencing immediately after the date on which the Trust Units were surrendered for retraction (the "Retraction Date"); and (ii) the "closing market price" on the principal market on which the Trust Units are quoted for trading on the Retraction Date.

The aggregate Retraction Price payable by the Trust in respect of any Trust Units surrendered for retraction during any calendar month shall be satisfied by way of a cash payment on the last day of the following month; provided that the entitlement of Unitholders to receive cash upon the retraction of their Trust Units is subject to the limitations that: (i) the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for retraction in the same calendar month shall not exceed $100,000 (provided that such limitation may be waived in the discretion of the Trustee; (ii) at the time such Trust Units are tendered for retraction the outstanding Trust Units shall be listed for trading on a Canadian exchange or traded or quoted on any other market which the Trustee considers, in its sole discretion, provides representative fair market value prices for the Trust Units; and (iii) the normal trading of Trust Units is not suspended or halted on any stock exchange on which the Trust Units are listed (or, if not listed on a stock exchange, on any market on which the Trust Units are quoted for trading) on the Retraction Date or for more than five trading days during the 10 day trading period commencing immediately after the Retraction Date.

If a Unitholder is not entitled to receive cash upon the retraction of Trust Units as a result of the foregoing limitations, then the Retraction Price shall, subject to any applicable regulatory approvals, be paid and satisfied by way of a distribution in specie of debt securities of PC then held by the Trust (the "PC Notes") having a rate of interest which is no less than the highest rate of interest charged by the Trust to PC. If the Trust does not hold PC Notes having a sufficient principal amount outstanding to effect such payment, the Trust will be entitled to create and, subject to any applicable regulatory approvals, issue in satisfaction of the Retraction Price its own debt securities (the "Trust Retraction Notes") having such terms and conditions as the Trustee may determine and with recourse of the holder limited to the assets of the Trust.

The retraction right described above will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. The PC Notes, Trust Retraction Notes or other assets which may be distributed in specie to Unitholders in connection with a retraction will not be listed on any stock exchange and no market is expected to develop in such PC Notes or Trust Retraction Notes.

Meetings of Unitholders

The Trust Indenture provides that the following must be approved by Special Resolution: (i) removing or appointing the Trustee (subject to exceptions such as the Trustee failing to qualify to act as trustee and insolvency-related events); (ii) amendments to the Trust Indenture (except as described under "Governance of the Trust and PC - Trust Indenture - Amendments to the Trust Indenture"); (iii) amendments to the Royalty Agreement; (iv) subdivisions or consolidations of Trust Units; (v) the termination of the Trust; (vi) any matter required to be approved by Special Resolution under the Royalty Agreement, (vii) the sale of the property of the Trust as an entirety or substantially as an entirety; (viii) directing the Trustee to exercise, or refrain from exercising, any power under the Trust Indenture; (ix) directing the Trustee with respect to legal proceedings in connection with the Trust; and (x) approving the disposition of properties having a value in excess of 35% of the asset value of the properties of the Trust.

The Trust holds meetings of Unitholders on an annual basis for the purposes of electing the directors of PC.

A meeting of Unitholders may be convened at any time and for any purpose by the Trustee and must be convened if requested by the holders of not less than 25% of the Trust Units then outstanding by a written requisition. A requisition must specify the purpose for which the meeting is to be called.

Amendments to the Trust Indenture

Except as specifically provided otherwise, the Trust Indenture may only be amended by Special Resolution.

The Trustee is entitled to make certain amendments to the Trust Indenture without the approval of the Unitholders. These include amendments for the purposes of ensuring compliance with applicable laws, ensuring the Trust satisfies the requirements of the Tax Act to be a unit trust and mutual fund trust, providing additional protection for Unitholders, removing conflicts or inconsistencies (if such amendment is not detrimental to the interests of the Unitholders) and correcting ambiguities or errors (provided the rights of the Trustee and the Unitholders are not prejudiced thereby).

Limitation of Non-Resident Ownership

Under the Trust Indenture, PC may require declarations as to the jurisdictions in which beneficial holders of Trust Units are resident. It may also make a public announcement advising that it will not accept a subscription for Trust Units from, or issue or register a transfer of Trust Units to, a person unless the person provides a declaration that the person is not a non resident of Canada. If, notwithstanding the foregoing, PC determines that a majority of the Trust Units are held by non residents, PC may send a notice to non resident holders of Trust Units, chosen in inverse order to the order of acquisition or registration or in such other manner as PC may consider equitable and practicable, requiring them to sell their Trust Units or a specified portion thereof within a specified period of not less than 60 days. If the Unitholders receiving such notice have not sold the specified number of Trust Units or provided PC with satisfactory evidence that they are non residents within such period, PC may on behalf of such Unitholders sell such Trust Units and in the interim, may suspend the voting and distribution rights attached to such Trust Units. Any such sale shall be made on any stock exchange on which the Trust Units are listed and, upon such sale, the affected holders shall cease to be holders of Trust Units and their rights shall be limited to receiving the net proceeds of sale upon surrender of the certificates representing such Trust Units.

Termination of the Trust

Unless the Trust is terminated earlier, the Trustee will commence to wind up the affairs of the Trust on December 31, 2066. If, in the opinion of the Board of Directors of PC, it would be in the best interests of the Unitholders to wind up the Trust, the Trust will be wound up. In addition, the Unitholders may, by Special Resolution, decide to terminate the Trust. Upon a decision to terminate the Trust, the Trustee will sell the assets of the Trust and distribute the net proceeds to Unitholders, or wind up the Trust as otherwise directed by the Unitholders or the Board of Directors.

Borrowing

The Trust and PC may finance the acquisition of securities and royalties of oil and gas companies, oil and gas properties and related assets and capital expenditures in respect thereof through the issuance of equity or debt securities.

The Trust and PC are also permitted to borrow funds and to grant security in respect of their assets, in priority to the royalty granted by PC, for the purposes of financing the purchase of oil and gas properties and related assets, capital expenditures in respect thereof or the purchase of securities and royalties of oil and gas companies or to facilitate the repurchase of Trust Units.

The maximum amount which may be borrowed for such purposes shall not exceed 40% of the aggregate Asset Value of all properties and other resource assets (including, where applicable, those being acquired) held by Petrofund, PC and their subsidiaries and 40% of the net asset value of non-reserve based assets. "Asset Value" is defined as the present worth of all of the estimated pre-tax net cash flow from the proved reserves and 50% of the estimated pre-tax net cash flow from the probable reserves shown in the most recent engineering report relating thereto, discounted at an annual rate equal to the then current annual yield of long term (10 year) Government of Canada bonds plus 400 basis points, subject to a maximum rate of 10% and using escalating price and cost assumptions.

In calculating the 40% borrowing restriction, amounts borrowed by the Trust or PC which the Trust or PC has the right to effectively repay or cause to be repaid through the issuance of Trust Units will not form part of the 40% borrowing restriction provided the Trust or PC, as applicable, has agreed to cause payment of such indebtedness to be made through the issuance of Trust Units prior to the maturity of such indebtedness to the extent necessary to ensure that the aggregate borrowings of the Trust and PC do not then exceed the 40% borrowing restriction.

PC Unanimous Shareholder Agreement

On the completion of the Internalization Transaction, the Unanimous Shareholder Agreement was terminated. As a result of such termination the Unitholders now have the right to designate all of the nominees to be elected to the Board of Directors of PC.

The Trust is to hold meetings on an annual basis for the purposes of implementing the appointment of such directors.

The Unanimous Shareholder Agreement provided for the establishment of the Executive Committee of the Board of Directors of PC comprised of three members, two of whom will be directors of PC nominated by Unitholders and one of whom will be a director nominated by NCEP Management. Any decision with respect to the following matters were to be approved by the Board of Directors and the Executive Committee to be effective:

(a) any acquisition or disposition of oil and gas properties or other assets by the Trust or PC in excess of $10 million;

(b) any borrowing of funds or granting of security in oil and gas properties or other assets held by the Trust or PC; and

(c) any related party transaction proposed to be entered into by the Trust or PC, including any amendment to or other matter involving the Management Agreement.

On the completion of the Internalization Transaction, the Executive Committee was terminated and the above matters have to be approved by the board of Directors.

Royalty Agreement

Under the Royalty Agreement, PC grants net royalties to the Trust of 99% of the revenue received in respect of each property held by PC net of certain related costs and expenses.

The net royalty consists of a 99% share of the royalty income from PC's properties. Net royalty income is gross production revenue less the following amounts:

- operating costs;
- debt service charges;
- general and administrative costs;
- management fees;
- taxes or other charges payable by PC; and
- amounts paid into the cash reserve established by PC to fund the payment of operating costs, capital expenditures, reclamation obligations, general and administrative costs, management fees and debt service charges.

Gross production revenues essentially consist of cash proceeds from the sale of oil, natural gas and other substances produced from PC's properties, any drilling credits resulting from any expenditures made on the properties (other than drilling credits applied to capital expenditures), amounts arising out of "take or pay" contracts for oil, gas and other products and any other consideration received by PC as a result of its ownership of the properties with the exception of revenues from the rental, sale or exchange of tangible assets and the proceeds from any unitization or pooling equalization payments relating to tangible assets and excluding the proceeds from the sale of any properties.

Operating costs are all expenditures from or allocated to a property made in connection with the maintenance of a property or any activities related to producing, gathering, treating, storing, compressing, processing and transporting oil, gas and other substances including, without limitation, overriding royalties and lessors' royalties.

PC is required to pay the royalty on the last business day of each month.

The properties in respect of which the Trust has net royalties may be encumbered by security granted by PC to secure its loan obligations. The obligations of PC to pay net royalties to the Trust are not secured. Borrowings are subject to the 40% borrowing restriction referred to under "Governance of the Trust and PC - Trust Indenture - Borrowing".

The Royalty Agreement provides that the sale of a property and the royalty thereto shall be approved by the PC Board of Directors, if the sale proceeds exceed $10,000,000.

Management Agreement

The Unitholders approved the Internalization Transaction at the annual and special meeting held on April 16, 2003, and in connection with the Internalization Transaction, PC acquired all of the shares of NCEP Management and the external management contract of Petrofund as described below and all related fees were eliminated.

Pursuant to the Management Agreement, NCEP Management was compensated for providing services to PC and Petrofund. As a result of the completion of the Internalization Transaction, no fees were payable to the NCEP Management under the Management Agreement in respect of the period commencing on January 1, 2003 to the closing date, April 29, 2003. The NCEP Management received a quarterly fee paid on the last business day of each quarter of each year equal to 3.25% (reduced from 3.75%, effective January 1, 2002) of the sum of net production revenue less Crown royalties and other Crown charges attributable to PC's properties for the applicable quarterly period. In addition the NCEP Management received acquisition fees equal to 1.5% (reduced from 1.75%, effective January 1, 2002) of the purchase costs of all oil and gas properties, oil and gas companies and other related assets acquired by PC, other than replacement properties. In the event that PC properties were

sold, NCEP Management also received disposition fees of 1.25% (reduced from 1.5%, effective January 1, 2002) of the sale price of the properties sold.

PC is entitled to a residual 1% interest in the properties. The management fee and investment fee were paid in part, firstly, by applying any income received by PC in respect of its residual interest in the properties and, secondly, by applying any interest income of PC relating to the proceeds or revenue from the properties.

NCEP Management was also entitled to be reimbursed by PC for general and administrative costs and by Petrofund for trust expenses. PC was not responsible for the payment in any fiscal year of Petrofund of general and administrative costs in excess of the greater of (a) 5% of the gross production revenue for such fiscal year and (b) $240,000. To the extent that general and administrative costs paid by PC for any fiscal year of Petrofund exceed such maximum amount, PC was entitled to set off and deduct such excess amount from its liability to pay management fees to NCEP Management.

UNITHOLDER PROTECTION RIGHTS PLAN

The Trust has entered into an agreement with Computershare Trust Company of Canada dated May 14, 1999 creating a unitholder protection rights plan (the "Rights Plan"). The Rights Plan was approved by the Unitholders at a meeting held on November 12, 1999.

The Rights Plan utilizes the mechanism of the Permitted Bid (as hereinafter described), to ensure that a person seeking control of the Trust gives the Trust sufficient time in which to evaluate the bid, negotiate with the initial bidder and encourage competing bids to emerge. The purpose of the Rights Plan is to protect Unitholders by requiring all potential bidders to comply with the conditions specified in the Permitted Bid provisions failing which such bidders will become subject to the dilutive features of the Rights Plan.

Generally, to qualify as a Permitted Bid, a bid must be made to all of the Unitholders of the Trust and must be open for 60 days after the bid is made. If more than 50% of the Units held by Independent Unitholders (being Unitholders other than the bidder, its affiliates and persons acting jointly or in concert with it) are deposited or tendered to the bid and not withdrawn, the bidder may take up and pay for such Units. The take-over bid must then be extended for a further period of 10 business days on the same terms to allow those Unitholders who did not initially tender their Units to tender to the take-over bid if they so choose. Thus, there is no coercion to tender during the initial 60-day period because the bid must be open for acceptance for at least 10 days after the expiry of the initial tender period.

The term of the Rights Plan is May 14, 2004, which date is five years from the date of the Rights Plan, May 14, 1999, at which time the right to exercise a right will terminate, unless it is previously terminated in accordance with the terms of the Rights Plan.

On May 14, 1999, one right (a "Right") was issued for each Unit outstanding which is, until the Separation Time (as defined below), evidenced by a legend imprinted on a certificate for the Units. One Right will also attach to any subsequently issued Units. The initial exercise price of the Rights is $60.00 per Unit (the "Exercise Price"), subject to appropriate anti-dilution adjustments.

The Rights will separate from the Units to which they are respectively attached and will become exercisable at the time (the "Separation Time") which is 10 days after the earlier of (i) the announcement that a person has become the beneficial owner of 20% or more of the Units, other than by an acquisition pursuant to a Permitted Bid, or (ii) the commencement or announcement date, or such later date as may be determined by the directors of NCEP Management in respect of a take-over bid to acquire 20% or more of the Units, other than by an acquisition pursuant to a Permitted Bid. After the Separation Time and prior to the occurrence of a Flip-in

Event (as defined below), each Right will entitle the holder thereof to purchase, upon payment of the Exercise Price, one Unit, subject to anti-dilution adjustments.

The acquisition by a person (an "Acquiring Person"), including others acting in concert, of 20% or more of the Units, other than by way of a Permitted Bid, is referred to as a "Flip-in Event". Any Rights held by an Acquiring Person on or after the earlier of the Separation Time or the first date of public announcement by the Trust or an Acquiring Person that an Acquiring Person has become such, will become void upon the occurrence of a Flip-in Event. Ten trading days after the occurrence of the Flip-in Event, the Rights (other than those held by the Acquiring Person) will permit the holder to purchase, upon payment of the Exercise Price of $60.00, Units with a total market value of $120.00 (i.e., at a 50% discount).

Until a Right is exercised, the holder of such Right, as such, will have no rights as a Unitholder of the Trust.

DISTRIBUTION REINVESTMENT AND UNIT PURCHASE PLAN

The Trust has a distribution reinvestment and unit purchase plan (the "Plan"). The Plan allows Unitholders resident in Canada to acquire additional Trust Units by reinvesting their cash distributions or by making optional cash payments. Only Unitholders who are resident in Canada and hold in excess of 100 Trust Units may participate in the Plan. The Plan is not available to Unitholders who are residents of the United States or other foreign jurisdictions.

Under the Plan, Unitholders may direct the Trust to reinvest cash distributions on the Trust Units to acquire, in the discretion of NCEP Management, existing Trust Units through the facilities of the TSX or newly issued Trust Units from treasury. In addition, Unitholders may purchase newly issued Trust Units directly from the Trust by making cash payments to the Trust, subject to a minimum of $100 and a maximum of $1,000 per calendar quarter.

Cash distributions will be applied to the purchase of Trust Units on the TSX at prevailing market prices for a period of 10 trading days following the distribution date. The cost of such Trust Units to participants will be the average cost of the Trust Units purchased. If insufficient Trust Units are purchased during the said 10 trading day period, the uninvested portion will be applied to purchase Trust Units from treasury.

Optional cash payments will be applied to the purchase of newly-issued Trust Units on the cash distribution date following receipt.

In 2003, the Trust issued 316,785 Trust Units under the Plan.

DIRECTORS AND OFFICERS

Information concerning the directors and officers of PC as of the date hereof is set out below:

Name and Municipality of Residence	Position	Director Since
John F. Driscoll Toronto, Ontario	Chairman and Director	July 15, 1988
Jeffery E. Errico Calgary, Alberta	President, Chief Executive Officer and Director	April 16, 2003

Name and Municipality of Residence	Position	Director Since
Glen C. Fischer Calgary, Alberta	Senior Vice-President, Operations	
Vince P. Moyer Calgary, Alberta	Senior Vice-President, Finance and Chief Financial Officer	
Jeffrey D. Newcommon Calgary, Alberta	Executive Vice President	
Noel Cronin Calgary, Alberta	Vice-President, Production	
James E. Allard(1)(4) Calgary, Alberta	Director	April 16, 2003
Sandra S. Cowan(2)(3) Toronto, Ontario	Director	January 17, 2002
Wayne M. Newhouse(3)(4) Calgary, Alberta	Director	April 16, 2003
Frank Potter(1)(2)(3) Toronto, Ontario	Director	November 1, 2000
Peter N. Thomson(1)(2)(4) Nassau, Bahamas	Director	November 1, 2000

Notes:

(1) Member of the Audit Committee.
(2) Member of the Governance Committee.
(3) Member of the Human Resources and Compensation Committee.
(4) Member of the Reserves Audit Committee.

Set forth below are the particulars of the principal occupations of each director and officer of PC for the past several years.

John F. Driscoll is the Chairman, President, Chief Executive Officer and a director of Sentry Select Capital Corp. He also founded and has been Chairman of NCE Resources group since 1984 and Chairman of Petrofund since 1988. He has also been Chairman of Inter Pipeline Fund and strategic Energy Fund since October 2002 and May 2002 respectively. He specializes in closed-end funds and mutual funds and related advisory, management and consulting services. Mr. Driscoll received his Bachelor of Science degree from the Boston College Business School in 1964 and in 1967 attended the New York Institute of Finance. During the last 20 years, issuers of which Mr. Driscoll was responsible as an officer and/or director or in respect of which he was an officer and/or director of their managers have raised gross proceeds of approximately $4.0 billion. Mr. Driscoll also founded and has been President, since 1981, of J.F. Driscoll Investment Corp., a company specializing in investment management.

Jeffery E. Errico is a Professional Engineer who received a Bachelor of Science degree in Chemical Engineering from the University of British Columbia in 1973. He has over 20 years experience in the oil and gas industry, serving as Vice-President, Operations of Deminex Canada Limited prior to joining NCE Resources Group in April, 1995.

Glen C. Fischer is a Professional Engineer who received a Degree in Mechanical Engineering from the University of Calgary. He has over 20 years of engineering and management experience in the oil and gas industry and from 1984 to 1996 was Manager, Engineering & Operations for ATCOR Ltd. and its successor Canadian Forest Oil Ltd. Mr. Fischer joined the NCE Resources Group in July, 1996.

Vince P. Moyer received his Chartered Accountant's designation in 1975 and a Master of Business Administration degree in 1972 from the University of Manitoba, majoring in finance. From 1981 to 1991 he held various positions with Enron Oil Canada Ltd., including most recently as Vice-President, Finance and Administration from 1986 to 1991. Mr. Moyer joined the NCE Resources Group in June, 1991.

Jeffrey D. Newcommon received his Bachelor of Arts degree in Finance and Economics from the University of Western Ontario in 1983. From 1984 to 1995 he held various positions with Canadian Hunter Exploration Ltd., including, most recently, Land Manager. He joined the NCE Resources Group in April, 1995.

Noel Cronin is a Professional Engineer with over 20 years of diversified experience in the petroleum industry in western Canada, including reservoir management/exploitation, economic evaluations, joint interests and production operations. He has worked for various Calgary-based oil and gas producers during his career and joined the NCE Resources Group as Production Manager in 1997.

James E. Allard has focused his career in international finance and the petroleum industry for the past 40 years serving as CEO, CFO and director of a number of publicly traded and private companies during that period. During the past five years he has continued to serve on the board of the Alberta Securities Commission, act as the sole external trustee and advisor to a mid-sized pension plan and serve as a director and advisor to several companies. From 1981 to 1995, he served as a senior executive officer of Amoco Corporation as well as a director of Amoco Canada, then Canada's largest natural gas producer.

Sandra S. Cowan is Partner and General Counsel of EdgeStone Capital Partners, an independent private equity firm managing over $1 billion of private capital. Prior to joining EdgeStone in 2001, Ms. Cowan practiced law for over 15 years, most recently as a senior partner of Goodman and Carr LLP. Her practice specialized in private equity and corporate finance transactions, including fund formation, mergers, acquisitions and divestitures, cross-border and public market transaction. Ms. Cowan has an LLB from the University of Western Ontario and serves on a number of private and public boards.

Wayne M. Newhouse is a Professional Engineer and Oil and Gas Executive with over 40 years of broad industry experience. Since 1995 Mr. Newhouse has served as President of Newhouse Resources Management Ltd. and subsequently Morgas Ltd., both private oil and gas production companies, as well as being a director of several publicly traded companies. From 1989 to 1994, Mr. Newhouse served as Senior Vice President, Production and Senior Vice President, Exploration and International Development with Norcen Energy Resources Ltd.

Frank Potter has been the Chairman since 1995 of Emerging Markets Advisors, Inc., a Toronto-based consultancy that assists corporations in making and managing direct investments internationally. Prior thereto, Mr. Potter was executive director of The World Bank Group in Washington, and was subsequently senior advisor at the federal Department of Finance. Mr. Potter is a director of a number of public and private corporations and public service organizations.

Peter Nesbitt Thomson has been the Chairman of the Board of the West Indies Power Corporation Limited for over 10 years. He attended Lower Canada College and Sir George Williams College. He received an honorary Doctorate of Laws Degree from St. Thomas University, Fredericton, New Brunswick. Beginning his professional career in Montreal with investment dealer Nesbitt Thomson, he later was Chairman, President and Chief Executive Officer of Power Corporation of Canada. He has served as a director of numerous Canadian companies, including Petrofina Canada Limited and Norcen Energy Resources Ltd.

Ownership of Trust Units by Directors and Officers

As at December 31, 2003, the directors and executive officers of PC beneficially owned, directly or indirectly, 596,166 Trust Units representing less than 1% of the issued and outstanding Trust Units and 851,471 PC Exchangeable Shares representing 100% of the issued and outstanding PC Exchangeable Shares.

ESCROWED SECURITIES

There are 85,244 Trust Units in escrow which were issued to executive management in connection with the internalization of management. They are released evenly each quarter to March 31, 2008. The escrow agent is Goodman and Carr LLP.

MARKET FOR SECURITIES

The Trust Units are listed and posted for trading on the TSX under the symbol "PTF.UN" and the American Stock Exchange under the symbol "PTF".

CONFLICTS OF INTEREST

Many of the directors and officers of PC are directors and officers of other entities which may be in competition to the interests of PC and the Trust. In the ordinary course of business, these other entities may acquire properties or explore other business opportunities that may be suitable for Petrofund. No assurances can be given that opportunities identified by such board members will be provided to PC and the Trust.

ADDITIONAL INFORMATION

Additional financial information is available on Sedar at www.sedar.com and on the Trust's website at www.petrofund.ca.

The Trust will provide to any person, upon request to PC:

(a) when the securities of the Trust are in the course of a distribution pursuant to a short form prospectus or a preliminary short form prospectus has been filed in respect of a distribution of its securities,

  (i) one copy of the annual information form of the Trust, together with one copy of any document, or the pertinent pages of any document, incorporated by reference therein,

(ii) one copy of the comparative financial statements of the Trust for its most recently completed financial year together with the accompanying report of the auditor and one copy of any interim financial statements of the Trust subsequent to the financial statements for its most recently completed financial year,

(iii) one copy of the information circular of the Trust in respect of its most recent annual meeting of Unitholders that involved the election of directors or one copy of any annual filing prepared in lieu 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 the 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 (a)(i), (ii) and (iii) above, provided the Trust may require the payment of a reasonable charge if the request is made by a person who is not a security holder of the Trust.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the issuer's securities, options to purchase securities and interests of insiders in material transactions, if applicable, is contained in the issuer's information circular for its most recent annual meeting of Unitholders that involved the election of directors, and additional financial information is provided in the issuer's comparative financial statements for its most recently completed financial year.

For additional copies of this annual information form please contact:

Petrofund Corp.
444 - 7th Avenue, S.W.
Suite 600
Calgary, Alberta
T2P 0X8

Attention: Investor Relations

MANAGEMENT DISCUSSION &ANALYSIS

NAME CHANGE AND REVISED TRADING SYMBOL

This is the first annual report that reflects the name change of the Trust to Petrofund Energy Trust ("Petrofund" or the "Trust") from NCE Petrofund. The name change was announced on October 23, 2003, and became effective November 1, 2003.

On the same date, the name of the Trust's 100% owned subsidiary was changed to Petrofund Corp. ("PC") from NCE Petrofund Corp. As a result of the name change, the Trust adopted the new trading symbols PTF.UN on the Toronto Stock Exchange and PTF on the American Stock Exchange. The Trust units commenced trading under the new symbols on November 3, 2003.

The name change reflects the restructuring of the Trust. The restructuring began with the internalization of management early in 2003 and the consolidation of the remaining activities in the Calgary office over the year. Petrofund has an experienced and competent team of oil and gas professionals and support groups who have assembled an excellent portfolio of quality assets. This team has been an instrumental part of the significant growth of the entity which had an enterprise value of $1.5 billion as at December 31, 2003.

SPECIAL NOTES

The following discussion and analysis of financial results should be read in conjunction with the audited consolidated financial statements of the Trust for the fiscal years ended December 31, 2003 and 2002 presented later in this report. This commentary is based on information available to February 15, 2004.

All amounts are stated in Canadian dollars unless otherwise noted. Where amounts and volumes are expressed on a barrel of oil equivalent basis, gas volumes have been converted to barrels of oil at 6,000 cubic feet per barrel (6 mcf/bbl).

Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flows or operating profits for the period, nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital.

Reserves at December 31, 2003, are based on total proved plus probable company interest reserves prior to royalties as defined in National Instruments 51-101 ("NI 51-101"). Reserves volumes and values for 2003 have been calculated and disclosed in accordance with this standard. Reserve numbers for other years and previously announced acquisitions for the current year, are based on established company interest (proved plus 50% probable) reserves prior to royalties. Under those definitions, probable reserves were adjusted by a factor to account for the risk associated with their recovery. The Trust previously applied a risk factor of 50% in reporting probable reserves. Under current NI 51-101 reserves definitions, estimates are prepared such that the full proved plus probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "best estimate").

FORWARD-LOOKING STATEMENTS

This disclosure includes statements about expected future events and/or financial results that are forward-looking in nature and subject to substantial risks and uncertainties. For those statements, Petrofund claims the protection of the safe harbor for forward-looking statements provisions contained in the

U.S. Private Securities Litigation Reform Act of 1995. Petrofund cautions that actual performance will be affected by a number of factors, many of which are beyond its control. These include general economic conditions in Canada and the United States; industry conditions including changes in laws and regulations; changes in income tax regulations; increased competition; and fluctuations in commodity prices, foreign exchange and interest rates. In addition, there are numerous risks and uncertainties associated with oil and natural gas operations and the evaluation of oil and natural gas reserves. As a result, future events and results may vary substantially from what Petrofund currently foresees.

A more complete discussion of the various factors that may affect future results is contained in Petrofund's recent filings with the Securities and Exchange Commission and Canadian securities regulatory authorities.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates. Changes in these judgments and estimates could have a material impact on the Trust's financial results and financial condition. The Trust has determined that the process of estimating reserves is critical to several accounting estimates. The process of estimating reserves is complex and requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development and production activities becomes available, and as economic conditions impacting oil and natural gas prices, operating costs, and royalty burdens change. Reserve estimates impact net income through depletion, the provision for site reclamation and abandonment and in the application of the ceiling test, whereby the value of the oil and natural gas assets are subjected to an impairment test. The reserve estimates are also used to asses the borrowing base for the Trust's credit facilities. Revision or changes in the reserve estimates can have either a positive or a negative impact on net income or the borrowing base of the Trust.

2003 HIGHLIGHTS

The Trust paid out cash distributions of $127.3 million or $2.09 per unit, an increase of 22% over the $1.71 per unit paid in 2002.

The Trust's payout ratio for the year was 70% (87% for the fourth quarter).

Net income increased 252% to $85.8 million.

The Trust generated cash flow of $187.6 million, an increase of 67% over 2002.

Production on a boe basis increased 10% to 28,418 boepd.

Average prices were relatively strong, up 32% on a boe basis from the prior year.

The Canadian dollar strengthened in the second half of the year more than offsetting the increase in the West Texas Intermediate ("WTI") U.S. oil prices. The average WTI price in the second half of 2003 was up 9% to $30.16 a barrel from the same period in 2002, however, the Canadian par price at Edmonton was down 6% or $2.77 per bbl over the same period.

The internalization of management transaction was completed resulting in the elimination of management fees and lower general and administrative costs.

Petrofund acquired interests in various long-life oil and gas properties for $115.6 million (excluding the non-cash future income tax adjustment of $4.7 million on the purchase of Solaris Oil and Gas Inc.). The properties added proved plus probable reserves of 19.4 million boe.

Petrofund continued an active development drilling and farmout program, investing $71.4 million on development drilling, facilities and other costs. During the year 254 wells were drilled at an overall success rate greater than 90%. These activities added production at $28,600 per boepd. The combined result of the acquisition and development programs was to add 20.3 million boe's of reserves and replace 200% of 2003 production.

Petrofund ended 2003 with a very strong balance sheet with long-term debt outstanding equivalent to 59% of 2003 cash flow.

The Trust completed two equity offerings, raising net proceeds of $193.4 million.

The Trust had a balanced production profile consisting of 49% gas and 51% oil and liquids.

The Trust reached a milestone with market capitalization exceeding $1.3 billion.

Corporate governance was strengthened including the establishment of Governance, Reserve Audit, and Human Resources and Compensation committees all consisting of independent directors. The Audit committee previously consisted of all independent directors. Petrofund meets all governance guidelines prescribed by the TSX and the AMEX.

Internalization of Management

One of the key achievements in the first half of 2003 was the elimination of the external management contract and all related fees.

At the Annual and Special Meeting held on April 16, 2003, unitholders of the Trust voted over 90% in favour of the proposed internalization of management resolution, and on April 29, 2003, the transaction was closed. As a result of the internalization, NCE Petrofund Management Corp. ("NCEP Management"), the Previous Manager of the Trust and NCE Management Services Inc. ("NMSI"), which employed all of the Calgary-based personnel who provided services to the Trust and PC, became wholly-owned subsidiaries of PC. Effective January 1, 2004 all the Calgary employees became direct employees of PC, the operating company.

As a result of the transaction, all management, acquisition and disposition fees payable to the Previous Manager were eliminated effective January 1, 2003, and the Trust's operations were consolidated in Calgary. To ensure an orderly transition of the services previously provided by NCEP Management through its office in Toronto, PC entered into an agreement with Sentry Select Corp. ("Sentry") to provide certain services to the Trust and PC until December 31, 2003. The cost decreased from $1 million in the first quarter to $500,000 in the second quarter and to

$250,000 in each of the third and fourth quarters, after which Sentry no longer provides any services to Petrofund. Sentry was an affiliate of NCEP Management and is a company in which John Driscoll, the Chairman of the Board of Directors, owns a controlling interest.

The elimination of management fees and the reduction in general and administrative costs resulting from the streamlining and consolidation of on-going management in Calgary improved the operating structure of the Trust. The internalization was accretive to Petrofund's net asset value, distributions and cash flow per unit.

The elimination of management fees and the increased management ownership further aligned the interests of the unitholders and management and improved Petrofund's competitiveness for acquisitions as a result of the elimination of acquisition and disposition fees. The completion of the internalization is also expected to enhance the attractiveness of the units to a wider range of potential investors, expand the investor base, and may result in a lower cost of capital.

The cost of the internalization to Petrofund was $30.9 million, consisting of the issue of 1,939,147 exchangeable shares, 100,244 Trust units, and cash of $8.0 million, including $3.4 million to repay indebtedness owing to NCEP Management. Initially, each Exchangeable Share was exchangeable into one Trust unit. The exchange rate is adjusted from time to time to reflect distributions paid on each Trust unit after the closing date. The purchase price was based on numerous factors, including a fairness opinion by CIBC World Markets, who were retained by a special committee of the Board of Directors formed to consider this transaction and negotiate the terms of the internalization.

CASH DISTRIBUTIONS

Trust unitholders who held their units throughout 2003 received cash distributions of $2.09 per unit as compared to $1.71 per unit in 2002 and $4.24 in 2001. During each of the first two months of 2004, the Trust distributed $0.16 per unit.

The Trust generated cash flow available for distributions of $180.7 million in 2003. A total of $30 million of this cash flow was allocated to capital expenditures during the year in accordance with the Trust's policy to use a portion of the cash flow generated to offset production decline and enhance long-term unitholder returns. The $30 million represents 17% of cash flow for the year. A total of $127.3 million was paid out in distributions representing a payout ratio of 70%. In the fourth quarter, the Trust generated cash flow available for distribution of $41.6 million before deducting $7.5 million of capital and paid out $36.3 million in distributions for a payout ratio of 87%. For a detailed analysis of cash flow available for distribution and distributions paid refer to Note 12 to the Consolidated Financial Statements.

At December 31, 2003, the Trust had $53.5 million available to pay future distributions, capital and other costs, of which $23.6 million was used to pay the January and February 2004 distributions.

RESULTS OF OPERATIONS

PRODUCTION

In accordance with Canadian practice, production volumes and reserves are reported on a working interest basis, before deduction of Crown and other royalties, unless otherwise indicated.

Production volumes averaged 28,418 boe/d, an increase of 10% over average production volumes of 25,782 boe/d in the previous year. The majority of the increase is due to the additional properties purchased for $62 million in the second quarter of 2003, the additional Swan Hills Unit interest purchased in the third quarter of 2003 and the acquisition of NCE Energy Trust on May 31, 2002. Production from the second quarter acquisition is included in this report effective June 1, 2003, and the additional Swan Hills interest is included effective September 1, 2003.

For the years ended December 31,	2003	2002	2001
Daily Production			
Oil (bbls)	12,454	11,162	8,156
Gas (mmcf)	83.3	76.9	67.2
Natural gas liquids (bbls)	2,079	1,808	1,452
Total (boe 6:1)	28,418	25,782	20,810

PRICING & PRICE RISK MANAGEMENT

Revenues from the sale of crude oil, natural gas, and natural gas liquids and sulphur increased 45% to $393.1 million in 2003 from $270.7 million in 2002 due to a 10% increase in production and 32% increase in prices on a boe basis.

Crude oil sales increased to $172.3 million in 2003 from $141.3 million in 2002 due to a 12% increase in production from 11,162 bbl/d in 2002 to 12,454 bbl/d in 2003. The average WTI U.S. oil price increased from $26.08 per bbl in 2002 to $31.04 in 2003 or 19%, however, the Canadian par price at Edmonton increased only 8% from $39.91 per bbl to $43.14 bbl due to the significant strengthening of the Canadian dollar relative to the U.S. dollar, especially in the last half of the year. The average Canadian wellhead price increased from $34.68 per barrel in 2002 to $37.91 per barrel in 2003. Hedging losses reduced the price by $1.00 per bbl in 2003 and $2.10 per bbl in 2002. About 72% of the Trust's crude production is sold directly to refiners, up from 62% a year ago and nearly double the level of 2001. This reflects Petrofund's strategy of reducing sales to marketers and middlemen to achieve higher levels of security for both credit and the actual physical delivery of the crude. The balance of the crude is delivered to marketers. Crude differentials were relatively stable and tight during 2003 with Petrofund's actual differentials from Edmonton postings before hedging at $4.23/bbl versus $3.16/bbl the previous year. Western Canadian crude differentials for 2004 are expected to be similar to those seen in 2003. Heavy oil differentials, to which Petrofund has little exposure, may be weaker and the bias is for tighter differentials for the lighter and medium sour crudes comprising the bulk of the Trust's portfolio. Petrofund's crude portfolio is over 97% light and medium crudes.

Natural gas sales increased to $194.2 million in 2003 from $110.7 million in 2002 due to an 8% increase in production in addition to a 62% increase in average prices from $3.95 per mcf in 2002 to $6.39 per mcf in 2003 net of a hedging loss of $0.11 per mcf. The monthly AECO price increased from $4.07 per mcf in 2003 to $6.71 per mcf in 2003. Production volumes were 83.3 mmcf/d in 2003 compared to 76.9 mmcf/d in 2002. Petrofund sold 34% of its production in 2003 to aggregators at netback pricing, down slightly from 38% in 2002 and similar to volumes delivered in 2001. The Trust sold the remaining 66% on daily and monthly spot market pricing in Alberta, Saskatchewan and British Columbia.

Sales of natural gas liquids increased to $26.6 million in 2003 from $18.7 million in 2002 as production increased to 2,079 bbl/d in 2003 from 1,808 bbl/d in 2002. The average price increased from $28.30 per barrel in 2002 to $34.66 per barrel in 2003. The majority of the Trust's NGL is sold to two buyers under one-year contract terms at market sensitive pricing. NGL netbacks lagged the recovery in crude oil prices during the year owing to mid-year weakness in natural gas prices. Petrofund expects NGL's to continue to return attractive pricing for 2004 with very strong pricing for condensate.

Crude oil sales accounted for 44% of total production in 2003 (2002 - 43%, 2001 - 39%), while natural gas sales contributed 49% of production in 2003 (2002 - 50%, 2001 - 54%). Natural gas liquid volumes accounted for 7% of total production in all three years. The Trust continues to maintain an excellent balance between oil and gas production.

Sales Prices

Average prices for the year ended December 31,	2003	2002	2001
Oil (1)	$ 37.91	$ 34.68	$ 34.37
Gas (2)	6.39	3.95	5.09
Natural gas liquids	34.66	28.30	32.57
Weighted average (6:1)	$ 37.87	$ 28.77	$ 32.19
(1) The oil price was increased (decreased) per bbl due to hedging	$ (1.00)	$ (2.10)	$ 1.05
(2) The gas price was decreased per mcf due to hedging	$ (0.11)	$ -	$ (0.13)
Production Revenue (millions)			
Oil	$ 172.3	$ 141.3	$ 102.3
Gas	194.2	110.7	125.0
Natural gas liquids	26.6	18.7	17.2
Total	$ 393.1	$ 270.7	$ 244.5

The Trust implemented a formal risk management policy which provides the Risk Management Committee with the ability to use specified price risk management strategies up to 50% of crude oil, natural gas and NGL production including: fixed price contracts; costless collars; the purchase of floor price options; and other derivative financial instruments to reduce price volatility and ensure minimum prices for a maximum of two years beyond the current date. The program is designed to provide price protection on a portion of the Trust's future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. In this way the Trust seeks to provide a measure of stability to cash distributions as well as ensure Petrofund realizes positive economic returns from its capital development and acquisition activities.

As at December 31, 2003, Petrofund has hedged 26 mmcf/d of gas and 5,328 bbl/d of crude oil for 2004. The Trust increased its gas hedges for 2004 by 7 mmcf/d and its crude oil hedges by

1,569 bbl/d over the third quarter. Petrofund's 2004 gas hedges include: 18.5 mmcf/d collared between $5.42/mcf-$7.90/mcf and 7.5 mmcf/d fixed at $6.15/mcf. The Trust will lose its floor protection on about 9% of the collared volumes if AECO drops below $4.74/mcf but will receive a premium of $1.06/mcf in this event. Petrofund's 2004 crude hedges include 1,995 bbl/d fixed at $38.59/bbl in the first half and 668 bbl/d fixed at $36.41 in the second half of the year. The Trust has also collared 4,000 bbl/d in 2004 between $31.20/bbl-$36.86/bbl. The Trust will lose its floor protection on 50% of the collared volume in the event WTI averages less than $27.40/bbl ($21.13 US. Under these transactions Petrofund will receive a premium of $3.89/bbl ($3.00 US) to the actual price. For the first quarter of 2005, the Trust has 9.5 mmcf/d of gas hedged under a $5.80/mcf-$8.97/mcf three way collar. At year end, the Petrofund's 2005 crude hedges include 1,000 bbl/d in a three way collar between $31.12/bbl-$37.60/bbl.

Petrofund also fixed the price on approximately 50% of its power consumption at $44.50/MWh for 2004 and 2005 to control future costs. During 2003, the monthly average power costs ranged from $44.47/MWh to $89.80/MWh.

In early January 2004, Petrofund entered into the following additional hedge transactions:

1) 1,000 bbl/d of crude oil was fixed for March-May 2004 at $41.92/bbl;

2) 1,000 bbl/d of crude oil was fixed for November-December 2004 at $37.73/bbl;

3) 2,000 bbl/d of crude oil for 2005 under a three way WTI collar between $34.75 and $43.18/bbl ($26.81-$33.30 US). Under this transaction, if WTI averages less than $30.46 ($23.50 US), Petrofund will lose the floor protection, but will still receive a $4.54/bbl ($3.50 US) premium to the actual price.

The Trust also increased its AECO gas hedges subsequent to year end by collaring an additional 1.9 mmcf/d between $5.28/mcf and $7.65/mcf for the period April 1, 2004 to October 31, 2004.

All foreign exchange calculations in this section of the report incorporate the Bank of Canada US dollar rate at the close on December 31, 2003, ($1.2965 C$:US$). For a complete listing of all hedge transaction details please see Note 14 to the Consolidated Financial Statements.

Royalties	2003	2002	2001
Royalties (millions)	$ 84.8	$ 50.4	$ 54.7
Average royalty rate (%)	21.6%	18.6%	22.4%
$/boe	$ 8.18	$ 5.36	$ 7.21

Royalties, which include crown, freehold and overrides paid on oil and natural gas production, increased to $84.8 million in 2003 from $50.4 million in 2002, net of the Alberta Royalty Credit. Royalties increased to 21.6% of revenues in 2003 from 18.6% of revenues in 2002 and 22.4% in 2001. The variation in the average rates is mainly due to the fluctuations in natural gas prices as the gas royalty rate changes with natural gas prices.

Expenses	2003	2002	2001
Expenses (millions)			
Lease operating	$ 91.3	$ 74.8	$ 48.2
General & administrative	13.0	15.5	14.4
Management fee	-	4.7	5.3
Net interest	8.7	8.3	7.8
Expenses per boe			
Lease operating	$ 8.80	$ 7.95	$ 6.35
General & administrative	1.26	1.65	1.90
Management fee	-	0.50	0.70
Net interest	0.84	0.88	1.03

Lease Operating

Oil and gas operating expenses increased to $91.3 million in 2003 from $74.8 million in 2002 (2001 - $48.2 million) due to the additional wells on production and the increase in costs on a boe basis. Operating costs on a boe basis increased to $8.80 in 2003 from $7.95 in 2002 (2001 - $6.35).

The most significant contributor to the higher operating costs in 2003 was the increased costs for workover activities. These activities included rate acceleration projects, well repair, facility turnarounds and other facility maintenance work. There are two components to the increased costs. Firstly, costs in general have risen due to high industry activity levels. Secondly, more workover projects were undertaken for production enhancement because the return on these projects is very good in the current product price environment.

GENERAL & ADMINISTRATIVE

General and administrative costs decreased to $13.0 million in 2003 from $15.5 million in 2002 (2001 - $14.4 million). Costs decreased 24% to $1.26 per boe in 2003 from $1.65 per boe in 2002 as a result of the consolidation of all activities in Calgary and the increased production volumes.

MANAGEMENT FEES

No management fees were payable in 2003 and no future fees will be paid due to the internalization of management. Fees of $4.7 million were paid in 2002 to the Previous Manager (2001 - $5.3 million).

INTEREST

Interest expense increased to $8.7 million in 2003 from $8.3 million in 2002 (2001 - $7.8 million), due to the increase in the average loan balance outstanding.

The bank loan outstanding at December 31, 2003, was $109.7 million as compared to $212.3 million at the end of the previous year.

DEPLETION AND DEPRECIATION &

PROVISION FOR RECLAMATION AND ABANDONMENT

Depletion and depreciation is provided on the unit-of-production method based on total estimated proved reserves. Depletion and depreciation expense was $113.9 million in 2003 compared to $98.8 million in 2002 (2001 - $68.5 million). The depletion rate per boe increased to $10.98 in 2003 from $10.50 in 2002 (2001 - $9.01). The $0.48 increase in the depletion rate from 2002 to 2003 was mainly due to the negative reserve revisions at the end of 2002. Unproved properties are included in the depletion and depreciation rate. The provision for reclamation and abandonment per boe in 2003 was $0.60, compared to $0.62 in 2002 (2001 - $0.48).

RECLAMATION & ABANDONMENT RESERVE

At the end of the year, PC had $3.8 million set aside in cash to fund future abandonment costs. This cash fund is increased by $0.075 per boe produced on an ongoing basis. This cash fund is in place to fund significant future reclamation costs, such as the decommissioning of a major facility.

PC is committed to conducting its operations in a safe and environmentally responsible manner and has an established program in place to manage environmental liabilities. The Trust performs well reclamation and abandonments, flare pit remediation work, etc. on a routine basis to proactively address environmental concerns. Petrofund's activities in this area in 2003 were significant as $4.7 million was spent on these types of projects. This compares to $2.2 million in 2002 and $0.4 million in 2001. PC expects to spend a further $3 million on reclamation and abandonment work in 2004.

NET INCOME

Net income increased to $85.8 million, up 252% from the $24.4 million reported in 2002 (2001 - $54.0). The increase was mainly due to the 35% improvement in operating netbacks as prices were up 32% on a boe basis. In addition, production was up 10% over the prior year.

Net income for the year ended December 31, 2003, was impacted by the costs of the internalization of the management contract and the reduction of income taxes for the decrease in future income tax rates. Net income was reduced by $30.9 million for management internalization costs and increased by $36.7 million for future income tax reductions.

QUARTERLY FINANCIAL DATA

($millions, except per Unit amounts)	Net Oil and Natural Gas Sales(1)	Net Income	Net income per Unit (2) Basic	Diluted
2003				
First quarter	$ 84.9	$ 32.2	$ 0.59	$ 0.59
Second quarter	74.8	15.1	0.26	.26
Third quarter	73.4	14.9	0.23	0.23
Fourth quarter	75.2	23.6	0.33	0.33
	$ 308.3	$ 85.8	$ 1.41	$ 1.40
2002				
First quarter	$ 42.7	$ 0.9	$ 0.02	$ 0.02
Second quarter	53.1	8.5	0.17	0.17
Third quarter	55.8	9.6	0.18	0.18
Fourth quarter	68.6	5.4	0.10	0.10
	$ 220.2	$ 24.4	$ 0.49	$ 0.49
2001				
First quarter	$ 54.4	$ 26.3	$ 1.19	$ 1.19
Second quarter	46.9	16.4	0.60	0.60
Third quarter	45.4	7.7	0.20	0.20
Fourth quarter	43.0	3.6	0.09	0.09
	$ 189.7	$ 54.0	$ 1.71	$ 1.71

(1) Net after royalties
(2) Net income per unit numbers are calculated quarterly and therefore do not add.

Discussion of Results for the Fourth Quarter of 2003

Production for the fourth quarter of 2003 was 29,211 boe/d as compared to 27,362 boe/d for the same period in the prior year. Oil was up 13% from 12,096 boe/d to 13,645 boe/d. Natural gas was up marginally to 80.3 mmcf/d from 79.9 mmcf/d and natural gas liquids increased to 2,185 boe/d from 1,946 boe/d. Oil revenues increased to $44.0 million from $40.6 million due to the increase in volumes as the oil price decreased to $35.06 per bbl from $36.48 per bbl. Natural gas revenue was up to $43.1 million from $37.9 million mainly due to the natural gas price which increased 13% from $5.15 per mcf to $5.84 per mcf. Revenues from natural gas liquids increased to $6.9 million from $6.0 million due to volumes and prices. The average price was $34.46 per bbl in the fourth quarter of 2003, as compared to $33.34 per bbl in the fourth quarter of 2002.

Royalties increased from $15.8 million in 2002 to $19.0 million in 2003. Royalties were 19% of revenue in the fourth quarter of 2002 and 20% in the same period in 2003, mainly due to the increased natural gas prices.

Operating costs increased to $24.8 million in 2004 from $21.3 million in 2003, due to the additional wells on production and a general increase in costs experienced by the oil and gas industry.

General and administrative costs decreased from $3.6 million, or $1.43 per boe, in the fourth quarter of 2002 to $2.9 million or $1.10 per boe for the same period in 2003.

Depletion and site reclamation and abandonment expenses increased from $28.6 million in 2002 to $33.7 million in 2003 or $1.20 per boe.

Income before income taxes was $11.4 million in the fourth quarter of 2003 as compared to $10.2 million in the fourth quarter of 2002. Net income, however, was up to $23.6 million from $5.4 million due to a future income tax recovery in 2003 of $12 million as compared to a future tax expense of $5.0 million in 2002. The future tax liability at December 31, 2002 included a provision for income taxes for entities that were acquired by the Trust. These entities were under audit at the time and the CCRA (Canada Customs and Revenue Agency) had made large proposed adjustments. The Trust was successful in having these adjustments reversed to a minimal amount. As a result, the Trust has taken the provision back into income in 2003.

CAPITAL EXPENDITURES

Acquisitions

During the year, PC incurred $115.6 million for property acquisitions, excluding the non-cash future tax adjustment of $4.7 million recognized on the Solaris Oil and Gas Inc. ("Solaris") acquisition, and acquired 19.4 million boe of Established Reserves. The properties were heavily weighted to oil and had a reserve life index of 14.4 years.

