PETROFUND ENERGY TRUST
Form 40-F
March 17, 2005

U.S. Securities and Exchange Commission

Washington, D.C. 20549
Form 40-F

(Check One)

Registration statement pursuant to Section 12 of the Securities Exchange Act of 1934

or

Annual report pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934

For Fiscal year ended:

December 31, 2004

Commission File number:

00-115124

PETROFUND ENERGY TRUST

(Exact Name of Registrant as Specified in Its Charter)

Ontario, Canada

(Province or Other Jurisdiction of Incorporation or Organization)

1331

(Primary Standard Industrial Classification Code Number, if Applicable)

600, 444 7th Avenue S.W.
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, New York 10011

U.S.A.

(212) 894-8700

(Name, Address (Including Zip Code) and Telephone Number (Including Area Code)
of Agent For Service in the United States)

Securities registered pursuant to Section 12(b) of the Act:

Title Of Each Class:	Name Of Each Exchange On Which Registered:
Trust Units	The American Stock Exchange

Securities registered or to be registered pursuant to Section 12(g) of the Act:

None

(Title of Class)

Securities for which there is a reporting obligation pursuant to Section 15(d) of the Act:

None

(Title of Class)

For annual reports, indicate by check mark the information filed with this form:

þ

Annual Information Form

þ

Audited Annual Financial Statements

Indicate the number of outstanding shares of each of the issuer s classes of capital or common stock as of the close of the period covered by the annual report:

99,511,576 Trust Units

Indicate by check mark whether the registrant by filing the information contained in this form is also thereby furnishing the information to the Commission pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934 (the Exchange Act). If Yes is marked, indicate the file number assigned to the registrant in connection with such rule.

Yes **G**

No þ

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13(d) or 15(d) of the Exchange Act during the proceeding 12 months (or for such shorter period that the registrant was required to file such reports); and (2) has been subject to such filing requirements for the past 90 days.

Yes þ

No **G**

UNDERTAKING AND CONSENT TO SERVICE OF PROCESS

Undertaking

The Registrant undertakes to make available, in person or by telephone, representatives to respond to inquiries made by the staff of the Securities and Exchange Commission (the SEC), and to furnish promptly, when requested to do so by the SEC staff, information relating to the securities in relation to which the obligation to file an annual report on Form 40-F arises or transactions in said securities.

Consent to service of Process

The Registrant has previously filed with the SEC a written irrevocable consent and power of attorney on Form F-X in connection with the Trust Units.

SIGNATURES

Pursuant to the requirements of the Exchange Act, the Registrant certifies that it meets all of the requirements for filing on Form 40-F and has duly caused this annual report to be signed on its behalf by the undersigned, thereto duly authorized.

PETROFUND ENERGY TRUST

Date: March 15, 2005

By: *(signed)* *Jeffery E. Errico*

Jeffery E. Errico

President and Chief Executive Officer

EXHIBIT INDEX

Exhibit No.	**Description**
1	Annual Information Form for the year ended December 31, 2004.
2	Management s Discussion and Analysis for the year ended December 31, 2004.
3	Audited Consolidated Financial Statements, including the notes thereto, dated December 31, 2004 and 2003 and for the years ended December 31, 2004, 2003 and 2002, together with the reports of the Independent Registered Chartered Accountants thereon.
4	Disclosures regarding the Registrant s Disclosure Controls and Procedures.
5	Disclosures regarding the Registrant s Audit Committee Financial Expert.
6	Disclosures regarding the Registrant s Code of Ethics.
7	Disclosures regarding the Registrant s Audit Committee Pre-Approval Policies and Procedures and Principal Accountant Fees and Services.
8	Consent of Gilbert Laustsen Jung Associates Ltd.
9	Consent of Independent Registered Chartered Accountants.
10	Comments by Independent Registered Chartered Accountants on Canada United States of America Reporting differences.
11	Officers Certifications pursuant to Rule 13a-15(f) or Rule 15d-15(f).
12	Officers Certifications pursuant to Rule 13a-14(b) or Rule 15d-14(b) and Section 1350 of Chapter 63 of Title 18 of the United States Code.

EXHIBIT 1

Annual Information Form

For the year ended December 31, 2004

PETROFUND ENERGY TRUST

RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2004

March 15, 2005

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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 PC Exchangeable Shares held by the holder for 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.
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 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 14, 2005 with respect to the petroleum, natural gas and NGL reserves of PC effective as at December 31, 2004.
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.
PVT:	Petrofund Ventures Trust, a wholly owned subsidiary trust of Petrofund formally known as Ultima Ventures Trust.
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 PC 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 November 16, 2004 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 November 16, 2004 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.
Ultima:	Ultima Energy Trust.
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.
Voting Shareholder Agreement:	The voting shareholder agreement made as of April 29, 2003, as amended as of April 12, 2004, between PC and Petrofund relating to, among other things, the election of the Board of Directors.

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

PETROFUND ENERGY TRUST

RENEWAL ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2004

DATED March 15, 2005

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, head office and operations of the Trust are 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, a wholly-owned subsidiary, and a 99% net royalty interest granted by PVT (formerly Ultima Ventures Trust), also a wholly owned subsidiary. PC is a corporation incorporated under the laws of Alberta, and PVT is a trust created under the laws of the Province 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; and hold the legal interest to all properties beneficially owned by PVT. PVT receives 99% of the net revenue from these properties, which it in turn pays out to Petrofund in the form of the 99% net royalty noted above. 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:

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 or PVT, 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 "Internalization of Management".

Employees and Consultants

As at December 31, 2004 PC had 106 office employees and 22 full time consultants. PC also has 38 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 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. was 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. Sentry was an affiliate of NCEP Management in which John F. Driscoll owns a controlling interest. John F. Driscoll is Chairman of the Board of PC.

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.

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 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.

Outlook for Next Year

The level of cash flow for 2005 will be affected by oil and gas prices, the $US/$CDN 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 2004 and this trend is expected to continue in 2005. 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 2004 significantly moderated the net effect of these prices on Petrofund s cash flow. The exchange rate $US/$CDN averaged $0.769 in 2004 as compared to $0.715 in 2003 reaching a high of $0.836 in November, 2004. We expect the Canadian dollar to remain fairly strong throughout 2005.

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.

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
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

In addition, on June 16, 2004, 26,449,102 Trust Units were issued to purchase Ultima.

Acquisitions

The following is a description of significant acquisitions made by PC in the last three completed financial years.

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.

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 Trust Unit 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.

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. 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.

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. The properties contained a large percentage of unit production.

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 approximately 1,100 Boepd of production.

2004

Ultima Energy Trust

On June 16, 2004 PC acquired Ultima. Under the terms of the agreement, each Ultima unit was effectively exchanged for 0.442 of a Trust Unit on a tax-deferred rollover basis and PC acquired all the assets and assumed all of the liabilities of Ultima. Ultima unitholders also received an aggregate $10 million one-time special distribution from Ultima of $0.167113 per Ultima unit on June 15, 2004. The aggregate cost of the transaction was $563.1 million consisting of 26.4 million Petrofund Trust units valued at $17.12 per unit, which was the weighted average trading price of the Units for the period commencing five days before and ending five days after the acquisition was announced, the assumption of debt and negative working capital of $119.7 million and transaction costs incurred by the Trust of $1.9 million.

Production from the Ultima properties from January 1, 2004 to the date of closing was approximately 9,900 Boepd of which 78% was oil and natural gas liquids. Ultima had a diversified group of assets with a reserve life index of over 11 years. Ultima s proved plus probable reserves were estimated at 41.4 MMboe at December 31, 2003.

The major properties acquired were Weyburn, Spirit River, Cherhill, Kerrobert and Westerose. The Weyburn and Kerrobert properties have common ownership with Petrofund s existing holdings. Ultima s properties were held either by Ultima Energy Inc., as trustee for Ultima, or by Ultima Ventures Corp., as trustee for Ultima Ventures Trust, now PVT, a wholly owned subsidiary of Ultima Energy Trust. Ultima Energy Inc. was amalgamated into PC and Ultima Ventures Corp. was wound up and dissolved into PC, and all properties have now been transferred to and are held by PC on behalf of Petrofund, or PVT, now a wholly owned subsidiary of Petrofund.

BUSINESS AND PROPERTIES

PC acquires, manages and disposes of petroleum and natural gas property rights and interests. As of December 31, 2004, 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

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31, 2004, PC's asset base included proved plus probable gross reserves (before deduction of royalties) of 86.0 MMbbls of oil, 283.7 Bcf of natural gas and 8.3 MMbbls of natural gas liquids based on forecast prices and cost assumptions, and an inventory of undeveloped land totalling 547,829 gross acres and 231,120 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.

The following is a summary of PC's properties as at December 31, 2004. Unless otherwise specified, gross and net acres and well count information are as at December 31, 2004. Gross reserve amounts are stated, before deduction of royalties, as at December 31, 2004 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	2004 Average Production (Boepd)	Proved Plus Probable Reserves (Mboe)
Weyburn	EnCana Oil & Gas Partnership	21.0%	Oil	3,720	35,984
Swan Hills	Various	(1)	Oil	1,950	13,469
Pembina	Various	(1)	Oil & Gas	1,180	8,707
Kerrobert	PC	90.0%	Oil	820	5,986
Fort Saskatchewan	PC	97.0%	Gas	950	4,920
Three Hills	PC	80.0%	Gas	815	4,092
Willesden Green	Various	(1)	Oil & Gas	390	4,010
Ring Border	Burlington Resources	9.4%	Gas	785	3,765
Hatton	Apache	95.0%	Gas	880	3,718
Cherhill	PC	90.0%	Oil & Gas	670	3,426
Others	Various	Various	Oil & Gas	19,268	53,475
				31,428	141,552

Note:

(1)

Working interest varies among multiple properties.