Effective January 1, 2003, PC acquired 100% of the outstanding common share of Solaris, and on February 7, 2003, amalgamated Solaris into PC. PC paid $7.4 million in cash, and assumed debt and negative working capital of $1.2 million, for a total cost of the oil and gas properties of $8.6 million. The acquisition added 720,000 boe of Established Reserves and approximately 200 boe/d of production.

In the second quarter of 2003, PC closed the acquisition of a diverse group of oil and natural gas properties for $61.7 million after adjustment. The properties added Established Reserves of 9.7 million boe as estimated by the independent engineering firm, Gilbert Laustsen Jung Associates Ltd. At the time of acquisition, production from the properties was approximately 2,300 boe/d of which 42% was natural gas. Production and cash flow has been included in this report effective from June 1, 2003. The properties contained a large percentage of unit production, and had a reserve life index on an Established basis of 11.6 years.

On August 21, 2003, PC purchased a 7.22% interest in Swan Hills Unit #1 for

$37.1 million from a private Canadian company. This acquisition increased PC's interest in the unit, bringing PC's total interest in the unit to 9.87%. This acquisition added 8.5 mmboe of Established Reserves and approximately 1,100 boe/d of production. The Established reserve life index of the property was over 20 years.

Finding & Development Costs

During the year PC incurred $71.4 million on drilling and development activities as compared to $40.8 million in 2002. A total of 214 wells were drilled, of which 115 were gas, 84 oil and 15 dry and abandoned for an overall success rate of 93%. These activities added 2,500 boepd of production at an average cost of $28,600 per boepd and offset more than half of the decline in existing production.

Farmout Activities

During 2003, Petrofund entered into farmout agreements with various industry partners which resulted in 40 wells being drilled in 2003 on Petrofund's undeveloped land base. This drilling yielded 32 natural gas wells, 3 oil wells and 5 abandoned wells.

Although terms are slightly different for each farmout, they are generally structured such that Petrofund is carried for the costs of each well and receives a gross overriding royalty before payout of such costs and an after payout working interests for each well which generally equates to 50% of it pre-farmout interest.

Disposition of Properties

During 2003, Petrofund disposed of approximately 5 million boe of Established Reserves for $33.5 million. Eighty percent of these reserves were sold as a package of non-core east central Alberta properties marketed publicly late in the year. All of the properties disposed of were non-core to Petrofund's ongoing operations, had high operating costs and high decline rates. These dispositions are an integral part of Petrofund's ongoing portfolio management process.

The properties sold are expected to reduce 2004 production by approximately 1,500 boepd.

A summary of capital expenditures for the last three years is as follows (in millions):

For the years ended December 31,	2003	2002	2001
Property acquisitions (1)	$ 115.6	$ 218.5	$ 222.4
Property dispositions	(33.5)	(30.0)	(3.7)
Net acquisitions	82.1	188.5	218.7
Finding & development costs:			
Land & seismic	2.5	2.8	2.1
Drilling & completion	42.5	22.2	17.0
Well equipping	7.9	6.7	2.1
Tie-ins	5.2	2.7	2.2

Facilities	8.4	3.2	3.5
	Other	4.9	3.2-
Total	71.4	40.8	26.9
Total net capital expenditures	$ 153.5	$ 229.3	$ 245.6

(1) The property acquisition totals exclude non-cash future income tax adjustments for the difference between the cost and tax bases of assets acquired by way of corporate acquisitions.

DEBT

The borrowing base was increased to $265 million, in conjunction with the closing of the second quarter 2003 property acquisition. As at December 31, 2003, the amount outstanding on the credit facility was $110 million with $155 million available to finance future activities.

The revolving period on the syndicated facility was scheduled to end on May 30, 2003; however, it has been extended for an additional 364-day period ending May 28, 2004.

WORKING CAPITAL

The working capital deficit was $30 million at December 31, 2003, an increase of $23.1 from the $6.9 million deficit at the end of the prior year. The primary reason for this change is a corresponding increase in distributions payable to unitholders of $23 million. This amount represents the cash flow available for distribution generated during the year in excess of distributions paid.

LIQUIDITY AND CAPITAL RESOURCES

Total long-term debt and capital leases decreased $108.9 million from $219.2 million at December 31, 2002 to $110.3 million at the end of the current year.

The major changes in total long term debt were due to:

	$000's
Net proceeds from the May and December equity issues	$ 193.4
Proceeds received from the exercise of options	20.5
Proceeds received from the sale of properties	33.5
Increases in working capital deficit	23.1
Cash flow available for distributions in excess of distributions paid	23.4
Property acquisitions	(115.6)
Expenditures on oil and gas properties	(71.4)
Miscellaneous	2.0
	$ 108.9

Capitalization Analysis

($ thousands, except per unit and percent amounts)	2003	2002	2001
Working capital (deficiency)	$ (30,006)	$ (6,909)	$ (20,564
Bank debt	109,707	212,253	128,783
Capital lease obligation	608	6,965	16,168
Net debt obligation	$ 140,321	$ 226,127	$ 165,515
Units outstanding and issuable for exchangeable shares	73,628	54,108	41,916
Market Price at December 31,	$ 18.79	$ 10.85	$ 11.97
Market capitalization	$1,383,465	$ 587,069	$ 501,731
Total capitalization	$1,523,786	$ 813,196	$ 667,246
Net debt as a percentage of total capitalization	9.2%	27.8%	24.8%
Cash flow	$ 187,585	$ 112,570	$ 110,176
Net debt to cash flow	0.7:1.0	2.0:1.0	1.5:1.0

Long-term debt will increase in 2004 due to the capital expenditure program which is expected to be in the $60 million range. If the Trust is successful in completing one or more significant acquisitions in 2004 these would be financed by further utilization of the credit facility or a combination of additional bank borrowing and a possible equity issue of treasury units.

UNITHOLDERS' EQUITY

The Trust had 72,688,577 trust units outstanding at December 31, 2003, compared to 54,108,420 trust units at the end of 2002. In April 2003, 1,939,147 exchangeable shares and 100,244 Trust units were issued in connection with the internalization transaction. During the year, 906,635 Exchangeable Shares were converted to 1,000,000 Trust units and 181,041 were redeemed for cash leaving 851,471 exchangeable shares outstanding at year end which can be converted, at the option of the unitholder into 939,147 trust units. The weighted average number of trust units outstanding including those issuable on the exchange of exchangeable shares, was 61,010,105 trust units for 2003 as compared to 49,921,523 for 2002.

During 2003, the Trust completed two equity offerings. In May 2003, the Trust issued 9.2 million units at a price of $10.60 per unit for net proceeds of $92.3 million. In December 2003, 6.6 million units were issued at a price of $16.20 per unit for net proceeds of $101.1 million.

During the year, 1,673,404 options were exercised for the same number of trust units generating proceeds of $20.5 million. (For complete details of options exercised and outstanding at the end of the year refer to note 11 of the

Consolidated Financial Statements).

Under the Distribution Reinvestment Plan ("DRIP") unitholders can elect to receive distributions or make optional cash payments to acquire trust units from treasury or in the open market. Under the DRIP plan 316,785 trust units were issued at an average price of $13.21 for total proceeds of $4.2 million. In 2002, 288,981 units were issued under the DRIP plan at an average price of $12.16 per trust unit.

TAXES

Current taxes consist of the Federal Large Corporations Tax and some minor amounts relating to income taxes of corporate entities acquired. The Federal Large Corporations Tax is based primarily on the debt and equity balances of PC at the end of the year. The Federal Large Corporations Tax rate is proposed in the Federal Budget of 2003 to be reduced in stages over a period of five years so that by 2008, the tax will be eliminated.

Capital taxes of $2.5 million in 2003 and $2.1 million in 2002 are primarily the Saskatchewan Capital Tax and Resource Surcharge, which is based upon Saskatchewan gross revenues.

Future income tax liabilities arise due to the differences between the tax basis of PC's assets and their respective accounting carrying cost. Future income taxes were increased by $4.7 million due to the purchase of Solaris. This liability arose as the purchase price of Solaris's assets was in excess of its tax pools. In the Trust's structure, payments are made between PC and the Trust which thereby transfers both income and future tax liability to the individual unitholders. Accordingly, it is the opinion of management that no cash income taxes will be paid by PC in the future and, as such, the future income tax liability recorded on the balance sheet will be recovered through earnings over time. Future income tax recoveries of $44.5 million in 2003 and $14.3 million in 2002 have resulted in a remaining future income tax liability of $77.0 million at December 31, 2003. The future income tax liability was reduced by approximately $36.7 million to reflect reductions in the Federal and Alberta income tax rates in 2003.

Cash distributions paid to unitholders resident in Canada or the United States have differing tax consequences depending on each unitholder's circumstances. The Trust sets out some brief comments regarding the taxability of the distributions but does not intend to provide legal or tax advice. Unitholders or potential investors should seek their own legal or tax advice in this regard.

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Generally, Canadian unitholders include in their income the portion of the distribution that is taxable income earned by the Trust. The portion that is a return of capital reduces the adjusted cost base of the Trust unit of the unitholder. In 2003, 51.223% of distributions paid to unitholders was ordinary income and 48.777% was a return of capital.

Generally, United States unitholders include in their income the portion of the distribution that is taxable income earned by the trust. Such amount is considered a dividend for U.S. purposes and is subject to Canadian withholding tax. The portion that is a return of capital and not taxable reduces the tax basis of the Trust unit. In 2003, 83.346% of distributions to United States unitholders was dividend income and 16.654% was a return of capital.

BUSINESS RISKS

The success of the Trust in meeting its objective of stable distributions over the long term depends mainly on management's ability to:

1) Identify and acquire oil and gas properties and/or companies at prices that add value to the Trust.

2) Cost effectively add or extend reserves with internal development and drilling or farmouts.

3) Manage and control costs.

There are numerous factors beyond management's control that have a major influence on distribution levels including product prices, unforeseen production declines and cost increases from major suppliers. (A detailed assessment of risk factors and offsetting strategies appears elsewhere in this report).

Below is a table that shows sensitivities to pre-hedging cash flow as a result of product price and operational changes. The table is based on actual 2003 prices received and production volumes of 27,000 boepd. These sensitivities are approximations only and are not necessarily valid at other price and production levels. As well, hedging activities can significantly affect these sensitivities.

Sensitivity Analysis

	Change	$000's	$/unit per year
Price per barrel of oil*	$ 1.00 U.S.	$ 5,331	$ 0.072
Price per mcf of natural gas*	$ 0.25 Cdn.	$ 5,585	$ 0.076
US/Cdn exchange rate	$ 0.01	$ 2,650	$ 0.036
Interest rate on debt ($125 million)	1%	$ 1,250	$ 0.017
Oil production volumes*	100 bbl/day	$ 1,131	$ 0.015
Gas production volumes*	1 mmcf/day	$ 1,784	$ 0.024

* After adjustment for estimated royalties.

OUTLOOK FOR 2004

The level of cash flow for 2004 will be affected by oil and gas prices, the Canadian - US dollar exchange rate and the Trust's ability to add reserves and production in a cost effective manner. Both product prices and the exchange rate showed significant volatility in 2003 and this trend is expected to continue in 2004.

The acquisition market is expected to continue to be active and supply should increase with the recent announcement by three large producers of their intention to dispose of their Canadian properties in 2004. Nevertheless, competition for these assets is expected to be fierce due to increased demand resulting from the increasing number of oil and gas companies that have converted to a trust structure. We expect prices for quality, long life assets to be at or near record levels. Petrofund expects to be an active participant in this market but success will be tempered by a commitment to maintain historic discipline and bid only at levels consistent with the best long term interest of our unitholders.

Acquisition activities will be complemented by an extensive drilling and farmout program that will be conducted on our existing land base.

Although product prices have remained at high levels, the strengthening of the Canadian dollar in the second half of 2003 significantly moderated the net effect of these prices on Petrofund's cash flow. We expect the Canadian dollar to remain very strong in the short term with a possible decrease toward the end of 2004.

Petrofund pursues a well defined risk management program to help offset the effect of price fluctuations. This program utilizes collars as the main hedging tool but Petrofund also enters into fixed price transactions when commodity prices approach historic highs. To date, the Trust has not entered into any currency related transactions. A discussion of the risk management strategies and hedged position appears elsewhere in this report.

CONTRACTUAL OBLIGATIONS

For details on contractual obligations refer to note 17 of the Consolidated Financial Statements.

OFF-BALANCE SHEET ARRANGEMENTS/ VARIABLE INTEREST ENTITIES

The Trust has no off-balance sheet arrangements or variable interest entities.

IMPACT OF NEW CANADIAN ACCOUNTING PRONOUNCEMENTS

In September 2002, the CICA approved Section 3063, "Impairment of Long-Lived Assets" (S.3063). S.3063 establishes standards for the recognition, measurement and disclosure of the impairment of longlived assets, and applies to long-lived assets held for use. An impairment loss is recognized when the carrying amount of a long-lived asset is not recoverable and exceeds its fair value. The new Section is effective for fiscal years beginning on or after April 1, 2003. The application of the impairment test for companies following the full cost method of accounting for oil and natural gas activities has been included in Accounting Guideline 16, "Oil and Gas Accounting - Full Cost" AcG-16 issued in September 2003. The new guideline limits the carrying value of oil and natural gas properties to their fair value. The fair value is equal to estimated future cash flows from proved and risked probable reserves using future price forecasts and costs discounted at a risk-free rate. This differs from the current cost recovery ceiling test that uses undiscounted cash flows and constant prices and costs less general and administrative and financing costs. There is no write-down of the Trust's oil and gas royalty and property interests under either method at December 31, 2003. AcG-16 also adopted the reserve evaluation and disclosure requirements of NI 51-101 which have been followed in the preparation of this report.

In December 2001, the Canadian Institute of Chartered Accountants (CICA) issued Accounting Guideline 13, "Hedging Relationships" (AcG-13) originally effective for fiscal years commencing on or after July 1, 2002. Implementation was then postponed to the fiscal years commencing on or after July 1, 2003. AcG-13 established certain conditions for when hedge accounting may be applied. If hedge accounting is not applied, the fair values of derivative financial instruments are recorded as an asset or a liability on the balance sheet. As the guideline is effective for fiscal years beginning on or after July 1, 2003, Petrofund will be adopting the guideline effective January 1, 2004. Petrofund enters into numerous derivative financial instruments to reduce price volatility and establish minimum prices for a portion of its oil and natural gas production. These contracts are effective economic hedges, however, a number do not qualify for hedge accounting due to the very detailed and complex rules outlined in AcG-13. Petrofund has elected to use the fair value method of accounting for all derivative transactions as we believe it would be confusing to the reader if the Trust were to use hedge accounting for some of its hedging contracts and fair value accounting for others. Also the additional costs to use hedge accounting would be significant as detailed documentation requirements must be met and each individual contract would need to be analyzed to determine which method of accounting to use. Effective January 1, 2004, Petrofund will record the fair value of the derivative financial instruments as at December 31, 2003, in the amount of $6.8 million as a liability on the balance sheet. The change in the fair value from period to period will be recorded in the income statement on a separate line as unrealized gains/losses. This line item will also include realized gains and losses on the derivative financial instruments which currently are recorded in oil and gas sales.

In December 2002, the CICA approved Section 3110, "Asset Retirement Obligations" which requires liability recognition for retirement obligations associated with our property, plant and equipment. The obligations are initially measured at fair value, which is the discounted future value of the liability. The fair value is capitalized as part of the cost of the related assets and amortized to expense over their useful lives. The liability accretes until the retirement obligations are settled. S.3110 is effective for fiscal years beginning on or after January 1, 2004. The accrued reclamation and abandonment liabilities on the balance sheet which have been calculated on a unit of production basis will be reversed January 1, 2004. Oil and gas properties will be increased and a liability set up for the amount calculated under the new standard. In 2004 the accounting will follow the new standard and the comparative numbers for 2003 and prior periods will be restated.

The impact of this standard will be to increase oil and gas royalty and property interests on the balance sheet by $18.6 million at December 31, 2003, and by $18.5 million at December 31, 2002. The accrued reclamation and abandonment liability (asset retirement obligation) will increase to $34.4 million at December 31, 2003, from $16.8 million and the liability at December 31, 2002 will increase to $34.5 million from $15.3 million. The effect on the income statement will be to increase (decrease) net income before income taxes by $ 1.5 million in 2003, (2002 - $1.1 million, 2001 - $ (0.9) million).

Effective March 31, 2004, the Trust and all reporting issuers in Canada will be subject to new disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument is effective for fiscal years beginning on or after January 1, 2004. The Instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and the Annual Information Form ("AIF"). The Instrument also proposes enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for the Trust to mail annual and interim financial statements and MD&A to unitholders, but rather these documents will be provided on an "as requested" basis. The Trust continues to assess the implications of this new instrument which will be implemented in

2004.

Other accounting standards issued by the CICA during the year ended December 31, 2003, are not expected to impact the Trust at this time.

CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures. The Trust's principal executive officer and its principal financial officer, after evaluating the effectiveness of the Trust disclosure controls and

procedures (as defined in U.S. Exchange Act Rules 13a - 15 (e) and 15d - 15(e)) the end of the period covered by this annual report, have concluded that, as of such date, the Trust's disclosure controls and procedures were adequate and effective to ensure that material information relating to the Trust and its subsidiaries would be made known to them by others within those entities.

Changes in internal control over financial reporting. There was no change in the Trust's internal control over financial reporting that occurred during the period covered by this annual report that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting.

Changes in internal controls. There were no significant changes in the Trust's internal controls or in other factors that could significantly affect the Trust's internal controls subsequent to the date of their evaluation nor were there any significant deficiencies or material weaknesses in the Trust's internal controls. As a result, no corrective actions were required or undertaken.

STATEMENT OF CORPORATE GOVERNANCE

Petrofund adheres to all required regulatory and security commission guidelines as required by the TSX and the AMEX at December 31, 2003. This has resulted in Petrofund's acceptance of a 'best practices' corporate governance structure. To this end, four sub-committees of the Board, all composed of independent directors, act in the best interests of the Trust. Additional information about the board and the committee compositions are detailed in the annual report and within Petrofund's annual information form.

The President and Chief Executive Officer and Senior Vice-President, Finance and Chief Financial Officer have signed a code of ethics which is posted on the Trust's website.

AUDITORS' REPORT

TO THE DIRECTORS OF PETROFUND CORP.:

We have audited the consolidated balance sheet of Petrofund Energy Trust (an Ontario open-ended investment Trust) as at December 31, 2003 and 2002 and the consolidated statements of operations, unitholders' equity and cash flows for the years then ended. These financial statements are the responsibility of the management of Petrofund Corp. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of Petrofund Energy Trust as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

The consolidated financial statements of Petrofund Energy Trust for the year ended December 31, 2001 were audited by other auditors who have ceased operations. Those auditors expressed an opinion without reservation on those financial statements in their report dated February 14, 2002. As described in Note 18, the Trust adopted the new accounting standards with respect to asset retirement obligations for United States reporting purposes and Note 18 includes certain additional disclosures related thereto. We have audited the adjustments described in Note 18 that were applied to provide the additional disclosures for 2001. In our opinion, such adjustments are appropriate and have been properly applied. However, we were not engaged to audit, review or apply any procedures to the 2001 consolidated financial statements of the Trust other than with respect to such additional disclosures and, accordingly, we do not express an opinion or any other form of assurance on the 2001 financial statements taken as a whole.

(signed) Deloitte & Touche LLP
Chartered Accountants
Calgary, Alberta
February 6, 2004
(except as to Note 19 which
is as of April 30, 2004)

THIS AUDITORS' REPORT IS A COPY OF THE REPORT PREVIOUSLY ISSUED BY ARTHUR ANDERSEN LLP AND HAS NOT BEEN REISSUED IN CONNECTION WITH ITS INCLUSION HEREIN.

Auditors' Report

To the Unitholders of NCE Petrofund:

We have audited the consolidated balance sheet of NCE Petrofund (an Ontario open-ended investment trust) as at December 31, 2001 and 2000 and the consolidated statements of operations, unitholders' equity, cash flows and distributions accruing to unitholders for each of the years in the three-year period ended December 31, 2001. These financial statements are the responsibility of the management of NCE Petrofund Management Corp. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of NCE Petrofund as at December 31, 2001 and 2000 and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2001 in accordance with Canadian generally accepted accounting principles.

Calgary, Alberta	(Signed) Arthur Andersen LLP
February 15, 2002	Chartered Accountants

Consolidated Balance Sheet
(thousands of dollars)

As at December 31,	2003	2002
Assets		
Current assets		
Cash	$ 2,182	$ -
Accounts receivable	48,268	41,953
Due from affiliates	-	164
Prepaid expenses	10,036	10,090
Total current assets	60,486	52,207
Reclamation and abandonment reserve (Note 7)	3,779	3,001
Oil and gas royalty and property interests, at cost less accumulated depletion and depreciation of $468,208 (2002 - $354,309) (Notes 2 and 3)	879,633	835,366
	$ 943,898	$ 890,574
Liabilities and unitholders' equity		
Current liabilities		
Bank overdraft	$ -	$ 1,572
Accounts payable and accrued liabilities	36,684	22,007
Payable to affiliates (Note 4)	-	2,168
Current portion of capital lease obligations (Note 6)	356	3,304
Distributions payable to Unitholders	53,452	30,065

Total current liabilities	90,492	59,116
Long-term debt (Note 5)	109,707	212,253
Capital lease obligations (Note 6)	608	6,965
Future income taxes (Notes 2 and 15)	77,005	116,845
Accrued reclamation and abandonment costs	16,846	15,298
Total liabilities	294,658	410,477
Unitholders' equity (Notes 8 and 9)	649,240	480,097
	$ 943,898	$ 890,574

Signed on behalf of Petrofund Energy Trust by Petrofund Corp.:

(signed) Jeffery E. Errico, Director   (signed) James E. Allard, Director

The accompanying notes to consolidated financial statements are an integral part of this consolidated balance sheet.

Consolidated Statement of Operations
(thousands of dollars)

For the years ended December 31,	2003	2002	2001
Revenues			
Oil and gas sales	$ 393,109	$ 270,669	$ 244,512
Royalties, net of incentives	(84,804)	(50,427)	(54,746)
	308,305	220,242	189,766
Expenses			
Lease operating	91,251	74,774	48,237
Management fee (Note 4)	-	4,728	5,307
Interest on long-term debt (Note 5)	8,748	8,291	7,806
General and administrative (Note 4)	13,047	15,514	14,436
Capital taxes	2,454	2,137	1,719
Depletion and depreciation	113,899	98,777	68,453
Provision for reclamation and abandonment	6,199	5,856	3,680
Internalization of management contract (Note 9)	30,850	-	-
	266,448	210,077	149,638
Income before provision for income taxes	41,857	10,165	40,128
Provision for (recovery of) income taxes (Note 15)			
Current	569	38	1,701

Future	(44,516)	(14,252)	(15,561)
	(43,947)	(14,214)	(13,860)
Net income	$ 85,804	$ 24,379	$ 53,988
Net income per trust unit (Notes 2 and 16)			
Basic	$ 1.41	$ 0.49	$ 1.71
Diluted	$ 1.40	$ 0.49	$ 1.71

The accompanying notes to consolidated financial statements are an integral part of these consolidated statements.

Consolidated Statement of Unitholders' Equity
(thousands of dollars)

For the years ended December 31,	2003	2002	2001
Balance, beginning of year	$ 480,097	$ 398,702	$ 136,812
Units issued, net of issue costs (Note 8)	226,325	154,460	318,548
Exchangeable shares issued/ converted to Trust units (Note 10)	10,518	-	-
Redemption of exchangeable shares (Note 10)	(2,792)	-	-
Net income	85,804	24,379	53,988
Distributions accruing to Unitholders (Note 12)	(150,712)	(97,444)	(110,646)
Balance, end of year	$ 649,240	$ 480,097	$ 398,702

The accompanying notes to consolidated financial statements are an integral part of these consolidated statements.

Consolidated Statement of Cash Flows
(thousands of dollars)

For the years ended December 31,	2003	2002	2001

Cash provided by (used in):			
Operating activities			
Net income	$ 85,804	$ 24,379	$ 53,988
Add items not affecting cash:			
Depletion and depreciation	113,899	98,777	68,453
Provision for reclamation and abandonment	6,199	5,856	3,680
Future income taxes	(44,516)	(14,252)	(15,561)
Actual abandonment costs incurred (Note 7)	(4,651)	(2,190)	(384)
Internalization of management contract (Note 9)	30,850	-	-
Cash flow	187,585	112,570	110,176
Net change in non-cash operating working capital balances	6,410	(30,938)	18,334
Cash provided by operating activities	193,995	81,632	128,510
Financing activities			
Bank loan	(102,546)	83,470	14,216
Distributions paid	(127,325)	(85,218)	(126,883)
Redemption of exchangeable shares	(2,792)	-	-
Capital lease repayments	(9,305)	(11,366)	(2,629)
Issuance of Trust units (Note 8)	214,002	55,821	161,409
Advances to affiliates (Note 4)	-	948	-
Cash provided by (used in) financing activities	(27,966)	43,655	46,113
Investing activities			
Reclamation and abandonment reserve (Note 7)	(776)	(706)	(447)
Acquisition of property interests	(186,956)	(158,516)	(177,729)
Proceeds on disposition of properties	33,466	30,019	3,736
Cash acquired on acquisition (Note 3b)	-	427	-
Internalization of management contract (Note 9)	(8,009)	-	-
Cash used in investing activities	(162,275)	(128,776)	(174,440)
Net change in cash	3,754	(3,489)	183
Cash (bank overdraft), beginning of year	(1,572)	1,917	1,734
Cash (bank overdraft), end of year	$ 2,182	$ (1,572)	$ 1,917
Interest paid during the year	$ 8,885	$ 8,016	$ 7,806
Income taxes paid during the year	$ 842	$ 1,281	$ 1,065

The accompanying notes to consolidated financial statements are an integral part of these consolidated statements.

Notes to consolidated financial statements

December 31, 2003, 2002 and 2001

1. ORGANIZATION

Petrofund Energy Trust ("Petrofund" or the "Trust") is an open-ended investment trust created under the laws of the Province of Ontario pursuant to a trust indenture, as amended from time to time (the "Trust Indenture"), between Petrofund Corp. ("PC") and Computershare Trust Company of Canada (the "Trustee"). Active operations commenced March 3, 1989. The beneficiaries of the Trust are the holders of the trust units ("Unitholders").

PC, a wholly-owned subsidiary of the Trust, acquires oil and gas properties for its own account and sells a royalty interest (the "Royalty") to the Trust. The Royalty acquired from PC effectively transfers substantially all of the economic interest in the oil and gas properties to the Trust. The Trust is entitled to 99% of the production revenue from properties purchased by PC, less operating costs, general and administrative expenses, management fees (prior to 2003), debt service charges (including principal and interest) and taxes payable by PC.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The consolidated financial statements have been prepared by the management of PC following Canadian generally accepted accounting principles. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimated. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements.

(a) Basis of consolidation

The consolidated financial statements include the accounts of the Trust and its wholly-owned subsidiaries, PC, 1518274 Ontario Ltd., NCE Management Services Inc. ("NMSI"), which employed all of the personnel who provided services to the Trust, and NCE Petrofund Management Corp. ("NCEP Management", the "Previous Manager") collectively, the "Subsidiaries". NMSI and NCEP Management were acquired to effect the internalization of management and the shares of 1518274 Ontario Limited are exchangeable into Trust units (see Notes 9 and 10).

(b) Oil and gas royalty and property interests

Oil and gas royalty and property interests are accounted for using the full cost method of accounting whereby all costs of acquiring oil and gas royalty and property interests and equipment are capitalized. General and administrative costs and interest are not capitalized.

The provision for depletion and depreciation and the provision for site reclamation and abandonment costs are computed using the unit-of-production method based on the estimated gross proven oil and gas reserves. Proceeds on sale or disposition of oil and gas royalty and property interests are credited to oil and gas royalty and property interests, unless this results in a change in the depletion and depreciation rate by 20% or more, in which case a gain or loss is recognized in the consolidated statement of operations. The provision for reclamation and abandonment costs is accumulated as a long-term liability, which is reduced as actual expenditures are made.

The carrying value of the oil and gas royalty and property interests, net of accumulated depletion and depreciation, accrued reclamation and abandonment costs and future income taxes is limited to an amount equal to the estimated future net revenue, net of production-related general and administrative costs, reclamation and abandonment costs, and income taxes. Future net revenue was calculated using year end oil and gas prices and costs.

Effective January 1, 2004, the carrying value of the oil and gas royalty and property interests is limited to their fair value determined by the expected discounted future revenue from the properties.

(c) Distributions payable to Unitholders

Distributions payable to Unitholders are equal to amounts received or receivable by the Trust on the cash distribution date. Income earned, but not received, is distributed on the cash distribution date following receipt.

(d) Future income taxes

The Trust follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Subsidiaries and their respective tax bases, using enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on acquisitions result in future income tax assets or liabilities.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to the Unitholders. As the Trust distributes all of its taxable income to the Unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no provision for future income taxes in the Trust has been made.

(e) Net income per Trust unit

Basic net income per Trust unit is computed by dividing net income by the weighted average number of Trust units outstanding for the period. Diluted per unit amounts reflect the potential dilution that would occur if options to issue Trust units were exercised and Trust units were issued. The treasury stock method is used to determine the effect of dilutive instruments.

(f) Hedging activity

The Trust uses derivative instruments to reduce its exposure to commodity price fluctuations. Gains and losses on contracts, all of which constitute effective hedges, are deferred and recognized as a component of the price of the related transaction.

(g) Trust unit incentive plan

A Trust Unit Incentive Plan (the "Unit Incentive Plan") was established authorizing the issuance of options to acquire Trust units to directors, senior officers, employees and consultants of NCEP, Management, NCE Petrofund Advisory Corp., NMSI and certain other related parties, all of whom are deemed to be employees of the Trust. No options have been issued since 2002.

The Trust has elected to prospectively adopt amendments to the recommendations of the CICA on accounting for stock based compensation in accordance with the transitional provisions contained therein. Under the amended recommendations, the Trust must account for compensation expense based on the fair value of the options at the grant date. As the Trust has not granted any options since December 31, 2002, this change in accounting policy has no impact on the consolidated financial statements.

For options granted in 2002, the Trust elected to continue accounting for compensation expense based on the intrinsic value of the options at the grant date and disclose pro forma net income and pro forma net income per Trust unit as if the fair value method had been adopted retroactively. The exercise price of options granted under the Unit Incentive Plan may be reduced in future periods in accordance with the

terms of the Unit Incentive Plan. The amount of the reduction cannot be reasonably determined as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and gas, and the determination of the amount to be withheld from future distributions to fund capital expenditures. Therefore, it is not possible to determine a fair value for the options granted under the Unit Incentive Plan and compensation expense has been determined based on the excess of the unit price over the reduced exercise price at the date of the financial statements and recognized in income over the vesting period of the options with a corresponding increase or decrease in contributed surplus. After the options have vested, compensation expense is recognized in income in the period in which a change in the market price of the Trust units or the exercise of the options occurs. The compensation expense under this method in 2003 for the options issued in 2002 is $2.0 million. Net income would have been reduced by this amount and net income per Trust unit would have decreased by $0.03. For 2002, net income would have been reduced by $60,000 with negligible impact on net income per Trust unit.

Consideration paid upon the exercise of the options together with any amount previously recognized in contributed surplus is recorded as an increase in unitholders' capital.

3. ACQUISITIONS

(a) Solaris Oil & Gas Inc.

On February 7, 2003, PC acquired 100% of the outstanding common shares of Solaris Oil & Gas Inc. for $7.4 million in cash and assumed $1.2 million of debt including negative working capital and the outstanding bank loan.

The acquisition was accounted for using the purchase method. A summary of the net assets acquired is as follows:

	$000's
Working capital	$ (813)
Oil and gas properties	13,219
Bank loan	(370)
Future income taxes	(4,676)
	$ 7,360

(b) NCE Energy Trust

On May 30, 2002, Petrofund Energy Trust acquired NCE Energy Trust for 0.2325 of a Trust unit for each Trust unit on a tax-free rollover basis. The value assigned to the Trust units of $13.024 per unit issued on the acquisition was based on the average market value of the Trust units five days before and after the acquisition was announced.

The acquisition was accounted for using the purchase method. A summary of the net assets acquired is as follows:

	$000's
Working capital	$ (39,518)
Oil and gas properties	165,254
Future income taxes	(27,097)
	$ 98,639

Prior to the acquisition, Petrofund advanced $37.3 million to NCE Energy Trust to pay down the bank debt of NCE Energy Trust.

(c) Magin Energy Inc. ("Magin")

On June 25, 2001, PC acquired 93.6% of the outstanding common shares of Magin and on July 3, 2001 acquired the remaining shares. Magin was amalgamated into PC on July 3, 2001.

In total, PC acquired 38,338,535 Magin common shares for $58.6 million in cash, 8.5 million trust units with a deemed value of $18.56 per unit and the assumption of $43.7 million of debt including negative working capital, the outstanding bank loan and capital leases. In addition, other transaction costs of $11.8 million were incurred.

The acquisition was accounted for using the purchase method. A summary of the net assets acquired is as follows:

	$000's
Working capital	$ (4,749)
Oil and gas properties	381,043
Bank loan	(21,569)
Capital leases	(17,359)
Future income taxes	(109,790)
	$ 227,576

4. RELATED PARTY TRANSACTIONS

(a) Management, advisory and administration agreement

PC, NCEP Management, the Previous Manager, and the Trust had entered into an agreement which was amended from time to time, whereby the Previous Manager was to provide management, advisory and administrative services to PC and the Trust. During 2002 the Previous Manager was paid a management fee equal to 3.25% of net operating income plus Alberta Royalty Credit (2001- 3.75%). In addition the Previous Manager received an investment fee of 1.5% (1.75% prior to January 1, 2002) of the purchase cost of all properties purchased by PC other than replacement properties, and a disposition fee equal to 1.25% (1.5% prior to January 1, 2002) of the sale price of properties sold. During 2002, the Previous Manager received a management fee from PC of $4.7 million (2001 - $5.3 million). In addition, the Previous Manager received investment fees of $1.3 million (2001 - $5.2 million), which were capitalized as part of the acquisitions, and disposition fees of $116,000 (2001 - $3,000), which reduced the proceeds of disposition. No management fees have been charged directly to the Trust.

Due to the internalization of management, no fees were payable in 2003. (See Note 9)

Under the terms of the agreement, the Previous Manager was entitled to be reimbursed by PC for general and administrative expenses. In any year, PC was to reimburse the Previous Manager no less than $240,000 and no more than 5% of gross production revenue for general and administrative expenses. To the extent that general and administrative expenses exceed 5% of gross production revenue, PC was entitled to set off and deduct the excess from its liability to pay management fees to the Previous Manager.

(b) Management agreement

The Previous Manager had entered into an agreement with NMSI to provide oil and gas investment, consulting, administrative and management services to PC. An officer and director of the Previous Manager is the sole beneficial shareholder of NMSI. During 2002 PC paid NMSI $11.7 million (2001 - $9.3 million) for accounting and administrative services, which is included in general and administrative expenses and $838,000 (2001 - $1.4 million) for project sourcing and evaluation services, which have been capitalized to oil and gas properties. In addition, PC reimbursed NMSI $300,000 (2001 - $600,000) for marketing and other related equity issue costs. No amounts for

these services have been charged directly to the Trust. The amounts for general and administrative expenses paid to NMSI are subject to the same limitations noted for the Previous Manager in (a) above. Due to the internalization of management, no amounts were paid to NMSI in 2003.

5. LONG-TERM DEBT

Under the loan agreements, PC has a revolving working capital operating facility of $25 million and a syndicated facility of $240 million. Interest on the working capital loan is at prime and interest on the syndicated facility varies with PC's debt to cash flow ratio from prime to prime plus 75 basis points or, at the Trust's option, banker's acceptances rates plus stamping fees. As at December 31, 2003, there was no amount outstanding under the working capital facility and $110 million outstanding under the syndicated facility.

The revolving period on the syndicated facility ends on May 28, 2004, unless extended for a further 364 day period. In the event that the revolving bank line is not extended at the end of the 364 day revolving period, no payments are required to be made to non-extending lenders during the first year of the term period. However, Petrofund will be required to maintain certain minimum balances on deposit with the syndicate agent.

The limit of the syndicated facility is subject to adjustment from time to time to reflect changes in PC's asset base.

The credit facility is secured by a debenture in the amount of $350 million pursuant to which a Canadian chartered bank (the "Lender"), as principal and as agent for the other lender, received a first ranking security interest on all of PC's assets.

The loan is the legal obligation of PC. While principal and interest payments are allowable deductions in the calculation of royalty income, the Unitholders have no direct liability to the bank or to PC should the assets securing the loan generate insufficient cash flow to repay the obligation.

Substantially all of the credit facility is financed with Bankers' Acceptances, resulting in a reduction in the stated bank loan interest rates.

6. CAPITAL LEASE OBLIGATIONS

The future minimum lease payments under the capital leases are as follows:

	$000's
2004	$ 423
2005	621
Total minimum lease payments	1,044
Less imputed interest at rates ranging from 7.37% to 8.425%	(80)
Obligation under capital leases	964
Current portion	(356)
Long-term portion	$ 608

7. RECLAMATION AND ABANDONMENT RESERVE

PC maintains a cash reserve to finance large and unusual oil and gas property reclamation and abandonment costs by withholding distributions accruing to Unitholders. At December 31, 2003, the cash reserve was $3.8 million (2002 - $3.0 million, 2001 - $2.1 million). In 2003, PC increased the cash reserve by withholding $776,000 (2002 - $706,000, 2001 - $447,000) from distributions accruing to Unitholders.

In addition, routine ongoing reclamation and abandonment costs of $4.7 million in 2003 (2002 - $2.2 million, 2001 - $384,000) were incurred and deducted from distributions accruing to Unitholders.

8. TRUST UNITS

Authorized: unlimited number of Trust units	Number of Units	$000's
Issued		

December 31, 2000	21,914,079	$ 321,344
Issued for cash	11,183,334	167,350
Issued for Magin acquisition (Note 3(c))	8,464,399	157,139
Commissions and issue costs	-	(11,781)
Options exercised	341,305	5,620
Unit purchase plan	13,279	220
December 31, 2001	41,916,396	639,892
Issued for cash	4,600,000	59,800
Issued for NCE Energy acquisition (Note 3(b))	7,573,874	98,639
Commissions and issue costs	-	(4,190)
Options exercised	7,966	85
Unit purchase plan	10,184	126
December 31, 2002	54,108,420	794,352
Issued for cash	15,800,000	204,440
Issued for internalization of management contract (Note 9)	100,244	1,123
Exchangeable shares converted	1,000,000	11,200
Commissions and issue costs	-	(11,001)
Options exercised	1,673,404	20,474
Unit purchase plan	6,509	89
December 31, 2003	72,688,577	$ 1,020,677

The Trust has a Distribution Reinvestment and Unit Purchase Plan (the "Plan") for Canadian residents. Under the terms of the Plan, Unitholders can elect, firstly, to reinvest their cash distributions and obtain either newly issued units of the Trust directly from the Trust or previously issued units of the Trust purchased in the open market and, secondly, to purchase for cash newly issued units directly from the Trust.

For the years ended December 31,	2003	2002	2001
Distributions reinvested to acquire previously issued units (000's)	$ 4,095	$ 3,387	$ 6,979
Price per unit	$ 13.20	$ 12.15	$ 16.61
Number of units acquired	310,276	278,797	420,100
Distributions reinvested to acquire newly issued units (000's)	$ 89	$ 126	$ 220
Price per unit	$ 13.65	$ 12.36	$ 16.59
Number of units acquired	6,509	10,184	13,279

The weighted average Trust units/exchangeable shares outstanding are as follows:

For the twelve months ended December 31,	2003	2002	2001
Basic	61,010,105	49,921,523	31,593,378
Diluted	61,153,027	49,967,648	31,635,976

Trust units/exchangeable shares:

For the years ended December 31,	2003	2002	2001
Trust units outstanding	72,688,577	54,108,420	41,916,396
Trust units issuable on exchangeable shares (Note 10)	939,147	-	-
	73,627,724	54,108,420	41,916,396

9. INTERNALIZATION OF MANAGEMENT

On April 29, 2003, PC purchased 100% of the outstanding shares of NCEP Management, and NMSI. As a result of these transactions, all management acquisition and disposition fees payable to the Previous Manager were eliminated retroactive to January 1, 2003.

The total consideration paid was $30.9 million as detailed below.

Total Consideration	$000
Issuance of 1,939,147 exchangeable shares to the shareholder of the Previous Manager	$ 21,7
Cash payment to Trust for the repayment of indebtedness owing by the Previous Manager	3,4
Issuance of 100,244 units to executive management	1,1
Cash payment to executive management	7
Cash payment for distributions on exchangeable shares and trust units from January 1 to April 30, 2003,	1,3
Transaction costs	2,5
Total Purchase Price	$ 30,8

To ensure an orderly transition of the services that were provided by the Previous Manager through its offices in Toronto, PC entered into an agreement with Sentry Select Capital Corp. ("Sentry") to provide certain services to the Trust and PC until December 31, 2003, for a maximum cost of $2 million. The amount incurred decreased from $1 million in the first quarter of 2003 to $500,000 in the second quarter and to $250,000 in each of the third and fourth quarters. As of December 31, 2003, Sentry no longer provides any services to Petrofund or to any of its subsidiaries. Sentry is a company in which John Driscoll, the Chairman of the Board of Directors of PC, owns a controlling interest.

Prior to the acquisition, the Previous Manager was paid a management fee equal to 3.25% of net operating income plus Alberta Royalty Credit, an investment fee equal to 1.50% of the purchase price of all properties purchased by PC and a disposition fee of 1.25% of properties sold, except replacement properties.

10. EXCHANGEABLE SHARES

The number of Exchangeable Shares to be issued in connection with the internalization of the management contract was determined based on a negotiated value of $12.17 per share as set out in the Information Circular dated March 10, 2003. For accounting purposes, the 1,939,147 Exchangeable Shares were deemed to be issued at a value of $11.20 per share, being the average trading value of the Trust units for the last ten days prior to the closing date. Initially, each Exchangeable Share was exchangeable into one Trust Unit. The exchange ratio is adjusted from time to time to reflect the per unit distributions paid to unitholders after the closing date. Under the terms of the Exchangeable Share Agreement, the holder of the Exchangeable Shares is entitled to redeem for cash the number of shares equal to the cash distributions that would have been received had the Exchangeable Shares been converted to Trust units. As a result of the redemption feature, the number of Trust units issuable upon conversion is expected to remain constant over time. As the substance of this feature is to allow the holder of the Exchangeable Shares to receive cash distributions, the redemption has been accounted for as a distribution of earnings rather than a return of capital. In 2003, 181,041 Exchangeable Shares were redeemed for $2.8 million in cash.

On December 17, 2003, 906,635 Exchangeable Shares were converted to 1,000,000 Trust units at a rate of 1.10298. At December 31, 2003, 851,471 Exchangeable Shares were outstanding, at an exchange ratio of 1.10298 per Trust unit.

Issued and Outstanding	Number of Shares	$000's
Issued for Internalization of Management Contract	1,939,147	$ 21,718
Redemption of shares	(181,041)	-
Exchanged for Trust units	(906,635)	(11,200)
Balance, December 31, 2003	851,471	10,518
Exchange ratio, end of period	1.10298	-
Trust units issuable upon conversion	939,147	$ 10,518

11. UNIT INCENTIVE PLAN

A total of 5,200,000 units have been reserved for issuance under the Unit Incentive Plan of which 2,254,100 have been issued as at December 31, 2003.

A summary of the status of the Unit Incentive Plan as of December 31, 2003, 2002 and 2001, and changes during the years then ended is presented below:

For the years ended December 31,	2003		2002		
	Units	Weighted Average Exercise Price	Units	Weighted Average Exercise Price	Units

Options outstanding, beginning of year	3,028,280	$ 13.21	1,840,190	$ 15.92	941,278
Issued	-	-	1,468,100	10.65	1,477,800
Forfeited	(555,754)	16.82	(272,044)	16.66	(237,583)
Exercised	(1,673,404)	12.88	(7,966)	10.65	(341,305)
Options outstanding before reduction of exercise price	799,122	$ 14.74	3,028,280	$ 13.31	1,840,190
Reduction of exercise price	-	(1.81)	-	(0.10)	-
Options outstanding, end of year	799,122	$ 12.93	3,028,280	$ 13.21	1,840,190
Options exercisable, end of year	440,656	$ 15.36	1,593,681	$ 14.10	745,565

The options granted in 2002 and 2001 are exercisable at the original option prices, which were the market prices of the units on the date of the grants, or if so elected by the participant, at reduced prices as described below. The option prices are reduced for each calendar quarter ending after the date of the grant by the positive amount, if any, equal to the amount by which the aggregate distributions made by the Trust in any calendar quarter ending after the date of the grant exceed 2.5% of the oil and gas royalty and property interests on the Trust's consolidated balance sheet at the beginning of the applicable calendar quarter divided by the issued and outstanding units at the beginning of the applicable quarter.

The following table summarizes the options outstanding at December 31, 2003:

Number of Units	Exercise Price	Reduced Exercise Price	Expiry Date
4,689	$ 15.00	N/A	May 8, 2005
280,666	$ 19.35	$ 16.23	January 30, 2006
109,067	$ 17.25	$ 14.78	April 4, 2006
21,800	$ 14.71	$ 13.31	July 20, 2006
382,900	$ 10.65	$ 9.93	July 25, 2007

12. Distributions accruing to unitholders

Under the terms of the Trust Indenture, the Trust makes monthly distributions within a specified period following the end of each month ("Cash Distribution Date"). Distributions are equal to amounts received by the Trust on the Cash Distribution Date less permitted expenses. Distributions to Unitholders coincide with cash receipts of royalty income from PC. An overall analysis is as follows:

For the period ended	Cash Distribution Date	2003	2002	2001

November 30	January 31	$ 0.15	$ 0.15	$ 0.42
December 31	February 28	0.16	0.15	0.42
January 31	March 31	0.17	0.13	0.42
February 28	April 30	0.17	0.13	0.42
March 31	May 31	0.18	0.14	0.45
April 30	June 30	0.18	0.14	0.45
May 31	July 31	0.18	0.14	0.36
June 30	August 31	0.18	0.14	0.32
July 31	September 30	0.18	0.14	0.25
August 31	October 31	0.18	0.15	0.25
September 30	November 30	0.18	0.15	0.25
October 31	December 31	0.18	0.15	0.23
Cash Distributions per Trust unit		$ 2.09	$ 1.71	$ 4.24

Reconciliation of Distributions Accruing to Unitholders
(thousands of dollars except per unit amounts)

For the years ended December 31,	2003	2002	2001
Distributions payable, beginning of year	$ 30,065	$ 12,188	$ 28,425
Distributions accruing during the year			
Cash flow from operating activities	187,585	112,570	110,176
Redemption of exchangeable shares	(2,792)	-	-
Proceeds on disposition of property interests	-	946	3,546
Reclamation and abandonment reserve	(776)	(706)	(447)
Less capital lease repayment (2) (3)	(3,305)	(5,366)	(2,629)
Capital expenditures	(30,000)	(10,000)	-
Total distributions accruing during the year	150,712	97,444	110,646
NCE Energy Trust cash flow (1)	-	5,651	-
Total distributable income for the year	150,712	103,095	110,646
Distributions paid	(127,325)	(85,218)	(126,883)
Distributions payable, end of year (4)	$ 53,452	$ 30,065	$ 12,188

Distributions accruing to Unitholders per Trust unit

Basic	$ 2.47	$ 2.07	$ 3.50
Diluted	$ 2.46	$ 2.06	$ 3.49

(1) Remaining undistributed cash flow of NCE Energy Trust on May 30, 2002 (see Note 3b).
(2) Net of $6 million refinanced by increased bank loan in 2002.
(3) Net of $6 million refinanced by increased bank loan in 2003.
(4) It is expected that a portion of this amount will be used to fund capital expenditures.

13. FINANCIAL INSTRUMENTS

The Trust's financial instruments consist of cash, accounts receivable and payable, long-term debt, capital lease obligations and derivative instruments. As at December 31, 2003, the carrying value of the cash and accounts receivable and payable approximated their fair value due to their short-term nature. The carrying

value of the long-term debt approximated its fair value due to the floating rate of interest charged under the facilities. The carrying value of the capital lease obligations is not significantly different from their fair values.

The derivative instruments have no carrying value (see Note 14). The derivative instruments at December 31, 2003, had a negative fair value of $6.8 million based on quotes provided by brokers. This fair value represents an approximation of amounts that would be paid to counterparties to settle these instruments at the balance sheet date. The Trust plans to hold all derivative instruments outstanding at December 31, 2003, to maturity.

14. DERIVATIVE FINANCIAL INSTRUMENTS AND PHYSICAL CONTRACTS

The Trust enters into various pricing mechanisms to reduce price volatility and establish minimum prices for a portion of its oil and gas production. These include fixed-price contracts and the use of derivative financial instruments.

The outstanding derivative financial instruments, all of which constitute effective hedges, and the related unrealized gains or losses, and physical contracts as at December 31, 2003, are summarized separately below:

Natural Gas	Term	Volume mcf/d	Price $/mcf	Delivery Point	Unrealized Gain (Loss) $000's
Collar	November 1, 2003 to March 31, 2004	9,475	$6.23-$8.34	AECO	$ 118
Collar	November 1, 2003 to March 31, 2004	9,475	$5.80-$10.98	AECO	164
Fixed	January 1, 2004 to March 31, 2004	4,737	$6.07	AECO	(316)
Fixed	January 1, 2004 to March 31, 2004	4,737	$6.23	AECO	(246)
Fixed	January 1, 2004 to March 31, 2004	4,737	$6.81	AECO	18
Fixed	January 1, 2004 to March 31, 2004	4,737	$7.39	AECO	255
Collar	April 1, 2004 to October 31, 2004	9,475	$5.17-$7.28	AECO	268
Collar	April 1, 2004 to October 31, 2004	9,475	$5.07-$6.81	AECO	(66)
Collar	April 1, 2004 to October 31, 2004	1,895	$5.28-$7.39	AECO	56
Fixed	April 1, 2004 to October 31, 2004	4,737	$5.33	AECO	(550)
Collar	November 1, 2004 to March 31, 2005	9,475	*(1)	AECO	54

Total	$ (245)

*(1) At Prices above $8.97/mcf Petrofund receives $8.97/mcf. At Prices between $5.80/mcf and $8.97/mcf receives the market price. At Prices below $4.74/mcf Petrofund receives a premium of $1.06/mcf.

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Oil	Term	Volume bb/d	Price $/bbl	Delivery Point	Unreal Gain (L $0
Fixed Price	January 1, 2004 to June 30, 2004	1,995	$38.59	Edmonton	$ (
Fixed Price	July 1, 2004 to December 31, 2004	668	$36.41	Edmonton	(
Collar	January 1, 2004 to March 31, 2004	2,000	$31.12-$35.98	Edmonton	(
Three Way Collar	January 1, 2004 to June 30, 2004	2,000	*(1)	Edmonton	(1,
Collar	April 1, 2004 to June 30, 2004	2,000	$31.12-$36.56	Edmonton	(
Three Way Collar	July 1, 2004 to December 31, 2004	2,000	*(2)	Edmonton	(
Collar	July 1, 2004 to September 30, 2004	2,000	$31.12-$36.30	Edmonton	(
Collar	October 1, 2004 to December 31, 2004	2,000	$31.12-$36.30	Edmonton	(
Three Way Collar	January 1, 2005 to December 31, 2005	1,000	*(3)	Edmonton	(
Total					$ (6,

*(1) At Prices above $37.27 Petrofund receives $37.27/bbl. At Prices between $31.12 and $37.27/bbl Petrofund receives the market price. At Prices below $27.55 Petrofund receives a premium of $3.89/bbl.

*(2) At Prices above $37.60 Petrofund receives $37.60/bbl. At Prices between $31.45 and $37.60/bbl Petrofund receives the market price. At Prices below $27.87 Petrofund receives a premium of $3.89/bbl.

*(3) At Prices above $37.60 Petrofund receives $37.60/bbl. At Prices between $31.12 and $37.60/bbl Petrofund receives the market price. At Prices below $25.93 Petrofund receives a premium of $5.19/bbl.

All the oil hedges are at U.S. WTI prices and have been converted to Canadian dollars at the year end exchange rate of $1.2965 C$:US$.

Electricity	Term	Volume MW/h	Price $/MWh	Delivery Point	Unrealize Gain (Los $000's
Fixed Price	January 1, 2004 to December 31, 2005	3.0	$ 44.50	Alberta Power Pool	$ 303

The gains or losses are recognized on a monthly basis over the terms of the contracts and adjust the prices received.

Derivative financial instruments and physical hedge contracts involve a degree of credit risk, which the Trust controls through the use of financially sound counterparties. Market risk relating to changes in value or settlement cost of the Trust's derivative financial instruments is essentially offset by gains or losses on the underlying physical sales.

15. INCOME TAXES

The future income tax liability (asset) includes the following temporary differences (thousands of dollars):

As at December 31,	2003	2002	2001
Oil and gas properties	$ 77,005	$ 119,825	$ 106,961
Resource allowance	-	(2,980)	(2,961
	$ 77,005	$ 116,845	$ 104,000

The provision for current and future income taxes differs from the result which would be obtained by applying the combined federal and provincial statutory tax rates to income before income taxes. This difference results from the following:

For the years ended December 31,	2003	2002	200
Income before income tax provision	$ 41,857	$ 10,165	$ 40,12
Income tax provision computed at statutory rates	$ 17,052	$ 4,294	$ 17,30
Effect on income tax of:			
Income attributed to the Trust	(41,468)	(24,435)	(32,66
Internalization of management contract	12,568	-	
Non-deductible crown charges, net of Alberta Royalty Credit	24,190	17,055	19,27
Resource allowance	(20,730)	(15,045)	(16,66
Capital taxes	1,000	831	1,13
Income tax rate reductions on opening balances	(36,688)	-	(32
Temporary differences in resource allowance	-	(19)	(2,42

Other	129	3,105	51
Provision for (recovery of) income taxes	$ (43,947)	$ (14,214)	$ (13,86

The petroleum and natural gas properties and facilities owned by the Subsidiaries have a tax basis of $232.7 million ($212 million - 2002, $153.3 million - 2001) available for future use as deductions from taxable income. Included in this tax basis are non-capital loss carry forwards of $43.6 million ($34.0 million - 2002, $33.6 million - 2001), which could expire in various years through 2010.

16. NET INCOME PER TRUST UNIT

Basic per unit calculations are based on the weighted average number of Trust units and exchangeable shares outstanding. Diluted calculations include additional Trust units for the dilutive impact of options. There were no adjustments to net income in calculating diluted per Trust unit amounts.

The weighted average units/exchangeable shares outstanding are as follows:

For the years ended December 31,	2003	2002	20
Basic	61,010,105	49,921,523	31,593,3
Diluted	61,153,027	49,967,648	31,635,9

17. LONG TERM COMMITMENTS

PC has the following long term commitments for the years indicated:

(thousands of dollars)	2004	2005	2006	2007	2008
Capital leases (Note 6)	$ 0.4	$ 0.6	$ -	$ -	$ -
Office lease	1.1	0.8	-	-	-
Processing & transportation agreement	1.8	1.8	2.0	2.1	2.2
CO_2 purchases	3.9	4.7	4.1	3.5	3.3
	$ 7.2	$ 7.9	$ 6.1	$ 5.6	$ 5.5

18. DIFFERENCES BETWEEN CANADIAN AND UNITED STATES GENERALLY ACCEPTED ACCOUNTING PRINCIPLES ("GAAP")

The Trust's consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). These principles, as they pertain to the Trust's consolidated financial statements, differ from United States generally accepted accounting principles ("U.S. GAAP") as follows:

(a) The Canadian GAAP ceiling test is comparable to the Securities and Exchange Commission ("SEC") method using constant prices, costs and tax legislation except that the SEC requires the resulting amounts to be discounted at 10%. In addition, the SEC does not require the inclusion of any general and administrative or interest expenses in the calculation.

(b) U.S. GAAP utilizes the concept of comprehensive income, which includes items not included in net income. At the current time, there is no similar concept under Canadian GAAP.

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

Hedge accounting treatment allows unrealized gains and losses to be deferred in other comprehensive income (for the effective portion of the hedge) until such time as the forecasted transaction occurs and requires that an entity formally document, designate and assess effectiveness of derivative instruments that receive hedge accounting treatment. Upon adoption, the Trust formally documented and designated all hedging relationships and verified that its hedging instruments are effective in offsetting changes in actual prices received by the Trust. Such effectiveness is monitored at least quarterly and any ineffectiveness is reported in other revenues (losses) in the consolidated statement of operations. In 2003, the Trust has elected to use fair value accounting for its derivative instruments for U.S. GAAP and the change in fair value of these contracts has been reported in income.

(d) Prior to January 1, 2003, for Canadian GAAP purposes, compensation expense for options granted under the Unit Incentive Plan was measured based on the intrinsic value of the award at the grant date. For the years ended December 31, 2003, and 2002, pro forma disclosures are included in the notes to the financial statements of the impact on net income and net income per Trust unit had the Trust accounted for compensation expense based on the fair value of options granted during 2002. Effective January 1,

2003, the Trust accounts for compensation expense for options granted on or after January 1, 2003, based on the fair value method of accounting as described in Note 2g.

For U.S. GAAP purposes, the Unit Incentive Plan is a variable compensation plan as the exercise price of the options is subject to downward revisions from time to time. Accordingly, compensation expense is determined as the excess of the market price of the Trust units over the adjusted exercise price of the options at each financial reporting date and is deferred and recognized in income over the vesting period of the options. After the options have vested, compensation expense is recognized in income in the period in which a change in the market price of the Trust units or the exercise price of the options occurs.

At December 31, 2001, the exercise price of the options granted under the Unit Incentive Plan exceeded the market price of the Trust units. Therefore, no compensation expense was recorded in 2001. No options have been granted subsequent to December 31, 2002.

(e) In June 2001, the U.S. Financial Accounting Standards Board issued Statement No. 143, "Accounting for Asset Retirement Obligations" (FAS 143). FAS 143 requires recognition of a liability for the future retirement obligations associated with property, plant and equipment. These obligations are initially measured at fair value, which is the discounted future value of the liability. The liability is accreted each period for the change in present value and the accretion expense is charged to income. The fair value of the liability is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The Trust adopted FAS 143 effective January 1, 2003, for U.S. reporting purposes and the cumulative effect adjustment from initial application has been charged to net income in the current year. Under current Canadian GAAP prior to asset retirement obligations are accrued using the unit-of-production method based on the undiscounted value of the liability. Effective January 1, 2004, the Trust must adopt new Canadian accounting standards for accounting for asset retirement obligations which are expected to eliminate this difference in future years.

Under the old accounting rules, the Trust's net income under the US GAAP would have been:

($000's)	2003
Net income under US GAAP, as reported	$ 94,697
Cumulative effect of change in accounting principle	2,419
Depletion and depreciation	2,164
Asset retirement obligation	(3,955)
Future income taxes	320
Net income under US GAAP, as adjusted	$ 95,645
Net income per unit, as adjusted, - basic	$ 1.57
- diluted	$ 1.56

Had FAS 143 been applied during all periods presented, the asset retirement obligation would have been reported as follows:

($000's)	As reported	Pro Forma
January 1, 2002	$ 11,631	$ 33,771
December 31, 2002	$ 15,298	$ 34,496
December 31, 2003	$ 34,363	$ 34,363

The change in the asset retirement obligation since the beginning of the year is as follows:

($000's)	2003
Asset retirement obligation at January 1	$ 34,496
Obligation incurred	2,274
Abandonment expenditures	(4,651)
Accretion	2,244
Asset retirement obligation at December 31	$ 34,363

Had FAS 143 been applied during all periods presented, the December 31, 2002 and 2001 results would have been reported as follows:

($000's, except per unit amounts)	2002	2003
Net income - US GAAP		
As reported	$ 38,598	$ (98,924)
DD&A and accretion	(4,408)	(4,475)
Adjusted	$ 34,190	$(103,399)
Earnings per unit ($/unit)		
Basic as reported	$ 0.77	$ (3.16)
Adjusted	0.68	(3.27)
Diluted as reported	$ 0.77	$ (3.16)
Adjusted	0.68	(3.27)

(f) In November 2002, the FASB issued Interpretation No. 45, "Guarantors' Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others" (FIN 45). FIN 45 elaborates on the disclosures that must be made regarding obligations under certain guarantees issued by the Trust. It also requires that the Trust recognize, at the inception of a guarantee, a liability for the fair value of the obligations undertaken in issuing the guarantee. The initial recognition and initial measurement provisions are to be applied to guarantees issued or modified after December 31, 2002. There are no guarantees outstanding at December 31, 2003.

(g) The Trust presents cash flow before changes in non-cash operating working capital as a subtotal in the Consolidated Statement of Cash Flows. This line item would not be presented in a cash flow statement prepared in accordance with U.S. GAAP. This difference does not result in an adjustment to the financial results as reported under the Canadian GAAP.

Under US GAAP, the Trust's bank overdraft would be presented as a financing activity rather that as a component of cash. Therefore, cash provided by (used in) financing activities under US GAAP would be $(29,538) in 2003 (2002 - $45,227; 2001 - $46,113).

The net change in non-cash operating working capital balances is comprised of the following:

($000's)	2003	2002	2001
Accounts receivable	$ (6,315)	$ (28,987)	$ 3,290
Due from affiliates	164	-	-
Prepaids and deposits	54	(5,506)	428
Accounts payable and accrued liabilities	14,677	687	15,157
Payable to affiliates	(2,168)	-	-
	$ 6,410	$ 33,806	$ 18,875

(h) Under US GAAP, interest expense would be classified as a non-operating expense in the statement of operations.

(i) Accounts payable and accrued liabilities is comprised of the following:

($000's)	2003	2002
Accounts payable	$ 20,959	$ 9,959
Accrued capital expenditures	12,295	10,099
Other accrued liabilities	3,430	1,949
	$ 36,684	$ 22,007

(j) The following pro forma amounts would have been realized by the Trust in 2002 and 2001 had the acquisition of NCE Energy Trust occurred on January 1, 2001:

$000's, except per unit amounts)	2003	2002
	(Unaudited)	
Net revenues after royalties	$ 238,700	$ 280,100
Net income	26,200	61,500
Net income per Trust unit	0.50	1.42

(k) Under US GAAP, the number of authorized and issued Trust units and Exchangeable Shares would be disclosed on the face of the balance sheet. This information is disclosed in Notes 8 and 10.

The following presents the consolidated statement of Unitholders' Equity for the three years ended December 31, 2003 under US GAAP:

Petrofund Energy Trust
Consolidated Statement of Unitholders' Equity (US GAAP)

For the Three Years Ended December 31, 2003

(000's)	Unitholder's Capital	Exchangeable Shares	Accumulated Distributions	Retained Earnings	C
December 31, 2000	$ 321,344	$ -	$ (219,505)	$ 32,106	
Units issued	324,489	-	-	-	
Commissions & issue costs	(11,781)	-	-	-	
Options exercised	5,620	-	-	-	
Unit purchase plan	220	-	-	-	
Net Income	-	-	-	(99,956)	
Comprehensive income - unrealized gain (loss) on derivatives	-	-	-	-	
Distribution accruing to unitholders	-	-	(110,646)	-	
December 31, 2001	639,892	-	(330,151)	(67,850)	
Units issued	158,439	-	-	-	
Commissions & issue costs	(4,190)	-	-	-	
Options exercised	85	-	-	-	
Unit purchase plan	126	-	-	-	
Net Income	-	-	-	40,081	
Comprehensive income - unrealized gain (loss) on derivatives	-	-	-	-	
Stock based compensation expense	59	-	-	-	
Distribution accruing to unitholders	-	-	(94,444)	-	
December 31, 2002	794,411	-	(427,595)	(27,796)	
Units issued	205,563	-	-	-	
Exchangeable shares issued	-	21,718	-	-	
Exchangeable shares converted	11,200	(11,200)	-	-	
Redemption of exchangeable shares	-	-	(2,792)	-	
Commissions & issue costs	(11,001)	-	-	-	
Options exercised	20,474	-	-	-	
Unit purchase plan	89	-	-	-	
Net Income	-	-	-	94,697	
Comprehensive income - unrealized gain (loss) on derivatives	-	-	-	-	
Stock based compensation expense	3,144	-	-	-	
Distribution accruing to unitholders	-	-	(150,712)	-	
December 31, 2003	$ 1,023,880	$ 10,518	$ (581,099)	$ 66,928	

(l) The following standards issued by the FASB do not have an impact on the Trust, at the current time:

- o FAS 150 "Accounting for Certain Instruments with Characteristic of Book Liabilities and Equity".

- o FIN 46 and FIN 46-R "Consolidation of Variable Interest Entities".

The Trust will continue to assess the applicability of these standards in the future.

The application of U.S. GAAP would have the following effects on net income as reported:

For the years ended December 31, ($000's)	2003	2002
Net income as reported in consolidated statement of operations	$ 85,804	$ 24,379
Adjustments:		
Unrealized loss on derivatives	(6,774)	(563)
Compensation expense	(3,144)	(59)
Depletion and depreciation	21,098	24,552
Asset retirement obligation	3,955	-
Ceiling test write down	-	-
Deferred income taxes	(3,823)	(8,228)
Net income, as adjusted, before cumulative effect of a change in accounting principle	97,116	40,081
Cumulative effect of a change in accounting principle, net of income taxes	(2,419)	-
Net income, as adjusted, after cumulative effect	94,697	40,081
Unrealized gain (loss) on derivatives, net of income tax expense (recovery) of $330 (2002 -$(1,113), 2001 - $783)	451	(1,483)
Comprehensive income	$ 95,148	$ 38,598
Net income (loss) per unit, as adjusted before accumulative effect		
Basic	$ 1.59	$ 0.77
Diluted	$ 1.59	$ 0.77
Net income (loss) per unit, as adjusted after cumulative effect		
Basic	$ 1.55	$ 0.77
Diluted	$ 1.55	$ 0.77

Accumulated other comprehensive income:

For the years ended December 31, ($000's)	2003	2002
Opening balance at January 1	$ (451)	$ 1,032
Unrealized gain (loss) on derivatives, net of income tax expense (recovery) of $330 (2002 - $(1,113), 2001 - $783)	451	(1,483)
Closing balance at December 31	$ -	$ (451)

The application of US GAAP would have the following effects on the consolidated balance sheet as reported:

As at ($000's)	As reported	Increase (Decrease)	US GA
December 31, 2003			
Oil and gas derivative instruments	$ -	$ (6,774)	$ (6,77
Oil and gas royalty and property interests, net	879,633	(157,172)	722,46
Future income taxes	77,005	(52,450)	24,55
Accrued reclamation and abandonment costs	16,846	17,517	34,64
Unitholders' equity	649,240	(129,013)	520,22
December 31, 2002			
Oil and gas derivative instruments	$ -	$ (1,194)	$ (1,19
Oil and gas royalty and property interests, net	835,366	(198,651)	632,71
Future income taxes	116,845	(58,344)	58,50
Unitholders' equity	480,097	(141,501)	338,59

19. SUBSEQUENT EVENT

On March 29, 2004, Petrofund and Ultima Energy Trust ("Ultima") announced that they had entered into an agreement providing for the combination of Petrofund and Ultima. Under the terms of the agreement, each Ultima unit will be exchanged for 0.422 of a Petrofund unit on a tax-deferred rollover basis. Subject to regulatory approval and the approval of Ultima unitholders by a majority vote of at least two-thirds at a meeting to be held on or about June 4, 2004, the transaction is expected to close on or about June 16, 2004.

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ADDITIONAL INFORMATION

The following information has been prepared utilizing information contained in the Information Circular of Petrofund Energy Trust dated February 27, 2004 (the "Information Circular") which was prepared in connection with the annual and special meeting of holders of trust units of Petrofund Energy Trust held April 14, 2004 (the "Meeting") and updating such information to reflect, among other things, the result of voting on certain matters which were placed before such Meeting.

GLOSSARY OF TERMS

The following terms used in the discussion that follows shall have the meanings set out below:

"Board of Directors" or "Board" means the Board of Directors of PC;

"Business Day" means a day which is not (i) a Saturday or a Sunday; or (ii) a day observed as a holiday under the laws of the Province of Ontario, the Province of Alberta or the federal laws of Canada applicable therein;

"HR&C Committee" means the Human Resources and Compensation Committee of the Board of Directors;

"Internalization" or "Internalization Transaction" means Petrofund's indirect purchase of all of the shares of the Previous Manager and related transactions which were completed in April, 2003. Pursuant to the Internalization, Petrofund acquired all of the shares of the Previous Manager, a party to the Management Agreement, and all of the shares of NCE Services, which employed all of the

Calgary-based personnel who provided management, operational and administrative services to PC and Petrofund;

"Management Agreement" means the amended and restated management, advisory and administration agreement dated as of January 1, 2002 among PC, the Trustee and the Manager;

"Manager" means the Previous Manager;

"Meeting" means the annual and special meeting of Unitholders to be held on Wednesday, April 14, 2004 at 2:00 p.m. MST (Calgary time), and any adjournment thereof;

"NCE Services" means NCE Management Services Inc.;

"Ordinary Resolution" means a resolution approved in writing by Unitholders holding not less than 50% of the outstanding Units or a resolution passed at a meeting of Unitholders (including an adjourned meeting) duly convened for the purpose and held in accordance with the provisions of the Trust Indenture and passed by the affirmative votes either in person or by proxy of the holders of not less than 50% of the Units represented at the meeting;

"PC" means Petrofund Corp.;

"PC Exchangeable Shares" means non-voting exchangeable shares in the capital of PC;

"Petrofund" or the "Trust" means Petrofund Energy Trust;

"Petrofund Incentive Plan" means the former incentive plan established on May 3, 1996, authorizing the issuance of options to acquire Units to directors, senior officers, employees and consultants of PC and certain related parties;

"Petrofund Unit Rights Incentive Plan" means the incentive plan established on January 30, 2001, and approved by the Unitholder at that annual and special meeting held on June 11, 2001, authorizing the issuance of options to acquire Units to directors, senior officers, employees and consultants of PC and certain related parties;

"Previous Manager" means NCE Petrofund Management Corp.;

"Royalty Agreement" means the amended and restated royalty agreement made as of April 16, 2003 between PC and Petrofund;

"Special Resolution" means a resolution approved in writing by Unitholders holding not less than 66-2/3% of the outstanding Units or a resolution passed as a special resolution at a meeting of Unitholders (including an adjourned meeting) duly convened for the purpose and passed by the affirmative votes either in person or by proxy of the holders of not less than 66-2/3% of the Units represented at the meeting and voted on a poll upon such resolution.

"Trust Indenture" means the amended and restated trust indenture governing Petrofund made as of April 16, 2003 between PC and the Trustee;

"Trustee" means Computershare Trust Company of Canada, the trustee of Petrofund;

"TSX" means the Toronto Stock Exchange;

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

"Unitholders" means holders of Units.

PRINCIPAL UNITHOLDERS

To the best of the knowledge of the directors and senior officers of PC, no person beneficially owns, directly or indirectly, or exercises control or direction over, Units carrying more than 10% of the voting rights attached to the issued and outstanding Units.

CERTAIN MATTERS VOTED ON AT MEETING

Approval of Issuance of Units Under Restricted Unit Plan

On February 17, 2004, the Board of Directors approved the adoption of a restricted unit plan (the "Restricted Unit Plan") which authorizes the Trust to grant restricted units ("Restricted Units") to directors, officers, employees or consultants of the Trust or any of its subsidiaries which will vest over time and which, upon vesting, may be redeemed by the holder for cash or Units. The Restricted Unit Plan is an alternative to the incentive bonus plans and unit right incentive plans employed by many other trusts. At the Meeting, Unitholders were asked to consider and, if thought fit, to pass a resolution authorizing the issuance of up to a maximum of 1,200,000 Units from treasury, over the life of the plan, pursuant to the terms of the Restricted Unit Plan. For a description of the Restricted Unit Plan, see "- Description of the Restricted Unit Plan" below.

The issuance of Units from treasury under the Restricted Unit Plan is subject to the approval of the TSX, which approval has been obtained.

At the Meeting, Unitholders approved the following Ordinary Resolution in relation to the Restricted Unit Plan:

> "BE IT RESOLVED as an ordinary resolution of the unitholders of Petrofund Energy Trust (the "Trust") that the Trust be and is hereby authorized to issue up to a maximum of, subject to adjustment as provided in the Restricted Unit Plan, 1,200,000 trust units of the Trust from treasury pursuant to the terms of the Restricted Unit Plan as described in the Information Circular of the Trust dated February 27, 2004."

Description of the Restricted Unit Plan

A considerable amount of time has been spent by management and the HR&C Committee, in consultation with independent third party consultants, reviewing the compensation packages of other similar trusts in both the oil and gas industry and other industries. The goal of this effort was to design a compensation package that will both provide an effective incentive compensation mechanism and more closely align the interests of management of the Trust with the interests of the Unitholders.

Generally speaking, many trusts in the oil and gas industry typically have in place both an incentive bonus plan and a unit rights incentive plan. Typically, the incentive bonus plan sets aside a non-discretionary bonus pool of approximately 2.0% to 2.5% of net operating income. This bonus pool is distributed annually, or semi-annually, to participants and payment is typically made in cash, trust units or a combination thereof. The existing unit rights incentive plan is very similar to a stock option plan, under which participants are granted rights to purchase trust units at a predetermined price.

Upon completion of its review, management, the HR&C Committee and the Board of Directors concluded that the unit rights incentive plan was not particularly effective in achieving either of the goals outlined above. As an alternative to this plan, on February 17, 2004, the Board of Directors approved the Restricted Unit Plan for directors, officers, employees, or consultants of the Trust and of its subsidiaries, including PC.

Under the terms of the Restricted Unit Plan, any director, officer, employee or consultant of the Trust, or any of its subsidiaries who, in each case, in the opinion of the directors of PC, holds an appropriate position with the Trust, or any of its subsidiaries, to warrant participation in the Restricted Unit Plan (collectively, the "Participants") may be granted Restricted Units which vest over time and, upon vesting, can be redeemed by the holder, at the election of PC and subject to certain restrictions, for cash or Units. The Restricted Unit Plan is administered by the HR&C Committee.

The Restricted Unit Plan is intended to replace the existing Petrofund Unit Rights Incentive Plan which will be terminated should the Restricted Unit Plan receive all necessary approvals. This termination is not conditional on approval of the LTIP. Rights that have been previously issued under the Petrofund Unit Rights Incentive Plan which remain outstanding will not be affected by the termination of the plan. The Restricted Unit Plan will operate independently of the LTIP and STIP made available to the Senior Executives (see "Approval of Issuance of Units Under the Long Term Incentive Plan" below); however, such persons will be eligible to participate in the Restricted Unit Plan.

The Restricted Unit Plan authorizes the issuance of 1,200,000 Restricted Units (subject to adjustments, including adjustments resulting from cash distributions paid to holder of Units) of which no greater than 200,000 Restricted Units (subject to adjustments, including adjustments resulting from cash

distributions paid to holders of Units) may be granted to the directors of the Trust or its subsidiaries who are not officers or employees of the Trust or its subsidiaries.

The purpose of the Restricted Unit Plan is to provide incentive compensation to Participants which is calculated based on a grant of Restricted Units and the appreciation in value of the Units (including distributions payable in respect thereof) from the date of the grant to the date of redemption by the Participant. In this way, Participants will be rewarded for their efforts in the year in which the Restricted Units are granted and are also provided with additional incentive for their continued efforts in promoting the growth and success of the business of the Trust.

The number of Restricted Units granted to a Participant will be increased on the second Business Day following each date on which a cash distribution is paid to holder of Units by an amount equal to the product of the number of Restricted Units granted to the Participant which have not been redeemed and the fraction which has as its numerator the cash distribution paid, expressed as an amount per Trust Unit and which has as its denominator the weighted average of the prices at which the Units traded on the TSX for the 20 trading days immediately preceding the record date for such distribution.

Essentially, the Restricted Unit Plan provides for the granting of Restricted Units to Participants at the discretion of the Board of Directors, based on recommendations received from the HR&C Committee. Unless otherwise determined by the Board of Directors at the time of a particular grant of Restricted Units, Restricted Units will vest and become available for redemption as to 33-1/3% on each of the first, second and third anniversaries of the grant date. The number of Restricted Units which can be granted from time to time and which have a vesting date which occurs earlier than the foregoing vesting schedule is limited to 5% of the number of Restricted Units which are authorized for issuance pursuant to the Restricted Unit Plan; provided, however, that the proposed grant by the Board of Directors of approximately 65,000 Restricted Units to employees and consultants of PC, which will vest as to 33-1/3% on each of January 1, 2004, January 1, 2005, and January 1, 2006, will be considered to have been granted in accordance with the normal vesting schedule set forth above.

The Restricted Unit Plan provides that any grant of Restricted Units to a Participant who is a director of the Trust or a subsidiary of the Trust will be subject to the restrictions that: (i) the Restricted Units will not vest and, accordingly, will not become available for redemption until the third anniversary of the date of grant; and (ii) upon redemption of the Restricted Units the Payout Amount (as defined below) will only be satisfied by PC delivering Units issued from treasury. Accordingly, directors of the Trust or of subsidiaries of the Trust could not be granted Restricted Units under the Restricted Unit Plan unless and until approval of Unitholders of the issuance of Units from treasury pursuant to the Restricted Unit Plan was obtained at the Meeting.

The Restricted Unit Plan also provides that at the time of a grant of Restricted Units to a Participant who is an officer, employee or consultant of the Trust or a subsidiary of the Trust the Participant has the right to elect that the grant of Restricted Units will be subject to the restrictions that: (i) the Restricted Units will not vest and, accordingly, will not become available for redemption until the third anniversary of the date of grant; and (ii) upon redemption of the Restricted Units the Payout Amount will only be satisfied by PC delivering Units issued from treasury. Accordingly, the foregoing election could be made unless and until Unitholder approval of the issuance of Units from treasury pursuant to the Restricted Unit Plan was obtained at the Meeting.

Upon redemption of Restricted Units which have vested, Participants will be required to pay $0.10 in cash for each Restricted Unit which is redeemed. Upon redemption, the Trust is required to pay to the Participant the fair market value of the redeemed Restricted Units based on the weighted average of the price at which the Units traded on the TSX for the 20 trading days immediately preceding the

redemption date (the "Payout Amount"). Subject to the restrictions noted above, the Payout Amount shall be satisfied at the discretion of the Board of Directors by making a cash payment, purchasing Units in the market and delivering such Units to the Participant or, subject to the approval of the Unitholders as contemplated herein, by issuing Units from treasury. In the event that the approval of Unitholders of the issuance of Units from treasury pursuant to the

Restricted Unit Plan had not been obtained at the Meeting, the Restricted Unit Plan provided that the Payout Amount may be satisfied through the payment of cash or by way of open market purchases of Units.

The Restricted Unit Plan provides that no Units may be issued to a Participant under the Restricted Unit Plan if such issuance could result, at any time, in (i) the number of Units reserved for issuance pursuant to issuances under the Restricted Unit Plan in respect of Restricted Units granted to insiders of the Trust exceeding 3% of the aggregate issued and outstanding Units (including Units issued on the exercise of outstanding PC Exchangeable Shares), (ii) the issuance to insiders of the Trust, within a one-year period, of a number of Units exceeding 3% of the aggregate issued and outstanding Units (including Units issued on the exercise of outstanding PC Exchangeable Shares), or (iii) the issuance to any one insider of the Trust, or such insider's associates, within a one year period, of a number of Units exceeding 0.5% of the aggregate issued and outstanding Units (including Units issued on the exercise of outstanding PC Exchangeable Shares).

In the event of a change in control of the Trust, as defined in the Restricted Unit Plan, the vesting provisions attaching to the Restricted Units shall be accelerated and all unexercised Restricted Units shall become available for redemption by the Participant for a period of 90 days following the effective date of such change of control.

The Restricted Unit Plan also provides for the vesting and/or termination of Restricted Units in the event of the cessation of employment or death of a Participant.

Approval of Issuance of Units Under Long Term Incentive Plan

On February 17, 2004, the Board of Directors approved a long term incentive plan (the "LTIP") for the President and Chief Executive Officer, the Executive Vice President, the Senior Vice President, Finance and Chief Financial Officer and the Senior Vice President, Operations of PC (collectively, the "Senior Executives") and other employees of PC who may, in the future, be designated as participants under the LTIP.

At the Meeting, Unitholders were asked to consider and, if thought fit, to pass a resolution authorizing the issuance of up to 800,000 Units from treasury, over the life of the LTIP, pursuant to the terms of the LTIP. For a description of the LTIP, see "- Description of the Long Term Incentive Plan" below.

The issuance of Units from treasury under the LTIP is subject to the approval of the TSX, which approval has been obtained.

At the Meeting, Unitholders approved the following Ordinary Resolution in relation to the LTIP:

> "BE IT RESOLVED as an ordinary resolution of the unitholders of Petrofund Energy Trust (the "Trust") that the Trust be and is hereby authorized to issue up to a maximum of, subject to adjustment as provided in the long term incentive plan, 800,000 Units of the Trust from treasury pursuant to the terms of the long term incentive plan as described in the Information Circular of the Trust dated February 27, 2004."

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The Board believes that the issuance of Units from treasury under the

LTIP (as opposed to the payment of cash to the Senior Executives) better aligns the interests of the Senior Executives with the interests of the Unitholders.

Description of the Long Term Incentive Plan

The LTIP is intended to encourage and reward outstanding performance by participants, and if certain performance measures are met, participants may receive a significant portion of their annual cash compensation through the LTIP. As awards under the LTIP are paid out to the participants over time, the LTIP is also designed to act as a participant retention tool as well as encouraging outstanding performance.

The LTIP was approved by the Board of Directors subject to obtaining the approval of Unitholders of the issuance of Units from treasury under the LTIP at the Meeting. The Board believes that the issuance of Units from treasury under the LTIP (as opposed to the payment of cash to the Senior Executives) better aligns the interests of the Senior Executives with the interests of the Unitholders. If the issuance of the Units to the Senior Executives under the LTIP is not approved, the HR&C Committee will work in good faith with the Senior Executives to implement an alternative compensation plan which, failing a satisfactory agreement with respect to such alternative plan, may require PC to compensate the Senior Executives with cash. Such cash payments could result in a reduction of the aggregate sum of distributions available for Unitholders or may result in an increase in the debt of PC and the Trust. Accordingly, the Board recommends that Unitholders vote in favour of the proposed issuance of Units under the LTIP.

The LTIP is administered by the HR&C Committee. From time to time the HR&C Committee will review the objectives of the LTIP to ensure that the LTIP continues to properly encourage outstanding participant performance and retention, and to help achieve PC's and the Trust's strategies and value creation. After such review, reasonable adjustments and amendments may be made to the LTIP in the sole discretion of the HR&C Committee, provided that the HR&C Committee acts in a reasonable manner.

Subject to the discretion of the HR&C Committee and future changes to the roles of the participants, the LTIP establishes threshold, target, and maximum opportunities for each of the participants. The amount of the award for any given year which is given to a participant under the LTIP depends upon the degree to which performance levels, as described below, and individual performance, where applicable, have been met in that year. The size of the LTIP award for any given year is expressed as a percentage of the participant's base salary (not including any bonus, incentive or LTIP compensation, or the value of benefits or perquisites).

The LTIP presently has two financial and operational performance measures: (i) total unitholder return ("TUR"); and (ii) reserve life index ("RLI"). TUR is measured relative to the total unitholder return of relevant peer oil and gas trusts. RLI is measured relative to the prior year's RLI of the Trust. It is considered at the present time by the Committee that it is important for the fund to maintain an RLI of 10.0 years or greater. An RLI of 10.0 years is presently considered the "Optimum RLI" under the LTIP. The HR&C Committee may, in its discretion, but only after consultation with the Senior Executives, review from time to time what the Optimum RLI should be and may change the performance milestones for the RLI based on such review and consultation.

Subject to the discretion and judgement of the HR&C Committee, the two performance measures are weighted equally. The HR&C Committee may, however, change the weighting of such measures from time to time in order to achieve the objectives of the LTIP. In addition to the above two performance measures, the HR&C Committee will take into account in certain circumstances the individual performance of the LTIP participants in determining the LTIP award.

As at the date hereof, and subject to individual performance considerations, the two performance measures at the following percentiles would result in the following awards under the LTIP.

TUR Component:

- a TUR that equals or exceeds the 25th percentile, but is less than the 50th percentile, of the peer group for total unitholder return would result in a threshold LTIP calculation equal to 50% of the target incentive for this component;
- a TUR that equals or exceeds the 50th percentile (median), but is less than the 75th percentile, of the peer group for total unitholder return would result in a LTIP calculation equal to the target incentive for this component; and
- a TUR that is at or above the 75th percentile of the peer group for total unitholder return would result in a maximum LTIP calculation equal to 200% of the target incentive for this component.

RLI Component:

Should the RLI equal or exceed the Optimum RLI, the calculation will be 200% of the target incentive.

Where the RLI falls below the Optimum RLI:

- a change in the RLI at or above the 25th percentile, but less than the 50th percentile, would result in a threshold LTIP calculation equal to 50% of the target incentive for this component;
- a change in the RLI at or above the 50th percentile, but less than the 75th percentile, would result in a LTIP calculation equal to the target incentive for this component; and
- a change in the RLI at or above the 75th percentile would result in a maximum LTIP calculation equal to 200% of the target incentive for this component.

Subject to the discretion of the HR&C Committee and future changes to the roles of the participants, the following are the present threshold, target and maximum opportunities for each of the Senior Executive participants in the following positions:

Level 1 - President and Chief Executive Officer
Level 2 - Executive Vice President
Level 3 - Senior Vice Presidents

	Annual Long Term Incentive (as a % of base salary)	
	Threshold	Maximum

Participation Level	(50% of Target)	Target	(200% of Target)
1	50%	100%	200%
2	37.5%	75%	150%
3	32.5%	65%	130%

As an example, for a participant at participation level 1 whose base salary is equal to $100,000, where the target incentive of the participant is 100% of the participant's base salary (which amount is equal to $100,000) then, subject to individual performance considerations, the payment under the LTIP to the participant would be: nil if the Trust did not meet the threshold performance measures; $50,000 (50% of $100,000) if the Trust met but did not exceed the threshold performance measures; $100,000 (100% of $100,000) if the Trust met but did not exceed the target performance measures; and $200,000 (200% of $100,000) if the Trust met or exceeded the maximum performance measures.

The awards under the LTIP will be based on the participant's base salary earned during the LTIP year with respect to which the award was made. LTIP awards will be made in the form of a grant of restricted Units. The number of restricted Units awarded under the LTIP will be calculated as follows:

- as determined by the HR&C Committee, the percentage of base salary to be awarded to the specific participant will be applied to the base salary for the LTIP year to arrive at a dollar value for the LTIP award;

- the dollar value for the LTIP award will be divided by the average of the closing price of Units on the TSX during the 20 days immediately preceding the award date to arrive at the number of restricted Units to be awarded to the participant;

- the restricted Units will vest one-third on January 1 of the year following the LTIP year with respect to which the award was made and one-third on January 1 of each of the two subsequent years (notwithstanding the foregoing, however, in the existing employment agreements for each of the Senior Executives, it has been agreed that the vesting schedule for the distribution of awards to such persons under the LTIP shall be: (i) for any LTIP award for 2003 performance, two-thirds of the LTIP award shall be vested on the grant date and the remaining one-third of the LTIP award will be vested on the first anniversary of the grant date; and (ii) for any LTIP award for 2004 or 2005 performance, one-third of the LTIP award would be vested on the grant date, one-third of the LTIP award shall be vested on the first anniversary of the grant date and the remaining one-third of the LTIP award shall be vested on the second anniversary of the grant date;

- prior to vesting, distributions on the account balance will be credited and notionally reinvested; and

- on vesting, the balance of the account representing the vested portion of the LTIP award will be issued in Units from treasury to the credit of the participant.

Provided the LTIP receives the necessary Unitholder and regulatory approval, the dollar value of the Units which will be issued from treasury pursuant to the LTIP to each of the Senior Executives will depend on each executive meeting certain individual and corporate performance targets, and is expected to be at the maximum for 2003 of: $610,000 for the President and Chief Executive Officer; $337,500 for the Executive Vice President; $266,500 for the Senior Vice President, Finance and Chief Financial Officer; and $240,000 for the Senior Vice President, Operations. The actual number of Units which will be issued is determined by dividing each dollar amount by an amount equal to the average closing market price of the Units over the 20 trading days preceding the date of the award. The initial grant of Units under the LTIP, based on the foregoing, was approved by the Board of Directors on February 17, 2004, subject to the receipt of all necessary regulatory and Unitholders approvals. Vesting of these Units is two-thirds of the LTIP award on December 31, 2003, and the remaining one-third of the LTIP award on December 31, 2004. If necessary regulatory and Unitholder approval is not obtained it is intended that alternative compensation will be awarded which is equivalent to the award under the LTIP.

Subject to any employment agreement that is in place with the Senior Executives, PC and the HR&C Committee have the right and discretion, provided they act reasonably, to amend the LTIP, in whole or in part, or to terminate the LTIP at any time. Upon termination of the LTIP, all rights to the participants under the LTIP shall cease as of the date of termination, except with respect to LTIP awards that have been declared by the HR&C Committee but not yet paid to the participants.

Amendments to Trust Indenture and Royalty Agreement

Management presented to the Board of Directors a number of proposed amendments to the Trust Indenture and the Royalty Agreement and, after considering such amendments, the Board of Directors placed before Unitholders at the Meeting a Special Resolution approving amendments to the Trust Indenture and the Royalty Agreement as follows.

Additional Resource Assets

As at the date of the Information Circular, the Trust Indenture provided that any funds within the Trust Fund (as defined in the Trust Indenture) are to be used for certain purposes, which purposes include, among others, acquiring, holding and investing, directly or indirectly, in "Additional Resource Assets".

As at the date of the Information Circular, the Trust Indenture and the Royalty Agreement defined "Additional Resource Assets" as "securities of Resource Issuers, royalties or other interests of Resource Issuers and properties and related assets of Resource Issuers" and also define a "Resource Issuer" as "any company, partnership, limited partnership, trust or other entity whose principal business activity is or relates to the exploration, production, drilling, recovery, removal, disposal, production, processing or transportation of Petroleum Substances (as defined in the Trust Indenture and the Royalty Agreement) or related activities".

The business environment is continually changing in the energy sector and, as such, the Board of Directors believed it would be prudent to expand the scope of the Trust's business to include all business related to the energy business rather than only business related to oil and gas assets. While the primary focus of the Trust shall continue to be oil and gas assets, the Board of Directors feels it is prudent to permit investments in the future by the Trust in other energy related investments such as electricity or power generating assets.

Accordingly, at the Meeting it was proposed to amend the definition of "Resource Issuer" in each of the Trust Indenture and the Royalty Agreement to read as follows:

> "Resource Issuer" means any company, partnership, limited partnership, trust or other entity whose principal business activity is or relates to petroleum and natural gas or other energy related assets including, without limitation, Petroleum Substances, facilities of any kind, oil sands interests, electricity or power generating assets and pipeline, gathering, processing and transportation assets;

Acquisition Criteria of Properties

As at the date of the Information Circular, the Trust Indenture provided that acquisitions of Additional Resources Assets which are "Properties" (and which are defined as petroleum and natural gas rights and related tangibles and miscellaneous interests) were to comply with the acquisition criteria set forth in section 3.2 of the Royalty Agreement. One of the acquisition criteria contained in Section 3.01(b) of the Royalty Agreement was that Properties shall be located in Western Canada, namely, Alberta, Saskatchewan, British Columbia and Manitoba and, at the time of purchase, not more than 10% of the Asset Value (as defined in the Royalty Agreement), after giving effect to the proposed acquisition may be

represented by Properties located outside of Western Canada. It was an additional criterion contained within Section 3.01(b) of the Royalty Agreement that all of the Properties must be located in Canada.

The Board of Directors felt that it would be prudent to increase the maximum percentage of Properties which can be located outside of Western Canada from 10% to 20% in order that the Trust is not limited in its ability to acquire a greater interest in attractive oil and gas assets which are located outside of Western Canada, and also remove the restriction that all of the properties must be located in Canada.

Accordingly, at the Meeting it was proposed to amend the acquisition criteria set forth in Section 3.01(b) of the Royalty Agreement to read as follows:

> "The Properties shall be located primarily in Western Canada, namely, Alberta, Saskatchewan, British Columbia and Manitoba and, at the time of purchase, not more than 20% of the Asset Value, after giving effect to the proposed acquisition, may be represented by Properties located outside of Western Canada."

Option to Designate Principal Office of Trustee

As at the date of the Information Circular, the Trust Indenture provided that the register of Unitholders, and all books and records of the Trust, be kept at the principal corporate trust office of the Trustee in the City of Toronto. The Board of Directors felt that it would be prudent and expeditious to have the option to designate the principal corporate trust office of the Trustee in the City of Calgary as the custodian of the register of Unitholders and the books and records of the Trust.

Accordingly, at the Meeting it was proposed to amend the provisions of the Trust Indenture to give the Board of Directors the option to designate the principal corporate trust office of the Trustee in either the City of Toronto or the City of Calgary as the custodian of the register of Unitholders and the books and records of the Trust.

Definition of Asset Value

As at the date of the Information Circular, the Trust Indenture defined "Asset Value" as the present worth of the total estimated pre-tax cash flow from the proved reserves and 50% of the probable reserves, as shown in the most recent engineering report relating thereto. However, the introduction of the new National Instrument 51-101 has imposed a new definition of probable reserves on the industry as a whole. The Board of Directors felt that it would be prudent and expeditious to amend the definition of Asset Value in the Trust Indenture to reflect the new definition contained in NI 51-101.

Accordingly, at the Meeting it was proposed to amend the definition of "Asset Value" in the Trust Indenture to read as follows:

> "Asset Value" means the present worth of all of the estimated pre-tax net cash flow from the proved reserves plus probable reserves, as such terms are defined for the purposes of National Instrument 51- 101 (or any replacement thereof), shown in the most recent engineering report relating thereto, discounted at an annual rate equal to the then current annual yield of long-term (10 year) Government of Canada bonds plus 400 basis points, subject to a maximum rate of 10% and using forecast price and cost assumptions;".

Unitholder Approval

At the Meeting, Unitholders approved the following Special Resolution in relation to the amendments to the Trust Indenture and the Royalty Agreement which are described above:

> "BE IT RESOLVED as a special resolution of the Unitholders of Petrofund Energy Trust that:
>
> 1. the definition of "Resource Issuer" contained in each of the Trust Indenture and the Royalty Agreement be amended to read as follows:
>
>   "Resource Issuer" means any company, partnership, limited partnership, trust or other entity whose principal business activity is or relates to petroleum and natural gas or other energy related assets including, without limitation, Petroleum Substances, facilities of any kind, oil sands interests, electricity or power generating assets and pipeline, gathering, processing and transportation assets;";
>
> 2. the acquisition criteria contained in Section 3.01(b) of the Royalty Agreement be amended to read as follows:
>
>   "The Properties shall be located primarily in Western Canada, namely, Alberta, Saskatchewan, British Columbia and Manitoba and, at the time of purchase, not more than 20% of the Asset Value, after giving effect to the proposed acquisition, may be

represented by Properties located outside of Western Canada.";

3. the designation of the principal corporate trust office of the Trustee contained in the first paragraph of Section 13.2 of the Trust Indenture be amended to read as follows:

   "A register shall be kept, at the discretion and option of the Board of Directors of the Corporation, at the principal corporate trust office of the Trustee in either the City of Toronto or the City of Calgary by the Trustee or by a Transfer Agent designated to act on behalf and under the direction of the Trustee, which register shall contain the names and addresses of the Unitholders, the respective number of Units held by them, the certificate number of the Certificates representing such Units and a record of all transfers thereof. In addition, the Trustee shall maintain a branch register at its principal offices in Halifax, Montreal, Vancouver, and either Calgary or Toronto and in such other locations as the Trustee may designate from time to time."; and

4. the designation of the principal office of the Trustee contained in Section 18.2 of the Trust Indenture be amended to read as follows:

   "The Trustee shall keep such books, records and accounts as are necessary and appropriate to document the Trust Fund and each transaction of the Trust. Without limiting the foregoing, the Trustee will, at its principal office, as designated by the Board of Directors of the Corporation, in either Toronto, Ontario, or Calgary, Alberta, keep records of all transactions of the trust, a list of the assets of the Trust Fund from time to time and a copy of this Trust Indenture and the Royalty Agreement with any amendments thereto.".

5. the definition of "Asset Value" contained in Section 1.1 of the Trust Indenture be amended to read as follows:

   "Asset Value" means the present worth of all of the estimated pre-tax net cash flow from the proved reserves plus probable reserves, as such terms are defined for the purposes of National Instrument 51-101 (or any replacement thereof), shown in the most recent engineering report relating thereto, discounted at an annual rate equal to the then current annual yield of long-term (10 year) Government of Canada bonds plus 400 basis points, subject to a maximum rate of 10% and using forecast price and cost assumptions;".

In accordance with the terms of the Trust Indenture the proposed amendments to the Trust Indenture and the Royalty Agreement required the approval of not less than 66-2/3% of the Units represented at the Meeting and voted on such resolution.

EXECUTIVE COMPENSATION PRIOR TO THE INTERNALIZATION

Management Agreement

The Unitholders approved the Internalization Transaction at the annual and special meeting held on April 16, 2003, and in connection with the Internalization Transaction, PC acquired the Manager and the external management contract of Petrofund as described below and all related fees were eliminated.

Pursuant to the Management Agreement, the Manager was compensated for providing services to PC and Petrofund. As a result of the completion of the Internalization, no fees were payable to the Manager under the Management Agreement in respect of the period commencing on January 1, 2003 to the closing date, April 29, 2003. Previously the Manager received a quarterly fee paid on the last Business Day of each quarter of each year equal to 3.25% (reduced from 3.75%, effective January 1, 2002) of the sum of net production revenue less Crown royalties and other Crown charges attributable to PC's properties for the applicable quarterly period.

In addition the Manager received acquisition fees equal to 1.5% (reduced from 1.75%, effective January 1, 2002) of the purchase costs of all oil and gas properties, oil and gas companies and other related assets acquired by PC, other than replacement properties. In the event that PC properties were sold, the Manager also received disposition fees of 1.25% (reduced from 1.5%, effective January 1, 2002) of the sale price of the properties sold.

PC is entitled to a residual 1% interest in the properties. The management fee and investment fee were paid in part, firstly, by applying any income received by PC in respect of its residual interest in the properties and, secondly, by applying any interest income of PC relating to the proceeds or revenue from the properties.