Weyburn, Saskatchewan

The Weyburn Unit, operated by EnCana Oil & Gas Partnership, is situated 30 kilometres south of Weyburn in south-eastern Saskatchewan. This unit has an exceptional long reserve life index (19+ years) due to ongoing enhanced recovery operations by both water and CO_2 flooding. PC increased its ownership in this core asset to 21% from 9.3% through its mid year acquisition of Ultima. The Weyburn Unit 11.7136 percent net royalty interest acquired with the Ultima acquisition has been treated as a working interest as PC has been receiving the production in kind and is responsible for its share of capital costs, operating costs, royalties and abandonment costs. The unit s average production in 2004 was 23,405 Boepd which once again exceeded the budget expectations. PC s average working interest production for 2004 was 3,720 Boepd and working interest production in December 2004 was over 5,400 Boepd. 2004 development activities included further expansion of the CO_2 flood by 12 patterns, drilling 24 horizontal producers and drilling three horizontal injectors. Cost efficiency in drilling was enhanced by the re-entry of certain existing vertical wellbores. PC s total proved plus probable reserves as of December 31, 2004, amounted to 35,984 Mboe, consisting of 35,177 Mbbl of oil and 806 Mbbl of NGL.

Swan Hills, Alberta

PC s Swan Hills (including Swan Hills North) property is located approximately 200 kilometres northwest of Edmonton, Alberta and includes significant ownership in two major oil units, Swan Hills Unit #1 and House Mountain Unit #1, as well as minor interests in Deer Mountain Unit No. 2, Judy Creek West Beaverhill Lake Unit and South Swan Hills Unit. All of these units exhibit long life reserves due to enhanced recovery through waterflooding and/or miscible hydrocarbon flooding. In the fall of 2004, a pilot CO_2 enhanced recovery project was initiated in Swan Hill Unit #1. There were also 5 vertical infill wells drilled in this unit in 2004, as well as one horizontal solvent injector. In House Mountain Unit #1, a total of 3 horizontal wells were drilled. PC s working interest Swan Hills production averaged 1,950 Boepd in 2004. PC s total proved plus probable reserves as of December 31, 2004, totalled 13,469 Mboe, consisting of 11,814 Mbbl of oil, 3.5 Bcf of gas and 1,078 MBbl of NGL.

Pembina, Alberta

Located 100 kilometers southwest of Edmonton, Alberta, PC has holdings in six non-operated oil units and six operated properties. Twelve wells were drilled in these non-operated units in 2004. Also in 2004, PC acquired an approximately 20% additional interest in the Rose Creek property to average 85% working interest. In mid 2004, PC commenced blowing down its Alder Flats Belly River gas cap. PC s Pembina production averaged 1180 Boepd in 2004. PC s total proved plus probable reserves as of December 31, 2004, totalled 8,707 Mboe, comprising of 6,626 Mbbl of oil, 8.9 Bcf of gas and 603 Mbbl of NGL.

Kerrobert, Saskatchewan

PC s Kerrobert property is located approximately 25 kilometres north of Kindersley in west central Saskatchewan. Wells are predominantly operated, with a working interest averaging approximately 95%. PC s working interest production from this area averaged 820 Boepd in 2004. Significant production and reserves were added to PC s existing Kerrobert Area following PC s mid-year acquisition of Ultima. PC s total proved plus probable reserves as of December 31, 2004, were 5,986 Mboe, consisting of 4,701 Mbbl of oil, 6.5 Bcf of gas and 190 Mbbl of NGL.

Fort Saskatchewan, Alberta

PC operates its Fort Saskatchewan gas property located immediately east of Edmonton, Alberta. PC s Fort Saskatchewan property includes the Beaverhill Lake Viking Gas Unit #1 and several non-unit wells, all of which produce from a large mature Viking gas pool extending from Ft. Saskatchewan on the west side of the Elk Island National Park to Beaverhill Lake east of Tofield. PC s working interest throughout this entire area averages 97%. Besides the 30 producing gas wells, PC owns and operates 3 associated compression-dehydration facilities. During 2004, PC concentrated on optimizing and upgrading the compression and gas gathering system, and as a result, production increased 10% over 2003. In late 2004, PC installed additional compression and began an infill drilling program for Beaverhill Lake Viking Gas Unit #1 which is forecast to improve production by approximately 25% and accelerate recovery of the remaining reserves. PC also began exploiting the deeper (Mannville) gas horizons in the area with the successful drilling of a Mannville gas well. PC s working interest production averaged 950 Boepd throughout 2004. PC s total proved plus probable reserves as of December 31, 2004, amounted to 4,920 Mboe, consisting of 29.5 Bcf of gas.

Three Hills Creek, Alberta

PC s Three Hills Creek property is located approximately 16 km southeast of the city of Red Deer, Alberta. PC has an extensive position in the area covering approximately one hundred sections of land. PC has a high working interest in these lands and operates most of its production. PC s net production from the area in 2004 averaged 815 Boepd (largely gas). Productive horizons include the Lower Mannville, Blairmore, Viking, Belly River, and Edmonton Sands. During 2004, PC was engaged in developing an Edmonton Sands gas pool as well as recompleting several suspended wells for gas production in the Belly River zone. In addition, PC commenced participating for its 35% interest in a Coalbed Methane project operated by MGV Energy Ltd. During 2005 PC plans to participate in the drilling of approximately 80 development wells including the installation of production facilities. PC s total proved plus probable reserves as of December 31, 2004, were 4,092 Mboe, comprised of 160 Mbbl of oil, 21.6 Bcf of gas and 329 Mbbl of NGL.

Willesden Green, Alberta

PC s Willesden Green property is situated approximately 50 kilometres west of Red Deer, Alberta. Willesden Green is a collection of several individual operated and non-operated oil and gas fields. Producing horizons include the Glauconitic (gas) and the Cardium (oil). Late in the 3rd quarter of 2004, PC acquired a 50% working interest in a producing Cardium oil property. PC expects to further develop this acquired property beginning in 2005 by expanding an existing waterflood and by drilling several infill wells. PC s average working interest production in 2004 was 390 Boepd and working interest production in December 2004 was 750 Boepd. PC s total proved plus probable reserves as of December 31, 2004, were 4,010 Mboe, made up of 2,788 Mbbl of oil, 6.7 Bcf of gas and 109 Mbbl of NGL.

Ring Border, British Columbia

PC s Border gas property is located 190 kilometres northeast of Fort St. John in north-eastern British Columbia and is operated by Burlington Resources Canada. PC owns a 9.4% interest in the Border Bluesky-Gething-Montney Unit "B" and a similar interest in various surrounding non-unit lands. PC also has ownership in the Border gas plant. Twelve unit and non-unit wells were drilled and placed on production in early 2004. A similar infill drilling program is planned for early 2005 (winter access only). PC s 2004 working interest production averaged 785 Boepd. PC s total proved plus probable reserves as of December 31, 2004, were 3,765 Mboe, consisting of 19.7 Bcf of gas and 488 Mbbl of NGL.

Hatton, Saskatchewan

PC s Hatton gas property is located approximately 140 kilometres west of Swift Current, Saskatchewan. PC operates 265 shallow gas wells. PC s production originates from the shallow Medicine Hat and Milk River sand zones. PC s working interest production averaged 880 Boepd in 2004. PC s total proved plus probable reserves as of December 31, 2004, were 3,718 Mboe, comprised of 22.3 Bcf of gas.

Cherhill, Alberta

PC s Cherhill property, acquired from Ultima in mid 2004, is located approximately 100 kilometres northwest of Edmonton, Alberta. PC operated thirty two oil wells and four gas wells with an average working interest of 90%. Following the Ultima acquisition, PC s working interest production averaged 1,445 Boepd, and the full year average working interest production in 2004 was 670 Boepd. Development activity in 2004 included the drilling of 2 successful horizontal Banff oil wells, which together added 415 Boepd to PC s production. In addition, PC commenced the construction of a facility upgrade designed to add significant water handling capabilities that in turn will allow additional infill drilling, production optimization, and well reactivations. PC s

total proved plus probable reserves as of December 31, 2004, were 3,426 Mboe, made up of 2,926 Mbbl of oil, 2.6 Bcf of gas and 70 Mbbl of NGL.

The above 10 properties account for approximately 60% of Petrofund s total proved plus probable reserves as at December 31, 2004.

Other Properties

Petrofund has various interests in numerous other properties located in Alberta, British Columbia, Manitoba and Saskatchewan. Petrofund s proved plus probable reserves for these other properties as at December 31, 2004 amounted to approximately 53,475 Mboe. In total these properties represent approximately 40% of Petrofund s proved plus probable reserves as at December 31, 2004.

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

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 14, 2005. The effective date of the Statement is December 31, 2004 and the preparation date of the Statement is February 7, 2005. The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the Report on Reserves Data by Independent Qualified Reserves Evaluator in Form 51-101F2 are attached as Appendices A and B to this Annual Information Form.

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, 2004 contained in the GLJ Report dated February 14, 2005. 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.

It should not be assumed that the estimates of future net revenue presented in the tables below represent the fair market value of the reserves. There is no assurance that the constant price and cost assumptions and forecast 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 and natural gas liquid reserves may be greater than or less than the estimates provided herein. For more information as to certain risks involved, see "Risk Factors".

Petrofund is a taxable entity under the Tax Act and is taxable only on income that is not distributed or distributable to the Unitholders. As Petrofund distributes all its taxable income to Unitholders, and meets the requirements of the Tax Act applicable to it, future net revenue after income taxes is not included in the disclosure below.

Reserves Data (Constant Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES

AND NET PRESENT VALUES OF FUTURE NET REVENUE

as of December 31, 2004

CONSTANT PRICES AND COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
RESERVES CATEGORY	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)
PROVED RESERVES								
Developed Producing	52,021	45,438	981	872	212,540	167,924	5,670	4,067
Developed Non-Producing	458	434	0	0	10,398	8,119	132	93
Undeveloped	15,360	13,869	0	0	9,417	7,585	471	316
TOTAL PROVED RESERVES	67,839	59,740	981	872	232,354	183,628	6,274	4,477
PROBABLE	18,899	16,319	235	210	57,133	45,682	2,213	1,742
TOTAL PROVED PLUS PROBABLE	86,738	76,059	1,216	1,082	289,487	229,310	8,486	6,219

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$)	20 (MM$)
PROVED RESERVES						
Developed Producing	1,677.2	1,260.8	1,022.5	953.2	867.2	757.5
Developed Non-Producing	50.9	33.7	25.4	23.2	20.5	17.1
Undeveloped	292.7	174.1	108.7	91.0	70.1	46.0
TOTAL PROVED RESERVES	2,020.9	1,468.6	1,156.7	1,067.3	957.8	820.7
PROBABLE	665.0	373.1	240.2	206.8	168.8	126.0
TOTAL PROVED PLUS PROBABLE	2,685.9	1,841.7	1,396.8	1,274.1	1,126.6	946.6

TOTAL FUTURE NET REVENUE

(UNDISCOUNTED)

as of December 31, 2004

CONSTANT PRICES AND COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)
Proved Reserves	4,515,503	808,653	1,363,568	250,820	71,609	2,020,852
Proved Plus Probable Reserves	5,707,297	1,021,953	1,628,129	298,530	72,810	2,685,875

FUTURE NET REVENUE

BY PRODUCTION GROUP

as of December 31, 2004

CONSTANT PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	660,075
	Heavy Oil (including solution gas and other by-products)	9,006
	Natural Gas (including by-products but excluding solution gas from oil wells)	512,317
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	819,568
	Heavy Oil (including solution gas and other by-products)	10,214

Natural Gas (including by-products but excluding solution gas from oil wells)	591,413

Reserves Data (Forecast Prices and Costs)

SUMMARY OF OIL AND GAS RESERVES

AND NET PRESENT VALUES OF FUTURE NET REVENUE

as of December 31, 2004

FORECAST PRICES AND ESCALATING COSTS

	RESERVES							
	LIGHT AND MEDIUM OIL		HEAVY OIL		NATURAL GAS		NATURAL GAS LIQUIDS	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net
RESERVES CATEGORY	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(MMcf)	(MMcf)	(Mbbl)	(Mbbl)
PROVED RESERVES								
Developed Producing	50,535	44,056	982	864	208,577	164,794	5,509	3,965
Developed Non-Producing	492	464	0	0	10,256	8,016	128	91
Undeveloped	15,273	13,858	0	0	9,401	7,589	470	317
TOTAL PROVED RESERVES	66,301	58,378	982	864	228,234	180,398	6,107	4,374
PROBABLE	18,483	15,990	233	206	55,485	44,366	2,161	1,710
TOTAL PROVED PLUS PROBABLE	84,783	74,368	1,214	1,070	283,719	224,765	8,268	6,083

	NET PRESENT VALUES OF FUTURE NET REVENUE BEFORE INCOME TAXES DISCOUNTED AT (%/year)					
	0	5	10	12	15	20
RESERVES CATEGORY	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)	(MM$)
PROVED RESERVES						
Producing	1,472.2	1,143.5	953.1	896.9	826.4	735.0
Non-Producing	49.1	31.5	23.6	21.5	19.0	16.0

Undeveloped	277.9	165.0	103.0	86.2	66.5	43.8
TOTAL PROVED RESERVES	1,799.2	1,340.0	1,079.6	1,004.5	911.9	794.8
PROBABLE	639.3	352.1	224.8	193.3	157.7	117.9
TOTAL PROVED PLUS PROBABLE	2,438.5	1,692.1	1,304.4	1,197.8	1,069.6	912.7

TOTAL FUTURE NET REVENUE

(UNDISCOUNTED)

as of December 31, 2004

FORECAST PRICES AND ESCALATED COSTS

RESERVES CATEGORY	REVENUE (M$)	ROYALTIES (M$)	OPERATING COSTS (M$)	DEVELOPMENT COSTS (M$)	WELL ABANDONMENT COSTS (M$)	FUTURE NET REVENUE BEFORE INCOME TAXES (M$)
Proved Reserves	4,468,426	800,308	1,516,074	260,657	92,140	1,799,248
Proved Plus Probable Reserves	5,732,580	1,019,184	1,864,669	311,122	99,099	2,438,506

FUTURE NET REVENUE

BY PRODUCTION GROUP

as of December 31, 2004

FORECAST PRICES AND COSTS

RESERVES CATEGORY	PRODUCTION GROUP	FUTURE NET REVENUE BEFORE INCOME TAXES (discounted at 10%/year) (M$)
Proved Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	648,849
	Heavy Oil (including solution gas and other by-products)	11,550
	Natural Gas (including by-products but excluding solution gas from oil wells)	446,628
Proved Plus Probable Reserves	Light and Medium Crude Oil (including solution gas and other by-products)	801,544

Heavy Oil (including solution gas and other by-products)	12,990
Natural Gas (including by-products but excluding solution gas from oil wells)	516,994

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

- 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.

<u>Levels of Certainty for Reported Reserves</u>

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; and
- 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.

"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.

8.

"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.

9.

"Exploration well" means a well that is not a development well, a service well or a stratigraphic test well.

10.

"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.

11.

"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.

12.

Numbers may not add due to rounding.

13.

The estimates of future net revenue presented in the tables above do not represent fair market value.

14.

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.

15.

Both the constant and forecast price and cost assumptions assume the continuance of current laws and regulations.

16.

The extended character of all factual data supplied to GLJ were accepted by GLJ as represented. No field inspection was conducted.

Pricing Assumptions

The following sets out the benchmark reference prices, as at December 31, 2004, reflected in the Reserves Data. These price assumptions were provided to PC by GLJ, PC s independent reserves evaluator.

SUMMARY OF PRICING ASSUMPTIONS

as of December 31, 2004

CONSTANT PRICES AND COSTS

	OIL				NATURAL GAS				
	WTI Cushing Oklahoma	Edmonton Par Price 40° API	Hardisty Heavy 12° API	Cromer Medium 29.3° API	AECO Gas Price	Edmonton Propane	Edmonton Butane	Edmonton Pentanes Plus	EXCHANGE RATE(1)
Year	($US/Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	($Cdn/MMBtu)	($Cdn/Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	($US/$Cdn)
As at December 31, 2004	43.45	46.54	24.33	32.12	6.79	29.79	34.44	48.97	0.8308

Note:

(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, 2004

FORECAST PRICES AND COSTS

	OIL				NATURAL GAS					
	WTI Cushing Oklahoma	Edmonton Par Price 40° API	Hardisty Heavy 12° API	Cromer Medium 29.3° API	AECO Gas Price	Edmonton Propane	Edmonton Butane	Edmonton Pentanes Plus	INFLATION RATES(1)	EXCHANGE RATE(2)
Year	($US/Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	($Cdn/MMBtu)	($Cdn/Bbl)	($Cdn/Bbl)	($Cdn/Bbl)	%/Year	($US/$Cdn)
Forecast:										

2005	42.00	50.25	27.50	43.75	6.60	32.25	37.25	50.75	2.0	0.82
2006	40.00	47.75	28.50	41.50	6.35	30.50	35.25	48.25	2.0	0.82
2007	38.00	45.50	28.75	39.50	6.15	29.00	33.75	46.00	2.0	0.82
2008	36.00	43.25	27.25	37.75	6.00	27.75	32.00	43.75	2.0	0.82
2009	34.00	40.75	25.50	35.50	6.00	26.00	30.25	41.25	2.0	0.82
2010	33.00	39.50	24.75	34.25	6.00	25.25	29.25	40.00	2.0	0.82
2011	33.00	39.50	24.75	34.25	6.00	25.25	29.25	40.00	2.0	0.82
2012	33.00	39.50	24.75	34.25	6.00	25.25	29.25	40.00	2.0	0.82
2013	33.50	40.00	24.75	34.75	6.10	25.50	29.50	40.50	2.0	0.82
2014	34.00	40.75	25.50	35.50	6.20	26.00	30.25	41.25	2.0	0.82
2015	34.50	41.25	25.75	36.00	6.30	26.50	30.50	41.75	2.0	0.82

Notes:

(1)

Inflation rates for forecasting prices and costs. Prices escalate 2.0% in 2016 and thereafter.

(2)

Exchange rates used to generate the benchmark reference prices in this table.