The Manager was also entitled to be reimbursed by PC for general and administrative costs and by Petrofund for trust expenses. PC was not responsible for the payment in any fiscal year of Petrofund of general and administrative costs in excess of the greater of (a) 5% of the gross production revenue for such fiscal year and (b) $240,000. To the extent that general and administrative costs paid by PC for any fiscal year of Petrofund exceed such maximum amount, PC was entitled to set off and deduct such excess amount from its liability to pay management fees to the Manager.

Compensation of Directors

Prior to the Internalization Transaction each director of PC was entitled to receive a quarterly retainer of $5,000, in addition each director received a fee of $1,000 for each meeting of the board of directors attended and $1,500 for each meeting of Unitholders attended. Subsequent to the Internalization Transaction each director of PC is entitled to receive a quarterly retainer of $7,500, and the committee

chairs also receive an annual retainer of $10,000, except for the chair of the audit committee who receives an annual retainer of $15,000. Each director of PC also receives a fee of $1,750 for each board of directors, unitholders, or committee meeting attended. All amounts paid to the directors of PC are paid by Petrofund.

For Petrofund's fiscal year ended December 31, 2003, the directors were paid an aggregate of $360,500 for retainer fees and attending regular meetings of the Board of Directors, $20,750 for attending audit committee meetings, and $43,250 for participation on two special committees, pertaining to the Internalization Transaction. John F. Driscoll, the Chairman of the Board of Directors, receives a fixed amount of $125,000 a year in lieu of retainer and meeting fees.

Executive Compensation

Summary Compensation Table

The following table provides a summary of compensation information for the chief executive officer plus the four other most highly compensated policy making executive officers of PC (collectively, the "Named Executive Officers") for the period January 1, 2003 to December 31, 2003.

	Annual Compensation ("Comp")			Long-Term Comp		
				Awards		Payout
Name and Principal Position	Salary (1) ($)	Bonus ($)	Other(2) Annual Comp ($)	Securities Under Options / SARs Granted	Restricted Shares or Restricted Share Units	LTIP Pay-outs
Jeffery E Errico, President & CEO	$305,000	$195,000	(2)	-	(3)	-
Jeffrey D. Newcommon, Executive Vice President	$218,333	$156,000	(2)	-	(3)	-
Vince P. Moyer, CA Senior Vice President, Finance & CFO	$205,000	$149,500	(2)	-	(3)	-
Glen C. Fischer, Senior Vice President, Operations	$185,000	$149,500	(2)	-	(3)	-
Noel F. Cronin Vice President, Production	$158,000	$40,000	(2)	-	(3)	-

Notes:

(1) For the period January 1, 2003 to December 31, 2003. Note also that amounts prior to April 29, 2003 were paid by the Manager and reimbursed by PC.

(2) The value of perquisites and other personal benefits received by the Named Executive Officers was not greater than 10% of the total salary and bonus for the period.

(3) See "Certain Matters Voted on at Meeting - Approval of Issuance of Units Under Long Term Incentive Plan for restricted Units which were granted under the LTIP, subject to regulatory and Unitholder approval.

Aggregate Unit Incentive Rights Exercised and Year End Values

The following table sets forth, with respect to the Named Executive Officers, the number of Trust Unit Incentive Rights exercised during the year ended December 31, 2003, and the value of the "in-the-money" unexercised Trust Unit Incentive Rights at December 31, 2003.

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Aggregate Unit Incentive Rights Exercised During the Most Recently Completed Financial Year and Financial Year End Unit Incentive Rights Values

Name	Securities Acquired on Exercise (#)	Aggregate Value Realized ($)	Unexercised Unit Incentive Rights at FY-End (#) Exercisable/Unexercisable	Value of Unex In-the-Mone Incentive Ri FY-End (Exercisable/Un
J. E. Errico	141,133	554,303	41,667/ 50,000	106,668 / 4
J. D. Newcommon	101,667	406,900	33,333 / 35,000	85,332 / 31
V. P. Moyer	134,999	264,740	- / 35,000	- / 310,
G. C. Fischer	138,333	314,247	- / 35,000	- / 310,
N. F. Cronin	51,667	140,374	- / 9,000	- / 79,7

The value of the exercisable Unit Incentive Rights (market value of Units less exercise price) at December 31, 2003, was based upon the closing price of $18.79 for the Units on December 31, 2003, being the last day of trading of the Units in 2003, as quoted by the Toronto Stock Exchange.

Unit Incentive Plans

The Petrofund Incentive Plan authorized the issuance of options to acquire Units to directors, senior officers, employees and consultants of PC and certain related parties. As of December 31, 2003, 4,689 options were outstanding pursuant to the Petrofund Incentive Plan. The Petrofund Incentive Plan will be terminated once all options outstanding thereunder are exercised or expire unexercised.

All option rights to purchase Units are now granted under the Petrofund Unit Rights Incentive Plan. The purpose of the Petrofund Unit Rights Incentive Plan is to encourage ownership of Units by directors, senior officers, employees and consultants of PC, as designated from time to time by the Board of Directors, and personal holding corporations controlled by or registered retirement savings plans of any such persons.

The aggregate number of Units which may be reserved for issuance under the Petrofund Unit Rights Incentive Plan is 5,200,000 Units, of which 2,945,900 have been issued. As of February 27, 2004, 751,789 options were outstanding pursuant to the Petrofund Unit Rights Incentive Plan. The Petrofund Unit Rights Incentive Plan permits Petrofund to increase such maximum number from time to time, subject to the approval of the Unitholders. If the Restricted Unit Plan, outlined in this Information Circular, is approved no further options will be issued under the Petrofund Unit Rights Incentive Plan.

The exercise price of rights granted under the Petrofund Unit Rights Incentive Plan is based upon the market price of the Units at the date of grant or, at the election of the grantee, based upon such market price and the unit distribution levels subsequently achieved by Petrofund. In particular, the Petrofund Unit Rights Incentive Plan provides that the rights exercise price will be equal to either (a) the market price of the Units on the date of the grant of the right or, (b) if so elected by the holder no later than the exercise of the applicable right, the market price of the Units on the date of grant of the right reduced from time to time for each calendar quarter ending after the date of grant by the positive amount, if any, equal to:

(i) the amount by which the aggregate unit distributions made to Unitholders in any calendar quarter ending after the date of the grant exceed 2.5% of Petrofund's Oil and Gas Interests (as defined below) on its balance sheet at the beginning of the applicable calendar quarter,

divided by

(ii) the number of issued and outstanding Units as at the beginning of the applicable calendar quarter.

These provisions of the Petrofund Unit Rights Incentive Plan reflects Petrofund's primary objective of maximizing distributions in order to allow it to compete in the oil and gas business for the employment of qualified professionals. The exercise price of rights will effectively allow the holders of rights granted under the Petrofund Unit Rights Incentive Plan, at their election, to indirectly participate in Unit distributions in excess of 2.5% of the net book value per unit of Petrofund's consolidated oil and gas royalty and property interests (the "Oil and Gas Interests") on a quarterly basis.

Rights granted under the Petrofund Unit Rights Incentive Plan may be exercised during a period not exceeding five years, subject to earlier termination in the event of termination, retirement, disability or death. The rights are non-transferable. PC may from time to time amend or revise the terms of the Petrofund Unit Rights Incentive Plan or may terminate the Petrofund Unit Rights Incentive Plan at any time; provided, however, that the Petrofund Unit Rights Incentive Plan will be terminated should the Restricted Unit Plan receive all necessary approvals. Rights that have been previously issued under the Petrofund Unit Rights Incentive Plan which remain outstanding will not be affected by the termination of the plan.

Restricted Unit Plan

On February 17, 2004, the Board of Directors approved the adoption of the Restricted Unit Plan which authorizes the Trust to grant Restricted Units to directors, officers, employees or consultants of the Trust or any of its subsidiaries which will vest over time and which, upon vesting, may be redeemed by the holder for cash or Units.

At the Meeting, Unitholders approved a resolution authorizing the issuance of up to 1,200,000 Units from Treasury pursuant to the terms of the Restricted Unit Plan. For a description of the Restricted Unit Plan, see

"Certain Matters Voted on at Meeting - Approval of Issuance of Units under Restricted Unit Plan - Description of Restricted Unit Plan".

Long Term Incentive Plan

On February 17, 2004, the Board of Directors approved the LTIP for the President and Chief Executive Officer, the Executive Vice President, the Senior Vice President, Finance and Chief Financial Officer and the Senior Vice President, Operations of PC (collectively, the "Senior Executives") and other employees of PC who may, in the future, be designated as participants under the LTIP.

At the Meeting, Unitholders approved a resolution authorizing the issuance of up to 800,000 Units from treasury, over the life of the LTIP, pursuant to the terms of the LTIP. For a description of the LTIP and the grant of Units thereunder that has been made, subject to regulatory and Unitholder approval, see "Certain Matters Voted on at Meeting -- Approval of Issuance of Units Under Long Term Incentive Plan" above.

The issuance of Units from treasury under the LTIP is subject to the approval of the TSX, which approval has been obtained.

Short Term Incentive Plan

On February 17, 2004, the Board of Directors approved a short term incentive plan (the "STIP") for the Senior Executives and other employees of PC who may, in the future, be designated as participants under the STIP.

The STIP is intended to encourage and reward outstanding performance by participants, and if certain financial, operational and individual performance measures are met, participants may receive a significant portion of their annual cash compensation through the STIP. While the STIP is intended to reward outstanding performance, it is also intended to insulate the participants from the fluctuation of commodity prices as the participants should neither be rewarded nor penalized solely due to increases or decreases in commodity prices for reasons completely beyond their control. Rather, it is the intention of PC that participants be rewarded based on their ability to manage the Trust's business better than other similar businesses which are subject to the same market and economic forces. The STIP will not be allowed to promote decision-making by the participants that is contrary to the best interests of the Trust and PC. As such, those administrating the STIP shall retain the discretion, acting reasonably, to adjust awards, performance measures, and to look at individual performance, to ensure that the decision-making of the participants continues to be in the best interests of PC, the Trust, and its Unitholders.

The STIP was approved by the Board of Directors of STIP effective January 1, 2004, and the first year for consideration of compensation under the STIP is the fiscal year 2004. Should certain measures be achieved, the first awards under the STIP for the fiscal year 2004 would be made in the first quarter of 2005.

The STIP is administered by the HR&C Committee. From time to time the HR&C Committee will review the objectives of the STIP and the STIP to ensure that the STIP continues to properly encourage outstanding participant performance, and to help achieve PC's and the Trust's strategies and value creation. After such review, reasonable adjustments and amendments may be made to the STIP in the reasonable discretion of the HR&C Committee.

Subject to the discretion of the HR&C Committee and future changes to the roles of the participants, the STIP establishes threshold, target and maximum opportunities for each of the participants. The amount of the award for any given year which is given to a participant under the STIP depends upon the degree to which performance levels as described below (and individual performance, where applicable) have been met in that year. The size of the STIP award for any given year is expressed on a percentage of the participant's base salary (not including any bonus, incentive or STIP compensation, or the value of benefit or perquisites).

The STIP presently has five financial and operational performance measures: (i) total unitholder return; (ii) production per Trust Unit; (iii) operating and general and administrative costs; (iv) established reserves per Trust Unit; and (v) acquisition and development costs.

Subject to the discretion and judgement of the HR&C Committee, the five performance measures are weighted equally. The HR&C Committee may, however, change the weighting of such measures from time to time in order to achieve the objectives of the STIP. In addition to the above five performance measures, the HR&C Committee will take into account in certain circumstances the individual performance of the STIP participants in determining the STIP award.

As at the date hereof and subject to individual performance considerations, the five performance measures at the following percentiles would result in the following awards under the STIP:

- o the 25th percentile of the peer group for absolute and relative performance, as applicable, would result in a threshold STIP payment equal to 50% of the target incentive for each component;
- o the 50th percentile (median) of the peer group for absolute and relative performance, as applicable, would result in a STIP payment equal to the target incentive for each component; and
- o at or above the 75th percentile of the peer group for absolute and relative performance, as applicable, would result in a maximum STIP payment equal to 200% of the target incentive for each component.

Subject to the discretion of the HR&C Committee and future changes to the roles of the participants, the following are the present threshold, target, and maximum opportunities for each of the Senior Executive participants in the following positions:

Level 1 - President and Chief Executive Officer
Level 2 - Executive Vice President
Level 3 - Senior Vice Presidents

	Annual Short Term Incentive (as a % of base salary)		
Participation Level	Threshold (50% of Target)	Target	Maximum (200% of Target)
1	25%	50%	100%

2	22.5%	45%	90%
3	20%	40%	80%

The awards under the STIP will be determined at the conclusion of the STIP year and will be based on performance of the participants and the Trust during the STIP year. The amount of any STIP award will be based on the participant's base salary earned during the fiscal year under which the STIP award was granted. Awards under the STIP will be in cash and subject to appropriate withholding taxes.

Subject to any employment agreement that is in place with the Senior Executives, PC, and the HR&C Committee have the right and discretion, provided they act reasonably, to amend the STIP, in whole or in part, or to terminate the STIP at any time. Upon termination of the STIP, all rights to the participants under the STIP shall cease as of the date of termination, except with respect to STIP awards that have been declared by the HR&C Committee but not yet paid to the participants.

As the STIP is intended to encourage and reward outstanding performance by certain key PC employees rights under the STIP, subject to any employment agreement that is in place with the Senior Executives, generally cease upon the cessation of such employment.

Employment Contracts

The President and Chief Executive Officer and the other Named Executive Officers of PC are each a party to an employment agreement with PC, which continues indefinitely until terminated in accordance with its terms, and provides for payment of the executive's annual base salary and participation in benefits provided by PC as provided in the agreement. Each agreement further provides

for a bonus for the year 2003 and the payment of such bonus and the participation by the executive in the LTIP commencing January 1, 2003, and participating in the STIP commencing January 1, 2004, such participation in the LTIP (subject to unitholder approval) and STIP being as provided in the agreement. The agreements may be terminated by PC without cause upon payment of the following amounts: (i) a lump sum payment equal to the annual base salary multiplied by a range of 2.5 times to 1.75 times (the "Multiplier") depending on the executive's position; (ii) 20% of the amount calculated pursuant to (i) above as compensation for loss of benefits; (iii) depending on the termination date, a distribution under the LTIP consisting of a distribution of Units equal to the executive's target LTIP bonus for the year in which the termination occurs times the Multiplier if the termination occurs before January 2004 to 0.5 for the President and Chief Executive Officer and zero for the other executives in the event the termination occurs after January 1, 2009; and (iv) a lump sum payment equal to the Multiplier times the average of the STIP bonus awarded to the executive over the preceding three years. In addition, in the event of termination, any unvested but previously awarded LTIP grants shall be distributed to the executive and, subject to regulatory approval; any unvested rights to purchase Units of the Trust pursuant to the Unit Rights Incentive Plan of the Trust that would have vested over a specified period from the termination date shall vest. Furthermore, in the event that the agreements are terminated by PC without cause, PC shall pay to the executive a payment in lieu of continued participation in the 2003 bonus plan or in the STIP equal to the proportionate share of the amount that the executive would have received pursuant to the 2003 bonus plan or STIP had the agreement not been terminated. In addition, in the event of a change of control (as defined in the agreements), the executive has the right, for a period of six months following the event causing the change of control, to terminate the agreement and be entitled to the foregoing payments.

INDEBTEDNESS OF DIRECTORS AND OFFICERS

None of the directors or senior officers of Petrofund or PC and no affiliate or associate of any of the foregoing, has been indebted to Petrofund or PC at any time since January 1, 2003.

INTERESTS OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

To the knowledge of the Board, except for the internalization of management described below, none of the directors or senior officers of PC, or any associate or affiliate of the foregoing, has had any material interest, direct or indirect, in any transaction since January 1, 2003 that has materially affected Petrofund, or in any proposed transaction that would materially affect Petrofund.

Internalization of Management

On March 10, 2003, the Trust entered into an agreement to internalize its management structure such that Previous Manager became a wholly owned subsidiary of PC. Unitholder and regulatory approval of the Internalization was received at the annual and special meeting of Unitholders held on April 16, 2003. As a result of the Internalization all management, acquisition and disposition fees payable to the Previous Manager were eliminated effective January 1, 2003. The cost of the Internalization was $30.9 million including $2.5 million of transaction costs, all of which was expensed to the income statement. The transaction was effected in the following manner:

o Prior to the closing, the Previous Manager acquired NCE Services (which employed all of the Calgary-based personnel who provided services to the Trust and PC on behalf of the Previous Manager).

o At the closing, PC purchased all of the issued shares of the Previous Manager from Petro Assets Inc. for $21.7 million. Petro Assets Inc. is owned by the Driscoll Family Trust (a

trust established for the family of John F. Driscoll). John F. Driscoll was Chairman and Chief Executive Officer of PC at closing.

o The purchase price for the shares of the Previous Manager was satisfied by the issuance of 1,939,147 PC Exchangeable Shares, plus a cash amount per PC Exchangeable Share equal to the distributions paid or payable per Unit by the Trust to Unitholders of record from and after January 1, 2003 up to and including the closing date. Initially each PC Exchangeable Share was exchangeable into one Unit. The exchange rate is adjusted from time to time to reflect distributions paid on each Unit after the closing date. Each PC Exchangeable Share was initially ascribed a value of $12.1703, representing the weighted average trading price of the Units over the 10 trading days, ending on March 4, 2003 on the TSX. For accounting purposes the PC Exchangeable Shares were deemed to be issued at a value of $11.20 per share being the average trading value of the Units for the last ten days prior to the closing date.

- At closing, PC paid $3.4 million in cash to fund the repayment of indebtedness owing by the Previous Manager. In addition, as part of the Internalization NCE Services paid certain senior executives of the Previous Manager $780,000 in cash and issued 100,244 Units plus an amount per Unit equal to the distributions per Unit paid to holders of record of Units during the period commencing on January 1, 2003 and ending on the closing date.

Subsequent to the closing of the Internalization, the Trust proceeded to consolidate all activities in PC's offices in Calgary, Alberta. To ensure an orderly transition of the services then provided by the Previous Manager through its office in Toronto, Ontario, Sentry Select Capital Corp. ("Sentry") entered into an agreement on closing, which was effective January 1, 2003, with the Trust, PC and the Previous Manager to provide certain of these services to the Trust and PC at Sentry's cost until December 31, 2003, subject to a maximum cost of $2 million. After December 31, 2003, Sentry no longer provides any services. At closing Sentry was an affiliate of the Previous Manager and is a company in which John F. Driscoll owns a controlling interest.

As part of the agreement, all management fees, acquisition and disposition fees were eliminated retroactive to January 1, 2003.

APPENDIX "C"

INFORMATION RELATING TO ULTIMA ENERGY TRUST

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[OBJECT OMITTED]

ULTIMA
ENERGY TRUST

RENEWAL ANNUAL INFORMATION FORM

April 30, 2004

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DEFINITIONS

In this Annual Information Form, the terms set forth below have the following meanings:

"1032213" means 1032213 Alberta Ltd., a corporation incorporated under the laws of the Province of Alberta;

"ABCA" means the Business Corporations Act (Alberta), as amended from time to time;

"AcquireCo" means Ultima Acquisitions Corp., a corporation incorporated under the laws of the Province of Alberta;

"AcquireCo USA" means the amended and restated unanimous shareholder agreement dated as of June 23, 1999 among AcquireCo, Maximize and the Trustee, for and on behalf of the Trust, as amended;

"Additional Properties" means the working or other interests in any petroleum and natural gas rights and miscellaneous interests that may be acquired by Ventures Trust;

"Assets" means all forms of petroleum and natural gas related assets owned directly by AcquireCo or any entity acquired by AcquireCo;

"bbls" means barrels; one barrel equals 0.15891 cubic metres; "bbls/d" means barrels per day; and "mbbls" means thousands of barrels;

"boe" means barrels of oil equivalent, determined approximately on the basis that 6 mcf of natural gas is equivalent to one bbl of oil (the factor used to convert natural gas to oil equivalent is not based upon either energy content or prices); "boe/d" means barrels of oil equivalent per day; and "mboe" means thousands of barrels of oil equivalent;

"Calcrude Acquisition" has the meaning ascribed thereto under "General Development of the Business - Development - 2003 - Calcrude Acquisition";

"COGE Handbook" means the "Canadian Oil and Gas Evaluation Handbook";

"Distributable Income" means the income of the Trust that is distributed to Unitholders pursuant to the terms of the Trust Indenture;

"Energy Royalty" means the royalty in respect of revenues attributable to properties and working interests held by Ultima Energy payable to the Trust;

"Energy Royalty Agreement" means the royalty agreement dated as of June 26, 2003 between Ultima Energy and Ventures, for and on behalf of the Trust;

"Exempt Plan" means trusts governed by registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESPs") and deferred profit sharing plans ("DPSPs");

"Ferrybank Property" means the 100% working interest in an oil producing property in the Ferrybank area of central Alberta;

"GJ" means gigajoule;

"GLJ" means Gilbert Laustsen Jung Associates Ltd., a firm of independent petroleum engineering consultants located in Calgary, Alberta;

"GLJ Report" means the report dated effective January 1, 2004 prepared by GLJ setting forth certain information relating to the oil and natural gas reserves associated with the Weyburn NRI;

"gross" means:

(a) in relation to the Trust's interest in production and reserves, "gross reserves", which are Ventures' and Ultima Energy's interest (operating and non-operating) share before deduction of royalties and without including any royalty interests of Ventures or Ultima Energy. The Weyburn NRI is treated as a working interest as the Trust is responsible for its share of capital costs, operating costs, royalties and abandonment costs;

(b) in relation to wells, the total number of wells in which Ventures and Ultima Energy have an interest; and

(c) in relation to properties, the total area of properties in which Ventures and Ultima Energy have an interest;

"Initial Properties" means the petroleum and natural gas working interests and related assets in the Dodsland, Kerrobert, North Eureka, Gleneath, Plato, Smiley and Totnes areas located near Kindersley, Saskatchewan, acquired by Ventures Trust (through its predecessor in interest) as of July 29, 1996;

"M" means thousands; and "MM" means millions;

"Management Agreement" means the amended and restated management agreement dated as of August 31, 1997 among Maximize, Ventures, on its own behalf and on behalf of Ventures Trust, AcquireCo, the Trustee, for and on behalf of the Trust, and Maximum Energy Corp. (as it existed at the time), as amended;

"Management Internalization Transaction" has the meaning ascribed thereto under the heading "General Development of the Business - 2003 - Management Internalization";

"Manager" means Ultima Management Inc., a corporation incorporated under the laws of the Province of Alberta, which is the manager of the Trust, Ventures, Ventures Trust, AcquireCo and Ultima Energy;

"Maximize" means Maximize Management Corp., a corporation incorporated under the laws of the Province of Alberta, and the former manager of the Trust, Ventures, Ventures Trust and AcquireCo;

"McDaniel" means McDaniel & Associates Consultants Ltd., a firm of independent petroleum engineering consultants located in Calgary, Alberta;

"McDaniel Report" means the report prepared by McDaniel dated January 1, 2004, setting forth certain information relating to the oil and natural gas reserves of the Properties;

"mcf" means thousands of cubic feet; "mcf/d" means thousands of cubic feet per day; and "mmcf" means millions of cubic feet;

"net" means:

(a) in relation to the Trust's interest in production and reserves, "net reserves", which are Ventures' and Ultima Energy's interest (operating and non-operating) share after deduction of royalties obligations, plus Ventures' and Ultima Energy's royalty interests in production or reserves;

(b) in relation to wells, the number of wells obtained by aggregating Ventures' and Ultima Energy's working interest in each of its gross wells; and

(c) in relation to properties, the total area in which Ventures or Ultima Energy has an interest multiplied by the working interest owned by Ventures or Ultima Energy.

"NGLs" means natural gas liquids;

"NI 51-101" means National Instrument 51-101 - Standards of Disclosure for Oil and Gas Activities;

"Partnership" means the Weyburn Limited Partnership, a limited partnership formed under the laws of the Province of British Columbia;

"Partnership Redemption" has the meaning ascribed thereto under "General Development of the Business - Development - 2002 - Weyburn Limited Partnership Capital Contribution and Redemption";

"Permitted Investments" includes (i) obligations issued or guaranteed by the government of Canada or any province of Canada or any agency or instrumentality thereof, (ii) term deposits, guaranteed investment certificates, certificates of deposit or bankers' acceptances of or guaranteed by any Canadian chartered bank or other financial institution (including the Trustee and any affiliate of the Trustee) the short-term debt or deposits of which have been rated at least A1 or the equivalent by Standard & Poors Ratings Group or at least P1 or the equivalent thereof by Moody's Investors Service, Inc. or which have been rated at least A1 by Canadian Bond Rating Service Inc. or at least R1 by Dominion Bond Rating Service Limited, (iii) commercial paper rated at least A1 or the equivalent by Canadian Bond Rating Service Inc. and R1 (high) by Dominion Bond Rating Service Limited, in each case maturing within 180 days after the date of acquisition, and (iv) loan advances to Ventures to finance the acquisition of tangible equipment associated with Additional Properties provided that such advances, in the aggregate, do not exceed 8% of the total fair market value of the assets of the Trust Fund;

"Plato Property" means the 93% working interest in an oil producing property in the Plato area of west central Saskatchewan;

"Probable Reserves" are those additional reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable Reserves. At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves is the targeted level of certainty;

"Properties" means the petroleum and natural gas working interests and related assets, excluding the Weyburn NRI, which Ventures, on behalf of Ventures Trust, and Ultima Energy may hold from time to time;

"Proved Reserves" are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty;

"reserves" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates;

"Rights" means rights to purchase Trust Units granted pursuant to the TURIP;

"Royalty" means the royalty in respect of revenues attributable to the Properties held by Ventures, on behalf of Ventures Trust, payable to the Trust pursuant to the Royalty Agreement;

"Royalty Agreement" means the amended and restated royalty agreement dated as of as of June 23, 1999 between the Trustee, in its capacity as trustee of the Trust, and Ventures, in its capacity as trustee of Ventures Trust;

"Subsequent Investment" means an investment made to acquire a royalty in respect of Properties other than the Royalty or an investment made to acquire an interest or an additional interest in all forms of petroleum and natural gas related assets, including any Assets;

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

"Trioco Properties" has the meaning ascribed thereto under "General Development of the Business - Development - 2003 - Trioco Acquisition";

"Trust" means Ultima Energy Trust, an open-end investment trust formed under the laws of the Province of Alberta;

"Trust Fund" means, at any time, all monies, properties and other assets as are at such time held by the Trust, or by the Trustee on behalf of the Trust, including, without limitation:

(a) the Royalty;

(b) the trust units of Ventures Trust;

(c) the issued and outstanding shares of Ventures and AcquireCo held by the Trustee;

(d) any royalty payable by AcquireCo;

(e) the issued and outstanding shares of the Manager and Ultima Energy;

(f) any instrument pursuant to which any fees, costs or expenses associated with, and all interest, principal and other amounts payable in relation to, funds borrowed by AcquireCo from the Trust;

(g) all Permitted Investments in which funds of the Trust may from time to time be invested;

(h) all Subsequent Investments;

(i) all unapplied or undistributed funds which the Trust may have on hand from time to time including the unapplied or undistributed portion of:

(i) funds realized from the sale of Trust Units;

(ii) proceeds of disposition of any asset forming part of the Trust Fund; and

(iii) income, interest, profit and gains accruing to any asset forming part of the Trust Fund assets; and

(j) all accretions and additional assets, rights and benefits of any kind or nature whatsoever arising directly or indirectly from or in connection with or accruing to any asset forming part of the Trust Fund;

"Trustee" means Computershare Trust Company of Canada, in its capacity as trustee of the Trust and any predecessor trustee of the Trust;

"Trust Indenture" means the amended and restated trust indenture governing the Trust dated as of August 31, 1997 among the Trustee, Ventures, in its own capacity and for and on behalf of Ventures Trust, AcquireCo, Maximum Energy Corp. and Glenn C. Proudfoot, as amended;

"Trust Units" means units of the Trust, each representing an equal fractional undivided beneficial interest therein;

"TSX" means the Toronto Stock Exchange;

"TURIP" means the amended and restated trust unit rights incentive plan of the Trust dated May 23, 2003;

"Ultima Energy" means Ultima Energy Inc., a corporation incorporated under the laws of the Province of Alberta;

"Unitholders" means holders of Trust Units;

"Ventures" means Ultima Ventures Corp., a corporation incorporated under the laws of the Province of Alberta;

"Ventures Trust" means Ultima Ventures Trust, a trust formed under the laws of the Province of Alberta;

"Ventures Trust Indenture" means the trust indenture governing Ventures Trust dated as of August 31, 1997 between Ventures in its capacity as trustee of Ventures Trust and the Trustee in its capacity as trustee of the Trust, as amended;

"Ventures USA" means the unanimous shareholder agreement dated as of August 31, 1997 among Ventures, on its own behalf and for and on behalf of Ventures Trust, Maximize, and the Trustee, for and on behalf of the Trust, as amended;

"Weyburn Unit" means the Weyburn Unit located in southeastern Saskatchewan; and

"Weyburn NRI" means the 11.7136% net royalty interest held by Ventures Trust in the Weyburn Unit.

CONVERSION

In this Annual Information Form, certain measurements may be given in Standard Imperial or metric units only. The following table sets forth certain standard conversions.

TO CONVERT FROM	TO	MULTIPLY BY
mcf	cubic metres	28.174
cubic metres	cubic feet	35.494
barrels	cubic metres	0.159
cubic metres	barrels	6.293
feet	metres	0.305
metres	feet	3.281
miles	kilometres	1.609
kilometers	miles	0.621
acres	hectares	0.405
hectares	acres	2.471

A boe conversion may be misleading, particularly if used in isolation. A boe conversion ratio of 6 mcf: 1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

ORGANIZATION AND STRUCTURE OF ULTIMA ENERGY TRUST

Ultima Energy Trust

Formation and Structure

Ultima Energy Trust is an open-end investment trust formed under the laws of the Province of Alberta pursuant to the Trust Indenture for the purpose of acquiring and holding royalties on petroleum and natural gas properties and related assets. The trustee of the Trust is Computershare Trust Company of Canada. The sole beneficiaries of the Trust are the Unitholders. The head and principal office of the Trust is located at 1000, 350 - 7th S.W., Calgary, Alberta, T2P 3N9. The principal place of business of the Trustee is located at 600, 530 - 8th Avenue S.W., Calgary, Alberta, T2P 3S8.

The Trust holds: (i) all the issued and outstanding trust units of Ventures Trust and, accordingly, is the sole beneficiary of Ventures Trust; (ii) the Royalty equal to 99% of the net income derived from certain petroleum and natural gas properties, the working interests in which are held by Ventures Trust; (iii) all of the issued and outstanding shares of Ventures, the trustee of Ventures Trust; (iv) all of the issued and outstanding shares of AcquireCo, through which future petroleum and natural gas related corporate and facilities acquisitions may be made; (v) all of the issued and outstanding shares of Ultima Energy; (vi) the Energy Royalty equal to 99% of the net income derived from certain petroleum and natural gas properties, the working interests in which are held by Ultima Energy; (vii) all of the issued and outstanding shares of the Manager; and (viii) promissory notes granted by Ventures Trust and the Manager to the Trust (the "Notes").

Pursuant to the terms of Royalty Agreement and the Energy Royalty

Agreement, the Trust receives royalty payments from Ventures Trust and Ultima Energy in respect of the cash flow generated from the Properties. As the sole beneficiary of Ventures Trust, the Trust also receives distributions from Ventures Trust in respect of cash flow attributable to the Weyburn NRI.

Pursuant to the terms of the Trust Indenture, the boards of directors of Ventures and AcquireCo, have the authority and responsibility to make or approve most significant decisions affecting the Trust and its subsidiaries. At the Annual and Special Meeting of the Trust held on May 23, 2003, Unitholders resolved to amend the Ventures USA and the AcquireCo USA to provide that all of the directors of Ventures and AcquireCo be elected by the Unitholders. Each of the Ventures USA and the AcquireCo USA also provides that the boards of directors of Ventures and AcquireCo, respectively, may give special, but not exclusive, consideration to the interests of the Unitholders in determining whether a matter under its consideration is in the best interests of Ventures and AcquireCo, respectively.

The Manager has been engaged to provide services in connection with the management and administration of the Trust, Ventures Trust, Ventures and AcquireCo, and in connection with the operation of the assets and petroleum and natural gas properties owned or that may be acquired by Ventures Trust and/or AcquireCo. The Manager also provides services to Ultima Energy.

On March 26, 2003, the Trust, through 1032213, completed the acquisition of all of the issued and outstanding common shares of the Manager (the "Common Shares") in connection with the internalization of the management structure of the Trust. See "General Development of the Business - Development - 2003 - Management Internalization".

The Manager employs the employees and consultants that manage and administer the Trust's assets and undertakings. The Trust has no employees.

The Trust's current organizational structure is as follows:

[OBJECT OMITTED]