PC s weighted average prices received in 2004 after transportation and quality differentials were $48.83/Bbl for oil, $6.87/Mcf for natural gas and $41.96/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			ASSOCIATED AND NON ASSOCIATED GAS		
	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable
FACTORS	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Mbbl)	(Bcf)	(Bcf)	(Bcf)
December 31, 2003	37,793	9,678	47,471	750	183	933	164.3	36.1	200.4
Extensions	170	(7)	163	0	0	0	5.5	3.7	9.2
Improved Recovery	567	(69)	498	45	9	53	8.5	2.5	11.1
Technical Revisions	2,769	333	3,103	168	18	186	7.0	(1.4)	5.6
Discoveries	0	0	0	0	0	0	0.9	0.2	1.0
Acquisitions	23,163	6,363	29,525	0	0	0	21.3	4.6	25.9
Dispositions	0	0	0	0	0	0	(0.2)	0.0	(0.2)
Economic Factors	36	20	56	4	0	4	0.5	0.0	(0.6)
Production	(4,757)		(4,757)	(95)		(95)	(24.2)		(24.2)
December 31, 2004	59,740	16,319	76,059	872	210	1,082	183.6	45.7	229.3

	NATURAL GAS LIQUIDS			BARRELS OF OIL EQUIVALENT		
	Net Proved	Net Probable	Net Proved Plus Probable	Net Proved	Net Probable	Net Proved Plus Probable
FACTORS	(Mbbl)	(Mbbl)	(Mbbl)	(Mboe)	(Mboe)	(Mboe)
December 31, 2003	4,036	1,211	5,247	69,958	17,091	87,049

Extensions	17	12	28	1,005	621	1,721
Improved Recovery	56	10	66	2,090	371	2,461
Technical Revisions	353	32	384	4,461	144	4,605
Discoveries	8	2	10	151	29	180
Acquisitions	594	472	1,066	27,305	7,600	34,905
Dispositions	0	0	0	(26)	0	(26)
Economic Factors	9	4	13	138	29	166
Production	(596)		(596)	(9,482)		(9,482)
December 31, 2004	4,477	1,742	6,219	95,694	25,885	121,578

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	2004 (M$)
Estimated Net Present Value Before Tax at Beginning of Year	814,427
Oil and Gas Sales During the Period(1)	(312,752)
Changes due to Prices, Production Costs and Royalties Related to Forecast Production(2)	132,927
Development Costs During the Period(3)	(77,900)
Changes in Forecast Development Costs(4)	90,297
Changes Resulting from Extensions and Improved Recovery(5)	40,197
Changes Resulting from Discoveries(5)	1,962
Changes Resulting from Acquisitions of Reserves(5)	320,784
Changes Resulting from Dispositions of Reserves(5)	(334)
Accretion of Discount(6)	81,443
Net Change in Income Taxes(7)	N/A
Changes Resulting from Technical Reserves Revisions Plus All Other Changes	65,621
Estimated Net Present Value Before Tax at End of Period	1,156,672

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 of the GLJ Report. Capital expenditures to develop proved undeveloped reserves are estimated at $22.1 million in 2005 and $20.7 million in 2006. Capital expenditures to develop probable undeveloped reserves are estimated at $8.1 million in 2005 and $6.4 million in 2006.

Significant Factors or Uncertainties

Petrofund does not anticipate that any important economic factors or significant uncertainties would affect particular components of the reserves data. Notwithstanding that, a number of factors which are beyond Petrofund s and PC s control can significantly affect the reserves, including fluctuations in product pricing, royalty and tax regimes, changing operating and capital costs, surface access issues, availability of services and processing facilities and technical issues affecting well performance. See "Risk Factors".

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.

	Forecast Prices and Costs (M$)		Constant Prices and Costs (M$)
Year	Proved Reserves	Proved Plus Probable Reserves	Proved Reserves
2005	48,590	55,822	48,889
2006	33,776	40,132	33,419
2007	28,167	30,665	27,550
2008	19,551	23,680	19,077
2009	23,461	27,234	22,506
Remainder	107,112	133,589	99,379
Total Undiscounted	260,657	311,122	250,820
Total Discounted at 10%	174,546	204,928	170,897

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, 2004.

	Oil Wells				Natural Gas Wells				Service Wells	
	Producing		Non-Producing		Producing		Non-Producing			
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
Alberta	2,610	599.2	1,009	207.1	1,329	310.6	372	112.9	824	140.9
British Columbia	83	21.1	97	9.2	240	40.2	71	14.1	28	5.7
Manitoba	124	116.0	47	45.4	0	0	0	0	26	25.6
Saskatchewan	3,022	1,737.4	298	55.3	342	299.2	20	10.5	135	104.1
Total	5,839	2,473.7	1,451	317.0	1,911	650.0	463	137.5	1,013	276.3

Properties with no Attributable Reserves

The following table sets out PC s undeveloped land holdings as at December 31, 2004.

	Undeveloped Acres	
	Gross	Net
Alberta	319,550	127,121
British Columbia	129,230	42,848
Manitoba	1,041	1,021
Saskatchewan	98,008	60,130
Total	547,829	231,120

There are no material work commitments on the undeveloped land holdings.

PC expects that rights to explore develop and exploit 28,553 net acres of its undeveloped land holdings will expire by December 31, 2005.

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 3,000 net wells totalling $72.8 million net of salvage value ($24.3 million discounted at 10%) are included in the estimate of future net revenue. Facility abandonment costs and suspended well abandonment costs of $43.7 million ($16.0 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 $3.5 million in 2005, $3.6 million in 2006 and $3.9 million in 2007.

Forward Contracts

For details of material commitments to sell natural gas and crude oil which were outstanding at December 31, 2004, see Note 15 to the Trust s audited consolidated financial statement for the year ended December 31, 2004, which Note is incorporated herein by reference.

Tax Horizon

As a result of the Trust's tax efficient structure, annual taxable income is transferred from its operating entities to the Trust and from the Trust to Unitholders. Therefore, it is expected that no income tax liability will be incurred by the Trust for so long as the Trust maintains its organizational tax structure. PC also will not be taxable so long as the interest on the notes held by the Trust, royalties under the Royalty Agreement and other expenses in PC are sufficient to reduce taxable income to nil in the operating subsidiaries. PC is not expected to be taxable in 2005.

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, 2004:

	(M$)
Property acquisition costs[(1)]	
Proved properties	$605,840
Undeveloped properties	1,695
Exploration costs[(2)]	678
Development costs[(3)]	75,637
Total	$683,850

Notes:

(1)

Acquisitions are net of disposition of properties.

(2)

Cost of geological and geophysical capital expenditures and drilling costs for exploration wells drilled.

(3)

Development and facilities capital expenditures.

Exploration and Development Activities

The following tables set forth the gross and net exploratory and development wells in which PC participated during the year ended December 31, 2004:

Working Interest Wells

	Development Wells		Exploration Wells	
	Gross	Net	Gross	Net
Oil	91	15.1	1	0.3
Gas	52	18.6	14	5.8
Service	5	0.3	0	0
Dry	1	0.4	1	1.0
Total:	149	34.4	16	7.1

Farm-out Wells

	Development Wells	Exploration Wells
Oil	3	6
Gas	17	13
Service	0	0
Dry	3	1
Total:	23	20

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, 2005 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	Heavy Oil	Natural Gas	Natural Gas Liquids	BOE
	(Bpd)	(Bpd)	(Mcfpd)	(Bpd)	(Boepd)
Proved Producing	16,691	335	83,345	2,106	33,024
Total Proved	17,194	335	87,070	2,105	34,146
Proved plus Probable	17,698	340	89,293	2,155	35,076

No one area accounts for 20% or more of the estimated production disclosed.

Production History and Prices Received

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netbacks for the periods indicated below:

	Quarter Ended 2004			
	Dec. 31	Sept. 30	June 30	Mar. 31
Average Daily Production				
Gas (Mcfd)	90.1	90.1	79.7	77.9
Light and Medium Crude Oil (Bpd)	18,508	17,504	12,679	11,579
NGLs (Bpd)	2,502	2,427	2,074	2,040
Combined (Boepd)	36,025	34,950	28,043	26,607
Average Price Received				
Gas ($/Mcf)	$ 7.12	$ 6.50	$ 7.13	$ 6.76
Light and Medium Crude Oil ($/Bpd)	50.96	52.02	47.01	42.50
NGLs ($/Bpd)	48.20	43.68	37.13	37.06
Combined ($/Boepd)	47.33	45.85	44.27	41.15
Royalties Paid				
Gas ($/Mcf)	1.79	1.17	1.58	1.37
Light and Medium Crude Oil ($/Bpd)	8.19	9.80	8.54	6.43
NGLs ($/Bpd)	9.71	9.30	8.71	11.11
Combined ($/Boepd)	9.37	8.58	9.02	7.67
Production Costs				
Gas ($/Mcf)	1.17	1.27	1.24	0.84
Light and Medium Crude Oil ($/Bpd)	10.41	11.48	11.29	11.94
NGLs ($/Bpd)	7.84	8.48	8.50	6.79
Combined ($/Boepd)	8.82	9.62	9.26	8.19
Netback Received				
Gas ($/Mcf)	4.06	3.83	3.97	4.40
Light and Medium Crude Oil ($/Bpd)	23.70	21.81	20.48	19.00
NGLs ($/Bpd)	30.15	25.49	19.47	18.75
Combined ($/Boepd)	24.39	22.57	22.05	22.71

Note:

(1)

Heavy oil production is not significant and is included in light and medium crude oil.

CAPITAL STRUCTURE 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 28, 2005, 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.

Pursuant to the Voting Shareholder Agreement, Unitholders are entitled to designate the individuals to be elected as directors of PC by resolution of Unitholders and, following such designation, the Trust will take all actions necessary to elect or appoint the nominees so designated as directors of PC. In addition, the Board of Directors may, between annual meetings, appoint one or more additional directors of PC to serve as directors until the next annual meeting, but the number of additional directors may not at any time exceed 1/3 of the number of directors for available office at the expiration of the last annual meeting of PC. In addition, pursuant to the Voting Shareholder Agreement, Unitholders designate the independent auditors to be appointed as auditors of the Trust and PC by resolution passed by Unitholders.

PC Exchangeable Shares

PC is authorized to issue an unlimited number of PC Exchangeable Shares, of which, as at February 28, 2005, 742,512 PC Exchangeable Shares (756,648 as at December 31, 2004) are issued and outstanding which can be exchanged into 939,147 Trust Units. 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 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, exercisable 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 that Shareholders Agreement dated April 29, 2003, and made among Petrofund Energy Trust, Petrofund Corp., 1518274 Ontario Limited, and Petro Assets Inc., Petro Assets has agreed never to exercise the Conversion right in respect of any PC Exchangeable Shares held thereby.

INFORMATION RELATING TO THE TRUST

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. 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, a copy of which has been filed on SEDAR at *www.sedar.com.*

Trust Units

An unlimited number of Trust Units are issuable pursuant to the Trust Indenture. As at December 31, 2004, 100.5 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.

Special Voting Units

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 or exchangeable partnership interests. Each holder of a Special Voting Unit of record is entitled to vote at all meetings of Unitholders. The 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 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 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.

Management of the Trust

The Trust Indenture provides for the delegation to PC by the Trustee the authority to manage the business and affairs of the Trust and the authority to administer and manage the operations of the Trust. Without limiting the foregoing, the Trustee has delegated to PC: (i) the responsibility and authority for all matters relating to an offering of Units or any rights, warrants, options or other securities to acquire Units

or other securities of the Trust and all matters relating to the content and accuracy of disclosure contained in any offering documents, management proxy circulars or continuous disclosure documents relating thereto; (ii) the ability and other responsibilities to exercise all rights, powers and privileges in relation to all matters relating to any take-over bid, merger, amalgamation, arrangement, acquisition of all or substantially all of the assets of a person or similar transaction or form of business combination; (iii) the voting of investments and securities held by the Trust; (iv) the responsibility and authority for all matters pertaining to the repurchase and retraction of Units pursuant to the Trust Indenture; (v) the responsibility and authority for entering into and the amendment of the provisions of the Royalty Agreements; (vi) the responsibility and authority for any borrowing, securing of credit or granting of security by the Trust and related matters; (vii) the responsibility and authority to approve financial statements of the Trust and to furnish to Unitholders reports required under the Trust Indenture or by law; (viii) the responsibility and authority to call, hold and distribute materials in respect of meetings of Unitholders; (vix) the responsibility and authority to arrangement for payment of all costs and expenses incurred by the Trustee or any third party on account of the Trust in connection with the establishment and ongoing management of the Trust (but excluding any expenses deducted in determining royalty income for purposes of the Royalty Agreements); and (x) the responsibility and authority for all matters pertaining to tax and other matters.

PC has accepted such delegation and has agreed that it shall exercise its powers and carry out its functions honestly, in good faith and with a view to the best interests of the Trust and the Unitholders and, in connection with, shall exercise that degree of care, skill and diligence that a reasonably prudent person would exercise in comparable circumstances.

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) 95% of the "market price" (as defined in the Trust Indenture) of the Trust Units on the principal market on which the Trust Units are listed 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" (as defined in the Trust Indenture) 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 limitation that 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. If at the time any Units are tendered for retraction the Units are not listed on a Canadian stock exchange, are not traded in a manner that provides representative fair market value prices for the Units or the normal trading of the Units is suspended or halted, the retraction price of Units will be equal to 95% of the fair market value as of the Retraction Date as determined by the Board of Directors.

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 term determined by the Board of Directors ending not more than five years after the date of issue and a rate of interest which is no less than the then 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 "Information Relating to the Trust - Trust Indenture - Amendments to the Trust Indenture"); (iii) subdivisions or consolidations of Trust Units; (iv) the termination of the Trust; (v) 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).

Mutual Fund Trust

Under the Trust Indenture, PC may require declarations as to the jurisdictions in which beneficial holders of Trust Units are resident. Pursuant to the Trust Indenture, except to the extent permitted under the Tax Act, the Trust shall endeavour to satisfy the requirements of the Tax Act to maintain its status as a mutual fund trust.

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 plus 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 forecast 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 otherwise exceed the 40% borrowing restriction on maturity of the indebtedness.

Reporting to Unitholders

The financial statements of the Trust are audited annually by an independent recognized firm of chartered accountants. The audited financial statements of the Trust, together with the report of such chartered accountants, and the unaudited interim financial statements of the Trust will be mailed to Unitholders within the periods prescribed by securities legislation unless, in each case, such mailing is not required by applicable securities law. The year end of the Trust is December 31. The Trust is subject to the continuous disclosure obligations under applicable securities legislation.

Unitholders are entitled to inspect, during normal business hours, at the offices of the Trustee, and, upon payment of reasonable reproduction costs, to receive photocopies of the Royalty Agreements, the Trust Indenture and, subject to the provisions of the Trust Indenture, a listing of the registered holders of Trust Units.

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;
- 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.

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.

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 less than 80% of cash flow to unitholders over the long term. The payout ratio was 73% in 2004 and 70% in 2003. The payout ratio in 2004 was 73%, 80%, 75% and 67% in the first, second, third and fourth quarters respectively.

Distributions

The following cash distributions per Trust Unit in respect of the quarters indicated have been made to Unitholders since 2002:

	Cash Distributions		
	2004	**2003**	**2002**
First Quarter	$0.48	$0.48	$0.43
Second Quarter	0.48	0.53	0.41
Third Quarter	0.48	0.54	0.42
Fourth Quarter	0.48	0.54	0.45
Total Annual	$1.92	$2.09	$1.71

Credit Facility Limitations on Distributions

PC has a revolving working capital operating facility of $25 million and a syndicated facility of $300 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 PC 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 $214 million at December 31, 2004, compared to $110 million at the end of the prior year.

The revolving period on the syndicated facility ends on June 29, 2005, 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. In the event the lenders elect not to extend the revolving period, no payments are required to be made to non-extending lenders for a period of one year. However, during that year, PC will be required to maintain certain minimum balances on deposit with the syndicate agent. At the end of the one year period, the entire amount becomes due and payable. If this event were to occur, it is likely that PC would be forced to suspend royalty payments to the Trust, which, in turn, would be unable to make distributions to Unitholders. The revolving period has been extended each year by the lenders since the inception of the Trust.

In addition from time to time, the lenders have the right to review the borrowing base of PC s properties. If the borrowings exceed the redetermined borrowing base, on 60 days notice from the lender, PC is required to reduce its borrowing to the redetermined borrowing base. If, during the 60 day period, borrowings exceed the borrowing base by less than five percent, PC is permitted to make a cash payment to the Trust for one normal monthly distribution to unitholders. However, if the excess borrowings are greater than five percent, no distributions are permitted.

The credit facility is secured by a debenture in the amount of $500 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.

DIRECTORS AND OFFICERS

The Board of Directors of PC currently consist of nine individuals, all of whom were nominated for election of PC by Unitholders.

The name, municipality of residents, position held by each of the directors and executive officers of PC and period each director has served as a director are 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
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 F. 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
Arthur E. Dumont(2)(4) Calgary, Alberta	Director	July 28, 2004
Gary L. Lee(1) Calgary, Alberta	Director	July 28, 2004
Wayne M. Newhouse(3)(4) Calgary, Alberta	Director	April 16, 2003
Frank Potter(1)(3) Toronto, Ontario	Director	November 1, 2000
Peter N. Thomson(1)(2)(5) 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.

(5)

Mr. Thomson has advised that he will not be standing for re-election to the Board of Directors at the annual meeting of the Trust to be held on April 13, 2005 and at that meeting it is proposed that eight nominees be elected as directors of PC.

(6)

The term of office of each director is from the date of the meeting at which he or she is elected until the next annual meeting or until his or her successor is elected or appointed.

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 founding President, Chairman and Chief Executive Officer of Sentry Select Capital Corp. He also founded and has been Chairman of NCE Resources Group since 1984, and Chairman and founder of Petrofund Energy Trust since 1988. He has been Chairman of Inter Pipeline Fund, Strategic Energy Fund, and Endev Energy since October 2002, May 2002 and August 2002 respectively. Mr. Driscoll has been President, since 1981, of J.F. Driscoll Investment Corp., a company specializing in investment management and related advisory and consulting services. Mr. Driscoll received his Bachelor of Science degree from the Boston College Business School and attended the New York

Institute of Finance for advanced business studies. He has more than 30 years of diversified business experience. He is a member of the CFA Institute (formerly the Association for Investment Management and Research) and also attained the professional manager designation with the Canadian Institute of Management. He has founded numerous public partnerships as well as public and private energy and investment related companies. During the last 20 years, issuers of which Mr. Driscoll was Chairman or Chief Executive Officer have invested or managed the investment of more than $6 billion. He is Vice-Chair of the Royal Ontario Museum Foundation Board of Directors.