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                                                                UNITHOLDERS
                                                                      |
                                                                      |
                                    Ultima Ventures                 Ultima
                                         Corp.      ------ 100% ----- Energy
                                                                     Trust
                                          |                           |
                                          |                           |
                                Trustee of Ventures Trust             |
                                          |                           |
        ------------------------------------------------------------------------------------------
        |                                 |                           |
       100%                              100%                        100%
        |                                 |                           |
        |                                 |                           |
      Ultima                       Ultima Ventures                  Ultima
    Energy Inc.                          Trust                   Acquisitions
                                                                     Corp.
```

Holds petroleum and natural gas properties	Holds petroleum and natural gas properties and the Weyburn NRI	Holds future acquired corporations and facilities

As an open-end trust, the Trust is not as restricted in the type of assets it holds or the type of acquisitions it undertakes in order to maintain its status under the Tax Act as a "unit trust" and as a "mutual fund trust" so long as a retraction right is attached to the Trust Units. As an open-end trust, the activities of the Trust can be expanded from the acquisition and holding of royalties on petroleum and natural gas properties and related assets to include the direct or indirect acquisition and holding of all forms of petroleum and natural gas related assets (such as the shares of an oil and gas company or facilities without associated properties) that can be reasonably expected to provide long-term returns and Unitholder distributions.

Distributions to Unitholders

The Trust receives cash royalty payments from Ventures Trust under the Royalty Agreement, distributions from Ventures Trust in respect of cash flow attributable to the Weyburn NRI, cash royalty payments from Ultima Energy under the Energy Royalty Agreement and cash interest payments in respect of the Notes. Pursuant to the terms of the Trust Indenture, the Trust distributes substantially all such amounts to the Unitholders, subject only to certain adjustments that include fees and expenses paid to the Trustee and the Manager. See "Distribution Policy and Record".

Ultima Ventures Trust

Formation

Ventures Trust was formed under the laws of the Province of Alberta pursuant to the Ventures Trust Indenture. The sole beneficiary of Ventures Trust is the Trust, being the sole holder of the trust units of Ventures Trust. The head and principal office of Ventures Trust and the principal place of business of Ventures, the trustee of the Trust, is located at 1000, 350 - 7th Avenue S.W., Calgary, Alberta T2P 3N9.

Ventures Trust was established for the purpose of, and its business is restricted to, purchasing, holding, operating and divesting petroleum, natural gas and related hydrocarbons and related facility interests including the development of petroleum and natural gas, the transportation, processing, marketing and sale thereof and all business operations incidental or in any way related to the foregoing.

Since Ventures holds, as trustee for Ventures Trust, all the assets and property of Ventures Trust and conducts all business on behalf of Ventures Trust, Ventures Trust is bound by the same restrictions affecting Ventures in the Royalty Agreement, including a prohibition on spending funds on exploratory operations and the nature of acquisitions and dispositions that it may effect.

Distributions and Royalty Payments

Ventures, in its capacity as trustee of Ventures Trust, receives cash flow from the sale of petroleum and natural gas produced from the Properties held by it (and other properties that it may in the future acquire) and, to an immaterial extent, from the provision of processing services to third parties who use the gathering facilities located near the Properties. Pursuant to the terms of the Royalty Agreement, 99% of such cash flow, less the aggregate of all operating costs, capital expenditures not funded by debt, net contributions to Ventures' (and, therefore, Ventures Trust's) reclamation fund, debt service costs and debt repayments, fees paid or payable to the Manager and other general and administrative expenses, taxes, and certain other adjustments, is paid to the Trust as the Royalty. Ventures Trust also receives revenues attributable to the Weyburn NRI. Such amounts are distributed to the Trust as sole beneficiary of Ventures Trust.

Cash flow from the Royalty and the Weyburn NRI is, subject to certain deductions, distributed to Unitholders by the Trust. Such cash distributions may be taxable in whole or in part. In approving any future acquisition by Ventures, in its capacity as trustee of Ventures Trust, the board of directors of Ventures is required to consider and determine, among other things, that such acquisition is in the best interests of Ventures and the Trust.

Ultima Ventures Corp.

Incorporation and Organization

Ventures was incorporated under the ABCA on August 21, 1997. The registered office of Ventures is 4500, 855 - 2nd Street S.W. Calgary, Alberta T2P 4K7. The head and principal office of Ventures is located at 1000, 350 - 7th Avenue S.W., Calgary, Alberta T2P 3N9. The Trust is the sole shareholder of Ventures.

Ventures, in its capacity as trustee of Ventures Trust, has retained the Manager, pursuant to the Management Agreement, for the purposes of identifying, evaluating and assisting in the acquisition, disposition and ongoing management of its assets, including overseeing the operation and administration of the business of Ventures and Ventures Trust, all subject to the direction of the board of directors of Ventures. The Manager is required to exercise the degree of care, diligence and skill that a reasonably prudent oil and natural gas industry advisor and manager would exercise in comparable circumstances.

Ultima Energy Inc.

Incorporation and Organization

Ultima Energy was incorporated under the ABCA on June 23, 2003, and subsequently amalgamated with Trioco Resources Inc. ("Trioco") on June 26, 2003. The registered office of Ultima Energy is 4500, 855 - 2nd Street S.W. Calgary, Alberta T2P 4K7. Ultima Energy does not maintain its own premises. The Trust is the sole shareholder of Ultima Energy.

Ultima Energy was formed for the purpose of effecting the acquisition of all of the issued and outstanding shares of Trioco. See "General Development of the Business - Development - 2003 - Trioco Acquisition". Following the Trioco Acquisition (as defined below), Ultima Energy granted the Energy Royalty to the Trust effective June 26, 2003. Pursuant to the Energy Royalty Agreement, the Trust receives a royalty from Ultima Energy equal to 99% of the net cashflow, after costs, derived from petroleum and natural gas properties owned by Ultima Energy.

Ultima Acquisitions Corp.

Incorporation and Organization

AcquireCo was incorporated under the ABCA on August 21, 1997. The registered office of AcquireCo is 4500, 855 - 2nd Street S.W. Calgary, Alberta T2P 4K7. AcquireCo does not maintain its own premises. The Trust is the sole shareholder of AcquireCo.

AcquireCo has retained the Manager, pursuant to the Management Agreement, for the purposes of identifying, evaluating and assisting in the acquisition, disposition and ongoing management of its assets, including overseeing the operations and administration of the business of AcquireCo, all subject to the direction of the board of directors of AcquireCo. The Manager is required to exercise the degree of care, diligence and skill that a reasonably prudent oil and natural gas industry advisor and manager would exercise in comparable circumstances.

Restrictions on the Business of AcquireCo

AcquireCo was incorporated and organized for the sole purpose of, and its business is restricted in the AcquireCo USA to, acquiring, developing, exploiting and disposing of all forms of petroleum and natural gas related assets, including, without limitation, facilities of any kind (whether acquired with associated properties or not) and whether effected through an acquisition of assets or an acquisition of shares or other form of ownership interest in an entity the substantial majority of the assets of which are comprised of like assets and activities ancillary thereto. AcquireCo is prohibited from spending funds on exploratory operations, except as deemed necessary or advisable to wind-down existing exploration operations in progress in respect of assets at the time of their acquisition by AcquireCo, including funds necessary to fulfill any pre-existing contractual or other commitments or to enhance the value of any property, and except as approved by the board of directors of AcquireCo.

As at the date hereof, AcquireCo does not own any assets.

Dividends

As at the date hereof, AcquireCo does not own any assets and therefore has received no cash flow and made no dividend, interest or other payments to the Trust.

Pursuant to the terms of the AcquireCo USA, with the approval of its board of directors, AcquireCo will distribute to the Trust all of its available cash, subject to applicable law and certain deductions, including, without limitation, expenses, ongoing capital expenditures to the extent not funded by debt and subject to AcquireCo retaining such reasonable reserves or funds for the acquisition of replacement assets as may be considered appropriate by the board of directors of AcquireCo.

Ultima Management Inc.

Incorporation and Organization

The Manager was incorporated under the ABCA on October 25, 2000 and subsequently amalgamated with 1032213, a wholly-owned subsidiary of the Trust, on August 1, 2003 and continued under the name Ultima Management Inc. The registered office of the Manager is 4500, 855 - 2nd Street S.W., Calgary, Alberta T2P 4K7. The head and principal office of the Manager is located at 1000, 350 - 7th Avenue S.W., Calgary, Alberta T2P 3N9.

On March 26, 2003, the Trust, through 1032213, completed the acquisition of all of the issued and outstanding Common Shares for a total cost of $5,300,000. A total of $3,800,000, consisting of $3,000,000 in cash and 143,365 Trust Units (with a value of $800,000), was paid to purchase all of the Common Shares. The remaining $1,500,000 has been and will be used to fund retention obligations to the three senior officers and other management employees of the Manager. See "General Development of the Business - Development - 2003 - Management Internalization".

Business of the Manager

Pursuant to the terms of the Management Agreement, the Manager provides services in connection with the management and administration of the Trust, Ventures Trust, Ventures and AcquireCo, and in connection with the operation of the properties and assets owned, or which may be acquired, by Ventures Trust and/or AcquireCo. The delegation of authority to the Manager is subject to the supervision of, and restrictions imposed from time to time by, the boards of directors of Ventures and AcquireCo, and the provisions of the Management Agreement. In particular, the boards of directors of Ventures and AcquireCo have exclusive authority over matters such as the annual operating budget, acquisitions and dispositions of properties, capital expenditures and acquisitions in excess of $2,000,000, borrowing limits and policies, equity financing approval and the Trust's cash distribution policy. The Manager also provides services to Ultima Energy.

Compensation of the Manager

Pursuant to the Management Agreement, Ventures, for and on behalf of Ventures Trust, AcquireCo and the Trustee, for and on behalf of the Trust, paid the Manager a management fee (the "Management Fee") equal to the aggregate of (i) 3% of the net production revenue attributable to the Properties; and (ii) 1/99 of the royalty payable by Ventures Trust to the Trust. The Management Agreement also provided that the Manager be paid an acquisition fee equal to 1.5% of the purchase price of any assets acquired by Ventures Trust or AcquireCo (the "Acquisition Fee"), and an administration fee for management, administration and advisory services provided to Ventures, AcquireCo, Ventures Trust and the Trust (the "Administration Fee"). A Management Fee of $487,000 was paid to the Manager for the period commencing January 1, 2003 and ending on March 26, 2003. No Administration Fee or Acquisition Fee was earned for that period.

The Management Agreement also provides that Ventures, AcquireCo and the Trustee, for and on behalf of the Trust, reimburse the Manager for the time the Manager's personnel spend on the management and administration of the Trust, Ventures Trust, Ventures and AcquireCo. The boards of directors of Ventures and AcquireCo, having regard to industry salaries, approve the amounts paid in respect of salaries and benefits as part of their approval of the general and administrative budget of the Manager. A total of $554,000 was paid to the Manager by Ventures, AcquireCo and the Trustee, for and on behalf of the Trust, in respect of salaries, benefits and bonus for the period commencing January 1, 2003 and ending on March 26, 2003, the date on which the Management Internalization Transaction was completed.

As a result of the Management Internalization Transaction and subsequent amalgamation of the Manager with 1032213, the Manager is now a wholly-owned subsidiary of the Trust. Consequently, any fees paid or reimbursement of costs to the Manager are now effectively for the account of the

Trust as they remain within the Trust's structure.

GENERAL DEVELOPMENT OF THE BUSINESS

Formation

Maximum Energy Corp. ("Maximum") and the Trust were created in 1996 for the purpose of acquiring, developing and operating petroleum and natural gas properties and related assets. Maximum acquired the Initial Properties in July 1996 and granted a royalty on the properties to the Trust. During 1997, Maximum acquired a gas gathering system in the Kindersley area of west central Saskatchewan and petroleum and natural gas properties located in the Provost area of east central Alberta.

At a special meeting of Unitholders held in August 1997, the Unitholders approved the conversion of the Trust from a close-end unincorporated investment trust to an open-end unincorporated investment trust. At the same meeting, the Unitholders approved the sale, transfer and conveyance of all of the assets and liabilities of Maximum to the newly created Ventures Trust, which transaction was completed as of August 31, 1997. As part of the transaction, the credit facility maintained by Maximum, and the royalty obligation under the Royalty Agreement were assumed by Ventures Trust.

Pursuant to the Royalty Agreement, the Trust receives a royalty from Ventures Trust and the Trust distributes such royalty payments to the Unitholders, subject only to certain adjustments that include fees and expenses paid to the Trustee and the Manager. Since 1997, additional oil and gas properties have been acquired by Ventures Trust and the Trust has received royalties from those properties. As sole beneficiary of Ventures Trust, the Trust also receives distributions from Ventures Trust in respect of cash flow attributable to the Weyburn NRI. Pursuant to the Energy Royalty Agreement, the Trust receives a royalty from Ultima Energy in respect of certain petroleum and natural gas properties, the working interests of which are held by Ultima Energy.

Development

2001

Appointment of New Trustee

In April 2001, The Trust Company of Bank of Montreal resigned as trustee of the Trust. Pursuant to an assignment and novation agreement dated September 10, 2001, Computershare Trust Company of Canada accepted its appointment as, and assumed all the obligations of, trustee of the Trust.

Change of Name

As part of the restructuring of the Trust that began in December 2000, the Manager determined that the Trust should be renamed to better reflect the changes which had been implemented to the business and affairs of the Trust. Accordingly, a process was commenced in the Spring of 2001 to search for a new name for the Trust. "Ultima Energy Trust" was chosen to replace "Maximum Energy Trust" as the name of the Trust and "UET.UN" was chosen as the new trading symbol for the Trust Units on the TSX. The boards of directors of Ventures and AcquireCo approved the change of name of the Trust by resolution dated September 10, 2001 as permitted by the terms of the Trust Indenture.

The names of Ventures and AcquireCo were also changed as part of the restructuring process. Pursuant to the Ventures USA and the AcquireCo USA, changes in the names of Ventures and AcquireCo required the approval of the Trustee acting on the direction of a special resolution of Unitholders. At a Special Meeting of Unitholders held on October 15, 2001, the Unitholders approved the change of name of Ventures from "Maximum Holdings Corp." to "Ultima Ventures Corp." and the change of name of AcquireCo from "Maximum Acquisitions Corp." to "Ultima Acquisitions Corp." By Certificates of Amendment dated October 16, 2001, the names of Ventures and AcquireCo were changed to Ultima Ventures Corp. and Ultima Acquisitions Corp., respectively.

Change of Auditors

In the Spring of 2001, the Trust began realigning its relationships with its advisors and professional services firms. In furtherance of that objective, the boards of directors of each of Ventures and AcquireCo resolved to search for a replacement for Deloitte & Touche LLP as auditors of the Trust, Ventures Trust, Ventures and AcquireCo. At the Special Meeting of Unitholders held on October 15, 2001, the Unitholders accepted and approved the resignation of Deloitte & Touche LLP and approved, by ordinary resolution, the appointment of Arthur Andersen LLP as auditors of the Trust, Ventures Trust, Ventures and AcquireCo.

Trust Unit Rights Incentive Plan

At the Special Meeting of Unitholders held on October 15, 2001, the Unitholders adopted, by ordinary resolution, a Trust Unit rights incentive plan. The purpose of the TURIP is:

1. to develop the interest of directors, officers, employees and key consultants of the Trust, its affiliates and the Manager, in the growth and development of the Trust by providing such persons with the opportunity to acquire a proprietary interest in the Trust;

2. to provide a compensation mechanism for persons who provide a service to the Trust on an ongoing basis, or who have provided, or are expected to provide, a service of value to the Trust; and

3. to align the interests of directors, officers, employees and key consultants with those of Unitholders by devising a compensation mechanism which encourages the prudent maximization of distributions to Unitholders and long-term value growth of the Trust Units.

The TURIP permits the directors of Ventures and AcquireCo to grant Rights to those persons eligible to participate in the TURIP. Rights may only be granted with the approval of the directors of Ventures and AcquireCo. As at December 31, 2003, Rights to acquire 2,007,669 Trust Units were outstanding.

Asset Acquisition

On December 17, 2001, Ventures Trust acquired from Baytex Energy Ltd. two oil producing properties and associated facilities located at Westerose and Glenevis in central Alberta (the "Central Alberta Properties") with an average combined working interest of 93% for a purchase price of $35,000,000 in cash, before closing adjustments and costs of the acquisition. Production from the Central Alberta Properties at the time of purchase was approximately 1,375 bbls/d of light and medium quality oil (33 API average) and 150 mcf/d of natural gas.

Private Placements

On December 17, 2001, the Trust closed a private placement of 3,400,000 Trust Units at a price of $3.50 per Trust Unit for gross proceeds of $11,900,000. The proceeds of the private placement were used to partially fund the acquisition of the Central Alberta Properties. The Trust closed a subsequent private placement of 350,000 Trust Units on January 17, 2002 at a price of $4.30 per Trust Unit for gross proceeds of $1,505,000. The proceeds of the private placement were used to reduce bank debt incurred in connection with the purchase of the Central Alberta Properties.

2002

Cherhill Acquisition

On October 16, 2002, the Trust, through Ventures Trust, purchased an approximately 50% working interest in a light oil producing property and associated facilities in the Cherhill area of central Alberta (the "Cherhill Property") from Southward Energy Ltd. (the "Cherhill Acquisition"). The total purchase price of the Cherhill Acquisition, net to the Trust, was $10,260,000 in cash, before closing adjustments and expenses related to the Cherhill Acquisition. The Cherhill Acquisition was financed using Ventures Trust's credit facility.

McDaniel evaluated the Cherhill Property for the Trust and assigned 1.1 million boe of total proved reserves (suggesting a purchase price of $9.30 per proved boe) and 1.25 million boe of established reserves (suggesting a purchase price of $8.20 per established boe and an established reserve life index of approximately eight years) to the Cherhill Property.

Cyn-Pem Acquisition

On December 3, 2002, the Trust, through Ventures Trust, entered into an agreement with a number of Conoco Phillips entities to purchase working interests ranging from 25% to 65% in liquids-rich natural gas and light oil producing properties in the Cyn-Pem area of central Alberta (the "Cyn-Pem Properties") for a total purchase price of $16,750,000 in cash, before closing adjustments and expenses related to the acquisition (the "Cyn-Pem Acquisition"). The transaction was closed on December 17, 2002, with an effective date of October 1, 2002. The Cyn-Pem Acquisition was financed using Ventures Trust's credit facility.

The transaction was consistent with the Trust's strategy of asset diversification and growth of its central Alberta core area through acquisition of predictable, high quality, low operating cost reserves. The Cyn-Pem Properties are characterized by operating costs of less than $4.00 per boe and are located near the Central Alberta Properties.

McDaniel evaluated the Cyn-Pem Properties for the Trust and assigned 1.3 million boe of total proved reserves and 1.4 million boe of established reserves (suggesting a purchase price of $11.65 per established boe) to the properties.

Weyburn Limited Partnership Capital Contribution and Redemption

On December 31, 2002, with an effective date of November 1, 2002, the Trust sold its entire interest in the Partnership to Ventures Trust. Ventures

Trust subsequently advanced approximately $67,000,000 to the Partnership in the form of a capital contribution (the "Contribution"), which payment increased Ventures Trust's percentage partnership interest in the Partnership from 92% to approximately 99%. The Partnership then used the Contribution to repay, in full, a loan in the amount of approximately $67,000,000 (the "Loan") owing to EnCana Resources, the managing partner of the Partnership. Upon repayment of the Loan, Ventures Trust redeemed its entire limited partnership interest in the Partnership (the "Partnership Redemption"). As a result of the Partnership Redemption, the Trust, through Ventures Trust, acquired an interest in approximately 99% of the assets of the Partnership, primarily consisting of the Weyburn NRI, the Ferrybank Property and the Plato Property (collectively, the "Partnership Assets"). Ventures Trust designated the Weyburn NRI and the Plato Property, as well as the Partnership's working capital, as the Partnership Assets it would obtain in exchange for its interest in the Partnership pursuant to the Partnership Redemption. The Ferrybank Property, which accounted for less than 3% of the total value of the Partnership's reserves, was retained by the Partnership.

EnCana Resources granted the Weyburn NRI to the Partnership pursuant to a Net Royalty Agreement dated October 31, 2000 (the "NRI Agreement"). Under the terms of the NRI Agreement, the

Weyburn NRI entitles Ventures Trust, as a result of the Partnership Redemption, to receive a monthly royalty payment calculated by reference to the revenue from oil and natural gas production attributable to an 11.7136% participating interest in the Weyburn Unit (the "Revenue") less all costs and expenses, including capital expenditures and future reclamation costs, associated with such production. The Weyburn NRI is intended to be an interest in land and is to continue in full force and effect so long as there are petroleum and natural gas rights associated with the Weyburn Unit to which the Weyburn NRI applies. Prior to the Partnership Redemption, the NRI Agreement provided for the payment of capital costs incurred in connection with the Weyburn Unit's operations prior to January 1, 2003 to be deferred and accrue interest. Deferred capital expenditures and accrued interest were to be deducted from Revenue only on a monthly basis commencing January 2003 and ending December 2019 (the "Amortization Period"). Interest was accrued on the amount of the deferred capital expenditures at a base interest rate of 8.5% per annum, and was to be adjusted over the Amortization Period to provide for an effective interest rate of approximately 13% per annum throughout the Amortization Period, with the higher levels of interest accruing during the last five years of the Amortization Period. The maximum amount of the capital expenditures which was to be deferred in this manner was $18,778,000, plus accrued interest (the "Initial Deferred Capital Obligation").

In connection with the Partnership Redemption, the NRI Agreement was amended (the "NRI Amendment") to provide that:

(a) the base interest rate accrued on the Initial Deferred Capital Obligation will be reduced to 7.0% from 8.5% effective January 1, 2003;

(b) as at January 1, 2004, up to an additional $9,200,000 of capital expenditures applicable to the Weyburn NRI can be deferred for the years 2004 and 2005 (the "Other Deferred Capital Obligation"). The Trust shall have the right to select the amount of capital expenditures to be deferred each year, to a maximum of $8,000,000 of deferred capital expenditures in any given year. Interest will accrue on the Other Deferred Capital Obligation at the base interest rate of 7.0% per annum;

(c) the Initial Deferred Capital Obligation and the Other Deferred Capital Obligation (collectively, the "New Deferred Capital Obligation") will be consolidated and deducted from Revenue on a monthly basis pursuant to the deferred capital charge calculation, over a 15 year period commencing the month immediately following the month the Other Deferred Capital Obligation, excluding interest charges, reaches $15,000,000, or January 1, 2006, whichever occurs first (the "New Amortization Period"). Interest will continue to accrue on the amount of the outstanding New Deferred Capital Obligation at a base interest rate of 7.0% per annum and be adjusted over the New Amortization Period to provide for an effective interest rate of approximately 10% per annum throughout the New Amortization Period, with the higher levels of interest accruing during the last five years of the New Amortization period;

(d) the New Deferred Capital Obligation will be recovered by EnCana Resources as a deductible cost from Revenue in the calculation of the monthly Weyburn NRI payment only (Ventures Trust's assets do not secure the Weyburn NRI); and

(e) the Trust will have the right to prepay all or any part of the New Deferred Capital Obligation, plus accrued but unpaid interest along with an additional 7% of the amount of New Deferred Capital Obligation being prepaid, for cash at anytime which the Trust presently intends to do prior to the expiry of the New Amortization Period.

Prospectus Offerings

The Trust completed a public offering of 5,000,000 Trust Units at a price of $5.10 per Trust Unit in May of 2002. The net proceeds from the offering were used to reduce the outstanding bank debt primarily incurred by Ventures Trust to fund the acquisition of the Central Alberta Properties. The Trust completed another public offering of 10,000,000 Trust Units at a price of $4.90 per Trust Unit in December of 2002. The net proceeds from that offering, along with $20,350,000 drawn from the credit facility of Ventures Trust, was paid to the Partnership as a Contribution in connection with the Partnership Redemption. See "General Development of the Business - Development - 2002 - Weyburn Limited Partnership Capital Contribution and Redemption".

2003

Management Internalization

In the fall of 2002, a Special Committee comprised of independent members of the Boards was established to consider the merits of internalizing the management services provided by the Manager to the Trust, Ventures Trust, Ventures and AcquireCo pursuant to the Management Agreement in order to eliminate future management fees, improve the governance structure of the Trust and align the interests of management and the Trust (the "Management Internalization Transaction").

The Special Committee completed a comprehensive review of a wide range of issues relevant to the internalization process. In evaluating the alternatives available to the Trust, the Special Committee had several objectives, including:

1. retaining the management team of the Trust;

2. ensuring that the economic benefit to Unitholders realized by eliminating future third party management and acquisition fees would exceed the cost of the internalization and be accretive to future cash flow and net asset value; and

3. better aligning the interests of management and directors with the interests of Unitholders.

Upon completion of its review, the Special Committee unanimously recommended approval of the Management Internalization Transaction to the Boards and the Boards unanimously approved the Management Internalization Transaction. In approving the transaction, the Boards gave particular attention to the opinion of RBC Dominion Securities Inc., financial advisor to the Special Committee, that the consideration paid for the common shares of the Manager was fair, from a financial point of view, to the Trust.

On March 26, 2003, the Trust completed the Management Internalization Transaction for a total cost of $5,300,000. $3,800,000, consisting of $3,000,000 in cash and 143,369 Trust Units (valued at $800,000 based on the preceding 20-day average closing price of the Trust Units on the TSX), was paid by the Trust through 1032213 to purchase all of the issued and outstanding common shares of the Manager. The remaining $1,500,000 was used to fund retention obligations to the three senior officers and other management employees of the Manager. One-half of the retention, consisting of $500,000 in cash and 44,803 Trust Units (valued at $250,000, based on the preceding 20 day average closing price of the Trust Units on the TSX), was paid on closing of the transaction. The balance of the retention ($750,000) to be paid in Trust Units may be earned by the three senior officers of the Manager over the three-year period following the closing of the transaction, subject to certain conditions, including the officers remaining as employees of the Manager.

Calcrude Acquisition

On June 24, 2003, Ventures Trust, through Ventures, completed the purchase of an approximate 40% working interest in 29 gross (11.6 net) producing light oil and natural gas wells and associated facilities in the Cherhill Banff A pool located in central Alberta, and other minor property interests in central Alberta (collectively, the "Cherhill Properties") from Calgary Crude Oil Limited and Calcrude Oils Ltd. for a purchase price of $16,100,000, prior to any closing adjustments (the "Calcrude Acquisition"). Ventures Trust had previously purchased interests in the Cherhill Properties in 2002.

As of March 2003, production from the Cherhill Properties was approximately 600 boed, consisting of 350 bbls/d of light oil and natural gas liquids and 1.5 mmcfd of natural gas. Production is primarily from the medium depth Banff and Mannville zones. The Calcrude Acquisition increased the Trust's total working interest in the Cherhill Banff A pool to approximately 90%. Ventures assumed operatorship of the Cherhill Banff A pool following the Calcrude Acquisition.

McDaniel prepared a report for the Trust in respect of the Cherhill Properties acquired in connection with the Calcrude Acquisition representing approximately 95% of the reserves and net present value attributable to the Calcrude Acquisition and assigned 1.4 million boe of total proved reserves and

1.6 million boe of established reserves to the Cherhill Properties. The report excluded reserves attributable to the Cherhill Property acquired in 2002.

Trioco Acquisition

On June 26, 2003 the Trust, through Ultima Energy, completed the purchase of all of the issued and outstanding common shares and preferred shares in the capital of Trioco for an aggregate purchase price of $71,000,000, subject to certain adjustments (the "Trioco Acquisition"). The Trioco Acquisition closed on June 26, 2003 and was financed using the existing credit facilities of Ventures Trust and a $35,000,000 bridge facility of Ventures Trust. Upon closing of the Trioco Acquisition, Ultima Energy and Trioco amalgamated and the amalgamated company retained the name of Ultima Energy Inc. Effective June 26, 2003, Ultima Energy granted the Energy Royalty to the Trust.

Trioco was an Alberta-based oil and gas company with its primary producing properties located in the Spirit River area of the Peace River Arch and the St. Albert, Deanne and Caroline areas of central Alberta. In a report dated as of May 1, 2003 (the "Trioco Report"), McDaniel evaluated the reserves for the petroleum and natural gas interests acquired pursuant to the Trioco Acquisition for the Trust and assigned 5.1 million boe of total proved reserves and 6.1 million boe of established reserves to the properties (the "Trioco Properties"). As of June 2003, production from the Trioco Properties was approximately 2,050 boed, consisting of 660 boed of oil and natural gas liquids and 8.3 mmcfd of natural gas.

At the time of purchase, the Trioco Acquisition increased the Trust's total production to approximately 9,600 boed. The Trioco Acquisition also included 33,005 gross (15,580 net) acres of undeveloped land in the Peace River Arch area and central Alberta as well as proprietary seismic data valued at $1,400,000.

Exhibit "C" hereto sets forth certain financial information relating to Trioco and Exhibit "D" contains pro forma financial information of the Trust which gives effect to the Trioco Acquisition.

Prospectus Offerings

The Trust completed a public offering of 5,000,000 Trust Units at a price of $5.05 per Trust Unit in May of 2003. $23,987,500 of the net proceeds of the offering were used to fund the Calcrude Acquisition. "See "General Development of the Business - Development - 2003 - Cherhill Acquisition".

The balance of the net proceeds from the offering were used to repay a portion of the outstanding indebtedness of Ventures Trust and to fund future development of the Trust's properties.

The Trust completed a public offering of 12,000,000 Trust Units at a price of $5.20 per Trust Unit in July of 2003. The net proceeds of $59,280,000 from that offering were used to repay a portion of the outstanding indebtedness of Ventures Trust, which indebtedness was incurred, in part, to complete the Trioco Acquisition. See "General Development of the Business-Development - 2003 - Trioco Acquisition".

In December of 2003, the Trust completed another public offering of 6,000,000 Trust Units at a price of $5.70 per Trust Unit. The net proceeds of $32,490,000 from that offering were used to reduce outstanding bank debt of Ventures Trust, thereby freeing up capacity to fund the Trust's 2004 capital expenditures and acquisition program and for general purposes.

2004

Merger with Petrofund Energy Trust

On March 29, 2004, the Trust, Ventures, Petrofund Energy Trust ("Petrofund") and Petrofund Corp., entered into a combination agreement (the "Combination Agreement") whereby they agreed to combine the operations of the Trust and Petrofund. Pursuant to the terms of the Combination Agreement, each Trust Unit will be exchanged for 0.442 of a Petrofund unit on a tax-deferred rollover basis. Unitholders will also receive an aggregate of $10 million in the form of a one-time special distribution, estimated to be approximately $0.17 per Trust Unit and payable on or about June 15, 2004. Subject to regulatory approval and the approval of at least two-thirds of Unitholders voting at a meeting to be held on or about June 4, 2004, the transaction is expected to close on or about June 16, 2004.

DESCRIPTION OF BUSINESS

The business activities from which the Trust derives its revenues are presently conducted through or in connection with assets, properties and interests held by Ventures Trust (through Ventures) and Ultima Energy. All references herein to any business, assets, properties or interests of the Trust are made, without specifying the nature thereof, about the business, assets, properties and interests of Ventures Trust (or Ventures on behalf of Ventures Trust) and Ultima Energy.

The Trust engaged McDaniel to evaluate the oil and natural gas reserves associated with the Properties. The reserves associated with the Weyburn NRI were evaluated by another independent engineering firm, GLJ. References to reserve volumes in the following discussion are based on the McDaniel Report and the GLJ Report which have been combined by McDaniel for use by the Trust.

Properties

Ventures Trust owns oil and natural gas reserves located primarily in the Westerose, Cherhill and Cyn-Pem areas of central Alberta, the Kindersley area of west central Saskatchewan and the Provost area of east central Alberta. Ventures Trust also holds the Weyburn NRI which provides it an 11.7136% net royalty interest in the Weyburn Unit in southeastern Saskatchewan. Ultima Energy holds the Trioco Properties located in central and northwest Alberta.

The portfolio of Properties, including the Weyburn NRI, acquired and held by the Trust include primarily long life, unitized and non-unitized properties with well established production profiles. The following table sets forth a summary of the proved plus probable reserves and production attributable to the Properties and the Weyburn NRI:

Trust Reserves and Production

Property	Proved plus Probable Reserves as at January 1, 2004 (mboe)	Average Daily Production for the 12 months ended December 31, 2003 (boe/d)	Av for

Weyburn NRI	17,751	2,517
Spirit River	4,631	364
Cherhill	4,182	879
Westerose	2,262	897
Provost	2,118	387
Kerrobert	1,813	498
Glenevis	1,509	683
North Eureka	1,194	236
Cyn-Pem	987	477
Other	4,930	1,628
Total	41,377	8,566

Approximately 88% of the total proved plus probable reserves of Ventures Trust and Ultima Energy are in the nine principal areas described below.

The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties, due to the effects of aggregation.

Weyburn Unit, Saskatchewan

Effective December 31, 2002, Ventures Trust acquired from the Partnership an 11.7136% net royalty interest in the Weyburn Unit located in southeastern Saskatchewan pursuant to the Partnership Redemption. See "General Development of the Business - Development - 2002 - Weyburn Limited Partnership Capital Contribution and Redemption". The Weyburn Unit was formed in 1963 and produces medium gravity crude oil from the Midale formation. EnCana Corporation operates the Weyburn Unit and markets Ventures Trust's share of production.

The Weyburn Unit is one of Canada's largest oil pools and contained 1.4 billion barrels of oil when discovered in the 1950's. The Weyburn Unit has been under waterflood since 1964 and has been continuously developed through a horizontal infill drilling program that was initiated in 1991. A carbon dioxide miscible flood project aimed at significantly increasing the ultimate recovery of original oil reserves in place from the Weyburn Unit was implemented late in 2000. The majority of the future development costs of the Trust are attributable to the Weyburn NRI.

Spirit River, Alberta

The Spirit River property is located in the Peace River Arch area of northwest Alberta. As of December 31, 2003, production from the property, net to Ultima Energy, was approximately 930 boe/d consisting of 425 bbls/d of light oil and natural gas liquids and 3.1 mmcf/d of natural gas. Production is primarily from the medium depth Charlie Lake and Gething zones. The Trust holds interests in 32 gross (24 net) producing oil and natural gas wells for an average 75% working interest in the lands and facilities in the area, excluding penalty wells. The Trust, through Ventures, is the operator of the majority of its production in the area. Plans for 2004 include expanding the Charlie Lake E and M Unit waterflood and drilling up to 12 development wells targeting the Charlie Lake formation.

Cherhill, Alberta

As at December 31, 2003, Ventures Trust owned an average 90% working interest in 39 gross (35 net) operated light oil and natural gas wells and associated oil treating and natural gas processing facilities in the Cherhill area of central Alberta. The primary Cherhill asset consists of the Banff A Pool, which is a carbonate reef complex occurring at a depth of approximately 1,500 meters. This pool produces light oil and associated solution natural gas. Other natural gas production comes from three non-associated natural gas wells. The property was acquired in two stages. The first acquisition of an approximate 50% working interest was completed in the fall of 2002 and the second acquisition for the operatorship and the balance of the working interest was acquired as part of the Calcrude Acquisition.

The light crude oil is shipped via the Pembina pipeline system and sold under a 30-day contract. The natural gas production is sold to aggregators and into the spot market.

Plans for 2004 include installing high volume lift pumps on producing oil wells and drilling up to four development oil wells.

Westerose, Alberta

As at December 31, 2003, Ventures Trust owned an average 85% working interest in 39 gross (33 net) operated producing light oil and natural gas wells in the Westerose area of central Alberta. The property was acquired from Baytex Energy Ltd. in December 2001. Ventures Trust's production comes from the Belly River and Banff formations at depths of between 950 and 1,500 meters. The Westerose Belly River field was initially developed with vertical wells and subsequently developed with horizontal production and water injection wells commencing in 1997. The field has been under waterflood since 1997 and has shown significant positive response to the pressure maintenance scheme.

The field is equipped with a pipeline gathering system that delivers the produced hydrocarbons to a Ventures Trust-owned central battery facility where the light oil is separated from the associated natural gas and pipelined to the Pembina Pipeline system. Conserved solution gas is gathered, compressed, dehydrated and processed through Ventures Trust-owned facilities and delivered to the TransCanada Pipelines system for sale on the spot market.

Ventures Trust also holds a 14.3% interest in the Westerose Banff B Unit. The unit was formed in 2001 and produces medium quality oil from the Banff formation. The Unit is equipped with a pipeline gathering system that delivers the produced hydrocarbons to a Ventures Trust-owned central battery facility where the oil is separated from the associated natural gas and pipelined to the Pembina Pipeline system. Conserved solution gas is injected into the Banff formation under an enhanced recovery scheme that was implemented in early 2001.

Plans for 2004 include a two well development drilling program targeting the Belly River formation, continued production optimization efforts and enhancement of the waterflood scheme.

Provost, Alberta

As at December 31, 2003, Ventures Trust owned an average 93% working interest in 79 gross (73 net) operated producing light oil wells in the Provost area of east central Alberta. The Provost assets consist of two adjacent unitized light oil pools producing from the Viking Sandstone formation at a depth of approximately 900 metres. These assets are developed on 80-acre and 40-acre well spacing and have been under partial waterflood since the mid-1980s.

The field is equipped with a pipeline gathering system that delivers the produced hydrocarbons to two Ventures Trust-owned central battery facilities where the light oil is separated from the associated natural gas and trucked to the Ventures Trust's Kerrobert central battery for connection to the Mid-Sask Pipeline system. Conserved natural gas is compressed and processed at a nearby third party gas plant and marketed under an aggregator contract.

Kerrobert, Saskatchewan

As at December 31, 2003, Ventures Trust owned an average 84% working interest in 558 gross (467 net) operated producing Viking light oil wells in the Kerrobert area of west central Saskatchewan. The Kerrobert area assets consist of two adjacent unitized light oil pools producing from the Viking Sandstone formation at a depth of approximately 900 metres. The Kerrobert field was initially developed by wells drilled on 40-acre spacing units. Commencing in the fall of 1992, this field was infill drilled on 20-acre spacing units. The field is equipped with a pipeline gathering system that delivers the produced hydrocarbons to three central battery facilities where the light oil is separated from the associated natural gas and pipelined to the Mid-Sask Pipeline system. Production from a limited number of wells is trucked to the batteries. Conserved solution gas is gathered, compressed and dehydrated through the Altagas gathering system and delivered to the Transgas Coleville Gas Plant for processing. Residue gas is sold to the spot market.

Glenevis, Alberta

As at December 31, 2003, Ventures Trust owned a 91% working interest in 22 gross (20 net) operated producing oil and natural gas wells in the Glenevis area of central Alberta. The property was acquired from Baytex Energy Ltd. in December 2001 and further minor purchases occurred in 2002 and 2003. Ventures Trust's production comes from the medium depth Banff formation. The Glenevis Banff Pool was discovered in 1951 and was initially developed with vertical wells. In 1992, a horizontal infill drilling program was successfully implemented. A subsequent 1998 program yielded similar positive results.

The field is equipped with a pipeline gathering system that delivers the produced hydrocarbons to a Ventures Trust-owned central battery facility where the oil is separated from the associated natural gas and trucked to the Westerose facility.

North Eureka, Saskatchewan

As at December 31, 2003, Ventures Trust owned an average 99% working interest in 82 gross (81 net) operated producing Viking light oil wells in the North Eureka area of west central Saskatchewan. Ventures Trust's interests include a 99% interest in the North Eureka Unit that has been under waterflood since 1966. The North Eureka field was initially developed by wells drilled on 40-acre spacing units. Some 20-acre infill wells have subsequently been drilled on this property.

The field is equipped with a pipeline gathering system that delivers the produced hydrocarbons to a Ventures Trust-owned central battery facility where the light oil is separated from the associated natural gas and pipelined to the Mid-Sask Pipeline system. Production from a limited number of wells is trucked to the battery. Natural gas is utilized to fire electrical generators that in turn provide power to the property's wells and central production facility.

Cyn-Pem, Alberta

As at December 31, 2003, Ventures Trust owned an average 24% working interest in 17 gross (4 net) non-operated light oil and natural gas wells in the Cyn-Pem area of west central Alberta. Ventures Trust also owns a 0.773% working interest in the Carrot Creek Cardium F Unit Pool No. 3. The major producing horizons are the Rock Creek, Viking, Ostracod and Cardium formations, which occur at depths ranging from 1,950 metres to 2,500 metres.

Natural gas production is processed at third party facilities and sold into the spot market. Crude oil production is also treated at a third party facility, shipped on the Pembina pipeline system and sold under 30 day contracts.

Production

Average Daily Production Volumes

The average daily production volumes for the Trust for 2003 are set out below:

	1st Quarter	2nd Quarter	3rd Quarter	4th
Light and Medium Crude Oil (bbls/d)	5,848	6,654	6,957	
Natural Gas (mcf/d)	4,976	4,708	12,887	
NGLs (bbls/d)	199	167	417	
Light and Medium Crude Oil ($/bbl)				
Price	39.61	33.97	34.79	
Royalties	7.85	6.71	6.50	
Production Costs	9.30	8.12	9.04	
Netback	22.46	19.14	19.25	
Natural Gas ($/mcf)				
Price	7.36	6.81	5.96	
Royalties	1.55	1.56	1.39	
Production Costs	0.87	1.10	0.72	
Netback	4.94	4.16	3.85	
Natural Gas Liquids ($/bbl)				
Price	34.36	25.79	31.78	
Royalties	2.28	6.47	1.77	
Production Costs	5.48	5.27	3.86	
Netback	31.16	14.05	26.15	

Selected Reserve Information

The following tables set forth certain information relating to the oil and natural gas reserves of the Trust and the present value of the estimated future net cash flow associated with such reserves as at January 1, 2004. The information set forth below is derived from the McDaniel Report and the GLJ Report which have been combined by McDaniel for the Trust and have been prepared in accordance with the standards contained in the COGE Handbook and the reserves definitions contained in NI 51-101 and the COGE Handbook.

Prior to 2004, reserve reports were prepared in accordance with National Policy Statement 2-B ("NP-2B"). Reserve reports for the year ended December 31, 2003 are required to be prepared in accordance with NI 51-101. In accordance with the requirements of NI 51-101, the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 and the Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 are attached as Appendices A and B hereto, respectively.

All evaluations of future net revenue are stated prior to any provision for income taxes, interest costs or general and administrative costs and after the deduction of estimated future capital expenditures for wells to which reserves have been assigned. It should not be assumed that the estimated future net revenue shown below is representative of the fair market value of the Properties and the Weyburn NRI. There is no assurance that such price and cost assumptions will be attained and variances could be material. The recovery and reserve estimates of crude oil, natural gas liquids and natural gas reserves provided herein are estimates only and there is no guarantee that the estimated reserves will be recovered. Actual crude oil, natural gas liquids and natural gas reserves may be greater than or less than the estimates provided herein.

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of January 1, 2004

CONSTANT PRICES AND COSTS

	RESERVES				
	LIGHT AND MEDIUM OIL		HEAVY OIL		
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gros (MMcf
PROVED					
Developed Producing	18,814	16,331	0	0	21,86
Developed Non-Producing	65	60	0	0	5,41
Undeveloped	6,525	5,730	0	0	1,12
TOTAL PROVED	25,404	22,121	0	0	28,40
PROBABLE	8,259	7,037	0	0	10,28
TOTAL PROVED PLUS PROBABLE	33,662	29,157	0	0	38,68

	NET PRESENT VALUES OF FUTURE NET RE		
	BEFORE INCOME TAXES DISCOUNTED AT (%/		
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)
PROVED			
Developed Producing	381.1	300.7	250.0
Developed Non-Producing	22.1	12.4	8.2
Undeveloped	116.5	81.6	59.7
TOTAL PROVED	519.8	394.6	317.9
PROBABLE	228.9	144.2	99.8
TOTAL PROVED PLUS PROBABLE	748.7	538.8	417.7

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of January 1, 2004

CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)
Proved Reserves	1,090,289	182,639	283,522	90,545
Proved Plus Probable Reserves	1,479,168	251,581	354,084	110,942

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of January 1, 2004

CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	INCOM
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	
	Heavy Oil (including solution gas and other by-products)	
	Natural Gas (including by-products)	
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	
	Heavy Oil (including solution gas and other by-products)	
	Natural Gas (including by-products)	

SUMMARY OF OIL AND GAS RESERVES
AND NET PRESENT VALUES OF FUTURE NET REVENUE
as of January 1, 2004

FORECAST PRICES AND COSTS

	RESERVES				
	LIGHT AND MEDIUM OIL		HEAVY OIL		NAT G
RESERVES CATEGORY	Gross (Mbbl)	Net (Mbbl)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)
PROVED					
Developed Producing	18,525	16,095	0	0	21,674
Developed Non-Producing	65	60	0	0	5,423
Undeveloped	6,524	5,858	0	0	1,123
TOTAL PROVED	25,115	22,013	0	0	28,220
PROBABLE	8,232	7,058	0	0	10,269
TOTAL PROVED PLUS PROBABLE	33,347	29,071	0	0	38,489

	NET PRESENT VALUES OF FUTURE NET		
	BEFORE INCOME TAXES DISCOUNTED AT		
RESERVES CATEGORY	0 (MM$)	5 (MM$)	10 (MM$)
PROVED			
Developed Producing	255.9	208.3	177.6
Developed Non-Producing	18.0	9.7	6.2
Undeveloped	81.8	55.4	39.0

TOTAL PROVED	355.7	273.4	222.9
PROBABLE	180.0	113.3	78.2
TOTAL PROVED PLUS PROBABLE	535.7	386.7	301.1

TOTAL FUTURE NET REVENUE
(UNDISCOUNTED)
as of January 1, 2004

FORECAST PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)
Proved Reserves	939,975	151,314	319,508	95,615
Proved Plus Probable Reserves	1,293,668	210,791	410,385	118,516

FUTURE NET REVENUE
BY PRODUCTION GROUP
as of January 1, 2004

FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	INCOM
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products) Heavy Oil (including solution gas and other by-products) Natural Gas (including by-products)	
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products) Heavy Oil (including solution gas and other by-products) Natural Gas (including by-products)	

Notes:

(1) The Trust is entitled to deduct from its income all amounts which are paid or payable by it to Unitholders in a given financial year. As a result of amounts paid to Unitholders in the course of the most recent financial year, the Trust is not liable for any material amount of income tax on income. The net present values of future net revenue after income taxes are, therefore, the same as the net present values of future net revenue before income taxes.

(2) "Gross Reserves" means the working interest owner's share of gross reserves before the deduction of royalties. Royalty interest share of reserves is not included in this category. The Weyburn NRI is treated as a working interest as the Trust is responsible for its share of capital costs, operating costs, royalties and abandonment costs.

(3) "Net Reserves" means the working interest owner's share of gross reserves after the deduction of royalties. Royalty interest share of reserves is included in this category.

(4) The net cumulative cash flow forecasts are after direct lifting costs, freehold royalties, Crown mineral taxes and future investments but before income taxes An allowance for future well abandonment costs for all Working Interest wells was included, however, no allowance was made for the abandonment of any facilities.

(5) "Royalties" refers to royalties paid to others. The royalties deducted from the reserves are based on the percentage royalty calculated by applying the applicable royalty rate or formula. In the case of Crown sliding scale royalties which are dependent on selling prices, the price forecasts for the individual properties in question have been employed.

(6) "Reserves" are the estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on: analysis of drilling, geological, geophysical and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are classified according to the degree of certainty associated with the estimates.

(7) "Proved Reserves" are those Reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated Proved Reserves. At least a 90% probability that the quantities actually recovered will equal or exceed the estimated Proved Reserves is the targeted level of certainty.

(8) "Probable Reserves" are those additional Reserves that are less certain to be recovered than Proved Reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus

Probable Reserves. At least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable Reserves is the targeted level of certainty.

(9) "Proved Developed Reserves" are those Reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (e.g., when compared to the cost of drilling a well) to put the Reserves on production. The developed category may be subdivided into producing and non-producing.

(10) "Developed Producing Reserves" are those Reserves that are expected to be recovered from completion intervals open at the time of the estimate. These Reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainty.

(11) "Developed Non-Producing Reserves" are those Reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(12) "Undeveloped Reserves" are those Reserves expected to be recovered from known accumulations where a significant expenditure (e.g., when compared to the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the Reserves classification (proved, probable, possible) to which they are assigned.

(13) The pricing assumptions used in the McDaniel Report and the GLJ Report with respect to net cumulative cash flow as well as the inflation rates used for operating costs are set forth below.

SUMMARY OF PRICING ASSUMPTIONS
as of January 1, 2004

CONSTANT PRICES AND COSTS

	OIL				
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 400 API ($Cdn/bbl)	Hardisty Heavy 120 API ($Cdn/bbl)	Cromer Medium 29.30 API ($Cdn/bbl)	Albert Averag Plantga Price ($Cdn/Mmb
2003 (Year End)	32.78	39.76	22.75	34.25	5.87

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of January 1, 2004

FORECAST PRICES AND COSTS

	OIL					
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40o API ($Cdn/bbl)	Hardisty Heavy 12o API ($Cdn/bbl)	Cromer Medium 29.3o API ($Cdn/bbl)	Alberta Average Plantgate Price ($Cdn/Mmbtu)	G F (
Historical						
2000	30.31	44.72	27.80	40.10	5.20	
2001	25.97	39.60	18.05	32.22	5.25	
2002	26.10	39.95	27.60	34.93	3.89	
2003	30.95	43.10	27.45	36.90	6.35	
Forecast						
2004	29.00	37.70	22.70	32.20	5.65	
2005	26.50	34.30	21.55	29.71	5.30	
2006	25.50	33.00	21.56	28.84	4.95	
2007	25.00	32.30	20.63	28.06	4.75	
2008	25.00	32.30	20.39	27.97	4.60	
2009	25.50	32.90	20.76	28.48	4.65	
2010	26.00	33.50	21.11	29.00	4.65	
2011	26.50	34.20	21.56	29.61	4.75	

SUMMARY OF PRICING AND INFLATION RATE ASSUMPTIONS
as of January 1, 2004

FORECAST PRICES AND COSTS

	OIL					
Year	WTI Cushing Oklahoma ($US/bbl)	Edmonton Par Price 40o API ($Cdn/bbl)	Hardisty Heavy 12o API ($Cdn/bbl)	Cromer Medium 29.3o API ($Cdn/bbl)	Alberta Average Plantgate Price ($Cdn/Mmbtu)	G (

2012	27.00	34.80	21.91	30.11	4.85
2013	27.50	35.50	22.35	30.72	4.95
2014	28.10	36.20	22.79	31.32	5.05
Thereafter	+2.0%	+2.0%	+2.0%	+2.0%	+2.0%

(14) Total burdens include crown, freehold and overriding royalties as well as mineral taxes.

(15) Ventures Trust's interest in the Weyburn Unit, as reflected in the GLJ Report, is a royalty interest, the share of which is determined on a net profit basis. Gross reserve values presented herein are the share of reserves prior to deduction of lessor royalties, while the net share is their entitled value after lessor royalty burdens.

RECONCILIATION OF
NET RESERVES
BY PRINCIPAL PRODUCT TYPE

FORECAST PRICES AND COSTS

	LIGHT AND MEDIUM OIL			HEAVY OIL		
FACTORS	Net Proved (Mbbl)	Net Probable (Mbbl)	Net Proved Plus Probable (Mbbl)	Net Proved (Mbbl)	Net Probable (Mbbl)	Net P Pl Prob (Mb
January 1, 2003(a)	20,148	5,113	25,261	0	0	0
Extensions(b)	606	449	1,055	0	0	0
Improved Recovery	809	0	809	0	0	0
Technical Revisions	1,036	1,006	2,042	0	0	0
Discoveries	0	0	0	0	0	0
Acquisitions	1,895	366	2,261	0	0	0
Dispositions	-140	-54	-194	0	0	0
Economic Factors	-328	179	-149	0	0	0
Production	-2,013	0	-2,013	0	0	0
January 1, 2004	22,013	7,058	29,071	0	0	0

Notes:

(a) The evaluation of reserves as at January 1, 2003 was prepared using National Policy Statement 2-B reserves definitions. Under those definitions, probable reserves were adjusted by a factor to account for the risk associated with their recovery. The Trust previously applied a risk factor of 50% in reporting probable reserves. Under current NI 51-101 reserves definitions, estimates are prepared such that the full proved plus probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "best estimate"). The above reconciliation reflects current probable reserves versus previous risk adjusted (50%) probable reserves reported by the Trust.

(b) Consists entirely of infill drilling additions in 2003.

RECONCILIATION OF CHANGES IN
NET PRESENT VALUES OF FUTURE NET REVENUE
DISCOUNTED AT 10% PER YEAR

PROVED RESERVES
CONSTANT PRICES AND COSTS

PERIOD AND FACTOR
Estimated Net Present Value at Beginning of Year
Oil and Gas Sales During the Period Net of Production Costs and Royalties(a)
Changes due to Prices and Royalties Related to Forecast Production(b)
Development Costs During the Period(c)
Changes in Forecast Development Costs(d)
Changes Resulting from Extensions and Improved Recovery(e)
Changes Resulting from Discoveries(e)
Changes Resulting from Acquisitions of Reserves(e)
Changes Resulting From Dispositions of Reserves(f)
Accretion of Discount(g)
Net Change in Income Taxes(h)
Changes Resulting from Technical Reserves Revisions
All Other Changes(i)
Estimated Net Present Value as at End of Year

Notes:

(a) Company actual before income taxes, excluding G&A.

(b) The impact of changes in prices and other economic factors on future net revenue.

(c) Actual capital expenditures relating to the exploration, development and production of oil and gas reserves.

(d) The change in forecast development costs.

(e) End of period net present value of the related reserves.

(f) Start of the period net present value of the related reserves adjusted to the effective date of the disposition.

(g) Estimated as 10% of the beginning of period net present value. (h) The Trust should not be liable for any material amount of income tax on income. (i) Includes changes due to revised production profiles, development timing, operating costs, royalty rates, actual price received in 2003 versus forecast, etc.

Additional Information Relating to Reserves Data

Undeveloped Reserves