Jeffery E. Errico is a Professional Engineer with a Bachelor of Applied Science Degree in Chemical Engineering from the University of British Columbia. Prior to joining Petrofund he gained extensive experience in the areas of economic evaluations, reservoir and operations engineering having served as a senior executive for several oil and gas companies. Mr. Errico joined Petrofund Energy Trust in 1995 and has played a key role in its growth from 450 to the current 35,000 Boepd of production. He was appointed President in 2002 and CEO in 2003.

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 F. 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 received a Bachelor of Science degree in Business Administration from the University of Connecticut and completed the Advanced Management Program at Harvard University. Mr. 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.

Arthur E. Dumont is a Professional Engineer with a Bachelor of Science degree in Mechanical Engineering from the University of Saskatchewan. Mr. Dumont has over 36 years of professional experience in oil and gas, serving as president of several well known Calgary based companies. He is currently President and C.E.O. of Technicoil Corporation and serves on a number of boards and volunteer committees. Mr. Dumont is based in Calgary and was a director of Ultima prior to its recent acquisition by Petrofund.

Gary L. Lee is currently a director and principal of North West Capital Inc., a private merchant banking firm based in Calgary. Prior to joining North West Capital he was a lawyer with extensive experience in energy related transactions and financings. He has been actively involved as a principal and adviser in organizing and financing several oil and gas companies and oilfield service companies. Mr. Lee was a director of Ultima Energy Trust until it was acquired by Petrofund in June 2004.

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 two private oil and gas 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 attended Royal Military College of Science, and is a Fellow of the Institute of Canadian Bankers. Mr. 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 N. Thomson has been the Chairman of the Board of the Power Corporation of Cayman 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.

AUDIT COMMITTEE MANDATE AND TERMS OF REFERENCE

The Mandate and Terms of Reference of the Audit Committee of the board of director s is attached hereto as Appendix "C". The members of the Audit Committee are James E. Allard, Gary L. Lee, Frank Potter and Peter N. Thomson.

Composition of the Audit Committee

The members of the Audit Committee are independent (in accordance with National Instrument 52-110) and are financially literate.

Relevant Education and Experience

Refer to the biography section above.

Pre-Approval of Policies and Procedures

The Audit Committee shall have the sole authority to pre-approve all audit and non-audit services not prohibited by applicable law or the rules of the Toronto Stock Exchange or the American Stock Exchange to be provided by the Trust s external auditors including the remuneration and the terms of engagement.

External Auditor Service Fees

Audit Fees

The aggregate fees billed by the Corporation s external auditor in each of the last two fiscal years for audit services were $246,103 in 2004 and $254,500 in 2003. Audit fees relate to professional services rendered by Deloitte & Touche LLP for the audit of the Trust s annual financial statements, the review of the Trust s quarterly financial statements and procedure performed in connection with offering documents including the French translation of those documents.

Tax Fees

The aggregate fees billed in each of the last two fiscal years for professional services rendered by the Corporation s external auditor for tax compliance, tax advice and tax planning were $31,428 in 2004 and $77,845 in 2003. These fees relate to consultation on various tax matters. The fees incurred in 2003

related mainly to tax and other advice on the Internalization Transaction discussed under Internalization of Management on page 8 of this document and is disclosed in the Consolidated Statement of Operations and Accumulated Earnings and in Note 9 to the Consolidated Financial Statements.

All Other Fees

There were no other fees billed by the independent registered chartered accountants.

Ownership of Trust Units by Directors and Officers

As at December 31, 2004, the directors and executive officers of PC, as a group, beneficially owned, directly or indirectly, or exercised control or direction over, an aggregate of 1,414,052 Trust Units representing less than 1% of the issued and outstanding Trust Units and 756,648 PC Exchangeable Shares representing 100% of the issued and outstanding PC Exchangeable Shares which are exchangeable into 939,147 Trust Units.

Corporate Cease Trade Orders or Bankruptcies

None of the directors of executive officers of PC or a Unitholder holding a sufficient number of securities of the Trust to affect materially the control of the Trust have been subject to:

(a)

a cease trade or similar order or an order that denied the issuer access to any statutory exemptions for a period of more than 30 consecutive days; or

(b)

was declared bankrupt or made a voluntary assignment in bankruptcy, made a proposal under any legislation relating to bankruptcy and insolvency or been subject to or instituted any proceedings, arrangement, or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets.

Penalties or Sanctions

None of the directors or executive officers of PC or a Unitholder holding a sufficient number of securities of the Trust to affect materially the control of the Trust have been subject to any penalties or sanctions under securities legislations or any other penalties or sanctions imposed by a Court or regulatory body that would likely be considered important to a reasonable investor in making investment decisions.

Personal Bankruptcies

None of the directors or executive officers of PC have in the ten years preceding the date of this Annual Information Form become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or been subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold their assets.

Conflicts Of Interest

Circumstances may arise where members of the Board of Directors or officers of PC serve as directors or officers of corporations or other entities which are in competition to the interests of PC and the Trust. No assurances can be given that opportunities identified by such board members or officers will be provided to PC and the Trust.

The Business Corporations Act (Alberta) provides that in the event that a director or officer has an interest in a contract or proposed contract or agreement, the director or officer shall disclose his interest in such contract or agreement and such director shall refrain from voting on any matter in respect of such contract or agreement unless otherwise provided under such Act. To the extent that conflicts of interest arise, such conflicts will be resolved in accordance with the provisions of such Act.

PRICE RANGE AND TRADING VOLUME OF TRUST UNITS

The Trust is listed and posted for trading on the TSX under the symbol "PTF.UN" and on the American Stock Exchange under the symbol "PTF". The following sets forth the price ranges and trading volumes of the Common Shares on the TSX and AMEX for the periods indicated.

	TSX			AMEX		
	Price Range			Price Range		
	High	Low	Volume	High	Low	Volume
2004						
January	$19.24	$14.56	4,338,000	$14.96	$10.95	18,638,100
February	17.50	14.67	4,476,800	13.13	11.03	12,636,800
March	18.00	15.12	4,258,000	13.65	11.75	9,262,200
April	18.08	16.36	3,408,300	13.54	11.88	7,023,900
May	17.60	15.16	3,936,500	12.79	11.02	6,926,000
June	16.05	14.70	4,557,000	11.92	10.95	6,115,900
July	15.55	14.62	6,928,500	11.74	11.10	7,000,700
August	15.93	14.87	4,720,600	12.09	11.30	9,054,500
September	16.35	14.95	6,412,600	12.83	11.30	11,068,000
October	17.15	15.22	3,627,400	13.65	12.33	11,686,400
November	15.63	14.86	4,801,300	13.25	12.27	9,400,700
December	16.12	14.52	3,237,700	13.12	12.16	11,568,800

ESCROWED SECURITIES

There are 65,244 Trust Units remaining in escrow, of the original 100,244 Trust Units which were issued to executive management in connection with the internalization of management. They are released as to five percent of the original number issued at the end of each quarter to March 31, 2008. The escrow agent is Goodman and Carr LLP.

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

Volatility in Oil and Natural Gas Prices

The monthly cash distributions the Trust pays to Unitholders are highly dependant on the prices received for PC s oil and natural gas production. Oil and natural gas prices can fluctuate significantly 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: 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.

Foreign Currency Exchange Rates and Interest Rates

World oil prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that fluctuates over time. A material increase in the value of the Canadian dollar which occurred from 2003 to 2004 negatively impacted the Trust s net production revenue. The Canadian dollar averaged US $0.77 in 2004 versus US $0.71 in 2003. The increase in the exchange rate for the Canadian dollar and future Canadian/United States exchange rates will impact future distributions and the future value of the Trust s reserves as determined by independent evaluators.

Operations

PC s operations are subject to all of the risks normally associated with drilling for and the production and transportation of oil and natural 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 which cannot be insured against or which we may elect not to insure because of high premium costs or other reasons. See "Environmental Concerns".

Continuing production from a property, and to some extent the marketing of production there from, are largely dependant upon the ability of the operator of the property. Operating costs on most properties have increased over recent years. To the extent the operator fails to perform these functions properly, revenue may be reduced. PC markets and hedges a portion of its oil and natural gas production with a number of counterparties and therefore is subject to the risk that these parties may not be able to meet all their commitments under these contracts. A reduction of the distributions could result in such circumstances.

Expansion of Operations

The operations and expertise of management of the Trust are currently focused on conventional oil and gas production and development in the Western Canadian Sedimentary Basin. In the future, the Trust may acquire oil and gas properties outside this geographic area. In addition, the Trust Indenture does not limit the activities of the Trust to oil and gas production and development, and the Trust could acquire other energy related assets, such as oil and natural gas processing plants or pipelines, wind power generation, or an interest in an oil sands project. Expansion of activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors which may result in future operational and financial conditions of the Trust being adversely affected.

Competition

There is strong competition relating to all aspects of the oil and natural 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. There are numerous trusts in the oil and natural gas industry that are competing for the acquisition of properties with longer life reserves and with exploitation and developmental opportunities. As a result of the increasing competition, it may be more difficult to acquire reserves on beneficial terms.

Environmental Concerns

The oil and natural gas industry is subject to extensive environmental and safety regulations 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 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. In such an event, these environmental obligations would be funded out of PC s cash flow and could therefore reduce distributable income payable to Unitholders. In addition, the December 1997, Kyoto Protocol with respect to the reduction of greenhouse gases has been ratified by Canada. Although it is not possible at this time to assess the potential impacts on the business and operations of the Trust, they could be significant.

Business-Related Risks

Reserves

The value of the Trust Units depends upon, among other things, the reserves attributable to PC s properties. The reserves and recovery information contained in PC s independent reserve evaluation is only an estimate. The actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by the independent reserve evaluator. The reserve report was prepared using certain commodity price assumptions that are described in the notes to the reserve tables. If lower prices for crude oil, natural gas liquids and natural gas are realized by the Trust, the present value of estimated future net cash flows for the Trust s reserves would be reduced and the reduction could be significant.

Depletion of Reserves

The Trust has certain unique attributes which differentiate it from other oil and natural gas industry participants. Distributions by the Trust, absent commodity price increases or cost effective acquisition and development activities, will decline. As the Trust will not be reinvesting the majority of its cash flow, absent acquisitions and development activities, the Trust s production levels and reserves will decline. PC s reserves and production, and therefore its cash flows, are highly dependant upon its success in exploiting its reserve base and acquiring additional reserves. 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.

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 are 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 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 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, and these 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.

Sensitivity Analysis

As discussed above Petrofund is subject to numerous business and industry related risks.

In 2004, PC s cash flow from operating activities was $236.2 million, and net income was $77.4 million. The sensitivity of PC s cash flow and net income before income taxes to oil price, gas price, $US/$CDN 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 2004 prices received and the fourth quarter of 2004 production volumes of 36,025 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]	$ 1.00US	$7,860	$0.0783
Price per Mcf of natural gas [1]	$ 0.25Cdn	6,289	0.063
US/CDN exchange rate	$ 0.01	4,025	0.040
Interest rate on debt ($125 million)	1%	2,140	0.021
Oil production volumes [1]	100 Bpd	1,461	0.015
Gas production volumes [1]	1MMcfpd	1,918	0.019

1) After adjustment for estimated royalties.

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.

The Trust Units are not "deposits" within the meaning of the Canada Deposit Insurance Corporation Act (Canada) and are not insured under the provisions of that Act or any other legislation. Furthermore, the Trust is not a trust company and, accordingly, is not registered under any trust and loan company legislation as it does not carry on or intend to carry on the business of a trust company.

The after-tax return from an investment in Units to Unitholders subject to Canadian income tax can be made up of both a return on and a return of capital. That composition may change over time, thus affecting a Unitholder's after-tax return.

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.

The *Trust Beneficiaries' Liability Act*, 2004 (Ontario) was proclaimed in force as of December 16, 2004. The legislation provides that unitholders will not be liable, as beneficiaries of a trust, for any act, default, obligation or liability of the trust or its trustee that arises after the legislation came into force.

Stability Rating

The Trust does not have a stability rating and has no current plans to apply for a stability relating.

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.

Additional Financing

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. Conversely to the extent that external sources of capital, including the issuance of additional Trust Units become limited or unavailable, the Trust's and PC's ability to make the necessary capital investments to maintain or expand its oil and gas reserves will be impaired. To the extent that the Trust is required to use cash flow to finance capital expenditures or property acquisitions or to pay debt service charges or to reduce debt, the level of distributions paid by the Trust to Unitholders may be reduced.

Mutual Fund Trust

Pursuant to the Tax Act, in order for the Trust to qualify as "mutual fund trust" for the purposes of the Tax Act, it is required, among other things, that (i) the Trust not be considered to be a trust established or maintained primarily for the benefit of non-residents of Canada; or (ii) the Trust satisfies certain conditions as to the nature of the assets of the Trust as specified in the Tax Act (the "Asset Test"). The Trust Indenture provides that, except to the extent permitted under the Tax Act, the Trust shall endeavour to satisfy the requirements of the Tax Act to qualify as a "mutual fund trust" at all times. The Trust believes it has at all material times satisfied the Asset Test and, accordingly, for purposes of the requirements of these provisions should qualify as a "mutual fund trust" under the current provisions of the Tax Act.

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

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 taxation, may in the future be changed or interpreted in a manner that adversely affects the Trust and its Unitholders. Tax authorities having jurisdiction over the Trust or the Unitholders may disagree with how the Trust calculates its income for tax purposes or could change administrative practises to the detriment of the Trust or the detriment of its Unitholders.

PC intends that the Trust will continue to qualify as a mutual fund trust for purposes of the Tax Act. The Trust may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should the status of the Trust as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for the Trust and its Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- The Trust would be taxed on certain types of income distributed to Unitholders, including income generated by the royalties held by the Trust. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders that are not residents of Canada and residents of Canada that are otherwise exempt from Canadian income tax.
- The Trust would cease to be eligible for the capital gains refund mechanism available under Canadian tax laws if it ceased to be a mutual fund trust.
- Trust Units held by Unitholders that are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them.
- Trust Units would not constitute qualified investments for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESTs") or deferred profit sharing plans ("DPSPs"). If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to 1% of the fair market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units. If an RESP holds non-qualified Trust Units, it may have its registration revoked by the Canada Revenue Agency.

In addition, PC may take certain measures in the future to the extent it believes necessary to ensure that the Trust maintains its status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada as defined in the Tax Act.

INDUSTRY REGULATIONS

The oil and natural gas industry is subject to extensive controls and regulations governing its operations (including land tenure, exploration, development, production, refining, transportation and marketing) imposed by legislation enacted by various levels of government and with respect to pricing and taxation of oil and natural gas by agreements among the governments of Canada, Alberta, British Columbia and Saskatchewan, all of which should be carefully considered by investors in the oil and gas industry. It is not expected that any of these controls or regulations will affect the operations of PC in a manner materially different than they would affect other oil and gas companies of similar size. All current legislation is a matter of public record and PC is unable to predict what additional legislation or amendments may be enacted. Outlined below are some of the principal aspects of legislation, regulations and agreements governing the oil and gas industry.

Pricing and Marketing Oil and Natural Gas

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

The price of natural gas is determined by negotiation between buyers and sellers. Natural gas exported from Canada is subject to regulation by the NEB and the Government of Canada. Exporters are free to negotiate prices with purchasers, provided that the export contracts must continue to meet certain other criteria prescribed by the NEB and the Government of Canada. Natural gas exports for a term of less than 2 years or for a term of 2 to 20 years (in quantities of not more than 30,000 m3/day), must be made pursuant to an NEB order. Any natural gas export to be made pursuant to a contract of longer duration (to a maximum of 25 years) or a larger quantity requires an exporter to obtain an export licence from the NEB and the issuance of such licence requires the approval of the Governor in Council.

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

The North American Free Trade Agreement

The North American Free Trade Agreement ("NAFTA") among the governments of Canada, United States of America and Mexico became effective on January 1, 1994. NAFTA carries forward most of the material energy terms that are contained in the Canada United States Free Trade Agreement. Canada continues to remain free to determine whether exports of energy resources to the United States or Mexico will be allowed, provided that any export restrictions do not: (i) reduce the proportion of energy resources exported relative to domestic use (based upon the proportion prevailing in the most recent 36 month period); (ii) impose an export price higher than the domestic price; or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements.

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

Provincial Royalties and Incentives

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

From time to time the governments of the western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, 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.

In the Province of Alberta, a producer of oil or natural gas is entitled to a credit against the royalties payable to the Crown by virtue of the Alberta royalty tax credit ("ARTC") program. The ARTC rate is based on a price sensitive formula and the ARTC rate varies between 75% at prices at and below $100 per m3 and 25% at prices at and above $210 per m3. 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 a corporation claiming maximum entitlement to ARTC will generally not be eligible for ARTC. The rate will be established quarterly based on the average "par price", as determined by the Alberta Department of Energy for the previous quarterly period.

Crude oil and natural gas royalty programs for specific wells and royalty reductions reduce the amount of Crown royalties paid by PC to the provincial governments. In general, the ARTC program provides a rebate on Alberta Crown royalties paid in respect of eligible producing properties.

Land Tenure

Crude oil and natural gas located in the western provinces is owned predominantly by the respective provincial governments. Provincial governments grant rights to explore for and produce oil and natural gas pursuant to leases, licences and permits for varying terms from two years and on conditions set forth in provincial legislation including 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 granted by lease on such terms and conditions as may be negotiated.

Environmental Regulation

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

Environmental legislation in the Province of Alberta has been consolidated into the Alberta Environmental Protection and Enhancement Act (the "APEA"), which came into force on September 1, 1993. The APEA imposes stricter environmental standards, requires more stringent compliance, reporting and monitoring obligations and significantly increases penalties. PC is committed to meeting its responsibilities to protect the environment wherever it operates and anticipates making increased expenditures of both a capital and an expense nature as a result of the increasingly stringent laws relating to the protection of the environment and will be taking such steps as required to ensure compliance with the APEA and similar legislation in other jurisdictions in which it operates. PC believes that it is in material compliance with applicable environmental laws and regulations. PC also believes that it is reasonably likely that the trend towards stricter standards in environmental legislation and regulation will continue.

In December 2002 the Government of Canada ratified the Kyoto Protocol. This protocol calls for Canada to reduce its greenhouse gas emissions to 6 percent below 1990 levels during the period between 2008 and 2012. The protocol was ratified by the requisite number of countries and became legally binding on February 16, 2005. It is expected to affect the operation of all industries in Canada, including the oil and gas industry. As details of the implementation of this protocol have yet to be announced, the effect on PC and the Trust cannot be determined at this time.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There is no material interest, direct or indirect, of any director or executive officer, or to the knowledge of PC, any person or company that is the direct or indirect beneficial owner of, or who exercises control or direction over, more than 10% of outstanding Trust Units, or any associate or affiliate of any of the foregoing, in any transaction within the three most recently completed financial years except for the following.