The following table summarizes the volumes of net proved undeveloped reserves that were first attributed in each of the most recent five financial years and, in the aggregate, before that time based on forecast prices and costs:

PRODUCT	2003	2002	2001	2000	1
Light and Medium Crude Oil (mbbls)	5,858	5,439	1,211	0	1,
Heavy Oil (mbbls)	0	0	0	0	
Natural Gas (mmcf)	807	15	51	0	3,
Natural Gas Liquids (mbbls)	23	0	1	0	1
Total (mboe)	6,016	5441	1,221	0	1,

The following table summarizes the volumes of net probable undeveloped reserves that were first attributed in each of the most recent five financial years and, in the aggregate, before that time based on forecast prices and costs:

PRODUCT	2003	2002	2001	2000	1
Light and Medium Crude Oil (mbbls)	2,901	2,589	120	0	
Heavy Oil (mbbls)	0	0	0	0	
Natural Gas (mmcf)	978	11	23	0	
Natural Gas Liquids (mbbls)	419	204	0	0	
Total (mboe)	3,483	2,795	124	0	

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Undeveloped reserves are those reserves expected to be recovered from known accumulations where a significant expenditure is required to render them capable of production.

Significant Factors or Uncertainties

For details of significant economic factors or uncertainties affecting the reserves data of the Trust, see "Competitive Conditions and Risk Factors" and "Management's Discussion and Analysis".

Future Development Costs

The following table outlines development costs deducted in the estimation of future net revenue calculated using no discount and a 10% discount rate.

	2004 (MM$)		2005 (MM$)		2006 (MM$)		2007 (MM$)	
RESERVE CATEGORY	0%	10%	0%	10%	0%	10%	0%	1
Proved Reserves (Constant Prices and Costs)	27.2	25.9	16.2	14	11.5	9.1	10.6	7.
Proved Reserves (Forecast Prices and Costs)	27.4	25.9	16.5	14.3	12.0	9.5	11.2	8.
Proved & Probable Reserves: (Forecast Prices and Costs)	28.6	27.3	18.9	16.4	13.1	10.4	12.5	9.

The Trust's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent upon Ventures Trust's and Ultima Energy's success in exploiting their reserve bases and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Trust's reserves and production will decline over time as reserves are produced.

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, the Trust's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that the Trust is required to use cash flow to finance capital expenditures or property acquisitions, the level of Distributable Income will be reduced, all other factors remaining equal. See "Competitive Conditions and Risk Factors".

Other Oil And Gas Information

Oil and Gas Properties and Wells

As at December 31, 2003, the Trust had an interest in 2,047 gross (1,561 net) producing and non-producing oil and natural gas wells as follows:

	PRODUCING		NON-PRODUC
	Gross(1)(4)	Net (2)(4)	Gross(1)(4)
CRUDE OIL WELLS			
Alberta	237	176	199
Saskatchewan	1,286	1,098	133
NATURAL GAS WELLS			

Alberta	143	37	42
Saskatchewan	7	6	0
TOTAL	1,673	1,317	374

Notes:

(1) "Gross" wells means the number of wells in which the Trust has a working interest or a royalty interest that may be convertible to a working interest.
(2) "Net" wells means the aggregate number of wells obtained by multiplying each gross well by the Trust's percentage working interest therein.
(3) "Non-producing" wells includes water injection wells, disposal wells, service wells, standing wells and wells which are not producing but which are considered to be capable of production.
(4) Excludes the Weyburn NRI wells.

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Properties with No Attributed Reserves

The following table sets forth the gross and net acres of unproved properties held by the Trust and the net area of unproved property for which the Trust expects its rights to explore, develop and exploit to expire during the next year:

	UNPROVED PROPERTIES (acres)		
LOCATION	Gross	Net	Ne
Alberta	70,897	25,147	
Saskatchewan	13,948	10,123	
Other	0	0	
TOTAL	84,845	35,270	

Forward Contracts

For information relating to forward contracts, see "Competitive Conditions and Risk Factors - Volatility of Oil and Natural Gas Prices".

Abandonment & Reclamation Costs

Future abandonment and reclamation costs have been estimated based on actual costs incurred to date by Ventures and Ultima Energy for abandonment and reclamation activities. Costs to abandon approximately 1,561 net wells totaling $16.2 million net of salvage value ($5.2 million discounted at 10%) are included in the estimate of future net revenue. Only the abandonment costs associated with wells were deducted in estimating the future net revenue in the McDaniel and GLJ Reports. The additional liability associated with well reclamation costs and facility/pipeline abandonment and reclamation costs, which were estimated to be $6.7 million ($1.1 million discounted at 10%), were not deducted in estimating future net revenue. Abandonment and reclamation costs estimated for the next three years are $0.3 million in 2004, $0.2 million in 2005 and $0.4 million in 2006.

Tax Horizon

The Trust is entitled to deduct from its income all amounts which are paid or payable by it to Unitholders in a given financial year. As a result of amounts paid to Unitholders in respect of the most recent financial year, the Trust is not liable for any material amount of income tax on income.

Costs Incurred

The following table outlines costs incurred during the financial year ended December 31, 2003:

Acquisitions, Dispositions and Capital Expenditures

NATURE OF COST	AMOUNT (MM$)
Acquisition Costs(1)	
Proved	87.4
Unproved	1.4
Exploration Costs	0
Development Costs (excluding the Weyburn NRI)	19.6
Development Costs -- Weyburn NRI	13.5
Total	135.4

Note:

(1) All acquisition costs other than land and seismic are included in proved acquisition costs.

Exploration and Development Activities

The following table summarizes the results of exploration and development activities during the financial year ended December 31, 2003, excluding the Weyburn NRI.

	GROSS
DEVELOPMENT WELLS	21
Gas	5
Oil	16

Service	0
Dry	0
EXPLORATORY WELLS	0
Gas	0
Oil	0
Service	0
Dry	0
TOTAL WELLS	21

Production Estimates

The following table summarizes the annual volume of production estimated on a proved plus probable basis for 2004 using constant and forecast prices and costs.

	ESTIMATED PRODUCTION	
	Constant Prices and Costs	Forecast
Light and Medium Crude Oil (mbbls)	2,778	
Heavy Oil (mbbls)	0	
Natural Gas (mmcf)	4,991	
Natural Gas Liquids (mbbls)	166	

TRUST INDENTURE

An unlimited number of Trust Units have been created and may be issued pursuant to the Trust Indenture. Each Trust Unit represents an equal fractional undivided beneficial interest in the Trust Fund. All Trust Units outstanding from time to time are entitled to share equally in any distributions by the Trust and, in the event of termination of the Trust, in the net assets of the Trust.

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

Trustee

Computershare Trust Company of Canada is the trustee of the Trust and also acts as the transfer agent for the Trust Units. The Trustee is responsible, among other things for: (i) holding the Trust Fund in trust for the use and benefit of the Unitholders; and (ii) maintaining all records of the Trust and reporting to the Unitholders in accordance with the terms and conditions of the Trust Indenture.

The Trustee may resign upon giving not less than 60 days' notice in writing to Ventures, for and on behalf of Ventures Trust, and AcquireCo. The

Trustee may also be removed by special resolution of the Unitholders. Such resignation or removal becomes effective upon the appointment of a successor

approved by an ordinary resolution passed at a meeting of Unitholders, and the acceptance of such appointment by the successor trustee.

Nature of the Trust

The Trust is an open-end investment trust formed under the laws of the Province of Alberta pursuant to the Trust Indenture for the purpose of acquiring and holding all forms of petroleum and natural gas related assets including the Royalty.

Distributions

The Trust Indenture provides that the Trustee will distribute Distributable Income on the 15th day (or if such day is not a business day, the next business day following the 15th day) following the last day of each calendar month in each year.

Offerings

Pursuant to the Trust Indenture, the Trust may offer Trust Units, including rights to acquire Trust Units at such time or times and on such terms and conditions as Ventures, for and on behalf of Ventures Trust, or AcquireCo may determine.

Meetings and Voting

Pursuant to the Trust Indenture, Unitholders are entitled to receive notice of and to attend all meetings of the Unitholders. Pursuant to the Ventures USA and the AcquireCo USA, Unitholders are entitled to elect the directors of Ventures and AcquireCo, respectively. Only Unitholders of record are entitled to vote and each Unitholder is entitled to one vote per Trust Unit held with respect to all matters on which they are entitled to vote.

The Trust holds annual meetings of the Unitholders. Special meetings of Unitholders may be called at any time by the Trustee and shall be called by the Trustee upon the written request of Unitholders holding in aggregate not less than 20% of the Trust Units then outstanding. Notice of all meetings of Unitholders shall be given by unregistered mail to each Unitholder at his registered address, mailed at least 21 days and not more than 50 days prior to the meeting.

At any meeting of Unitholders, any holder of Trust Units entitled to vote thereat may vote either in person or by proxy and a proxy holder need not be a Unitholder. Two persons present in person or represented by proxy and representing in the aggregate not less than 5% of the votes attaching to all outstanding Trust Units constitute a quorum for the transaction of business at any meeting of Unitholders.

A special resolution approved by not less than 66 2/3% of the votes of Unitholders represented at a meeting is required to, among other things, amend the Trust Indenture, remove the Trustee or terminate the Trust.

Limitation on Non-Resident Ownership

In order for the Trust to maintain its status as a mutual fund trust under the Tax Act, the Trust must not be 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 at no time may non-residents be the beneficial owners of a majority of the Trust Units. If the Trustee becomes aware, as a result of requiring declarations as to beneficial ownership or otherwise, that the beneficial owners of 49% of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, the Trustee may make a public announcement thereof and shall not accept a subscription for Trust Units from or issue or register a transfer of Trust Units to a person unless the person provides a

declaration that the person is not a non-resident. If notwithstanding the foregoing, the Trustee determines that a majority of the Trust Units are held by non-residents, the Trustee may send a notice to non-resident holders of Trust Units, chosen in inverse order to the order of acquisition or registration or in such other manner as the Trustee may consider equitable and practicable, requiring them to sell their Trust Units or a portion thereof within a specified period of not less than 60 days. If the Unitholders receiving such notice have not sold the specified number of Trust Units or provided the Trustee with satisfactory evidence that they are not non-residents within such period, the Trustee may on behalf of such Unitholders sell such Trust Units and, in the interim, shall suspend the voting and distribution rights attached to such Trust Units. Upon such sale, the affected holders shall cease to be holders of Trust Units and their rights shall be limited to receiving the net proceeds of sale upon surrender of the certificates representing such Trust Units.

Laws in certain jurisdictions outside Canada may also limit the ownership of Trust Units by certain non-residents, and the Trustee may from time to time take steps similar to the foregoing to minimize any adverse consequences to non-resident Unitholders arising from such laws.

Redemption Rights

Each Unitholder is entitled to require the Trust to redeem at any time and from time to time at the demand of the Unitholder all or any number of the Trust Units registered in the name of the Unitholder. Upon receipt by the Trustee, in its capacity as transfer agent of the Trust Units, of the notice to redeem Trust Units, the Unitholder shall thereafter cease to have any rights with respect to the Trust Units tendered for redemption (other than to receive the redemption payment therefor) including the right to receive any distributions thereon which are declared payable to the Unitholders of record on a date which is subsequent to the date of receipt by the Trustee of such notice. Trust Units shall be considered to be tendered for redemption on the date that the Trustee has, to the satisfaction of the Trustee and the Manager, received the notice, certificates representing the Trust Units and other required documents or evidence as provided in the Trust Indenture.

Upon receipt by the Trustee of the notice to redeem Trust Units, the holder of the Trust Units tendered for redemption shall be entitled to receive a price per Trust Unit (hereinafter called the "Cash Redemption Price") equal to the lesser of:

(a) 95% of the market price of the Trust Units on the principal market on which the Trust Units are quoted for trading during the ten trading day period commencing immediately after the date on which the Trust Units were tendered 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 aggregate Cash Redemption Price payable by the Trust in respect of any Trust Units surrendered for redemption during any calendar month shall be paid by cheque in lawful money of Canada payable at par to or to the order of the Unitholder who exercised the right of redemption on the last day of the month following the month in which the Trust Units were tendered for redemption. The entitlement of Unitholders to receive the Cash Redemption Price is subject to the limitations that: (i) the total amount payable by the Trust in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month is not to exceed $100,000 (provided that such limitation may be waived at the discretion of the boards of directors of Ventures and AcquireCo); (ii) no payments of the Cash Redemption Price can be made unless, at the time such Trust Units are tendered for redemption, the outstanding Trust Units of the Trust are listed for trading on a stock exchange or traded or quoted on any other market which the boards of directors of Ventures and AcquireCo consider, in their discretion, provides representative fair market value prices for the Trust Units; and (iii) the normal trading of Trust Units is not suspended or halted on any stock exchange on which the Trust Units are listed (or, if not

listed on a stock exchange, on any market on which the Trust Units are quoted for trading) on the date that the Trust Units are tendered for redemption or for more than five trading days during the ten day trading period commencing immediately after the date on which the Trust Units are tendered for redemption.

If a Unitholder is not entitled to receive the entire Cash Redemption Price as a result of the foregoing limitations, then the Cash Redemption Price for such Trust Units is to be the fair market value thereof as determined by the boards of directors of Ventures and AcquireCo and, subject to any applicable regulatory approvals, is to be paid and satisfied by way of a distribution in specie of the Trust's interests in Ventures Trust and AcquireCo (the "Securities"). No fractional Securities will be distributed and where a number of Securities to be received by a Unitholder includes a fraction, such number will be rounded to the next lowest whole number. The Trust is entitled to all interest paid, or accrued and unpaid, and to all dividends paid or declared payable on the Securities on or before the date of the distribution in specie.

It is anticipated that this redemption right will not be the primary mechanism for Unitholders to dispose of their Trust Units. The Securities which may be distributed in specie to Unitholders in connection with a retraction will not be listed on any stock exchange and no market is expected to develop in the Securities. The Securities may be subject to resale restrictions under applicable securities laws. Securities so distributed may or may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income trusts and deferred profit sharing plans.

Canadian Federal Income Tax Considerations

A Unitholder who is resident in Canada for purposes of the Tax Act (other than Exempt Plans) will generally be required to include in computing income for a taxation year that part of the income of the Trust for tax purposes, including net taxable capital gains, if any, that is paid or becomes payable to the Unitholder by the Trust in that year. To the extent that amounts payable to a Unitholder are designated as taxable capital gains, those amounts will be treated as taxable capital gains realized by the Unitholder.

Distributions by the Trust to a Unitholder in excess of the Trust's income will generally reduce the adjusted cost base of the Unitholder's Trust Units. To the extent that the adjusted cost base of a Trust Unit held as capital property would otherwise be less than zero, the Unitholder will be deemed to have realized a capital gain equal to that negative amount.

A Unitholder who holds the Trust Units as capital property will generally realize a capital gain (or capital loss) on the disposition of such Trust Units to the extent that the proceeds of disposition exceed (or are less than) the aggregate of the Unitholder's adjusted cost base of the Trust Units and reasonable disposition expenses.

Exempt Plans will not generally be liable for any tax with respect to any distributions by the Trust or on any capital gain realized on the disposition of Trust Units.

A Unitholder who is not resident in Canada for the purposes of the Tax Act will generally be subject to a 25% Canadian withholding tax on distributions of the Trust's income unless such rate is reduced pursuant to the terms of an income tax treaty between Canada and the non-resident Unitholder's jurisdiction of residence.

Unitholders should also see "Competitive Conditions and Risk Factors - March 23, 2004 Federal Budget" for proposed amendments to the Tax Act. Effective January 1, 2003, the Trust Units constituted foreign property for the purposes of Part XI of the Tax Act. However, the Trust Units will not constitute

foreign property in 2004. See "Competitive Conditions and Risk Factors - Foreign Property Designation".

Termination of the Trust

The Unitholders may vote by special resolution (66 2/3% of the votes of Unitholders represented at a meeting) to terminate the Trust at any meeting of Unitholders duly called for that purpose, whereupon the Trustee shall commence to wind up the affairs of the Trust, provided that such a vote may only be held if it is requested in writing by the holders of not less than 25% of the outstanding Trust Units and holders of not less than 50% of the outstanding Trust Units are present in person or represented by proxy at the meeting at which the vote is taken. Unless the Trust is terminated or its term extended, the Trustee shall commence to wind up the affairs of the Trust on December 31, 2065.

Upon being required to commence to wind up the affairs of the Trust, the Trustee shall sell and convert into money or otherwise dispose of the Royalty and all other assets comprising the Trust Fund in one transaction or in a series of transactions at public or private sale and do all other acts appropriate to liquidate the Trust Fund. In no event shall the Trust be wound up until the Royalty shall have been sold, and under no circumstances shall any Unitholder come into possession of any interest in the Royalty as a result of the termination of the Trust.

After paying, retiring or discharging or making provision for the payment, retirement or discharge of all known liabilities and obligations of the Trust and providing for indemnity against any other outstanding liabilities and obligations, the Trustee shall distribute the remaining part of the proceeds of the sale of the Royalty and the other assets of the Trust to Unitholders of record as at the date the register of the Trust is closed on a pro rata basis.

COMPETITIVE CONDITIONS AND RISK FACTORS

The business activities from which the Trust derives its revenues are conducted through or in connection with assets, properties and interests held by Ventures Trust (through Ventures) or Ultima Energy, or subsidiaries or affiliates thereof. All references herein to any business, assets, properties or interests of the Trust are made, without specifying the nature thereof, about the business, assets, properties and interests held by Ventures Trust (or Ventures on Ventures Trust's behalf), Ultima Energy, or subsidiaries or affiliates thereof. There are no foreign properties or assets owned by Ventures Trust or Ultima Energy.

Nature of Trust Units

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 Ventures, AcquireCo, the Manager or Ultima Energy. The Trust Units represent a fractional interest in the Trust. The Trust's assets presently include Permitted Investments, the Royalty under the Royalty Agreement, the Energy Royalty under the Energy Royalty Agreement, all of the issued and outstanding trust units of Ventures Trust and all of the issued shares of Ventures, AcquireCo, Ultima Energy and the Manager. The market price of the Trust Units is sensitive to a variety of factors, including, but not limited to, commodity prices for petroleum products, interest rates, the ability of the Trust to acquire suitable oil and natural gas properties and past and expected future distributions to Unitholders. Changes in any of these factors may adversely affect the trading price of the Trust Units.

The Trust Indenture provides that Unitholders will not be liable for or in respect of the obligations of the Trust and that any contracts entered into on behalf of the Trust will not be personally binding on the Trustee, the Manager or any Unitholder and that any liability will be limited to and satisfied only out of the assets of the Trust. Notwithstanding the terms of the Trust Indenture, Unitholders may not be

protected from liabilities of the Trust to the same extent as a shareholder is protected from the liabilities of a corporation. Unlike many other royalty trusts, the structure of the Trust does not include the interposition of a limited liability entity such as a corporation or limited partnership which would provide further limited liability protection to Unitholders between the Properties and Ventures Trust.

Operational Matters

Continuing production from a property, and to some extent the marketing of production therefrom, are dependent upon the ability of the operator of the property and the performance of the reservoir. To the extent the operator fails to perform its functions properly revenue may be reduced. Payments from production generally flow through the operator. Where Ventures or Ultima Energy is not the operator, there is a risk of delay and additional expense in receiving such revenues. Any delay in payment along the production chain could adversely affect payment of Distributable Income.

The Trust's operations are subject to all of the inherent risks normally associated with the development and other operations conducted in respect of oil and natural gas properties. For example, in drilling wells, the Trust may encounter or experience unexpected formations or pressures, blow-outs, cratering and fires. In producing wells, the Trust may encounter or experience premature or unexpected declines of reservoirs or invasion of water into producing formations. The Trust's operations may also result in environmental or other damage. Any of these occurrences could result in material losses, liabilities or costs to the Trust. The wells and facilities of Ventures and Ultima Energy are covered by liability insurance coverage, where available, in amounts consistent with standard industry practice. Business interruption insurance is also purchased for selected facilities, to the extent such insurance is available. The Manager, Ventures Trust, Ventures, AcquireCo, Ultima Energy or the Trust may become liable for damages arising from such events against which they cannot insure or against which they may elect not to insure because of high premium costs or other reasons. Costs incurred to repair any such damage or pay any such liabilities will reduce Distributable Income.

Regulation and Competition

The Trust's oil and natural gas operations are subject to extensive controls and regulations imposed by various levels of government. See "Competitive Conditions and Risk Factors - Government Regulation". The future value of the Trust's properties is impacted by various local, national and international economic and political factors that are beyond the control of the Trust. The oil and natural gas industry is intensely competitive and the Trust competes against much larger, well-established companies with substantially greater technical and financial resources for capital, skilled personnel, undeveloped lands, reserves acquisitions, access to drilling rigs, service rigs and other equipment, access to processing facilities and pipeline and refining capacity and all other aspects of its operations. Some of those organizations not only explore for, develop and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a world wide basis and as such have greater and more diverse resources on which to draw.

Reserves

The reserves and estimated future net cash flows from the Properties have been independently evaluated in the McDaniel Report. The reserves and estimated future net cash flows attributable to the Trust's net royalty interest in the Weyburn NRI have been independently evaluated in the GLJ Report. See "Description of Business". These estimates include a series of assumptions relating to factors such as recoverability and marketability of production, future prices of oil and natural gas, operating costs, future capital expenditures and royalties and other government levies that may be imposed over the producing life of the reserves. The Trust's ability to increase reserves in the future will depend not only on its ability to develop its present properties, but also on its ability to select and acquire suitable producing properties or prospects. In that regard, the Trust is restricted from spending funds on exploratory operations and it is

not permitted to incur capital expenditures in excess of 10% of the annual net cash flow to which it is entitled from the Properties (excluding any interest in the Weyburn Unit or the Weyburn NRI) unless the incurrence of such capital expenditures is, in the opinion of the Manager and as determined by the boards of directors of Ventures or AcquireCo, as the case may be, necessary or advisable to maintain the integrity of the Properties (or other assets) in accordance with prudent oil and gas practices or unless such expenditures are funded by the public offering of additional Trust Units, debt, or a combination thereof. There is no assurance that the Trust's future development efforts will result in the discovery and development of additional commercial accumulations of oil and natural gas, notwithstanding the independent evaluations of McDaniel or GLJ.

The Trust's future oil and natural gas reserves and production, and therefore its cash flows, will be highly dependent upon Ventures Trust's, AcquireCo's and Ultima Energy's success in exploiting their reserve bases and acquiring additional reserves. Without reserve additions through acquisition or development activities, the Trust's reserves and production will decline over time as reserves are exploited.

To the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, the Trust's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that the Trust is required to use cash flow to finance capital expenditures or property acquisitions, the level of Distributable Income will be reduced, all other factors remaining equal.

The price for petroleum or natural gas interests to be acquired by the Trust will, in part, be based on engineering and economic assessments made by independent engineers. These assessments include a series of assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the Manager, Ventures Trust, AcquireCo, Ultima Energy or the Trust. In particular, changes in the prices of, and markets for, oil and natural gas from those anticipated at the time of making such assessments will affect the return on and value of the Trust Units. In addition, all such assessments involve a measure of geological and engineering uncertainty which could result in lower production and reserves than anticipated.

Volatility of Oil and Natural Gas Prices

The price that the Trust receives for its oil and natural gas production is market determined and has been subject to considerable volatility over which the Trust has no control. See "Competitive Conditions and Risk Factors - Government Regulation". There is also competition between the petroleum industry and other industries with respect to the supply of energy and fuel to industrial, commercial and individual customers. Any decline in oil or natural gas prices could have a material adverse effect on the Trust's operations, financial condition, Distributable Income, proved reserves and the level of expenditures for the development of its oil and natural gas reserves. The ability of the Trust to sell its oil and natural gas production is subject to many factors, including price and other market fluctuations, the proximity and capacity of both oil and natural gas pipelines and processing facilities and extensive government regulation. The economics of producing from some wells may change as a result of lower prices, which could result in a reduction in the volumes of the Trust's reserves. The Trust may also elect not to produce from certain wells at lower prices. All of these factors could result in a material decline in the Trust's net production revenue and overall value.

In order to partially hedge the effect that fluctuating oil prices have on the Trust, the Trust may, from time to time, enter into commodity price hedge arrangements and foreign currency hedge arrangements.

Summarized below are Ventures Trust's outstanding commodity price hedge arrangements as at December 31, 2003:

Crude Oil Hedges (US$/bbl except as indicated)	Daily Quantity	Fixed Price	Sold Call	Purchased Put	Sold P
Crude Oil	1,000 bbls	$35.00(CDN)	-	-	
Crude Oil	800 bbls	-	$27.50	$24.00	$20.0
Crude Oil	700 bbls	-	$30.00	$25.00	$21.0
Crude Oil	1,000 bbls	$27.00	-	-	

Natural Gas Hedges (CDN$/GJ)	Daily Quantity	Fixed Price
Natural Gas	1,000 GJs	$7.00
Natural Gas	4,000 GJs	$6.15

Currency Exchange Rates

The Trust's operating costs, including costs of production, are generally paid in Canadian dollars. World oil prices are quoted in U.S. dollars and the price Canadian producers receive is therefore affected by the Canadian/U.S. dollar exchange rate that will fluctuate over time. An increase in the value of the Canadian dollar may negatively impact the Trust's production revenue and reduce Distributable Income.

Debt Service

The Trust's bank indebtedness is based on variable interest rates that may fluctuate over time. A material increase in interest rates would lead to higher bank debt servicing costs that would negatively impact Ventures Trust's and Ultima Energy's royalty payments to the Trust. In order to partially hedge the effect that fluctuating bank interest rates have on the Trust, the Trust may, from time to time, enter into interest rate swaps that fix the effective rate of interest that the Trust will pay on a portion of its bank debt. The Trust is not currently a party to any interest rate swap transactions.

The Trust's deferred capital obligation is based on a fixed interest rate and repayment schedule.

Payment of Distributable Income

Although the Trust is structured for monthly payments of any Distributable Income, such Distributable Income does not necessarily reflect accrued royalty income in such month, but rather an estimate of the actual amounts received or receivable in the period. Estimates are required to be made because, in addition to the usual delays in payment by purchasers of oil and natural gas to the operator of the Properties, from the operator to Ventures Trust, AcquireCo or Ultima Energy (where the Manager is not the operator), from Ventures Trust, AcquireCo or Ultima Energy to the Trust and from the Trust to Unitholders, payments between any of such parties may also be affected or delayed by restrictions imposed by lenders, accounting delays, delays in the sale or delivery of products, delays in the connection of wells to a gathering system, blowouts or other accidents, adjustments for prior periods, recovery by the operator of expenses incurred in the operation of properties or the establishment by the operator of reserves for such expenses. As the accrued royalty income for each month is verified, adjustments to reflect the actual Distributable Income for each month are made to payments of Distributable Income in subsequent months.

The payment of Distributable Income may also be affected by obligations under Ventures Trust's credit facility. Under the terms of Ventures Trust's credit facility, the lender is paid in priority to distributions to Unitholders. To the extent that there are amounts due and unpaid under the facility, the Trust may be precluded from providing distributions on Trust Units and from redeeming any Trust Units until such outstanding amounts are paid. The lender under the credit facility may also restrict the Trust's ability to pay distributions when Ventures Trust is in breach or default of the credit facility.

Changes in Legislation

There can be no assurance that income tax laws and government incentive programs relating to the oil and natural gas industry, such as the resource allowance, will not be changed in a manner which adversely affects Unitholders.

Loss of Mutual Fund Trust Status

If the Trust ceases to qualify at any relevant time as a "mutual fund trust" under the Tax Act, the Trust Units will cease to be qualified investments for Exempt Plans. Where at the end of any month an Exempt Plan holds Trust Units that are not qualified investments, the Exempt Plan must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Trust Units at the time such Trust Units were acquired by the Exempt Plan. In addition, where an RRSP or RRIF acquires Trust Units that are not qualified investments, the RRSP or RRIF will become taxable on its income attributable to the Trust Units while they are not qualified investments and the annuitant or beneficiary, respectively, of such Exempt Plan will be required to include in income the fair market value of the non-qualified investment at the time of acquisition. If the Trust ceases to qualify as a "mutual fund trust" it may also be subject to taxation under Part XII.2 of the Tax Act which may have negative consequences for non-residents or other persons exempt from Part I tax under the Tax Act. For Unitholders who are non-residents of Canada, loss of mutual fund trust status will result in the Trust Units constituting taxable Canadian property for the purposes of the Tax Act, thus potentially subjecting the disposition of such Trust Units to tax under the Tax Act.

Foreign Property Designation

On April 5, 2002, the Trust announced that due to the strong financial performance of its investment in the Partnership, Trust Units will be deemed to be "foreign property" under Part XI of the Tax Act effective January 1, 2003 for RRSPs, DPSPs, RRIFs and other deferred income plans (collectively, "Registered Plans"). Trust Units were not "foreign property" for purposes of the Tax Act in 2001 and will not be "foreign property" in 2002 and, as such, holders of Trust Units will not be subject to any tax under Part XI of the Tax Act for 2001 or 2002 solely as a result of holding Trust Units. The designation of the Trust Units as "foreign property" does not affect Trust Units which are held outside of Registered Plans.

Part XI tax may be payable in respect of a Registered Plan in 2003 if, at the end of any month, the aggregate cost amount of all foreign property (including the Trust Units) of the Registered Plan exceeds 30% of the cost amount of all property of the Registered Plan. The tax payable under Part XI of the Tax Act is calculated at the end of each month at the rate of 1% of the amount, if any, by which the cost amount of all foreign property exceeds 30% of the aggregate cost amount of all property. However, Registered Plans which have acquired their Trust Units prior to January 1, 2003, will have a 24-month grace period before any tax is payable by them under Part XI of the Tax Act.

As a result of the Partnership Redemption, the Trust Units ceased to be "foreign property" as of January 1, 2004. See "General Development of the Business - Development - 2002 - Weyburn Limited Partnership Capital Contribution and Redemption". Unitholders whose Registered Plans have in excess of 30% foreign property by virtue of their investment in Trust Units acquired prior to January 1, 2003

should likely be able to take no action and avoid paying any tax pursuant to Part XI of the Tax Act due to the 24-month grace period described above. Trust Units acquired in 2003 will not be entitled to the 24-month grace period. As a consequence, if the acquisition of Trust Units in 2003 results in a Registered Plan exceeding the 30% foreign property content level, Part X1 tax should apply to such plan.

Income Tax Payable

There can be no assurance that the Canada Revenue Agency ("CRA") will agree with how the Trust calculates its income for tax purposes or that the CRA will not change its administrative practices to the detriment of the Trust or the Unitholders. In 2004, it is expected that a portion of the distributions paid or payable by the Trust will represent the income of the Trust and will thus be required to be included in the income of Unitholders.

March 23, 2004 Federal Budget

On March 23, 2004, Minister of Finance (Canada) Ralph Goodale tabled the federal budget (the "budget") which proposes amendments to the Tax Act that could have an impact on the Trust and its Unitholders.

In order to qualify as a mutual fund trust, among other things, Ultima cannot, and may not at any time, reasonably be considered to be established or maintained primarily for the benefit of non-resident persons unless at all times since February 21, 1990, all or substantially all of its property has consisted of property other than "taxable Canadian property" (as defined in the Tax Act) (the "property exception").

Subject to certain transitional relief available until December 31, 2006, the budget proposes that Canadian resource property (which includes the Royalty and the Energy Royalty) be considered taxable Canadian property for the purposes of the property exception after March 22, 2004. The transitional relief contained in the budget is available to those trusts that on March 23, 2004 (i) were maintained primarily for the benefit of non-resident persons and (ii) satisfied the property exception. The Trust has never been maintained primarily for the benefit of non-resident persons and thus the budget proposals in this regard will not have an adverse impact on the Trust.

The budget proposes a new 15% Canadian withholding tax on the non-taxable portion of the Trust's distributions, which, under the current provisions of the Tax Act, are not subject to any Canadian withholding tax. The budget proposes that the new 15% Canadian withholding tax be applicable to distributions made by the Trust after 2004. The new 15% Canadian withholding tax will only apply if, at the time of the distribution, Units of the Trust are listed on a prescribed stock exchange (which includes the Toronto Stock Exchange) and the value of the Trust's Units is primarily attributable to real property situated in Canada, Canadian resource property (which includes the Royalty and the Energy Royalty) or a timber resource property. If a subsequent disposition of a Unit results in a capital loss to a non-resident Unitholder, a refund of the new 15% Canadian withholding tax is available in limited circumstances, subject to the filing of a special Canadian tax return.

The budget also proposes a 25% withholding tax on distributions made to non-residents of Canada which are attributable to capital gains realized by the Trust after March 22, 2004 on the disposition of taxable Canadian property where the Trust has made certain designations on such capital gain with respect to its Unitholders. The 25% rate of Canadian withholding tax may be reduced pursuant to the terms of an applicable income tax treaty between Canada and the Unitholder's jurisdiction of residence.

It is expected that the budget proposals with respect to withholding tax on distributions will not have any impact on the Trust prior to the Merger, but could have an impact on the trust remaining after the merger of the Trust with Petrofund pursuant to the Combination Agreement.

Experience of Management

Subject to the annual audit by the independent auditors and supervision by the Boards, Unitholders are dependent on management in respect of the administration of all matters relating to the Royalty Agreement and the Trust Units. Moreover, Ventures Trust's and Ultima Energy's operations are also highly dependent on the executive officers and management employees of the Manager. The unexpected loss of the services of any of these individuals could have a detrimental effect on the operations of the Trust.

Potential Conflicts of Interest

Certain of the directors of Ventures, AcquireCo, Ultima Energy and the Manager may be associated with other oil and natural gas companies from time to time which could occasionally give rise to various conflicts of interest. In order to address those conflicts, Ventures, AcquireCo, Ultima Energy and the Manager and their directors comply with the provisions of the ABCA concerning conflicts of interest. Those provisions require a director who has an interest in a material contract or proposed material contract with Ventures, AcquireCo, Ultima Energy, the Manager or an affiliate thereof to disclose the nature and extent of that interest and, in most instances, to refrain from voting on any resolution to approve that contract. See "Conflicts of Interest".

Government Regulation

The oil and natural gas industry in Canada is subject to extensive controls and regulations imposed by various levels of government. In addition to federal regulation, in western Canada, the various provincial governments have enacted legislation and regulations which govern land tenure, production rates, royalties, environmental protection, the prevention of waste, safety regulation and other matters.

On March 3, 2003, the Department of Finance issued a technical paper on proposed changes to the taxation of the resource sector, including the tax treatment of Crown royalties and the resource allowance. In general, the proposed changes include the elimination of the resource allowance over five years in conjunction with making Crown royalties deductible over the same time period. The changes referred to in the technical paper were enacted into law in November 2003 and could adversely impact the taxation of the Trust.

Outlined below are some of the more significant aspects of the legislation, regulations and agreements governing the oil and natural gas industry. All current legislation is a matter of public record and the Manager is unable to predict what additional legislation or amendments may be enacted. The Trust does not expect these controls and regulations to affect its operations in a manner significantly different than they will affect other oil and gas producers of similar size.

Land Tenure

Oil and natural gas located in western Canada is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licenses and permits for varying terms from two years and on conditions set forth in provincial legislation which may include requirements to perform specific work or make payments. Oil and natural gas located in such provinces can also be privately owned and rights to explore for and produce such oil and natural gas are generally granted by lease from the freehold owner on such terms and conditions as may be negotiated.

Production

Provincial governments regulate production in accordance with sound engineering and conservation practices and usually establish daily production limits. Production is also limited by pipeline capacities, demand for natural gas and various grades of crude oil and, in limited circumstances, by production rate limitations imposed by regulatory authorities to encourage maximum ultimate recovery.

Price and Marketing

Governments in Canada play little role in the pricing of oil and natural gas. Producers of oil negotiate sales contracts directly with purchasers, with the result that the market determines the price of oil. Price normally depends on factors such as oil quality, price of competing oils, distance to market and value of refined products.

In Canada, the price of natural gas sold in interprovincial and international trade is determined by negotiation between buyers and sellers and normally depends on factors such as price of competing gas, distance to market, length of contract term and other contractual terms.

While the Trust is not directly involved in the business of oil or gas export, its sales are indirectly affected by governmental control and regulation of the removal of oil and natural gas from Saskatchewan and Alberta into other parts of Canada and further export beyond the borders of Canada. The governments of Alberta and Saskatchewan 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.

Crude oil and natural gas may be exported from Canada pursuant to export contracts with terms not exceeding one year in the case of light crude, and two years in the case of heavy crude and natural gas, provided that an approval order has been obtained from the National Energy Board (the "NEB"). Any export to be made pursuant to a contract of longer duration requires an export license from the NEB, the issuance of which requires the approval of the Governor in Council.

Although pipeline expansions are ongoing, the lack of firm pipeline capacity continues to affect the oil and natural gas industry and limit the ability to produce and to market natural gas production. The prorating of capacity on the interprovincial pipeline systems may also affect the ability to export oil.

Provincial Royalties and Incentives

The royalty regime applicable to particular oil and natural gas production is a significant factor in determining its profitability. Royalties payable on production from land other than Crown lands are determined by negotiation between the mineral owner and the lessee. Crown royalties are determined by government regulation and are generally calculated as a percentage of the value of gross production and vary depending on factors such as prescribed reference prices, well productivity, geographic location, field discovery date, method of recovery and the type and quality of the petroleum product produced. From time to time, the provincial governments of Alberta and Saskatchewan have established incentive programs for the purpose of encouraging oil and natural gas exploration and development. Such programs often provide for royalty reductions and royalty holidays, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improving earnings and cash flow within the industry. The trend in recent years has been for provincial governments to allow such programs to expire without renewal, and consequently few such programs are currently operative.

All properties and interests owned by the Trust as at December 31, 2003 were located in the Provinces of Saskatchewan and Alberta.

On October 13, 1992, the Government of Alberta implemented major changes to its royalty structure and created incentives for exploring for oil and natural gas reserves. The incentives include: (i) a one year royalty holiday on new oil discovered after October 1, 1992, (ii) incentive 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 royalty formula structure through the implementation of a third tier royalty with a base rate of 10% and 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 royalty reserved to the Crown has a base rate of 10% and a rate cap of 35%. 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.

In Alberta, certain producers of oil or natural gas are also entitled to a credit against the royalties payable to the Crown by virtue of the Alberta royalty tax credit program ("ARTC"). The ARTC rate is based on a price sensitive formula and varies between 75% at prices at and below $100 per cubic metre and 25% at prices at and above $210 per cubic metre. The ARTC 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 ARTC will generally not be eligible for ARTC. The rate is established quarterly based on the average "par price", as determined by the Alberta Resource Development Department for previous quarterly period.

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 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 1 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 metre 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 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 metres 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.

Kyoto Protocol

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 nations, upon ratification, to reduce their emissions of carbon dioxide and other greenhouse gases. Although it is not known what impact, if any, there will be on the Trust's operations, reductions in greenhouse gases from the Trust's operations may be required which could result in increased capital expenditures and reductions in production of oil and gas.

Environmental Regulation

The oil and gas industry is currently subject to environmental regulation pursuant to local, provincial and federal legislation. Environmental legislation provides for restrictions and prohibitions on releases or emissions of various substances produced or utilized in association with oil and gas industry operations. Legislation also requires that well and facility sites be abandoned and reclaimed to the satisfaction of provincial authorities. Compliance with such legislation may require significant expenditure and a breach of any such legislation may result in suspension or revocation of required licenses and authorizations, civil liability for resulting damage, the imposition of fines and penalties, or the issuance of clean-up orders.

In Saskatchewan, maintenance of environmental quality for oil and natural gas operations is governed primarily by the Oil and Gas Conservation Act (Saskatchewan) and the Environmental Management and Protection Act (Saskatchewan). Pursuant to those Acts and the regulations promulgated thereunder, spilled material is monitored and regulated and permits and approvals are required for any waste processing facility or any facility or operation which discharges any pollutant into the environment. Those Acts also regulate the decommissioning, abandonment and reclamation of wells and any related facility or operation.

Environmental legislation in Alberta has been consolidated into the Environmental Protection and Enhancement Act (Alberta) ("AEPEA"). Under the AEPEA, environmental standards and compliance for releases, clean-up and reporting are stricter. Also, the range of enforcement actions available and the severity of penalties have been significantly increased. These changes have had an incremental effect on the cost of conducting operations in Alberta.

Pursuant to the terms of the Royalty Agreement, funds have been set aside to provide for the future cost of abandonments and reclamation work on wells, plants and facilities. The Trust contributes $0.20 per boe of production from cashflow for future use and deposits such funds into a separate reserve account. A total of $625,000 was contributed during the 12 months ended December 31, 2003 and the total balance is $1,077,000 as at December 31, 2003. Actual reclamation expenditures in 2003 were $296,000.

The Trust is committed to meeting its legal and moral responsibility to protect the environment. The Trust anticipates making increased, although not material, expenditures of both a capital and expense nature as a result of the higher environmental standards demanded of oil and gas companies by both legislation and the general public. The amount of these expenditures cannot presently be determined.

The Trust is of the opinion that it has been in material compliance with all applicable environmental laws and regulations during the year ended December 31, 2003. The Trust's operations are, and will continue to be, affected in varying degrees by laws and regulations regarding the protection of the environment. It is impossible to predict the full impact of these laws and regulations on the Trust's operations; however, it is not anticipated that the Trust's competitive position will be adversely affected by current and future environmental laws and regulations governing its current oil and gas operations.

Safety Regulation

The Trust is committed to protecting and promoting the health and safety of its employees and other stakeholders in all of its operations. To that end, the Trust has implemented a formal safety program that it will continue to monitor and upgrade. This program is designed to ensure that the Trust meets or exceeds all applicable government regulations relating to health and safety.

SELECTED CONSOLIDATED FINANCIAL INFORMATION

The Trust, Ventures Trust, AcquireCo and Ultima Energy present their audited financial information on a consolidated basis. Prior to the Partnership Redemption, the Trust only recorded income from the Partnership to the extent of the Trust's 92% share of the Partnership's distributions, as the Trust did not control the Partnership. The Trust did not consolidate the financial results of the Partnership with the financial results of the Trust. Summary financial statements of the Partnership can be found in the notes to the Annual Consolidated Financial Statements of the Trust for the year ended December 31, 2003. The following table sets forth selected consolidated financial information of the Trust, Ventures Trust, AcquireCo and Ultima Energy for each of the three most recently completed financial years indicated:

SELECTED CONSOLIDATED FINANCIAL INFORMATI
(thousands except per Trust Unit amounts

	12 months ended December 31, 2003	12 months ended December 31, 2002(1)	12 mont December
Oil and natural gas revenues	$ 111,107	$ 38,253	$
Partnership Income	$ --	$ 4,198	$
Total revenues, net of royalties	$ 89,297	$ 42,451	$
Funds from operations	$ 54,880	$ 24,016	$
Funds from operations per unit, basic	$ 1.29	$ 1.09	$
Funds from operations per unit, fully diluted	$ 1.26	$ 1.08	$
Cash distributed	$ 48,135	$ 20,974	$
Cash distributed per unit	$ 1.09	$ 0.90	$
Net income	$ 12,278	$ 9,224	$
Net income per unit, basic	$ 0.29	$ 0.42	$
Net income per unit, fully diluted	$ 0.28	$ 0.41	$
Total book value of assets	$ 326,539	$ 218,175	$
Total long-term debt(2)	$ 81,376	$ 78,238	$
Unitholders' equity	$ 208,444	$ 125,374	$
Trust Units outstanding at period end	57,624,975	33,873,808	18,
Trust Unit price at period end	$ 6.24	$ 5.15	$

Notes:

(1) Prior periods have been restated to reflect a change in accounting policy. See note 2(l) to the Consolidated Financial Statements of the Trust for the year ended December 31, 2003.

(2) Includes long term bank debt and the deferred capital obligation associated

with the Weyburn NRI for 2002. The deferred capital obligation is only deductible from the royalty payment to be received by Ventures Trust from the Weyburn NRI. It is not secured by the Trust's other assets. See" General Development of the Business - Development - 2002 - Weyburn Limited Partnership Capital Contribution and Redemption".

The following table sets forth selected consolidated financial information of the Trust, Ventures Trust, AcquireCo and Ultima Energy (including the Partnership income distributed to the Trust) with respect to each of the last eight financial quarters ending on March 31 ("Q1"), June 30 ("Q2"), September 30 ("Q3") and December 31 ("Q4"), respectively:

SELECTED QUARTERLY FINANCIAL INFORMATION
(thousands except per Trust Unit amounts)

	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4(1)	200
Total revenues, net of royalties	$ 25,712	$ 24,635	$ 19,100	$ --	$ 13,044	$
Partnership Income	$ --	$ --	$ --	$ --	$ 424	$
Funds from operations	$ 15,923	$ 14,950	$ 11,670	$ 12,336	$ 7,351	$
Funds from operations, per unit	$ 0.30	$ 0.30	$ 0.33	$ 0.36	$ 0.31	$
Cash distributed	$ 14,187	$ 14,625	$ 10,131	$ 9,192	$ 6,528	$
Cash distributed per unit	$ 0.265	$ 0.285	$ 0.27	$ 0.27	$ 0.24	$
Net income	$ 4,765	$ 4,124	$ 3,352	$ 37	$ 2,403	$
Net income per unit	$ 0.10	$ 0.09	$ 0.10	$ 0.00	$ 0.10	$

Notes:
(1) Prior periods have been restated to reflect a change in accounting policy. See note 2(l) to the Consolidated Financial Statements of the Trust for the year ended December 31, 2003.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The information contained in the Management's Discussion and Analysis for the financial year ended December 31, 2003 is incorporated herein by reference and forms an integral part of this Annual Information Form.

MARKET FOR SECURITIES

The Trust Units have been listed and posted for trading on the Toronto Stock Exchange (the "TSX") since July 29, 1996 and trade under the symbol "UET.UN".

DISTRIBUTION POLICY AND RECORD

Distributable Income is calculated by the Manager and is approved by the boards of directors of Ventures and AcquireCo. The Trustee distributes Distributable Income to Unitholders on the 15th day of the month, or if such day does not fall on a business day, the next business day following the 15th day of the month. The following cash distributions have been made to Unitholders during 2002, 2003 and 2004:

Period for which Distribution Declared	Total Cash Distribution	Per Trust Unit
2002		
January	$ 1,131,000	$ 0.06
February	$ 1,131,000	$ 0.06
March	$ 1,320,000	$ 0.07
April	$ 1,320,000	$ 0.07
May	$ 1,908,571	$ 0.08
June	$ 1,908,571	$ 0.08
July	$ 1,908,571	$ 0.08
August	$ 1,908,571	$ 0.08
September	$ 1,908,571	$ 0.08
October	$ 1,908,571	$ 0.08
November	$ 1,908,571	$ 0.08
December	$ 1,908,571	$ 0.08

Period for which Distribution Declared	Total Cash Distribution	Per Trust Unit
2003		
January	$3,054,553	$ 0.090
February	$3,060,103	$ 0.090
March	$3,077,038	$ 0.090
April	$3,077,038	$ 0.090
May	$3,527,038	$ 0.090
June	$3,527,038	$ 0.090
July	$4,864,889	$ 0.095
August	$4,871,281	$ 0.095
September	$4,888,539	$ 0.095
October	$4,901,206	$ 0.095
November	$4,388,123	$ 0.085
December	$4,898,123	$ 0.085
2004		
January	$4,905,206	$ 0.085
February	$4,909,853	$ 0.085
March	$4,913,625	$ 0.085

DIRECTORS AND OFFICERS

Amendment of Ventures USA and AcquireCo USA

As a result of the Management Internalization Transaction, the boards of directors of Ventures and AcquireCo determined that the Manager, as a wholly-owned subsidiary of the Trust, no longer requires special voting rights in respect of the election of the directors of Ventures and AcquireCo. At the Annual and Special Meeting of Unitholders held on May 23, 2003, Unitholders passed a special resolution authorizing the amendment of the Ventures USA and the AcquireCo USA to increase the number of directors of each of Ventures and AcquireCo from five to seven, and to provide that Unitholders shall have the right to elect all of the directors of each of Ventures and AcquireCo.

Ultima Ventures Corp.

Pursuant to the terms of the Ventures USA, the board of directors of Ventures consists of seven members, all of whom are elected by the Unitholders. Pursuant to the terms of the Trust Indenture, the board of directors of Ventures, together with the board of directors of AcquireCo, has the authority and responsibility to make or approve most significant decisions affecting the Trust. Each director will hold office until the Trust's next annual meeting of Unitholders or until his successor is duly elected or appointed.

Ultima Acquisitions Corp.

Pursuant to the terms of the AcquireCo USA, the board of directors of AcquireCo consists of seven members, all of whom are elected by the Unitholders. Pursuant to the terms of the Trust Indenture, the board of directors of AcquireCo (together with the board of directors of Ventures) has the authority and responsibility to make or approve most significant decisions affecting the Trust. Each director will hold office until the Trust's next annual meeting of Unitholders or until his successor is duly elected or appointed.

Directors and Officers

Ventures and AcquireCo

The boards of directors of Ventures and AcquireCo are composed of the same directors. The following table sets forth the name, municipality of residence, positions/offices held, year first elected/appointed and principal occupation of each of the directors and officers of Ventures and AcquireCo as at the date hereof. Each director will hold office until the Trust's next annual meeting of Unitholders or until his successor is duly elected or appointed.

Name and Municipality of Residence	Position/Office	Year First Elected/Appointed	Principal Occ
Marshall M. Williams(1) Calgary, Alberta	Director and Chairman of the Board	1997	Businessman; Ch
S. Brian Gieni(2) Calgary, Alberta	Director, President and Chief Executive Officer	2000	President and Chie the Manager, Ven Ultim
Gary Lee(3) Calgary, Alberta	Director	2000	Director of Nort
John M. Gunn(4) Calgary, Alberta	Director	1999	Chief Executive Off Officer of T
Arthur E. Dumont(5)	Director	2001	Chairman and Chief

Calgary, Alberta			Technicoi
Henry R. Lawrie(6) Calgary, Alberta	Director	2003	Busi
David Tuer(7) Calgary, Alberta	Director	2003	Chairman and Chief Hawker Re
Kenneth G. Pinsky(8) Calgary, Alberta	Chief Financial Officer	2001	Chief Financial Of Ventures, Acquire
Michael P. Wihak(9) Calgary, Alberta	Chief Operating Officer	2001	Chief Operating Of Ventures, Acquire
John H. Kousinioris(10) Calgary, Alberta	Secretary	2003	Partner, Be Barristers

Notes:

1. Mr. Williams is a former Chairman of Alberta Treasury Branches. Mr. Williams has also served as Chairman of the Board and a Director of TransAlta Corporation and as a director of Stelco Inc. from 1984 to 1996 and as a director of Sun Life Assurance from 1978 to 1995.

2. Mr. Gieni is a finance and accounting professional who was employed in various senior management capacities at PanCanadian Petroleum Limited between 1997 and 2000. Prior to that, he was President, Chief Executive Officer and a director of Grantham Resources Inc., a junior resource company listed on the Alberta Stock Exchange.
3. Mr. Lee is a director and officer of North West Capital Inc. Prior to that, he was a partner with Hoar, Lee, Boers, Barristers & Solicitors, until December 1998.
4. Mr. Gunn was the Chairman of Renata Resources Inc., a TSX-listed oil and gas company, from 1996 until it was acquired in 2000. Prior thereto, Mr. Gunn was President and Chief Executive Officer of Ballistic Energy Corporation (formerly a TSX-listed oil and gas company).
5. Mr. Dumont was the President and Chief Executive Officer of CenAlta Energy Services and its predecessor companies from November 1998 until October 2000. He has also worked in senior roles at Western Rock Bit Company, Precision Drilling, Kenting Energy Services and Trimac Limited.
6. Mr. Lawrie is a Chartered Accountant - FCA. From July 1997 to February 2001 Mr. Lawrie was the Chief Accountant of the Alberta Securities Commission. Prior to that, Mr. Lawrie spent 35 years as a Chartered Accountant with PriceWaterhouseCoopers and acted as managing partner of the Calgary office before retiring in 1997.
7. Mr. Tuer has been Chairman and Chief Executive Officer of Hawker Resources Inc. since January 2003 and Chairman of the Calgary Health Region since October 2001. From December 1994 until October 2001, Mr. Tuer was President and Chief Executive Officer of PanCanadian Energy Corporation. Prior thereto, Mr. Tuer worked in various senior roles at PanCanadian Petroleum Limited.
8. Mr. Pinsky is a Chartered Accountant and a Chartered Financial Analyst. Most recently, Mr. Pinsky held management positions with Altana Exploration from September 1997 to December 2000 and Price Waterhouse from 1993 to 1997.
9. Mr. Wihak is a professional engineer and holds a Masters in Business Administration. Most recently, Mr. Wihak held a management position at Sunoma Energy Corp./Barrington Petroleum Ltd. from 1997 to 2001. Prior to

that, he was a senior exploitation engineer with Summit Resources Ltd. from 1993 to 1996.

10. Mr. Kousinioris joined Bennett Jones LLP in 1990. From February 1997 until September 1998, Mr. Kousinioris practiced with a leading law firm in London, England, following which, he returned to Bennett Jones LLP and is currently a partner in the Corporate/Commercial Department.

The board of directors of each of Ventures and AcquireCo has appointed a human resources committee, a reserves committee, a governance committee and, consistent with the requirements for a "distributing corporation" under the ABCA, an audit committee. The human resources committee consists of Mr. Lee (Chairman), Mr. Lawrie and Mr. Williams. The reserves committee consists of Mr. Gunn (Chairman), Mr. Tuer and Mr. Dumont. The governance committee consists of Mr. Dumont (Chairman), Mr. Tuer and Mr. Williams. The audit committee consists of Mr. Lawrie (Chairman), Mr. Gunn and Mr. Lee.

The directors and officers of Ventures and AcquireCo beneficially own, directly or indirectly, or exercise control or direction over 535,921 (1%) of the Trust Units currently issued and outstanding.

The Manager

The following table sets forth the name, municipality of residence, positions/offices held, year first elected/appointed and principal occupation of each of the directors and officers of the Manager as at the date hereof. Each director will hold office until the next annual meeting of shareholders of the Manager or until his successor is duly elected or appointed. It is presently intended that the directors and officers of the Manager will be the same as those of Ventures and AcquireCo.

Name and Municipality of Residence	Position /Office	Year First Elected/Appointed	Princip
Marshall M. Williams(1) Calgary, Alberta	Director and Chairman of the Board	2003	Business of
S. Brian Gieni(2) Calgary, Alberta	Director, President and Chief Executive Officer	2001	President and Ch of the Manager, V Ulti
Gary Lee(3) Calgary, Alberta	Director	2000	Director of Nor

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Name and Municipality of Residence	Position /Office	Year First Elected/Appointed	Princip
John M. Gunn(4)	Director	2003	Chief Executi

Calgary, Alberta			Financial Office
Arthur E. Dumont(5) Calgary, Alberta	Director	2003	Chairman and Chie Technico
Henry R. Lawrie(6) Calgary, Alberta	Director	2003	Bus
David Tuer(7) Calgary, Alberta	Director	2003	Chairman and Chie Hawker Re
Kenneth G. Pinsky(8) Calgary, Alberta	Chief Financial Officer	2001	Chief Financial O Ventures, Acquir
Michael P. Wihak(9) Calgary, Alberta	Chief Operating Officer	2001	Chief Operating O Ventures, Acquir
John H. Kousinioris(10) Calgary, Alberta	Secretary	2003	Partner, B Barristers

Notes:

1. Mr. Williams is a former Chairman of Alberta Treasury Branches. Mr. Williams has also served as Chairman of the Board and a Director of TransAlta Corporation and as a director of Stelco Inc. from 1984 to 1996 and as a director of Sun Life Assurance from 1978 to 1995.
2. Mr. Gieni is a finance and accounting professional who was employed in various senior management capacities at PanCanadian Petroleum Limited between 1997 and 2000. Prior to that, he was President, Chief Executive Officer and director of Grantham Resources Inc., a junior resource company listed on the Alberta Stock Exchange.
3. Mr. Lee is a director and officer of North West Capital Inc. Prior to that, he was a partner with Hoar, Lee, Boers until December 1998.
4. Mr. Gunn was the Chairman of Renata Resources Inc., a TSX-listed oil and gas company, from 1996 until it was acquired in 2000. Prior thereto, Mr. Gunn was President and Chief Executive Officer of Ballistic Energy Corporation (formerly a TSX-listed oil and gas company).
5. Mr. Dumont was the President and Chief Executive Officer of CenAlta Energy Services and its predecessor companies from November 1998 until October 2000. He has also worked in senior roles at Western Rock Bit Company, Precision Drilling, Kenting Energy Services and Trimac Limited.
6. Mr. Lawrie is a Chartered Accountant - FCA. From July 1997 to February 2001 Mr. Lawrie was the Chief Accountant of the Alberta Securities Commission. Prior to that, Mr. Lawrie spent 35 years as a Chartered Accountant with PriceWaterhouseCoopers and acted as managing partner of the Calgary office before retiring in 1997.
7. Mr. Tuer has been Chairman and Chief Executive Officer of Hawker Resources Inc. since January 2003 and Chairman of the Calgary Health Region since October 2001. From December 1994 until October 2001, Mr. Tuer was President and Chief Executive Officer of PanCanadian Energy Corporation. Prior thereto, Mr. Tuer worked in various senior roles at PanCanadian Petroleum Limited.
8. Mr. Pinsky is a Chartered Accountant and a Chartered Financial Analyst. Most recently, Mr. Pinsky held management positions with Altana Exploration from September 1997 to December 2000 and Price Waterhouse from 1993 to 1997.
9. Mr. Wihak is a professional engineer and holds a Masters in Business Administration. Most recently, Mr. Wihak held a management position at Sunoma Energy Corp./Barrington Petroleum Ltd. from 1997 to 2001. Prior to that, he was a senior exploitation engineer with Summit Resources Ltd. from 1993 to 1996.
10. Mr. Kousinioris joined Bennett Jones LLP in 1990. From February 1997 until

September 1998, Mr. Kousinioris practiced with a leading law firm in London, England, following which, he returned to Bennett Jones LLP and is currently a partner in the Corporate/Commercial Department.

CONFLICTS OF INTEREST

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

ADDITIONAL INFORMATION

Additional information relating to the Trust may be found on SEDAR at www.sedar.com.

Additional information, including information concerning remuneration and indebtedness of the directors and officers of Ventures, AcquireCo, the Manager and Ultima Energy, principal holders of Trust Units, any Rights to purchase Trust Units, and interests of insiders in material transactions, if applicable, is contained in the Information Circular prepared in relation to the Annual and Special Meeting of Unitholders to be held on June 4, 2004 and additional financial information is provided in the financial statements and Management's Discussion & Analysis of the Trust and the Trust's subsidiaries for the year ended December 31, 2003.

At any time, upon request made to the Chief Financial Officer of the Manager, the Manager will provide to any person or company:

a) when the securities of the Trust are in the course of a distribution under a preliminary short form prospectus or a short form prospectus,

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

   ii) one copy of the comparative financial statements of the Trust for its most recently completed financial year for which financial statements have been filed together with the accompanying report of the auditor and one copy of the most recent interim financial statements of the Trust 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 Trust in respect of its most recent annual meeting of Unitholders that involved the election of directors or one copy of any annual filing prepared instead of the information circular, as appropriate, and

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

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

The Chief Financial Officer of the Manager can be contacted as follows:

Ultima Management Inc.
1000, 350 - 7th Avenue SW
Calgary, AB T2P 3N9
Attention: Chief Financial Officer

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EXHIBIT "A"

FORM 51-101F2
REPORT ON RESERVES DATA BY
INDEPENDENT QUALIFIED RESERVES
EVALUATOR

Report on Reserves Data

To the board of directors of Ultima Ventures Corp., on behalf of Ultima Energy Trust and its affiliates (collectively referred to herein as "Ultima"):

1. We have evaluated Ultima's reserves data as at December 31, 2003. The reserves data consist of the following:

   (a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

   (ii) the related estimated future net revenue; and

   (b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and

   (ii) the related estimated future net revenue.

2. The reserves data are the responsibility of Ultima's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of Ultima evaluated by us for the year ended December 31, 2003, and identifies

the respective portions thereof that we have evaluated and reported on to Ultima's board of directors:

Independent Qualified Reserves Evaluator or Auditor	Description and Preparation Date of Evaluation Report	Location of Reserves (Country or Foreign Geographic Area)	Net Present Value of Future N (before income taxes, 10% d Evaluated
McDaniel & Associates Consultants Ltd.	100% of all reserves excluding Weyburn Unit NRI March 8, 2004	Canada	$216,479
Gilbert Laustsen Jung Associates Ltd.	Weyburn Unit NRI March 1, 2004	Canada	$84,630
Totals			$301,109

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We have no responsibility to update our reports referred to in paragraph 4 for events and circumstances occurring after their respective preparation dates.

6. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

Executed as to our report referred to above:

April 28, 2004, Calgary, Alberta, Canada.

McDaniel & Associates Consultants Ltd.

(Signed) P.A. Welch, P.Eng.
Executive Vice President

Gilbert Laustsen Jung Associates Ltd.

(Signed) Dana B. Laustsen, P.Eng.
Executive Vice President

EXHIBIT "B"

FORM 51-101F3
REPORT OF
MANAGEMENT AND DIRECTORS
ON OIL AND GAS DISCLOSURE

Management of Ultima Ventures Corp. (the "Company"), for and on behalf of Ultima Energy Trust (the "Trust") are responsible for the preparation and disclosure of information with respect to the Trust's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which consist of the following:

(a) (i) proved and proved plus probable oil and gas reserves estimated as at December 31, 2003 using forecast prices and costs; and

(ii) the related estimated future net revenue; and

(b) (i) proved oil and gas reserves estimated as at December 31, 2003 using constant prices and costs; and

(ii) the related estimated future net revenue.

An independent qualified reserves evaluator has evaluated and reviewed the Trust's reserves data. The report of the independent qualified reserves evaluator is presented below.

The Reserves Committee of the board of directors of the Company has

(c) reviewed the Company's procedures for providing information to the independent qualified reserves evaluator;

(d) met with the independent qualified reserves evaluator to determine whether any restrictions affected the ability of the independent qualified reserves evaluator to report without reservation; and

(e) reviewed the reserves data with management and the independent qualified reserves evaluator.

The Reserves Committee of the board of directors has reviewed the Company's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The board of directors has, on the recommendation of the Reserves Committee, approved

(f) the content and filing with securities regulatory authorities of the reserves data and other oil and gas information;

(g) the filing of the report of the independent qualified reserves evaluator on the reserves data; and

(h) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material.

(Signed) S. Brian Gieni	(Signed) Michael P. Wihak
S. Brian Gieni	Michael P. Wihak, P.Eng.

President & Chief Executive Officer	Chief Operating Officer
(Signed) John M. Gunn	(Signed) Arthur E. Dumont
John M. Gunn, P.Eng.	Arthur E. Dumont, P.Eng.
Director, Chairman Reserves Committee	Director

April 30, 2004

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EXHIBIT "C"

AUDITORS' REPORT

To the Directors
Trioco Resources Inc.

We have audited the balance sheets of Trioco Resources Inc. as at December 31, 2002 and 2001 and the statements of income and retained earnings and cash flows for the years ended December 31, 2002 and December 31, 2001. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2002 and 2001 and the results of its operations and its cash flows for the years ended December 31, 2002 and December 31, 2001 in accordance with Canadian generally accepted accounting principles.

(signed) "Collins Barrow Calgary LLP"
CHARTERED ACCOUNTANTS

Calgary, Alberta
March 31, 2003
(except for note 9 which
is dated June 20, 2003)

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TRIOCO RESOURCES INC.

BALANCE SHEETS

	March 31, 2003	December 31, 2002
	(unaudited)	
Assets		
Current assets		
Cash and cash equivalents	$ 1,223,850	$
Accounts receivable	3,616,027	2,252,36
Income taxes recoverable	-	2,30
Prepaid expenses and deposits	199,825	235,58
	5,039,702	2,490,25
Property and equipment (note 3)	40,854,374	37,782,65
	$45,894,076	$ 40,272,91
Liabilities		
Current liabilities		
Bank overdraft	$ -	$ 290,68
Accounts payable and accrued liabilities	4,701,451	3,084,63
Income taxes payable	-	
Bank loan (note 4)	10,000,000	14,090,00
	14,701,451	17,465,31
Future removal and site restoration costs	67,233	53,00
Future income taxes (note 5)	2,990,442	2,111,12
	17,759,126	19,629,45
Shareholders' Equity		
Share capital (note 6)	23,350,940	17,343,44
Retained earnings	4,784,010	3,300,02
	28,134,950	20,643,46
	$45,894,076	$ 40,272,91

Approved by the Board,

(signed) "David J. Macfie" , Director

(signed) "Donna J. Yee-Kwan" , Director

TRIOCO RESOURCES INC.
STATEMENTS OF INCOME AND RETAINED EARNINGS

	Three months ended March 31, 2003	March 31, 2002	Year end December 2002
	(unaudited)		
Revenue			
Petroleum and natural gas sales	$ 5,857,863	$ 3,807,397	$ 12,31
Less: Royalties, net of Alberta Royalty Tax Credit	(1,392,521)	(420,583)	(1,95
Interest and other	5,783	1,642	
	4,471,125	3,388,456	10,36
Expenses			
Production	685,417	464,124	1,96
General and administrative	236,899	225,441	98
Interest on bank loan	132,039	58,688	37
Depletion and depreciation	1,036,166	695,547	2,89
	2,090,521	1,443,800	6,21
Income before income taxes	2,380,604	1,944,656	4,14
Income taxes (note 5)			
Capital	17,300	8,032	5
Future	879,314	697,484	1,54
	896,614	705,516	1,60
Net income	1,483,990	1,239,140	2,54
Retained earnings (deficit), beginning of period	3,300,020	751,703	75
Retained earnings, end of period	$ 4,784,010	$ 1,990,843	$ 3,30
Earnings per share (note 6[g]) Basic	$ 0.07	$ 0.07	$
Diluted	$ 0.07	$ 0.07	$

TRIOCO RESOURCES INC.
STATEMENTS OF CASH FLOWS

	Three months ended March 31, 2003	Three months ended March 31 2002	Year e Decembe 200
	(unaudited)		
Operating activities			
Net income	$ 1,483,990	$ 1,239,140	$ 2,54
Add items not requiring cash			
Depletion and depreciation	1,036,166	695,547	2,89
Future income taxes	879,314	697,484	1,54
Funds from operations	3,399,470	2,632,171	6,97
Changes in non-cash working capital	(882,033)	425,514	(267
	2,517,437	3,057,685	6,71
Financing activities			
Proceeds from (repayment of) bank loan, net	(4,090,000)	(500,000)	10,09
Proceeds from issuance of share capital, net	6,007,500	-	
	1,917,500	(500,000)	10,09
Investing activities			
Capital, exploration and development expenditures, net	(4,093,653)	(1,043,395)	(18,042
Removal and site restoration costs	-	-	(3
Changes in non-cash working capital	1,173,250	(385,925)	31
	(2,920,403)	(1,429,320)	(17,733
Cash inflow (outflow)	1,514,534	1,128,365	(932
Cash and cash equivalents (bank overdraft), beginning of period	(290,684)	641,890	64
Cash and cash equivalents (bank overdraft), end of period	$ 1,223,850	$ 1,770,255	$ (290
Supplemental cash flows disclosure:			
Interest paid	$ 132,039	$ 58,688	$ 37
Capital taxes paid	$ 17,300	$ -	$9

TRIOCO RESOURCES INC.
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2002 AND DECEMBER 31, 2001

(Information as at March 31, 2003 and for the three-month periods ended March 31, 2003 and March 31, 2002 are unaudited)

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1. Company activities

The Company was incorporated under the laws of Alberta by Articles of Incorporation dated October 30, 2000. The Company is engaged in the exploration for and development of petroleum and natural gas properties in western Canada.

2. Summary of significant accounting policies

These financial statements have been prepared using accounting principles generally accepted in Canada which include:

(a) Cash and cash equivalents

Cash and cash equivalents consist of amounts on deposit with banks and highly liquid investments with maturities of 90 days or less at issue.

(b) Petroleum and natural gas exploration and development expenditures

(i) Capitalized costs

The Company follows the Canadian full cost method of accounting whereby all costs related to the exploration for and the development of petroleum and natural gas reserves are initially capitalized and accumulated in cost centres by country. Costs capitalized include land acquisition costs, geological and geophysical expenditures, rentals on undeveloped properties, costs of drilling productive and non-productive wells, together with overhead and interest directly related to exploration and development activities and lease and well equipment. Proceeds from the disposition of properties will be applied as a reduction of the cost of the remaining assets, except when a significant disposition occurs, in which case a gain or loss on disposal is recorded. Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless such a disposition would significantly alter the related cost centre's rate of depletion and depreciation. A significant disposition would cause a change of 20% or more in an annual depletion and depreciation rate.

(ii) Future capital costs

In addition to the capitalized costs incurred to date in the exploration and development of petroleum and natural gas properties, the operations and further development require future expenditures. For purposes of calculating depletion and depreciation expense and the ceiling test, estimates of future expenditures and recoveries have been prepared for:

- future development costs of proven developed and undeveloped reserves as determined by independent and Company engineers;
- site restoration costs as determined by management; and
- net realizable value of production equipment and facilities after proven reserves are fully produced as determined by management.

(iii) Depletion and depreciation

Costs capitalized are depleted and depreciated using the unit-of-production method by cost centre based upon gross proven developed and undeveloped petroleum and natural gas reserves as determined by independent and Company engineers. For purposes of the calculation, petroleum and natural gas reserves are converted to a common unit of measure on the basis of their relative energy content, whereby one barrel of oil is equivalent to six thousand cubic feet of natural gas.

The cost of significant unproved properties are excluded from the depletion and depreciation base until it is determined whether proved reserves are attributable to the properties, or impairment has occurred.

(iv) Future removal and site restoration costs

Estimated future removal and site restoration costs are provided for over the life of the proven reserves on a unit-of-production basis. Costs which include the cost of production equipment removal and environmental clean-up are estimated each year by management based on current regulations, costs, technology and industry standards. The current site restoration provision represents the annual recognition of such expense based upon production volumes of that year. The annual charge is included in the provision for depletion and depreciation and the actual restoration expenditures are charged to the accumulated provision account as incurred.

(v) Ceiling test

In applying the full cost method, the Company performs a ceiling test which restricts the capitalized costs less accumulated depletion and depreciation, future income taxes and future site restoration for each cost centre from exceeding an amount equal to the estimated undiscounted value of future net revenues from proven petroleum and natural gas reserves, based on year-end prices and costs, and after deducting estimated future production-related general and administrative expenses, estimated future removal and site restoration costs, financing costs and applicable income and capital taxes.

(vi) Measurement uncertainty

The amounts recorded for depletion and depreciation of exploration and development costs, the provision for future removal and site restoration costs and the ceiling test are based on estimated proven reserves, production rates, future petroleum and natural gas prices and future costs. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates in future periods could be significant.

TRIOCO RESOURCES INC.
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2002 AND DECEMBER 31, 2001
(Information as at March 31, 2003 and for the three-month periods ended March 31, 2003 and March 31, 2002 are unaudited)

(c) Depreciation

Other assets are depreciated using the straight-line method at an annual rate of 20%.

(d) Bank loan

Effective for the period commencing January 1, 2002, the Canadian Institute of Chartered Accountants ("CICA") amended Generally Accepted Accounting Principles to require all bank loans, where the lender has the right to demand repayment within 12 months (other than in the event of default or breach of covenants), to be classified as current liabilities. Since the Company's debt is of a demand nature, this loan has been classified as current. The bank loan at December 31, 2001 has been restated to conform with the current presentation. The Company is not in breach of any covenants under its credit facility.

(e) Income taxes

Income taxes are accounted for using the liability method of income tax allocation. Under the liability method, income tax assets and liabilities are recorded to recognize future income tax inflows and outflows arising from the settlement or recovery of assets and liabilities at the carrying values. Income tax assets are also recognized for the benefits from tax losses and deductions that cannot be identified with particular assets or liabilities, provided those benefits are more likely than not to be realized. Future income tax assets and liabilities are determined based on the tax laws and rates that are anticipated to apply in the year of realization.

(f) Flow-through shares

The Company, from time to time, issues flow-through shares to finance a portion of its capital expenditure program. Pursuant to the terms of the flow-through share agreements, the tax deductions associated with the expenditures are renounced to the subscribers. Accordingly, share capital is reduced and a future tax liability is recorded equal to the estimated amount of future income taxes payable by the Company as a result of the renunciations, when the expenditures are incurred.

(g) Stock-based compensation

The Company has three stock-based compensation plans as described in note 6(e).

Stock options granted to non-employees are accounted for using the fair value method under which compensation expense is recorded based on the estimated fair value of the options at the grant date.

No compensation expense is recognized when stock options are issued to directors, officers and employees. Any consideration received by the Company on exercise of stock options is credited to share capital.

On January 1, 2002, the CICA issued Section 3870, Stock-Based Compensation and Other Stock-Based Payments, which requires disclosure, on a pro-forma basis, had compensation expense for the stock options been determined using the fair value method. The Company elected to defer the application of this Section until fiscal years beginning after January 1, 2003 as allowed for private companies under Section 3870.

Effective January 1, 2003, the Company adopted prospectively Section 3870 with respect to accounting for stock-based compensation arrangements. The Company has elected to use the intrinsic value-based method of accounting for its stock option plans, whereby, no compensation expense is recorded for stock options issued to directors, officers and employees that have an exercise price equal to the fair value of the stock at the date options are granted. The Company disclosed in note 6(f) the pro-forma results of using the fair value method, under which compensation expense is recorded based upon the estimated fair value of the options. Pro-forma results will be presented only for the effects of options granted subsequent to January 1, 2003.

The amounts disclosed related to fair values of stock options issues, and the resultant pro-forma income effects (note 6[f]) are based on estimates of future volatility of the Company's share price, expected lives of the options, expected dividends to be paid by the Company and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect of changes in such estimates on the financial statements of future periods could be significant.

(h) Revenue recognition

Revenue from the sale of petroleum and natural gas is recognized based on volumes delivered to customers at contractual delivery points and rates. The costs associated with the delivery, including operating and maintenance costs, transportation and production-based royalty expenses are recognized in the same period in which the related revenue is earned and recorded.

(i) Earnings per share

The treasury stock method is used for the calculation of diluted earnings per share. This method assumes that the proceeds on the exercise of stock options are used to repurchase Company shares at a price of $1.50 (March 31, 2002 - $1.29; December 31, 2002 - $1.50; December 31, 2001 - $1.29).

(j) Joint venture accounting

Substantially all of the Company's exploration and production activities are conducted jointly with others, and accordingly, these financial statements reflect only the Company's proportionate interest in such activities.

TRIOCO RESOURCES INC.
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2002 AND DECEMBER 31, 2001
(Information as at March 31, 2003 and for the three-month periods ended March 31, 2003 and March 31, 2002 are unaudited)

(k) Hedging activities

The Company, from time to time, enters into forward contracts and swap agreements to hedge its exposure to the risks associated with fluctuating petroleum and natural gas prices. The purpose of the hedge is to lock in the price for a portion of the Company's production. Gains and losses associated with risk management activities are recorded as adjustments to the production revenue at the time the related production is sold.

The Company identifies all relationships between the hedging instruments and hedged production, as well as its risk management objective and strategy for undertaking various risk management transactions. The Company believes that the risk management activities are effective hedges, both at inception and over the term of the contracts. The contracts entered into are not speculative derivative transactions.

3. Property and equipment

	March 31, 2003	De 2002
Petroleum and natural gas properties including exploration and development thereon	$ 35,747,299	$ 32,605,460
Production equipment and facilities	10,275,665	9,340,170
Other	90,063	73,744
	46,113,027	42,019,374
Accumulated depletion and depreciation	5,258,653	4,236,715
	$ 40,854,374	$ 37,782,659

Future removal and site restoration costs are estimated in aggregate to be $675,000 (March 31, 2002 - $300,000; December 31, 2002 - $600,000; December 31, 2001 - $300,000) of which $14,228 (March 31, 2002 - $8,565; December 31, 2002 - $39,920; December 31, 2001 - $16,919) has been charged to income in the current period.

During the period, the Company capitalized $14,352 (March 31, 2002 - $29,383; December 31, 2002 - $99,209; December 31, 2001 - $114,134) of a total of $251,251 (March 31, 2002 - $254,824; December 31, 2002 - $1,082,583; December 31, 2001 - $752,639) in general and administrative expenses. No interest has been capitalized.

Costs of unproven petroleum and natural gas properties in the amount of $1,337,983 (March 31, 2002 - $919,700; December 31, 2002 - $1,337,983; December 31, 2001 - $919,700) have been excluded from costs subject to depletion.

4. Bank loan

The Company has available a demand revolving credit facility to a maximum of $17,000,000. The loan is available to the Company by way of prime rate loans, banker's acceptances and letters of credit. The production loan bears interest at a Canadian chartered bank's prime rate plus 0.75% per annum or banker's acceptance rates plus stamping fees of 1.75% per annum. The Company has provided security for the facility by way of a $25,000,000 floating charge demand debenture on all assets, a general assignment of book debts and a specific assignment of certain natural gas contracts. As of March 31, 2003, $10,000,000 has been drawn down on the facility.

The facility revolves for a period of 364 days, is scheduled for renewal on May 31, 2003 and may be extended upon the written consent of the bank.

Under the terms of the agreement, the Company is required to meet certain financial and engineering reporting requirements and may not breach certain financial tests without prior consent of the bank.

5. Income taxes

(a) Significant components of the future income tax liability are as follows:

	March 31, 2003	2002	December 31,
Temporary differences related to property and equipment and future site restoration	$ 3,049,859	$ 2,175,553	$
Share issuance costs	(31,052)	(47,647)	
Attributed Royalty Income deduction carryforward	(28,365)	(16,778)	
	$ 2,990,442	$ 2,111,128	

(b) Income tax expense differs from that which would be expected from applying the combined Canadian federal and provincial income tax rates of 41.12% (March 31, 2002 - 42.12%; December 31, 2002 - 42.12%; December 31, 2001 - 42.62%) to income before income taxes. The difference results from the following:

	Three months ended March 31, 2003	March 31, 2002	Year en December 2002
Expected income tax provision	$ 978,904	$ 819,089	$ 1,747
Increase (decrease) resulting from:			
Resource allowance	(503,361)	(298,225)	(886,
Non-deductible crown payments, net of Alberta Royalty Tax Credit	453,633	180,542	680,
Change in value of tax reserves due to tax reassessments and change in tax rates	(50,522)	(3,922)	(3,
Other	660	-	1,
Future income taxes	879,314	697,484	1,540,
Capital tax	17,300	8,032	59,
Reported tax provision	$ 896,614	$ 705,516	$ 1,600,

6. Share capital

(a) Authorized

Unlimited number of voting common shares
Unlimited number of voting, convertible preferred shares

Preferred shares are converted into common shares on a 1:1 ratio. Preferred shares share rateably with common shares in any dividends, as and when declared. The holders of preferred shares and common shares vote together as a single class.

NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2002 AND DECEMBER 31, 2001
(Information as at March 31, 2003 and for the three-month periods ended March 31, 2003 and March 31, 2002 are unaudited)

(b) Issued

	March 31, 2003		December 31, 2002		2
Common Shares	Number	Stated Value	Number	Stated Value	Number
Balance, beginning of period	921,060	$ 921	921,060	$ 921	5,000,0
Issued for cash	4,005,000	6,007,500	-	-	921,0
Conversion to preferred shares (note 6[c])	-	-	-	-	(3,500,00
Surrender of common shares (note 6[d])	-	-	-	-	(1,500,00
Balance, end of period	4,926,060	6,008,421	921,060	921	921,0
Preferred Shares					
Balance beginning of period	17,525,000	17,525,000	17,525,000	17,525,000	
Issued for cash	-	-	-	-	17,350,0
On conversion of common shares (note 6[c])	-	-	-	-	175,0
	17,525,000	17,525,000	17,525,000	17,525,000	17,525,0
		23,533,421		17,525,921	
Less: Share issuance costs, net of income tax benefit of $80,141		(107,896)		(107,896)	
Reduction due to income tax deductions renounced to subscribers		(74,585)		(74,585)	
Balance, end of period		$ 23,350,940		$ 17,343,440	

(c) In conjunction with financing provided by Natural Gas Partners VI L.P., the existing shareholders converted 3,500,000 common shares to 175,000 preferred shares.

(d) In conjunction with financing provided by Natural Gas Partners VI L.P., the existing shareholders surrendered 1,500,000 common shares for $75,000.

(e) Stock option plans

At March 31, 2003 the Company has three stock option plans which are described below.

(i) Time vesting options

Under the Company's time vesting option plan, the Company may grant options to its directors, officers, employees and consultants. The maximum number of shares which may be reserved for issuance under the plan is 2,071,780 common shares. The initial exercise price of the options is $1.00 and escalates by a factor of 10% per annum effective January 23, 2002. Options granted under the plan will expire January 23, 2006. All options granted vest one-third on each of the first, second and third anniversary dates of the granting of the options.

A summary of the status of the Company's time vesting stock option plan, as at March 31, 2003, December 31, 2002 and December 31, 2001 and changes during the periods then ending are as follows:

	March 31, 2003		Decembe 2002	
	Number of Options	Exercise Price	Number of Options	Exercise Price
Outstanding, beginning of period	1,707,740	$ 1.13	1,582,740	$ 1.10
Granted	-	-	125,000	$ 1.10
Outstanding, end of period	1,707,740	$ 1.13	1,707,740	$ 1.10
Options exercisable at period end	1,096,828		527,580	

(ii) Performance vesting options

Under the Company's performance vesting option plan, the Company may grant options to its directors, officers, employees and consultants. The maximum number of shares which may be reserved for issuance under the plan is 465,180 common shares. The initial exercise price of the options is $1.00.

Options granted under the plan will expire January 23, 2006. The performance vesting options are only exercisable upon the Company meeting a certain financial benchmark.

A summary of the status of the Company performance vesting stock option plan as of March 31, 2003, December 31, 2002, and December 31, 2001 and changes during the periods then ending are as follows:

	March 31, 2003		December 2002	
	Number of Options	Exercise Price	Number of Options	Exercise Price
Outstanding, beginning of period	381,126	$ 1.00	354,126	$ 1.00
Granted	-	-	27,000	$ 1.00
Outstanding, end of period	381,126	$ 1.00	381,126	$ 1.00
Options exercisable at period end	-		-	

(iii) New time vesting options

On January 23, 2003, the Company created a third stock option plan entitled "New Time Vesting Options". The maximum number of shares which may be reserved for issuance under the plan is 444,444 common shares. The exercise price of the options is set at $1.50. Options granted under the plan will expire January 23, 2006. All options granted vest two-thirds on the grant date and one-third on the first anniversary date of the grant date. On

January 23, 2003, 444,444 options were granted to employees under the plan and 296,296 are exercisable at March 31, 2003.

(f) Stock-based compensation expense

On January 23, 2003, the Company issued New Time Vesting Options to employees of the Company to purchase 444,444 common shares at a price of $1.50 per option. On a pro forma basis, had compensation expense for the stock options been determined based on the fair value method, the Company's net income and earnings per share for the period ended March 31, 2003 would have been as follows:

Net income	As reported	$
	Pro-forma	$
Earnings per share - As reported	- basic	$
	- diluted	$
Earnings per share - Pro forma	- basic	$
	- diluted	$

The fair value of the stock options at the date of grant was estimated using the Black-Scholes model with the assumptions being a risk free rate of 2.83%, an expected option life of three years, a share price volatility of 0% and a zero dividend yield. The

total fair value of the options granted was estimated to be $53,333 of which $35,555 has been recognized for pro forma disclosure.

(g) Per share amounts

Earnings per share has been calculated based on the weighted average number of common and preferred shares outstanding during the period of 21,472,060 (March 31, 2002 - 18,446,060; December 31, 2002 - 18,446,060; December 31, 2001 - 17,347,314).

Preferred shares are included in the calculation of weighted average number of shares outstanding as these shares have the same rights and privileges as common shares.

A reconciliation of the denominators for the per share calculations is outlined below:

	March 31,		
	2003	2002	2002

Basic weighted average shares	21,472,060	18,446,060	18,446,0
Effect of dilutive time vesting options	511,039	465,749	552,4
Diluted weighted average shares	21,983,099	18,911,809	18,998,5

There is no change to the numerator in the calculation of diluted earnings per share for either year. Performance vesting options are not included in the calculation of diluted weighted average shares as the performance criteria has not been satisfied. New Time Vesting Options have not been included in the calculation of diluted weighted average shares for the period ended March 31, 2003 as the effect is anti-dilutive.

7. Commitments

The Company is committed under a lease on its office premise expiring April 30, 2004 for future minimum lease payments including estimated operating costs for the fiscal years ending as follows:

December 31, 2003	$ 65,423
December 31, 2004	29,447
	$ 94,870

TRIOCO RESOURCES INC.
NOTES TO FINANCIAL STATEMENTS
DECEMBER 31, 2002 AND DECEMBER 31, 2001
(Information as at March 31, 2003 and for the three-month periods ended March 31, 2003 and March 31, 2002 are unaudited)

8. Financial instruments

(a) Fair values

The fair values of the Company's accounts receivable, deposits, bank overdraft and accounts payable and accrued liabilities are estimated to approximate their carrying values due to the immediate or short-term maturity of these financial instruments. The fair value of the Company's bank loan approximates its carrying value as it bears interest at variable market rates.

(b) Credit risk

Substantially all of the Company's accounts receivable are due from companies involved in the petroleum and natural gas industry in Canada and are, therefore, subject to the same economic risks as the industry as a whole.

The Company's maximum credit risk exposure is limited to the carrying value of its accounts receivable of $3,616,027 (December 31, 2002 - $2,252,365; December 31, 2001 - $906,903). Credit risk is managed by the Company through diversification of marketing counter parties and credit monitoring procedures.

(c) Hedging activities

(i) The Company enters into hedge transactions for natural gas sales. The agreements entered into are forward financial transactions providing the Company with a range of fixed prices. Net natural gas sales for the period ended March 31, 2003 include gains (losses) of ($1,085,851) (March 31, 2002 - $1,743,239; December 31, 2002 - $1,519,943; December 31, 2001 - $404,330) on these transactions. The fair market value of the hedge contracts equals the unrecognized loss as described below.

The following hedge transactions are outstanding at March 31, 2003:

Commodity	Notional Volume	Strike Price	Term
Natural gas	1,000 GJ/day	$3.575/GJ	March 1, 2002 - February 29, 2004

As per the terms of the hedge agreement, the Company issued a letter of credit for Cdn. $600,000.

(ii) In order to manage exposure to fluctuations in petroleum and natural gas prices, the Company entered into forward physical contracts during the year fixing market prices.

The contracts have firm physical delivery obligations and are, therefore, considered forward commitment contracts, not financial instruments.

Commodity	Physical Volume	Strike Price	Floor Price	Ceiling Price

Oil	bbls/day (physical)	-	$25/bbl U.S.	$27.60/bbl U.S.	N D
Natural gas	2000 GJ/day (physical)	$3.95/GJ CDN	-	-	J D

9. Subsequent events

(a) On May 1, 2003, the Company granted 364,040 Time Vesting Options with an exercise price of $1.13 and 84,054 Performance Vesting Options with an exercise price of $1.00 to employees of the Company.

(b) On June 19, 2003, the Company's directors entered into an agreement to sell all of the issued and outstanding common and preferred shares of the Company to Ultima Acquisition Corp. at a price of $2.47 per share. The transaction is expected to close June 26, 2003. All options outstanding will vest immediately.

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EXHIBIT "D"
Compilation Report

To the Directors of Ultima Ventures Corp. and Ultima Acquisitions Corp.:

We have read the accompanying unaudited pro forma combined statement of income of Ultima Energy Trust (the "Trust") for the year ended December 31, 2003 and have performed the following procedures:

1. Compared the figures in the columns captioned "Ultima" to the audited consolidated financial statements of the Trust for the year ended December 31, 2003 and found them to be in agreement.

2. Compared the figures in the columns captioned "Trioco" to the unaudited financial statements of Trioco Resources Inc. ("Trioco") for the three months ended March 31, 2003 and the unaudited financial records of Trioco for the period from April 1, 2003 to June 25, 2003 and found them to be in agreement.

3. Made enquiries of certain officials of the Trust who have responsibility for financial and accounting matters about:

   (a) the basis for determination of the pro forma adjustment; and

   (b) whether the pro forma combined financial statement complies as to form in all material respects with the regulatory requirements of the various securities commissions and regulatory authorities in Canada.

   The officials of the Trust:

   (a) described to us the basis for determination of the pro forma adjustments, and

   (b) stated that the pro forma combined financial statement complies as to form in all material respects with the regulatory requirements of the various securities commissions and regulatory authorities in Canada.

4. Read the notes to the pro forma combined financial statement, and found them to be consistent with the basis described to us for determination of the pro forma adjustments.

5. Recalculated the application of the pro forma adjustments to the aggregate of the amounts in the columns captioned "Ultima" and "Trioco" for the year ended December 31, 2003, and found the amounts in the column captioned "Pro Forma Combined" to be arithmetically correct.

A pro forma financial statement is based on management assumptions and adjustments which are inherently subjective. The foregoing procedures are substantially less than either an audit or a review, the objective of which is the expression of assurance with respect to management's assumptions, the pro forma adjustments, and the application of the adjustments to the historical financial information. Accordingly, we express no such assurance. The foregoing procedures would not necessarily reveal matters of significance to the pro forma combined financial statement, and we therefore make no representation about the sufficiency of the procedures for the purposes of a reader of such statements.

Calgary, Alberta, Canada	(Signed) Deloitte & Touche LLP
April 30, 2004	Chartered Accountants

Comments for United States of America Readers on Differences Between Canadian and United States Reporting Standards

The above opinion, provided solely pursuant to Canadian requirements, is expressed in accordance with standards of reporting generally accepted in Canada. Such standards contemplate the expression of an opinion with respect to the compilation of pro forma financial statements. United States of America standards do not provide for the expression of an opinion on the compilation of pro forma financial statements. To report in conformity with United States of America standards on the reasonableness of the pro forma adjustments and their application to the pro forma financial statements would require an examination or review which would be substantially greater in scope than the review as to compilation only that we have conducted. Consequently, under United States of America standards, we would be unable to express any opinion with respect to the compilation of the accompanying unaudited pro forma combined statement of income.

Calgary, Alberta, Canada	(Signed) Deloitte & Touche LLP
April 30, 2004	Chartered Accountants

Ultima Energy Trust
Pro Forma Combined Statement of Income
For the year ended December 31, 2003
(Unaudited)
(Expressed in thousands of Canadian dollars except, for per unit amounts)

Total

	Ultima	Trioco March 31, 2003	Trioco April 1 to June 25	Pro Forma Adjustmen
Revenue				
Oil and natural gas	$ 111,107	$ 5,858	$ 3,412	$ -
Royalties	(21,810)	(1,393)	(1,608)	(127
Other	-	6	-	-
	-	-		-
	89,297	4,471	1,804	(127
Expenses				
Oil and natural gas operating	25,485	685	678	-
General and administrative	9,914	237	4,502	-
Management fee	487	-	-	113
Interest on long-term debt	3,171	132	121	(198
Unit based compensation	260	-	-	-
Capital taxes	76	17	17	-
Depletion and amortization	38,526	1,036	1,070	1,389
	77,919	2,107	6,388	1,304
Net income before income taxes	11,378	2,364	(4,584)	(1,431
Future income tax (recovery)/expense	(900)	880	(1,785)	(550
Net Income/(loss)	$ 12,278	$ 1,484	$ (2,799)	$ (881
Net income per unit, basic	$ 0.29	$ -	$ -	
Net income per unit, diluted	$ 0.28	$ -	$ -	

Ultima Energy Trust
Notes to Pro Forma Combined Statement of Income
DECEMBER 31, 2003
(unaudited)

1. BASIS OF PRESENTATION

The accompanying unaudited pro forma combined statement of income for the year ended December 31, 2003 ("the "Pro Forma Statement") has been prepared for inclusion in the Proxy Statement and Information Circular of Ultima Energy Trust ("Ultima" or the "Trust") dated April 30, 2004 (the "Circular"). The Pro Forma Statement gives effect to the applicable transactions described in Note 2 as if they had occurred on January 1, 2003.

The Pro Forma Statement has been prepared from:

- The audited consolidated financial statements of Ultima for the year ended December 31, 2003;

- The unaudited interim financial statements of Trioco for the three months ended March 31, 2003;
- The unaudited financial records of Trioco for the period April 1, 2003 to June 25, 2003.

The Pro Forma Statement should be read in conjunction with the audited consolidated financial statements of Ultima for the year ended December 31, 2003.

In the opinion of management of Ultima, the Pro Forma Statement includes all material adjustments necessary for fair presentation in accordance with Canadian generally accepted accounting principles ("Canadian GAAP"). Accounting policies used in the preparation of the Pro Forma Statement are in accordance with those disclosed in the audited consolidated financial statements of Ultima for the year ended December 31, 2003.

The Pro Forma Statement is not necessarily indicative of the results of operations that would have occurred for the year ended December 31, 2003 nor are they necessarily indicative of the operations of future periods. In preparing the Pro Forma Statement, no adjustments have been made to recognize any operating synergies or general and administrative cost savings that may be expected to occur as a result of the transactions noted above.

2. Pro Forma adjustments and assumptions

The Pro Forma Statement gives effect to the following transactions, adjustments and assumptions:

a) The acquisition of Trioco by a wholly-owned subsidiary of the Trust for $71,000,000 including adjustments and other costs on June 26, 2003. The acquisition is accounted for using the purchase method and the purchase price is allocated as follows:

	(000s)
Current assets	$ 5,040
Capital assets	71,000
Goodwill	16,682
Current liabilities	(3,863)
Future income taxes	(15,298)
Future site restoration	(67)
	$ 71,000

Paid by	
Cash	$ 61,000
Bank indebtedness assumed	10,000
	$ 71,000

b) The interest charge on bank debt related to the acquisition, less the proceeds from the issue of 12,000,000 Trust units for net proceeds of $59,130,000 pursuant to a prospectus dated July 7, 2003, has been recorded at 4.5% per annum with no deemed principal repayments.

c) The 3.0% management fee in effect during 2002 and the first three months of 2003 has been charged on net operating cash flow.

d) Trioco's current taxes have been eliminated. In Ultima's structure, payments are made between Ultima's related entities and Ultima, transferring both income and tax liability from the entities to the unitholders. The future income tax expense has been adjusted to reflect the impact on earnings at the maximum statutory rate.

e) Depletion, depreciation and amortization is calculated using the unit of production method using the total proven oil and natural gas reserves ascribed by the Trust.

f) Alberta Royalty Tax Credits claimed by Trioco have been eliminated as Ultima is not eligible to claim these credits.

(g) Trioco's general and administrative expenses for the period April 1 to June 25, 2003 include severance costs paid to Trioco's employees and various other non-recurring expenses. No adjustment has been recognized in this statement for these one-time costs.

3. Per unit information

The calculation of net income per Trust Unit gives effect to the issuance of the additional Trust Units as set out in Note 2 b) and c) above.

Weighted average Trust units	December 31, 2003
Basic	49,406,224
Diluted	49,959,620

4. Other significant accounting policies

The acquisition of Trioco results in goodwill. This goodwill represents the excess of the purchase price over the fair value of the assets acquired and liabilities assumed. It will be assessed at least annually for impairment and any excess of the book value of goodwill over the implied fair value will be the amount of the impairment.

5. Application of United States of America GAAP ("U.S. GAAP")

The application of U.S. GAAP would have the following effects on the pro-forma combined net income and net income per Trust unit of Ultima:

	$ Cdn (000's)
Pro-forma combined net income	10,082
Ultima U.S. GAAP adjustments (1)	951
Pro-forma combined net income, as adjusted, before cumulative effect of change in accounting principle	11,033
Cumulative effect of change in accounting principle, net of income taxes	(1,484)
Pro-forma combined net income, as adjusted, after cumulative effect	9,549
Net income per unit, as adjusted, before cumulative effect	
Basic	$ 0.22
Dilutive	$ 0.22
Net income per unit, as adjusted, after cumulative effect	
Basic	$ 0.19
Dilutive	$ 0.19

(1) As described in Note 14 to Ultima's audited consolidated financial statements for the year ended December 31, 2003. No further differences arose as a result of the acquisition of Trioco or the application of the pro-forma adjustments.

[LOGO OMITTED]

For the year ended December 31, 2003

Management's Discussion and Analysis ("MD&A")

The following discussion is management's analysis of Ultima Energy Trust ("Ultima" or "the Trust") operating and financial results for the quarter and year to date ended December 31, 2003 compared with the comparative periods of 2002. This discussion also contains information and opinions concerning the Trust's future outlook based on currently available information at February 26, 2004, the date of the MD&A. This discussion should be read in conjunction with the Trust's audited consolidated financial statements for the year ended December 31, 2003, together with the accompanying notes.

Management uses cash flow (before changes in non-cash working capital) to analyze financial performance, as one measure to benchmark performance against peers, and as one measure to determine distribution levels. Cash flow is calculated as net income for the period plus charges to income not requiring an outlay of funds less credits to net income not involving a source of funds. Cash flow as presented does not have any standardized meaning prescribed by Generally Accepted Accounting Principles in Canada ("GAAP") and therefore it may not be comparable with the calculation of similar measures by other entities. Cash flow as presented is not intended to represent operating cash flows or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net income or other measures of financial performance calculated in accordance with GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital.

Reserve volumes and values at December 31, 2003 are based on Ultima's interest in its total proved and probable reserves prior to royalties as defined in National Instrument 51-101 - Standards of disclosure for oil and gas activities ("NI 51-101"). Reserve volumes and values for other years and previously announced acquisitions for the current year, are based on established (proved plus 50% probable) reserves prior to royalties. Under those definitions, probable reserves were discounted by an arbitrary risk factor of 50% in reporting established reserves. Under NI 51-101 reserves definitions, estimates are prepared such that the full proved and probable reserves are estimated to be recoverable (proved plus probable reserves are effectively a "most likely case"). As such the probable reserves now reported are already "risked". Overall there were no material revisions to Ultima's reserve volumes in transitioning to NI 51-101.

Forward-Looking Information

The following discussion contains forward looking information with respect to Ultima. Because forward-looking information relates to future events and conditions, it involves risks and uncertainties that could cause actual results to differ materially from those contemplated. The risks and uncertainties include commodity price levels; currency-exchange rates; the recoverability of reserves; transportation availability and costs; operating and other costs; interest rates; and changes in environmental and other legislation and regulations. This list of factors should not be construed as exhaustive. Please refer to the Trust's Annual Report and Renewal Annual Information Form for more details as to these risks and uncertainties. Management believes the expectations reflected in these forward looking statements are reasonable. However, there is no assurance that these expectations will prove to be correct.

All calculations required to convert natural gas to crude oil equivalent (boe) have been made using a ratio of 6 mcf to 1 barrel of crude oil.

Change in Accounting Policy

In order to be comparable to the majority of its peer group, in 2003 Ultima adopted the Full Cost Method of accounting for its capital assets pursuant to the Canadian Institute of Chartered Accountants ("CICA") Accounting Guideline ("AcG") 16 "Oil and Gas Accounting - Full Cost". The accounting policy change has been adopted retroactively and as a result net income has been restated for 2002 and 2003. The adoption of the Full Cost Method has resulted in net income for the 2002 and 2003 being substantially equal with that originally reported under the Successful Efforts Method. The change to the Full Cost Method had no effect on cash flow as presented for either period. The Full Cost Method and the Successful Efforts Method are the only two accounting options for the Trust's capital assets.

In 2003 Ultima adopted CICA section 3870 "Stock Based Compensation and Other Stock Based Payments". This standard was effective for fiscal years beginning on January 1, 2004, but early adoption was recommended. Ultima adopted this standard in 2003. Pursuant to the transitional provisions provided; unit based compensation expense is to be determined and accrued in income based upon the fair value of rights issued since January 1, 2003. As a result of the early adoption of this standard Ultima's net income decreased by $260,000 in 2003. There was no effect on cash flow.

In February 2003 the CICA issued AcG 14 "Disclosure of Guarantees". This guideline requires that all guarantees must be disclosed in the notes to the financial statements, of which there are none. There was no impact on net income or cash flow as a result of the implementation of this guideline.

Selected Annual Financial Information

The following table sets forth selected consolidated financial information of Ultima with respect to each of the last three years. This information has been restated to conform with the change in accounting policy as discussed above.

Selected Annual Financial Information - restated for change in accounting policy
($ thousands except per trust unit amounts)

	2003	2002	2001
Revenue, net of royalties	89,297	38,253	28,397
Partnership income	-	4,198	3,104
Cash flow (1)	54,880	24,016	17,728
Cash flow, per unit basic (1)	1.29	1.09	1.17
Cash flow, per unit diluted (1)	1.26	1.08	1.15
Cash distributions, per unit	1.09	0.90	1.00
Net income	12,278	9,224	(5,281)
Net income per unit, basic	0.29	0.42	(0.35)
Net income per unit, diluted	0.28	0.41	(0.34)
Total Assets	326,539	218,175	103,359
Total long-term financial liabilities (2)	81,376	78,238	30,209

(1) Excludes internalization costs of $4.7 million (0.11 per unit) in 2003. For 2003, cash flow in accordance with GAAP is $54.3 million (2002 - $23.2 million).
(2) Includes net bank debt and the deferred capital obligation, excludes future income taxes and site restoration provision.

Revenue and cash flow have increased over the three year term due to a number of acquisitions that were completed. Cash distributions per unit have fluctuated over the term due to commodity price volatility. Partnership income was not realized in 2003 as the Trust acquired the assets of

the Weyburn Limited Partnership ("WLP") late in 2002. A net loss per unit was incurred in 2001 due to a write-down of capital assets pursuant to the adoption of the Full Cost Method of accounting for capital assets. Net income per unit has decreased in 2003 due primarily to the internalization of the management contract and an increase in the number of trust units outstanding.

Selected Quarterly Financial Information

The following table sets forth selected consolidated financial information of Ultima with respect to each of the last eight financial quarters ending on March 31 ("Q1"), June 30 ("Q2"), September 30 ("Q3") and December 31 ("Q4"), respectively. This information has been restated to conform with the change in accounting policy as discussed above.

Selected Quarterly Financial Information - Restated for change in accounting
($ thousands except per trust unit amounts)

	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4	20
Total revenue, net of royalties	25,712	24,635	19,100	19,850	13,045	
Partnership income	-	-	-	-	424	
Cash flow	15,923	14,950	11,671	12,336	7,351	
Cash flow, per unit basic	$ 0.30	$ 0.30	$ 0.33	$ 0.36	$ 0.31	$
Cash distributions	14,187	14,625	10,131	9,192	6,528	
Cash distributions per unit	$ 0.265	$ 0.285	$ 0.27	$ 0.27	$ 0.24	$
Net income	4,765	4,124	3,352	37	2,403	
Net income per unit basic	$ 0.09	$ 0.10	$ 0.10	$ 0.00	$ 0.10	$

Highlights

Net income for Q4 2003 was $4.8 million ($0.09 per unit), compared to $2.4 million ($0.10 per unit) in 2002. For 2003, net income was $12.3 million ($0.29 per unit), compared to $9.2 million ($0.42 per unit) in 2002. The 2003 amount is after management internalization costs of $4.7 million, and a future income tax recovery of $900,000. Ultima expensed all internalization costs in Q1 2003 except for some minor amounts relating to the acquisition of the Calgary office furnishings.

Q4 2003 production volumes increased by 7% from the previous quarter and by 105% from Q4 2002 which, coupled with strong commodity prices, resulted in cash flow of $15.9 million ($0.30 per unit) in Q4 2003, compared to $7.4 million ($0.31 per unit) in Q4 2002. For 2003, cash flow was $54.9 million ($1.29 per unit), compared to $24.0 million ($1.09 per unit) in 2002. Cash flow for 2003 is before deducting internalization charges of $4.7 million and the effect of the recovery of future income taxes of $900,000.

Ultima declared distributions of $14.2 million ($0.265 per unit) in Q4 2003 with the balance of cash flow being used primarily to repay bank debt and contribute to the reclamation fund. Distributions declared in 2003 were $1.09 per unit, compared to $0.90 per unit in 2002. The increase in distributions per unit in 2003 is primarily due to higher overall commodity prices realized in 2003.

Ultima completed two major property acquisitions and three equity financings in 2003.

- On June 24, 2003 Ultima closed the purchase of a package of assets in central Alberta for $16.1 million before adjustments. The assets produced 600 boed at the time of purchase. The key asset was a 40% interest and operatorship of the Cherhill Banff A light oil pool. This acquisition brought the Trust's interest in this pool to 90%. An equity issue

of five million trust units for gross proceeds of $25.3 million was completed in May to fund the acquisition and for general purposes.

- On June 26, 2003 the Trust closed the purchase of Trioco Resources Inc.

("Trioco") for $71 million. Trioco's production at the time of purchase was approximately 2,050 boed (68% natural gas), concentrated in central Alberta and the Peace River Arch area of Alberta. The key asset was a 77% interest and operatorship of the Spirit River Charlie Lake E&M Unit and associated lands. An equity issue of 12 million trust units for gross proceeds of $62.4 million was completed in July to partially fund the acquisition.

- On December 17, 2003 the Trust issued six million trust units for gross proceeds of $34.2 million to partially fund the 2004 capital expenditure program and for general purposes.

Production Volumes, by product

	Q4 2003	Q4 2002	2003
Crude oil (barrels per day)	7,233	4,169	6,678
Natural gas liquids (barrels per day)	447	188	309
Natural gas (mcf per day)	15,200	3,795	9,480
Oil equivalent (boed)	10,214	4,990	8,566

Production Volumes, by area

Area: boe per day	Q4 2003	Q4 2002	2003
Central Alberta & the Peace River Arch	5,972	2,546	4,445
Weyburn Unit NRI	2,684	832	2,517
Kindersley	1,286	1,470	1,361
Other Properties	272	142	243
Oil equivalent (boed)	10,214	4,990	8,566

Working interest and royalty interest production volumes (together noted as "production volumes") increased by 105% in Q4 2003 to 10,214 boed compared to 4,990 boed for Q4 2002 and annual production volumes for 2003 increased by 127% to 8,566 boed compared to 3,781 boed for 2002. Production volumes are higher due to a number of acquisitions since the comparative period and Ultima's successful development program. Ultima has also doubled its weighting of natural gas production in Q4 2003 to 25% from 13% in Q4 2002.

Ultima had a very active year development drilling on the operated properties of Spirit River, Cherhill, Westerose and Glenevis in 2003. A total of 15 gross wells (12.6 net) were drilled on these operated properties by Ultima in 2003. All the wells drilled were successful and are now on production. At Cherhill, Ultima drilled two gross (1.8 net) horizontal light oil development wells in 2003 and has plans to drill another five gross (4.5 net) horizontal development wells in 2004. The Spirit River property was the key asset of the Trioco acquisition. In 2003, nine gross (6.6 net) wells were drilled by Ultima on this property and a further nine gross (7.4 net) wells are scheduled to be drilled in 2004.

Capital investment was also ongoing at the non-operated Weyburn Unit, with the third of seven planned carbon dioxide miscible flood expansion phases completed in the summer of 2003. Production response from the third phase is anticipated in mid 2004. Ultima's production at Weyburn increased by approximately 10% in 2003 and is anticipated to continue to increase each year until 2007.

Ultima's Q4 2003 average volume of 10,214 boed was a milestone for the Trust. Ultima anticipates average production volumes for 2004 to be approximately 10,100 boed, before any acquisitions of producing properties.

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Provided below is a summary of production growth and capital expenditures by quarter for 2003.

	Q1	Q2	Q3
Production volumes, boed	6,877	7,606	9,522
Capital expenditures ($ millions)			
Drilling and facilities	2.0	1.2	9.7
Weyburn Unit	2.4	3.1	3.7
Acquisitions, net	1.4	86.9	0.2
Total capital expenditures	5.8	91.2	13.6

Capital expenditures as presented above reflects capital expenditures accrued, paid for with cash and financed pursuant to the Weyburn Unit NRI agreement, and therefore differs from capital asset additions shown on the Statement of Cash flows which only reflects capital additions that have been paid for with cash.

Commodity Prices

The average commodity prices realized by Ultima for 2003 compared to 2002 are provided below:

	Q4 2003	Q4 2002(1)	2003	2002(1
Crude oil, before hedging ($ per bbl)	34.90	40.46	37.83	37.63
Crude oil, net of hedging ($ per bbl)	32.68	34.70	35.05	33.15
Natural gas liquids ($ per bbl)	27.58	34.67	29.84	30.00
Natural gas, before hedging ($ per mcf)	6.07	5.23	6.40	4.27
Natural gas, net of hedging ($ per mcf)	6.36	5.23	6.45	4.27
Price per boe, before hedging ($ per boe)	34.96	39.10	37.65	36.08
Price per boe, net of hedging ($ per boe)	33.82	34.28	35.53	32.23

(1) The 2002 amounts are before the effect of the WLP income.

Commodity prices remained strong in the last quarter of 2003. However, overall the price per boe, before the effects of hedging gains and losses, received by Ultima in Q4 2003 decreased by 11% to $34.96 per boe, compared to $39.10 per boe in the comparative period in 2002. The decrease in the average price per boe in Q4 2003 was primarily a result of the appreciation of the Canadian dollar over the US dollar. For 2003 Ultima's realized price per boe before hedging effects increased by 4%, largely due to higher realized natural gas prices.

The appreciation of the Canadian dollar over the US dollar during the year has had a negative effect on the Trust's cash flow in 2003 and we expect that the dollar will remain strong in 2004. For every $0.01 increase in the Cdn/US exchange rate, the Trust's cash flow from operations decreased by $0.03 per unit per year in 2003. Accordingly even though US$ West Texas Intermediate ("WTI") per bbl oil prices increased by 10% in Q4 2003 (US $31.16 per barrel) compared to Q4 2002 (US $28.27 per barrel), Ultima's realized Canadian dollar oil price per barrel decreased by 14% to $34.90 in Q4 2003 from $40.46 in Q4 2002. For the year oil prices averaged US $31.06 per barrel, compared to US $26.17 per barrel in 2002, however Cdn/US exchange rates averaged $0.71 in 2003, compared to $0.64 in 2002. At December 31, 2003 WTI crude oil was US $32.52 per barrel and the Cdn/US exchange rate was $0.77. As world crude oil prices increased in 2003 the Canadian dollar has also appreciated against the US dollar.

In 2004 should WTI crude oil prices increase management expects it would likely cause the US economy to slow and result in the US dollar depreciating against other currencies, including Canada's. Should WTI crude oil prices decline management expects that it would provide a stimulus to the US economy and the Canadian dollar would likely depreciate against the US dollar, all other factors remaining equal. Overall management expects that in 2004 the effect on Ultima's realized crude oil price resulting from volatility in the WTI crude oil price to be reduced by a movement in the Cdn/US exchange rate.

Oil and Natural Gas Hedging

Ultima follows a disciplined approach to risk management of its exposure to the volatility of commodity prices. The objectives of Ultima's risk management program are as follows:

- Provide greater certainty to cash flow;
- Support acquisition price parameters; and
- Layer up a hedge portfolio by entering into staggered smaller positions that, in aggregate, form a larger position.

For Q4 2003 Ultima incurred a hedging loss of $1.14 per boe compared to a hedging loss of $4.82 per boe in Q4 2002. For 2003, Ultima reported hedging losses of $2.12 per boe, compared to $3.86 per boe in 2002. Ultima's current commodity price hedge arrangements for 2004 are summarized below:

Crude Oil Hedges (US$/bbl except as indicated)

Daily Quantity	Fixed Price	Sold Call	Purchased Put	Sold Put	
1,000 bbls	Cdn$ 35.00				Calen
800 bbls		$ 27.50	$ 24.00	$ 20.00	Calen
700 bbls (1)		$ 30.00	$ 25.00	$ 21.00	Cale
1,000 bbls	$27.00				Jan. 1 to June

(1) For clarity and illustration:

If WTI Price is (US$/bbl)	Ultima receives
Greater than $30	$3
Between $25 per bbl and $30 per bbl	Act
Between $21 per bbl and $25 per bbl	$2
Less than $21 per bbl	Actual price plus $4.0

Natural Gas Hedges ($CDN/GJ)

Daily Quantity	Fixed Price	
1,000 GJs	$ 7.00	Apr. 1, 2003 to Mar.
4,000 GJs	$ 6.15	Aug. 1, 2003 to Mar.

As at December 31, 2003 the fair value of these commodity price hedge arrangements was a loss of $3.6 million, based on quoted market prices and if not available, on estimates from third-party brokers or dealers or amounts derived from valuation models. This unrealized loss is not reflected in the 2003 financial results. As the actual gain or loss attributable to the hedges is realized it will be included in income.

The Trust will likely hedge additional volumes for the second half of 2004 to bring the total volumes hedged in 2004 to range from 40% to 50% of production.

Revenue

Revenue after hedging losses increased to $111.1 million in 2003 compared to $44.5 million for 2002. Revenue for 2003 increased due to higher production volumes as a result of the Trioco and Cherhill acquisitions and higher overall realized commodity prices for 2003. Revenue and royalties for 2003 and 2002 are summarized below:

($ thousands)	Q4 2003	Q4 2002 (1)	2003	2002 (1)
Gross revenue	31,777	15,736	111,107	44,472
Royalties	(6,065)	(2,692)	(21,810)	(6,219)
Revenue, net of royalties	25,712	13,044	89,297	38,253

(1) Amounts exclude the WLP distributions earned by the Trust of $424,000 in Q4 2002 and $4.2 million for 2002.

Oil and Natural Gas Gross Revenue Variance Analysis

In order to better understand the effect the change in production volumes and commodity prices has had on revenue compared to the prior reporting period we provide the following variance analysis:

($ thousands)	Q4 2003	Q4 2002	2003	2002
Prior period ending December 31	15,736	7,443	44,472	30,526
Volume variance	16,090	4,901	54,484	19,333
Price variance	(49)	3,392	12,151	(5,387)

Current period ending December 31	31,777	15,736	111,107	44,472

Both increased volumes and increased overall realized prices have resulted in higher revenue for 2003. In Q4 2003 lower average prices reduced revenue.

Royalties

($ thousands)	Q4 2003	Q4 2002	2003	2002
Royalty expense	6,065	2,692	21,810	6,219
Royalties as % of gross revenue, before hedging	18.5%	15.0%	18.5%	12.5%

Royalties as a percentage of revenue have increased as the properties acquired since 2002 have had higher overall royalty rates due to a higher weighting of natural gas production, and higher average productivity per well. Ultima anticipates maintaining the Q4 2003 level of royalty rates going into 2004.

Oil and Natural Gas Operating Expense

($ thousands)	Q4 2003	Q4 2002	2003	2002
Operating costs	7,279	4,443	25,485	13,603
$'s per boe	7.75	9.68	8.15	9.86

On a per boe basis, operating expenses have decreased by 20% in Q4 2003 compared to Q4 2002. For 2003 operating expenses on a per boe basis decreased by 17% compared to 2002. Operating costs per boe have decreased because the properties being acquired by the Trust in 2002 and 2003 have lower operating cost structures. Management has targeted acquisitions with lower operating cost structures in order to decrease the Trust's overall operating costs on a per boe basis.

For 2004, operating costs on a per boe basis are expected to average approximately $7.85 per boe, in line with Q4 2003.

General and Administrative Expense

General and administrative ("G&A") expense for Q4 2003 was $1.65 million ($1.76 per boe), compared to $1.1 million ($2.32 per boe) in Q4 2002. For 2003, G&A expense totaled $9.9 million, including a $4.7 million charge related to the internalization of the management contract through the purchase of Ultima Management Inc., compared to $3.2 million for 2002. Excluding internalization costs, 2003 G&A expense per boe decreased by 28% to $1.66 per boe compared to $2.29 per boe for 2002. G&A expense per boe has decreased as the increased production has not resulted in a corresponding increase in G&A.

It is anticipated that G&A expense per boe will be approximately $1.50 per boe for 2004.

Internalization of Management Contract

On March 26, 2003 the Trust purchased all of the shares of Ultima Management Inc., thereby eliminating the payment of future management and acquisition fees. The purchase included an obligation to pay a retention bonus to the executive team of $750,000. The retention bonus is to be paid out over the three year period ending March 26, 2006 should the officers remain employed by the Trust. The costs incurred to internalize the management contract were expensed in Q1 2003 with the exception of $137,000 allocated to the acquisition of capital assets. The costs paid were as follows:

Cash payment to WhitePass Capital Inc.(1)	$	3,000,000
Value of trust units issued to WhitePass Capital Inc.(1)		800,000
Retention obligation paid, cash and trust units		750,000
Other transaction costs (2)		303,000
Less: capital assets purchased		(137,000)
Total	$	4,716,000

(1) WhitePass Capital Inc. was the previous owner of Ultima Management Inc.
(2) Fees incurred for financial and legal advisors.

Management fees paid in 2003 compared to 2002 are as follows:

($ thousands)	Q4 2003	Q4 2002	2003	2002
Management fee	-	315	487	856
On a per unit basis	-	0.01	0.01	0.04

Management and acquisition fees would have been approximately $3.3 million in 2003 had the internalization of the management contract not occurred.

Interest Expense

Interest expense for Q4 2003 totaled $804,000 versus $295,000 for the corresponding period in 2002. For 2003 interest expense was $3.2 million, compared to $817,000 in 2002. The increase in interest expense is a result of the higher average debt levels in 2003 over 2002 due to a number of acquisitions in 2003 and the latter half of 2002. Interest associated with the deferred capital obligation is capitalized pursuant to the Weyburn Unit NRI agreement.

On a per boe basis, 2003 interest expense was $1.01 per boe compared to $0.59 per boe for 2002.

The Trust's bank credit facility interest charge is based on prime lending rates and the Trust has not hedged or fixed any portion of its bank interest rate for 2004.

Unit Based Compensation Expense

In Q4 2003 the Trust adopted the expensing of unit based compensation. The Trust recorded $260,000 as a charge to income for 2003. The charge is based on the rights issued to employees since January 1, 2003. Included in Unitholders' Equity is Contributed Surplus of the same amount. The Trust has also provided pro-forma disclosure in respect of the unit based compensation expense that would have been incurred on rights issued in 2002.

There were approximately two million rights issued and outstanding at year end pursuant to the trust unit rights incentive plan. These rights had an average adjusted exercise price of $4.78 per

unit, before the available right exercise price reduction of $0.38 per unit and

$4.40 per unit if the reduction is included.

Netback and Net Income per boe

The operating netback on a per boe basis remained basically unchanged in Q4 2003 and for the year 2003 compared to the prior periods. Funds from operations per boe in Q4 2003 was higher than in Q4 2002 even though commodity prices realized were slightly lower compared to Q4 2002. The elimination of the WLP income per boe in 2003 was offset by the reduction in per boe operating costs. Net income per boe for 2003 compared to 2002 decreased primarily as a result of the internalization of the management contract and higher depletion and amortization expense on a per boe basis.

($ per boe)	Q4 2003	Q4 2002	2003
Oil and natural gas revenues, net of hedging	33.82	34.28	35.53
Royalties	(6.45)	(5.86)	(6.98)
Income from the WLP	-	0.92	-
	27.37	29.34	28.55
Oil and natural gas operating expense	(7.75)	(9.68)	(8.15)
Operating netback	19.62	19.66	20.40
General and administrative	(1.76)	(2.32)	(1.66)
Management fees	-	(0.69)	(0.16)
Internalization of Management Contract	-	-	(1.51)
Interest, taxes and unit based compensation	(0.91)	(0.64)	(1.04)
	16.95	16.01	16.03
Unit based compensation	(0.28)	-	(0.08)
Future income tax recovery	0.93	-	0.29
Depletion and amortization	(12.52)	(10.78)	(12.32)
Net Income	5.08	5.23	3.92

Income Tax

During 2003, the Ultima trust units were deemed to be foreign property for purposes of Canadian income tax exempt plans such as RRSPs, DPSPs, and RRIFs. The Ultima trust units are not foreign property for purposes of exempt plans effective January 1, 2004. For a full explanation of this matter, see Ultima's 2002 Annual Information Form, which was filed in May 2003.

A future income tax liability of $14.4 million was recorded in connection with the Trioco acquisition. Management does not expect the future income tax liability to be paid by the Trust because royalties paid by the corporate subsidiary to the Trust and future distributions paid to unitholders will effectively transfer this liability to the unitholders.

Income taxes are comprised of a current income tax provision of $nil and a recovery of future income taxes of $900,000 (2002 - $nil). The Trust has also accrued capital taxes of $76,000 for 2003, compared to $nil in 2002. Capital taxes relate to a corporate subsidiary, which resulted from the acquisition of Trioco in June 2003. In 2004 the Trust expects to record a further income tax recovery. There is no effect on 2003 cash flow due to the recovery of future income taxes.

For 2003, it is anticipated that distributions paid to unitholders will have a taxable component and a return of capital component. At this time, the taxable component is expected to range between 20% and 30% of the distributions paid. The taxability of distributions is sensitive to commodity price volatility; the higher the commodity prices, the more likely the taxable component will be higher, all other factors remaining equal.

For 2004, the taxable component of distributions is expected to range from 25% to 35%.

Capital Expenditures

Capital expenditures in Q4 2003 totaled $11.3 million, compared to $104.4 million in Q4 2002. For 2003 capital expenditures totaled $121.9 million, approximately equal with 2002 capital expenditures of $121.0 million. Capital expenditures by quarter in 2003 are summarized below.

($ millions)	Q1	Q2	Q3	Q4
Development drilling and facilities (1)	2.0	1.2	9.7	6.7
Weyburn Unit	2.4	3.1	3.7	4.3
Acquisitions, net of dispositions	1.4	86.9	0.2	0.3
Total	5.8	91.2	13.6	11.3

(1) Includes all operated and non-operated development drilling and facilities capital expenditures, excluding the capital expenditures attributable to the Weyburn Unit NRI.

Depletion, Depreciation and Amortization ("DD&A")

The Trust adopted the Full Cost Method of accounting for capital assets in 2003. The effect of this change is that the reported DD&A rate per boe is largely unchanged for 2003 and lower for 2002 than that under the previously used Successful Efforts Method of accounting for capital assets. Under the Full Cost Method, included in the DD&A calculation are expected future capital costs of approximately $86.6 million of which $80.0 million is attributable to the Weyburn Unit enhanced recovery process. The expected future capital costs are taken from the reserve evaluations prepared by the Trust's independent engineers. Under the Trust's previous method of accounting for capital assets these expected future development costs would not have been reflected in the DD&A calculation until they were incurred.

DD&A calculated on a unit of production basis totaled $11.8 million for Q4 2003, including a site restoration charge of $1.0 million. DD&A in the corresponding period of 2002 was $4.9 million, including $420,000 of site restoration expense. The higher DD&A and site restoration charge in 2003 is due to increased capital costs and production levels. The DD&A rate per boe was $12.52 per boe in Q4 2003, compared to $10.78 per boe in Q4 2002. The DD&A rate per boe has increased in Q4 2003 due to the acquisition cost per proven boe of reserves being higher in 2003 than the historical DD&A rate per boe. DD&A per boe for 2003 was $12.32

per boe, compared to $10.71 per boe for 2002. The foregoing amounts are based on the Full Cost Method of accounting.

Capital assets of $11.3 million associated with the Weyburn Unit NRI were excluded from the DD&A calculation as this amount relates to unproven property. This amount and related proved reserves are expected to be reflected in the DD&A calculation when the majority of the probable reserves attributable to the Weyburn Unit NRI reserve evaluation have become proved.

For 2004, DD&A per boe is expected to decrease due to the increase in proved oil and natural gas reserves as at January 1, 2004 being greater than the corresponding increase in net capital assets. Also future capital associated with the Weyburn Unit has been forecast to decrease due to the appreciation of the Canadian dollar versus the US dollar decreasing the Canadian dollar cost of future carbon dioxide purchases. The carbon dioxide is purchased in US dollars.

Cash Distributions

Ultima declared cash distributions to the unitholders in Q4 2003 in the amount of $14.2 million ($0.265 per unit) compared to $6.5 million ($0.24 per unit) in Q4 2002. Distributions for 2003 were $48.1 million ($1.09 per unit), compared to $21.0 million ($0.90 per unit) for 2002. The increase in distributions per unit is primarily due to higher production volumes in 2003 compared to 2002.

The payout ratio, defined as distributions declared over cash flow as presented, was approximately 87% in both 2003 and 2002. Ultima's distributions are highly dependent on commodity prices, primarily the price of crude oil. Ultima reduces the effect of crude oil price volatility on its cash flow by following a disciplined approach to hedging the price of crude oil. Ultima's cash distributions are also highly dependent upon production volumes. Further, Ultima's monthly cash distributions are comprised of a return of capital component and a return on capital component.

A monthly history of cash distributions declared for 2003 and 2002 is provided below.

2003 Distributions		Distribution per unit	
Record Date	Payment Date	2003	2002
January 31, 2003	February 17, 2003	$0.09	$0.06
February 28, 2003	March 17, 2003	$0.09	$0.06
March 31, 2003	April 15, 2003	$0.09	$0.07
April 30, 2003	May 15, 2003	$0.09	$0.07
May 30, 2003	June 16, 2003	$0.09	$0.08
June 30, 2003	July 15, 2003	$0.09	$0.08
July 31, 2003	August 15, 2003	$0.095	$0.08
August 29, 2003	September 15, 2003	$0.095	$0.08
September 30, 2003	October 15, 2003	$0.095	$0.08
October 31, 2003	November 17, 2003	$0.095	$0.08
November 28, 2003	December 15, 2003	$0.085	$0.08
December 31, 2003	January 15, 2004	$0.085	$0.08
Total Distributions Declared per unit for the year:		$1.09	$0.90

Balance Sheet
Assets

As at December 31, 2003, total assets were $326.5 million consisting of net capital assets of $294.5 million, current assets of $14.2 million, goodwill of $16.7 million and a reclamation fund of $1.1 million. Net capital assets have increased from 2002 primarily due to the acquisition of the Cherhill properties and the Trioco acquisition. Goodwill arose on the Trioco acquisition.

Liabilities and Unitholders' Equity

Liabilities totalled $118.1 million at December 31, 2003, consisting of a $45.0 million long-term bank loan, $22.5 million in current liabilities, a deferred capital obligation of $28.1 million, a future income tax liability of $14.4 million and a site restoration accrual of $8.1 million. The future income tax liability arose on the Trioco acquisition and represents the tax effect with respect to the excess of the fair value of the assets acquired, excluding goodwill, compared to their tax basis at the date of purchase.

The authorized capital of the Trust consists of an unlimited number of trust units. Unitholders' capital was $324.8 million at December 31, 2003, compared to $206.2 million at December 31, 2002. Provided below is a summary of the equity financings completed by the Trust in 2003.

Date	Units Issued	Price Issued ($/unit)	Gross Proceeds ($ thousands)
May	5,000,000	5.05	25,250
July	12,000,000	5.20	62,400
December	6,000,000	5.70	34,200
	23,000,000		121,850

Provided below is a schedule of the change in trust units outstanding for 2003 and 2002.

	2003 Number of Trust Units		2003 Value	2002 Number of Trust Units		V
Balance, beginning of year	33,873,808	$	206,154	18,447,142	$	1
Issued for cash, net of costs	23,000,000		115,197	15,350,000		
Issued on exercise of rights	512,998		3,301	16,666		
Issued for internalization	188,169		-	-		
Issued on exercise of options	50,000		169	60,000		
Balance, end of year	57,624,975	$	324,821	33,873,808	$	2

Cash flow

Cash flow on a per unit basis remained relatively unchanged in Q4 2003 at $0.30 per unit, compared to $0.31 per unit in Q4 2002. For 2003, cash flow per unit excluding internalization costs increased by 27% to $1.29 per unit, compared to $1.09 per unit in 2002. Higher production volumes were the primary driver of the increase in cash flow per unit.

Provided below is a summary of the calculation of cash flow for 2003 and 2002.

($ thousands)	Q4 2003	Q4 2002	2003	2002
Net Income	4,765	2,403	12,278	9,224
Add items not affecting cash flow				
DD&A	11,770	4,948	38,526	14,792
Internalization costs	-	-	4,716	-
Recovery of future income taxes	(872)	-	(900)	-
Unit based compensation expense	260	-	260	-
	15,923	7,351	54,880	24,016

Liquidity and Capital Resources

($ thousands)	December 31, 2003	December 31, 2002
Long term bank debt	45,007	55,358
Working capital deficiency	8,243	2,436
Net bank debt	53,250	57,794
Deferred capital obligation	28,126	20,444
Market value of Trust Units (1) (2)	359,420	174,450
Total capitalization	440,796	252,688
Net bank debt as a % of total capitalization	12%	23%
Total debt as a % of total capitalization	19%	31%

(1) The number of trust units issued at December 31, 2003 was 57.6 million and the closing price was $6.24.

(2) Total capitalization as represented in this table includes the market value of the Trust's equity, and does not represent the historical cost of the Trust's Unitholders' equity. Therefore total capitalization may not be comparable with the calculation of similar measures by other entities. A GAAP measure would use the book value of Unitholders' Equity, which at December 31, 2003 was $208.4 million, and total capitalization would therefore be $289.8 million. Management has presented debt as a function of total capitalization because management uses this measure to benchmark the financial position of the Trust.

Working capital deficit was $8.2 million at December 31, 2003. The deficit is primarily due to Q4 capital expenditures being accrued but unpaid in the amount of $3.2 million and accounts payable being paid on a 60 day basis. The Trust would normally expect a minor working capital deficit for any given month. A working capital deficit could be remedied by available unutilized bank facilities. At year end the Trust had approximately $43 million in available credit with its banking syndicate. This balance includes the pro-forma elimination of the working capital deficit.

Total debt outstanding at December 31, 2003 was $81.4 million, which includes net bank debt of $53.3 million and the deferred capital obligation associated with the Trust's Weyburn Unit NRI of $28.1 million. Ultima's oil and gas properties secure the bank debt. The Trust has a maximum bank credit facility of $95 million. The Trust is currently in compliance with all covenants and expects to remain so in the future. In the event that the banking syndicate requires repayment of the loan there is a two year term out, with no payments being required in the first year. The banking syndicate based upon the estimated value of the Trust's oil and natural gas reserves determines the amount of the maximum banking facility. The value of the maximum facility is evaluated and confirmed by the banking syndicate on a semi-annual basis.

The deferred capital obligation is a term of the Weyburn Unit NRI agreement and its payment is non-recourse in nature to the Trust's other properties. The Trust has the ability to defer up to $9.3 million of additional capital expenditure payments associated with the Weyburn Unit NRI until January 1, 2006. For 2004, the Trust anticipates that the deferred capital obligation will increase by $7.8 million, before accrued interest. Subsequent to January 1, 2006 management anticipates refinancing the deferred capital obligation. The parameters of this future refinancing will be dependent upon the capital market and interest rate environments at that time.

Capital Commitments

The Trust anticipates investing approximately $32 million in respect of development activities on its properties in 2004. These development activities include $16.5 million of development planned for drilling and waterflood optimization at Spirit River, Cherhill, Westerose and Glenevis. A total of 17 gross wells (14.8 net wells) are budget to be drilled by Ultima in 2004 on these properties. The carbon dioxide miscible flood project will continue to be expanded at the Weyburn Unit with the Trust's share of expenditures budget to be $15.5 million, compared to $13.5 million in 2003. The Trust anticipates funding its planned 2004 capital program from a combination of cash flow, available bank credit and the deferred capital program associated with the Trust's Weyburn Unit NRI. It is expected that cash flow generated during 2004 will be used primarily to pay distributions to unitholders.

Other Commitments

For 2004, the Trust has entered into a fixed price purchase commitment for one megawatt per hour ("mwh") of electricity at a price of $51 per mwh. Currently the Trust is incurring a power cost of approximately $55 per mwh. The contract represents a commitment of approximately $447,000.

The Trust has entered into an office lease agreement in respect of the Calgary head office that has a six year term, expiring on May 31, 2009. Minimum annual lease payments, before occupancy costs, range from $257,000 in 2004 to $291,000 in 2009.

Provided below is a table which details the contractual and/or balance sheet obligations of the Trust and the expected timing of when these items are anticipated to be paid.

($ thousands)	Total	Less than 1 year	1 to 3 years	4 to 5 years	Aft y
Long-term bank debt	45,007	-	-	-	45
Office lease	1,910	257	523	548	
Electricity contract	447	447	-	-	
Deferred capital obligation (1)	28,126	-	28,126	-	
Future Weyburn Unit NRI carbon dioxide purchases (2)	59,508	6,851	14,859	11,344	26

Site restoration provision	8,076	-	-	-	8

(1) The Trust expects to refinance this obligation on or shortly after January 1, 2006 by a combination of new debt and equity. However, if the obligation is not refinanced, payments are based upon a

blend of interest and principle over 15 years, plus an income tax equalization component. A pre-payment bonus of 7% of the pre paid amount is also due in the event the obligation is refinanced.

(2) These amounts represent the Trust's net share of future payments for carbon dioxide associated with the Weyburn Unit miscible flood enhanced recovery process. The operator has entered into a take-or-pay arrangement for the purchase of the carbon dioxide. These costs were determined by the Trust's independent engineers and are attributable to the total proved case for the oil and natural gas reserves. The Weyburn Unit NRI agreement has a provision that for any given month cash flow attributable to the NRI cannot be negative. Accordingly, the Trust's share of the Weyburn Unit carbon dioxide purchases is recourse only to the Weyburn Unit NRI, and is non-recourse in nature to the balance of the Trust's assets.

Reclamation Fund

Upon inception, Ultima established a reclamation fund into which cash is contributed at a rate of $0.20 per boe of production. For 2003, a total of $625,000 was contributed to the fund. During 2003 a total of $296,000 of abandonment and reclamation costs were incurred and funded from the fund balance. At year end the fund balance was $1.1 million.

Ultima has also begun to improve the quality of the assets of the Trust by selling its lesser quality production, which has a shorter reserve economic life and higher operating costs. These factors combine to provide a higher probability of resulting in a shorter time period for the abandonment of the property.

Future Trends and Risk Factors

The development and production of oil and natural gas reserves is inherently uncertain and subject to numerous operational and competitive risks. Evaluations of oil and natural gas reserves represent estimates only and include a number of assumptions, including assumptions regarding the future price of crude oil and natural gas and the success of exploitation and development and tertiary recovery activities intended to be undertaken on the Trust's properties in future years.

The economic performance of the Trust will be affected by a variety of market conditions that are beyond the Trust's control, including commodity pricing, interest rates, exchange rates and the ability to acquire suitable oil and natural gas properties. In particular, the price received for oil and natural gas production is market determined and has been subject to considerable volatility in the recent past. Ultima has taken steps to mitigate this risk as disclosed above under "Oil and Natural Gas Hedging".

The future oil and natural gas reserves and production are highly dependent on the success in exploiting the current reserve base. Future cash flows are highly dependent on both of these factors, together with the Trust's success in acquiring additional reserves. Without the addition of reserves, production is subject to continued decline. Accordingly, all other factors remaining equal, without the acquisition of additional reserves the Trust's future cash flows are expected to decline as the Trust's existing oil and natural gas reserves decline.

Future acquisitions will depend on the availability of economically attractive properties. Acquisitions must generally comply with certain pre-established guidelines or otherwise be approved by the Boards of Directors. All acquisitions with a purchase price of $2 million or greater must be approved by the Board of Directors, and be substantiated by a reserve evaluation prepared by independent engineers.

The oil and natural gas industry is subject to extensive controls and regulations imposed by various levels of government. All current legislation is a matter of public record and Ultima is unable to predict what additional legislation or amendments may be enacted

The oil and natural gas industry is also subject to environmental regulation pursuant to local, provincial and federal legislation. Ultima is committed to meeting its responsibilities to protect the

environment. The Board of Directors has put in place an environment and safety management system designed to ensure appropriate policies and procedures are maintained.

Effect of Future Changes in Accounting Policies

Effective for January 1, 2004, the Trust will adopt the CICA Handbook Section 3110 "Asset Retirement Obligations" accounting policy in respect of asset retirement and reclamation obligations associated with the Trust's oil and natural gas properties. The new policy is expected to increase the recorded amount of net capital assets and the site restoration obligation on the balance sheet. The effect on net income has not been determined at this time. There is expected to be no effect on cash flow as a result of the adoption of the new accounting policy.

Effective for January 1, 2004, the Trust will adopt AcG 13 "Hedging Relationships". This guideline requires that in order for a hedge to be considered "effective" for accounting purposes and qualify for hedge accounting treatment, specific and detailed criteria must first be met. Should a hedge not qualify for hedge accounting treatment the fair value of the hedge at the balance sheet date is recorded as an asset or liability on the balance sheet. All the Trust's hedges are deemed by management to be effective economic hedges. However, not all the Trust's hedges will be deemed to be effective hedges pursuant to AcG 13's criterion. Specifically the Trust's "three-way" crude oil hedges are not deemed to be effective hedges for accounting purposes as they do not provide by design a direct correlation between the change in the price of WTI crude oil and the hedged price received.

All or a portion of hedges that the Trust may enter into at a future date may be deemed not to be effective hedges for accounting purposes pursuant to AcG 13 and in that event those hedges would be recorded on the balance sheet at their fair value, along with the three-way crude oil hedges already in existence. Changes in the fair value of these hedges will be accounted for in the income statement.

Effective March 31, 2004 National Instrument 51-102 "Continuous Disclosure Obligations" comes into effect for reporting issuers. The primary impact of NI

51-102 is that it will bring forward reporting deadlines for annual and interim financial statements, oil and gas reserve reports, the Annual Information Form ("AIF") and the MD&A. The new instrument also will require additional disclosure compared to prior requirements for the annual and interim financial statements, AIF and MD&A.

Further, pursuant to NI 51-102 annual and interim financial statements will only be mailed to unitholders on the receipt of a formal request.

This MD&A has been prepared in accordance with NI 51-102 disclosure requirements.

Critical Accounting Assumptions and Estimates

The financial and operating results of Ultima incorporate certain critical estimates and assumptions. The following is a list of these critical assumptions and estimates:

- Estimates of oil and natural gas reserves that the Trust expects to recover in the future, which effect the determination of depletion, depreciation and amortization. Independent engineers pursuant to NI 51-101 prepare the estimate of oil and natural gas reserves.

- Estimates of production volumes, prices, royalties and operating costs as at a reporting date but for which actual production volumes, royalties and operating costs have not yet been received or paid.

- Estimates of development capital expenditures, which is in progress and for which actual costs have not yet been received or paid.

- Estimates of future development capital associated with the oil and natural gas reserves the Trust expects to recover in the future.

In order to allow the Trust to make reasonable estimates, appropriately trained and skilled staff and consultants are engaged, and provided with the appropriate systems to utilize their skills. A key part of the process of making reasonable estimates is a review of past estimates to actual results. However, there is a level of uncertainty inherent with any assumption.

Off Balance Sheet Arrangements and Guarantees

There are no undisclosed off balance sheet arrangements or undisclosed guarantees that the Trust is a party to.

Related Party Transactions

There are no undisclosed and material related party transactions. The only material related party transaction in 2003 was the internalization of the management contract and the purchase of Ultima Management Inc.

Trading Statistics

In order to understand the liquidity and price movement of the Ultima trust units in 2003, we provide a summary of trading statistics by quarter.

2003	Q1	Q2	Q3	Q4

High, $ per unit	5.68	5.52	6.23	6.28
Low, $ per unit	5.15	5.15	5.27	5.73
Close, $ per unit	5.30	5.42	6.13	6.24
Average Daily Trading Volume, thousands	152	204	395	266

2004 Outlook

It is the Trust's objective to provide value to unitholders by focusing on the key strategic objectives of the business plan. This focus has resulted in Ultima achieving exceptional results since revitalization in December 2000, by providing unitholders with cash distributions of $3.05 per unit and capital appreciation of $2.31 per unit, for a total return of $5.36 per unit.

The key future objectives of the business plan include:

- Annual reserve replacement;
- Ensuring acquisitions are strategic and enhance unitholder returns;
- Controlling costs: new reserve acquisition costs, operating costs and G&A
- Actively hedging a portion of the Trust's production;
- Frugal utilization of debt;
- Being an industry leader in health, safety and the environment; and
- Supporting community initiatives in the areas we operate and live.

In 2003, Ultima was successful in meeting these objectives and will continue to focus on and closely monitor these core objectives in 2004 and beyond.

The Boards of Directors has approved an operating budget for 2004 the highlights of which are summarized below:

($ millions)	
Revenues, net of royalties	101.0
Operating costs	(29.0)
General and Administrative	(5.4)
Interest	(2.5)
Cash flow	64.1

The Trust has assumed a WTI crude oil price of $US 28 per barrel, an AECO natural gas price of $5.50 per GJ and a Cdn/US exchange rate of 0.75.

Production is anticipated to average 10,100 boed, and there are no acquisitions reflected in the operating budget. However, the Trust anticipates completing further acquisitions in 2004 in order to broaden the Trust's asset base and add development opportunities. Acquisition criteria include that acquisitions are anticipated to be accretive to net asset value.

The Boards of Directors set the January 2004, February 2004 and March 2004 distributions at $0.085 per trust unit per month. Beyond this time frame the Boards of Directors will determine a distribution, which is in line with cash flow expectations and anticipated cash requirements of the Trust.

2004 Sensitivities

The following table summarizes the variables that are expected to have the most material effect on 2004 cash flow from operations.

Variable	Change	Cash flow Impact ($ thousands)	Cash flow impact per unit
Oil price, including hedging	$US1/bbl	2,300	4 cents
Natural gas price	$0.10/mmbtu	500	1 cent
Oil production	100 bbl/day	1,750	3 cents
Exchange rate (Cdn/US)	$0.01	1,000	2 cents
Interest rate	1%	600	1 cent

For reference purposes only, the mean crude oil price for the three year period 2000 to 2003 was approximately US $27.73 per barrel, and the standard deviation from the mean crude oil price was approximately US $3.95 per barrel.

Additional Information

Additional information on the Trust including previously released financial reports, Annual Information Forms and press releases can be found on SEDAR at www.sedar.com.

ULTIMA ENERGY TRUST

CONSOLIDATED FINANCIAL STATEMENTS

As at and for the Years Ended December 31, 2003 and 2002

AUDITORS' REPORT

To the Directors of Ultima Ventures Corp. and Ultima Acquisitions Corp.:

We have audited the consolidated balance sheet of Ultima Energy Trust as at December 31, 2003 and 2002 and the consolidated statements of income and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Trust's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Trust as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Calgary, Alberta
February 24, 2004 (except as to Notes 14 and 15 which are as of April 30, 2004)

(signed) Deloitte & Touche LLP
Chartered Accountants

ULTIMA ENERGY TRUST
CONSOLIDATED BALANCE SHEET
(thousands of dollars)

	December 31	
	2003	2002
ASSETS		
Current assets		
Accounts receivable	$ 12,442	$ 8,969
Prepaid expenses	1,803	528
	14,245	9,497
Reclamation fund (note 7)	1,077	748
Goodwill (note 5)	16,682	-
Capital assets, net (note 4)	294,535	207,930
Total Assets	$ 326,539	$ 218,175
LIABILITIES and UNITHOLDERS' EQUITY		
LIABILITIES		
Current liabilities		
Bank indebtedness	$ 977	$ 19
Accounts payable	16,613	9,204
Cash distributions payable	4,898	2,710
	22,488	11,933
Accumulated site restoration	8,076	5,066
Deferred capital obligation (note 6)	28,126	20,444
Future Income Taxes (notes 5 and 13)	14,398	-
Long-term bank debt (note 8)	45,007	55,358
Contingencies and Commitments (note 12)		

	118,095	92,801
UNITHOLDERS' EQUITY		
Unitholders' capital (note 9)	324,821	206,154
Contributed surplus (note 9)	260	-
Deficit	(4,944)	(17,222)
Accumulated cash distributions (note 3)	(111,693)	(63,558)
	208,444	125,374
Total Liabilities and Unitholders' Equity	$ 326,539	$ 218,175

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The accompanying notes are an intergral part of these consolidated financial statements

ULTIMA ENERGY TRUST
CONSOLIDATED STATEMENT OF INCOME AND DEFICIT
(thousands of dollars except for per unit amounts)

	Year Ended December 31	
	2003	2002
Revenue:		
Oil and natural gas	$ 111,107	$ 44,472
Royalties	(21,810)	(6,219)
Income from Weyburn Limited Partnership (note 6)	-	4,198
	89,297	42,451
Expenses:		
Oil and natural gas operating	25,485	13,603
General and administrative (note 10)	9,914	3,159
Management fee (note 10)	487	856
Interest on long-term debt (note 8)	3,171	817
Unit based compensation (note 9)	260	-
Capital taxes	76	-
Depletion and amortization (note 4)	38,526	14,792
	77,919	33,227
Net income before income taxes	11,378	9,224
Future income tax recovery (note 13)	$ 900	$ -
Net income	12,278	9,224
Deficit, beginning of year (note 2(l))	(17,222)	(26,446)

Deficit, end of year	$	(4,944)	$	(17,222)
Net income per unit, basic (note 2(k))	$	0.29	$	0.42
Net income per unit, diluted (note 2(k))	$	0.28	$	0.41

The accompanying notes are an intergral part of theses consolidated financial statements

ULTIMA ENERGY TRUST
CONSOLIDATED STATEMENT OF CASH FLOWS
(thousands of dollars)

	Year Ended December 31	
	20033	2002
Operating Activities:		
Net income	$ 12,278	$ 9,224
Add/(less) items not involving cash:		
Future income tax recovery	(900)	-
Unit based compensation	260	-
Internalization of management contract (note 10)	4,716	-
Depletion and amortization	38,526	14,792
	54,880	24,016
Changes in non-cash operating working capital	(572)	(816)
	54,308	23,200
Financing Activities:		
Issuance of Trust units, net	117,617	71,840
Bank loan	(10,351)	26,068
Cash distributions paid to unitholders	(45,947)	(19,371)
	61,319	78,537
Investing Activities:		
Capital asset additions	(23,884)	(5,690)
Investment in Weyburn Limited Partnership	-	1,042
Acquisitions of properties, net of divestments	(88,410)	(96,504)

Internalization of management contract		(3,666)		-
Reclamation fund contributions		(625)		(325)
		(116,585)		(101,477)
Increase/(Decrease) in bank indebtedness		(958)		260
Bank indebtedness, beginning of year		(19)		(279)
Bank indebtedness, end of year	$	(977)	$	(19)
Supplemental Information				
Cash income taxes paid	$	-	$	-
Cash interest paid	$	3,171	$	817

The accompanying notes are an intergral part of these consolidated financial statements

ULTIMA ENERGY TRUST
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

Years ended December 31, 2003 and 2002
(Tabular amounts in thousands of dollars except for per unit amounts)

1. Basis of Presentation

a. Structure

Ultima Ventures Corp. (the "Corporation"), Ultima Ventures Trust ("Ventures Trust") Ultima Energy Inc. ("Energy Inc."), Ultima Management Inc. ("the Manager") and Ultima Acquisitions Corp. ("Acquisitions Corp.") operate under common management. The financial statements include the accounts of Ultima Energy Trust ("the Trust"), and the accounts of its subsidiaries, the Corporation, Ventures Trust, Energy Inc., the Manager and Acquisitions Corp., on a consolidated basis. Inter-entity transactions and balances have been eliminated. These consolidated financial statements are prepared following accounting principles generally accepted in Canada.

The Trust is an open-ended, unincorporated investment trust formed under the laws of the Province of Alberta. The beneficiaries of the Trust and its subsidiaries are the unitholders. Ventures Trust and Energy Inc. hold oil and natural gas properties. The Trust acquires an interest in the cash flow generated by these properties in the form of a royalty with each of Ventures Trust and Energy Inc. The Trust was set up to acquire and hold the royalty(s) and to issue trust units. Each royalty consists of 99% of the net cash flow generated by the underlying properties, less certain expenditures, including capital expenditures funded by cashflow and any debt repayments.

2. Significant Accounting Policies

a. Joint Interests

Certain oil and natural gas activities are conducted jointly with others and, these consolidated financial statements reflect the Trust's proportionate interest in such activities.

b. Oil and Natural Gas Properties

The Trust follows the Full Cost Method of accounting whereby all costs relating to the acquisition and development of oil and natural gas reserves are capitalized. The Trust does not capitalize general and administration expenses. Interest relating to the Weyburn Unit NRI deferred capital obligation is capitalized pursuant to the terms of the agreement.

No gains or losses are recognized in income during the year in which oil and natural gas properties are sold unless the depletion and amortization rate changes by more than 20% as a result of the sale.

c. Depletion and Amortization

Capital costs of oil and natural gas properties, net of estimated salvage values, are depleted using the unit of production method. These capital costs are depleted based on estimated gross proved oil and natural gas reserves as determined by independent engineers. For purposes of these calculations production of crude oil, natural gas, natural gas liquids and proved reserves are converted to a common unit of measure on the basis of 6 thousand cubic feet of natural gas to 1 barrel of oil equivalent.

d. Future Site Restoration

Estimated future costs of site restoration are provided for over the life of the proved reserves on a unit of production basis. Costs are estimated each period by management using current costs and in accordance with existing legislation and underlying practice. The provision is included with depletion and amortization expense and actual site restoration expenditures are charged against the accumulated provision.

e. Ceiling Test

The Trust places a limit on the aggregate carrying amount of capital assets, which may be depleted against revenues of future periods (the "ceiling test"). Capitalized costs plus the estimated future capital associated with proved undeveloped reserves, less accumulated depletion and amortization are limited to an amount equal to the discounted future net revenues of the estimated proved and risked probable reserves.

f. Goodwill

The Trust recorded goodwill relating to a corporate acquisition. The goodwill was determined as the excess of the purchase price over the fair value of the acquired assets less liabilities, including future income taxes, of the acquired company. The goodwill balance is assessed for impairment at each balance sheet reporting date. Impairment would be charged to earnings in the period it was incurred. Goodwill is reported at cost less any impairment and is not subject to amortization.

g. Investment in Weyburn Limited Partnership ("WLP")

Effective November 1, 2002, the Trust increased its ownership in the WLP and immediately redeemed its entire interest (see Note 6) in the WLP. Prior to this time, the Trust's interest in the WLP was accounted for using the cost method. Pursuant to this method, no income with respect to the WLP was recorded in the accounts of the Trust except for cash distributions received or receivable. Cash distributions received or receivable were recorded as a reduction of the investment to the extent that such distributions represented a return of capital.

h. Hedging Contracts

From time to time the Trust enters into various arrangements to hedge against possible fluctuations in commodity prices, interest rates and exchange rates. Gains or losses from these arrangements, which constitute effective economic hedges, are reported as adjustments to the related revenue or expense accounts as they are settled.

i. Unit-Based Compensation Plan

The Trust has a Trust Unit Rights Incentive Plan ("the Plan"), which is described in Note 9. The exercise price of the rights awarded pursuant to the plan may be reduced in future periods in accordance with the terms of the Plan. The reduction is primarily a function of distributions to unitholders and the net book value of the Trust's capital assets. The reduction is calculated as the excess, if any, of quarterly distributions greater than 2.5% of the net book value of capital assets. It is not possible to determine a fair value for the rights awarded pursuant to the Plan at inception using an option-pricing model because the exercise reduction feature of the Plan is dependent upon a number of factors, including, but not limited to, future prices realized on the sale of oil and natural gas, future production levels of oil and natural gas, amounts withheld from future distributions and the purchase and sale of capital assets. Compensation expense has been determined based upon the intrinsic value of the rights at the date of exercise or at the date of the financial statements for unexercised rights.

The compensation expense associated with rights awarded under the Plan is deferred and recorded in earnings over the average vesting period of the rights awarded along with an equal increase or decrease in contributed surplus. Changes in the intrinsic value of the unexercised rights after the vesting period will be recognized in the corresponding period of the change, along with an accompanying increase or decrease to contributed surplus.

On the actual exercise of the rights by the holder the consideration paid and the amount of contributed surplus attributable to the exercised right will be recorded as an increase to Unitholders' capital.

j. Income Taxes

The Trust follows the liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements of the Trust's corporate subsidiaries and their respective tax base, using enacted income tax rates. The effect of a change in income tax rates on future tax liabilities and assets is recognized in income in the period in which the change occurs. Temporary differences arising on corporate acquisitions could result in future income tax assets and liabilities. It is anticipated that any future assets or liabilities would be for the account of the unitholders.

The Trust is a taxable entity under the Income Tax Act (Canada) and is taxable only on income that is not distributed or distributable to unitholders. As the Trust expects to distribute its taxable income to the unitholders and meets the requirements of the Income Tax Act (Canada) applicable to the Trust, no current provision for income taxes has been made.

k. Weighted Average Number of Units Outstanding

The Trust uses the treasury stock method to determine the dilutive effect of "in the money" options, rights and other dilutive instruments issued. The basic and diluted calculations presented in these financial statements are based on the following weighted average units outstanding:

	2003	2002
Basic	42,732,252	22,099,613
Diluted	43,285,647	22,334,714

All outstanding rights have been included in the calculation of diluted weighted average units outstanding.

l. Change in Accounting Policies

1. Capital Assets

In late 2003 Ultima retroactively adopted the Full Cost Method of accounting for its capital assets pursuant to the Canadian Institute of Chartered Accountants ("CICA") Accounting Guideline ("AcG") 16 "Oil and Gas Accounting - Full Cost". Previously the Trust used the Successful Efforts Method of accounting for its capital assets. The effect of the change in accounting policy on the financial statements of the Trust as previously presented is as follows:

As at December 31		2003 (1)		2002
Capital Assets, net				
As reported	$	301,904	$	212,092
Adjustment		(7,369)		(4,162)
As restated	$	294,535	$	207,930
Net Income				
As reported	$	14,644	$	9,191
Adjustment		(2,366)		33

As restated	$	12,278	$	9,224
Deficit				
Beginning of year	$	(13,060)	$	(22,251)
Adjustment		(4,162)		(4,195)
As restated		(17,222)		(26,446)
Net Income as restated		12,278		9,224
End of year	$	(4,944)	$	(17,222)

(1) For 2003, the amounts noted as "As reported" reflect the Successful Efforts Method of accounting for capital assets as if it had been applied for the full year.

There is no effect on cashflow in either period presented due to the adoption of the Full Cost Method.

2. Unit Based Compensation Plan

The Trust elected to prospectively adopt amendments to the CICA Handbook Section 3870, "Stock-Based Compensation and Other Stock-Based Payments". Pursuant to this accounting standard the Trust must account for compensation expense based upon the fair value of the rights awarded under the Plan. As the Trust is unable to determine the fair value of the rights upon issuance compensation expense has been determined based upon the intrinsic value of the rights at the exercise date or at the date of the financial statements for unexercised rights. Previously the Trust accounted for compensation expense based upon the intrinsic value of the rights at the award date. Because the rights were awarded at fair market value, no compensation expense was charged to net income at the time of the award under the previous method of accounting.

The intrinsic value is determined as the excess of the trading price of the Trust's trust units over the exercise price of the unexercised rights. For exercised rights the intrinsic value is determined as the excess of the trading price of the Trust's trust units over the exercise price of the rights at the time the rights were exercised.

For rights granted prior to 2003 the Trust elected to continue accounting for the compensation expense based upon the intrinsic value at the award date. For rights awarded in 2002 the Trust has disclosed the pro-forma results for 2002 and 2003. However, the net income for 2002 has not been restated. The pro-forma results are presented in Note 10.

For 2003 the Trust has recorded $260,000 as compensation expense, noted as a separate line in the income statement. Included in Unitholders' Equity is contributed surplus of the same amount. No amounts would have been recorded under the prior method of accounting.

There was no material effect on net income per unit as a result of adopting this method of accounting for unit based compensation.

3. Disclosure of Guarantees

The Trust has adopted AcG-14 "Disclosure of Guarantees". This guideline requires the Trust to disclose all guarantees to third parties, of which there are none. There is no effect on net income or cashflow as a result of adopting this guideline.

3. Cash Distributions to Unitholders

	2003	2002
Net income	$ 12,278	$ 9,224
Future income tax recovery (note 13)	(900)	-
Unit based compensation	260	-
Internalization of Management (note 10)	4,716	-
Depletion and amortization	38,526	14,792
Cash available for distributions	54,880	24,016
Reclamation fund contributions (note 7)	(625)	(325)
Cash applied to financing and investing activities	(6,120)	(2,717)
Cash distributions declared	48,135	20,974
Accumulated cash distributions, beginning of year	63,558	42,584
Accumulated cash distributions, end of year	$ 111,693	$ 63,558
Cash distributions declared per unit	$ 1.09	$ 0.90

4. Capital Assets

Oil and natural gas properties	Cost	Accumulated Depletion and Amortization	Net Book Value
2003	$ 443,550	$ 149,015	$ 294,535
2002	321,659	113,729	207,930

The balances shown above have been restated due to the change in accounting policy whereby the Trust adopted the Full Cost Method of accounting for its capital assets. See note 2 (l).

Estimated future capital costs included in the 2003 depletion and amortization calculation were $83,642,000 (2002 - $3,211,000), primarily attributable to the Weyburn Unit Net Royalty Interest ("Weyburn Unit NRI") acquired on the redemption of the Trust's interest in the WLP. Excluded from the calculation of depletion and amortization for 2003 is unproved property attributable to the Weyburn Unit NRI in the amount of $11,300,000 (2002 - $nil).

Included in the 2003 provision for depletion and amortization is a provision for future site restoration of $3,239,000 (2002 - $1,200,000).

5. Trioco Acquisition

On June 26, 2003, the Trust acquired all the issued and outstanding shares of Trioco Resources Inc. ("Trioco") a private company engaged in the exploration and development of oil and natural gas in Alberta. The transaction has been accounted for using the purchase method of accounting (results of operations have been included as at June 26, 2003) and the allocation of the purchase price is as follows:

Net assets acquired		
Current assets	$	2,546
Capital assets		71,000
Goodwill		16,682
Current liabilities		(3,863)
Future income taxes		(15,298)
Future site restoration		(67)
	$	71,000
Paid by		
Cash	$	61,000
Bank debt assumed		10,000
	$	71,000

6. Weyburn Limited Partnership and Deferred Capital Obligation

Effective November 1, 2000, the Trust acquired a 92% interest in the WLP in a transaction involving the sale to the WLP of the Trust's Plato property for $3.3 million and the investment of the proceeds of sale in the WLP. The capital assets of the WLP were comprised of the Plato property, the Ferrybank property acquired from another partner and an 11.7% net royalty interest ("Weyburn Unit NRI") in the Weyburn Unit. The Weyburn Unit NRI was acquired by the WLP from EnCana Resources, the managing partner of the WLP, in consideration for a note payable for $77.8 million ($66.9 million as at November 1, 2002). The note payable is a non-recourse instrument with respect to the Trust's assets held outside of the WLP.

Effective November 1, 2002, the Trust contributed additional capital of approximately $66.9 million in cash, before adjustments, to the WLP to allow repayment in full of the outstanding note payable to EnCana Resources. The Trust subsequently redeemed its entire limited partnership interest. As consideration for the redemption, the Trust received 100% of the WLP's interest in the Weyburn Unit NRI, the interest in the Plato property, cash and working capital. The Trust funded the additional capital contribution from the net proceeds of an equity offering of $46,550,000 along with approximately $20,383,000 of borrowings drawn from the bank credit facility of Ventures Trust.

The redemption price and consideration paid was as follows:

Net assets acquired on redemption:	
Cash and working capital	$ 1,042
Capital Assets	84,731
Total net assets	$ 85,773
Financed by:	
Bank borrowings	$ 20,383
Trust Units issued	46,550
Deferred capital obligation assumed	18,840
Total purchase price	$ 85,773

The deferred capital obligation arose pursuant to the Weyburn Unit NRI agreement whereby payment for capital costs incurred in connection with the Weyburn Unit's operations prior to January 1, 2003 was deferred until the earlier of the date when the costs deferred totalled $18,778,000 or December 31, 2002. Interest was accrued on the amount deferred at a base rate of 8.5% per annum. Pursuant to an agreement with EnCana Resources in connection with the redemption, payment of up to an additional $15 million of capital expenditures applicable to the Weyburn Unit NRI will be deferred for the years 2003, 2004 and 2005. The Trust has the right to select the amount of the payment to be deferred each year to a maximum of $8 million of deferred expenditures for any given year. Also beginning January 1, 2003, interest will accrue on the deferred capital obligation at a base rate of 7% per annum. Repayment will commence on the earlier of January 1, 2006, or the date on which the deferred capital payments total $33,778,000. The deferred capital obligation will be amortized over a 15 year period. Interest will continue to accrue over the amortization period at a base rate of 7%, however, the deferred capital obligation repayment terms include an after-tax equalization component. This component provides for an effective interest rate over the amortization period of approximately 10%. The income tax equalization component will primarily affect the payments made in the latter half of the amortization period.

At December 31, 2003, the capital costs that have been deferred in accordanc