John F. Driscoll is the Chairman of Board of PC. NCEP Management was purchased by PC from Petro Assets pursuant to the Internalization Transaction. Petro Assets was owned by the Driscoll Family Trust (a trust established for the family of John F. Driscoll). Subsequent to closing of the Internalization Transaction, Sentry agreed to provide certain management services to the Trust and PC and at Sentry's

cost until December 31, 2003. Sentry is a company in which John F. Driscoll owns a controlling interest. See "Petrofund Energy Trust Internalization of Management".

TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar for the Trust Units is Computershare Trust Company of Canada at its principal offices in Calgary and Toronto.

LEGAL PROCEEDINGS

There were no outstanding legal proceedings material to the Trust to which the Trust is a party or in respect of which any of its properties is subject, nor are there any such proceedings known to be contemplated.

MATERIAL CONTRACTS

Except for contracts entered into in the ordinary course of business, the only material contracts entered into by the Trust within the most recently completed financial year, or before the most recently completed financial year but which are still material and are still in effect, are the following:

1.

The Trust Indenture (see "Information Relating to the Trust").

2.

Credit agreement among Petrofund Corp. and a syndicate of lenders amended and restated as of June 30, 2004.

Copies of each of these documents have been filed on SEDAR at www.sedar.com.

INTEREST OF EXPERTS

There is no person or company whose profession or business gives authority to a statement made by such person or company and who is named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Trust during, or related to, the Trust's most recently completed financial year other than GLJ, the independent reserve evaluator, and Deloitte & Touche LLP, the Trust's independent registered chartered accountants. None of the principals of GLJ had any registered or beneficial interests, direct or indirect, in any securities of the Trust or the property of the Trust or affiliates either at the time they prepared the statement, report or valuation prepared by it, at any time thereafter or to be received by them.

In addition, none of the aforementioned persons or companies, nor any director, officer or employee of any of the aforementioned persons or companies, is or is expected to be elected, appointed or employed as a director, officer or employee of PC or of any of the Trust's associates or affiliates.

ADDITIONAL INFORMATION

Additional information relating to the Trust is available on SEDAR at www.sedar.com and on the Trust s website at www.petrofund.ca.

Additional information including directors' and officers' remuneration and indebtedness, principal holders of the Trust s securities, and securities authorized for issuance under share compensation plans, if applicable, is contained in the Trust 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

Trust s comparative financial statements (and related management s discussion and analysis) 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

APPENDIX A

REPORT OF MANAGEMENT AND DIRECTORS ON OIL AND GAS DISCLOSURE

Management of Petrofund Corp. (the "Company"), on behalf of Petrofund Energy Trust, 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, 2004 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, 2004 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
March 1, 2004

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

APPENDIX B

REPORT ON RESERVES DATA BY INDEPENDENT QUALIFIED RESERVES EVALUATOR

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

1.

We have prepared an evaluation of the Company's reserves data as at December 31, 2004. The reserves data consist of the following:

(a)

(i)

proved and proved plus probable oil and gas reserves estimated as at

December 31, 2004, 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, 2004, 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, 2004, 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 Foreign Geographic Area)	Net Present Value of Future Net Revenue (M$ before income taxes, 10% discount rate)			
		Audited	Evaluated	Reviewed	Total
February 7, 2005	Canada	-	$1,304.4 MM	-	$1,304.4 MM

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.

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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.

Executed as to our report referred to above:

Gilbert Laustsen Jung Associates Ltd., Calgary, Alberta, Canada

Dated: March 15, 2005

(signed) Wayne Chow, P.Eng.

Name: Wayne Chow, P.Eng

Title: Vice-President

APPENDIX C

Mandate and Charter of the Audit Committee

of the Board of Directors

Document Owner:	Approved by:	Previous Rev. Date:	Current Revision Date:
Hugo Potts, Corporate Secretary	Board of Directors	N.A.	January 15, 2004

I.

TERMS OF REFERENCE

WHEREAS Petrofund Corp. is a wholly-owned subsidiary of Petrofund Energy Trust (the "**Trust**")**;**

AND WHEREAS Petrofund Corp. is responsible for the overall governance of the Trust pursuant to the trust indenture of the Trust;

AND WHEREAS Petrofund Corp. is, in turn, governed by its board of directors (the "**Board**")**;**

AND WHEREAS, financial reporting and disclosure by the Trust constitute a significant aspect of the management of the Trust's business and affairs;

AND WHEREAS the objective of the monitoring of the Trust's financial reporting and disclosure (the **Financial Reporting Objective**) by the Board is to gain reasonable assurance of the following:

(a)

that the Trust complies with all applicable laws, regulations, rules, policies and other requirements of governments, regulatory agencies and stock exchanges relating to financial reporting and disclosure;

(b)

that the accounting principles, significant judgments and disclosures that underlie or are incorporated in the Trust's financial statements are the most appropriate in the prevailing circumstances;

(c)

that the Trust's quarterly and annual financial statements are accurate and present fairly the Trust's financial position and performance in accordance with Canadian (and if applicable, the United States of America) generally accepted accounting principles; and

(d)

that appropriate information concerning the financial position and performance of the Trust is disseminated to the public in a timely manner;

AND WHEREAS, the Board is of the view that the Financial Reporting Objective cannot be reliably met unless the following activities (the **Fundamental Activities**) are conducted effectively:

(i)

the Trust's accounting functions are performed in accordance with a system of internal financial controls designed to capture and record properly and accurately all of the Trust's financial transactions;

(ii)

the Trust's internal financial controls are regularly assessed for effectiveness and efficiency;

(iii)

the Trust's quarterly and annual financial statements are properly prepared by management;

(iv)

the Trust's quarterly financial statements are reviewed by an independent external auditor appointed by the Unitholders of the Trust (the **external auditors**) and the annual financial statements are reported on by the external auditors; and

(v)

the Disclosure Policy of the Trust, and in particular the financial components of such Disclosure Policy, are complied with by management and the Board;

AND WHEREAS, to assist the Board in its monitoring of the Trust's financial reporting and disclosure, the Board has established, and hereby continues the existence of, a committee of the Board known as the Audit Committee (the **Committee**);

The following shall be the mandate and charter of the Committee:

II.

OPERATING PRINCIPLES

The Committee shall fulfill its responsibilities within the context of the following principles:

2.

Committee Values

The Committee expects the management of the Trust to operate in compliance with any applicable code of conduct and corporate policies; with laws and regulations governing the Trust; and to maintain strong financial reporting and control processes.

3.

Communications

The Chairman of the Committee (and others on the Committee) expects to have direct, open and frank communications throughout the year with management, the Chairs of other committees, the Trust s external auditors and other key Committee advisors as applicable.

4.

Financial Literacy

All Committee members should be sufficiently versed in financial matters to understand the Trust's accounting practices and policies and the major judgments involved in preparing the financial statements.

5.

Annual Audit Committee Work Plan

The Committee, while not responsible for the planning or conduct of audits, may develop an annual audit committee work plan responsive to the Committee's responsibilities as set out in this charter. In addition, the Committee shall review the process developed by management in conjunction with the external auditors for review of important financial topics that have the potential to impact the Trust's financial disclosure.

6.

Meeting Agenda

Committee meeting agendas shall be the responsibility of the Chairman of the Committee in consultation with Committee members, senior management and the Trust s external auditors.

7.

Committee Expectations and Information Needs

The Committee shall communicate its expectations to management and the Trust s external auditors with respect to the nature, timing and extent of its information needs. The Committee expects that written materials will be received from management and the external auditors at least one week in advance of meeting dates.

8.

External Resources

To assist the Committee in discharging its responsibilities, the Committee may, in addition to the Trust s external auditors, at the expense of the Trust, retain one or more persons having special expertise.

9.

In Camera Meetings

At each meeting of the Committee, the members of the Committee may meet in private sessions with the Trust s external auditors, with management and with the Committee members only.

10.

Reporting to the Board

The Committee, through its Chairman, shall report after each Committee meeting to the Board at the Board's next meeting.

11.

The External Auditors

The Committee expects that, in discharging their responsibilities to Unitholders of the Trust, the Trust s external auditors shall be accountable to the Board through the Committee. The external auditors shall report all material issues or potentially material issues to the Committee.

III.

COMPOSITION AND MEETINGS

12.

The Committee shall consist of at least three members of the Board appointed annually by the Board,

(i)

each of whom shall be independent of management and 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 the Trust (other than interests and relationships arising from holding units of the Trust);

(ii)

at least one of whom meets the Securities and Exchange Commission definition of **Financial Expert** ; and

(iii)

none of whom is an officer or employee of the Trust.

The composition of the Committee shall also satisfy such other independence, financial literacy and other requirements of law, the Toronto Stock Exchange and the American Stock Exchange as may be applicable from time to time. The Board shall appoint one member as Chairman of the Committee.

13.

The members of the Committee may be removed or replaced, and any vacancies on the Committee shall be filled by, the Board. If and whenever a vacancy shall exist, the remaining members of the Committee may exercise all of its powers and responsibilities so long as a quorum remains in office.

14.

The Committee shall meet at least four times annually, or more frequently as circumstances dictate. Meetings may be called by the Chairman of the Committee, at the request of two members of the Committee or at the request of the Trust s external auditors. A meeting of the Committee may be called by letter, telephone, facsimile, email or other communication equipment, by giving at least 48 hours notice, provided that no notice of a meeting shall be necessary if all of the members are present either in person or by means of conference telephone or if those absent have waived notice or otherwise signified their consent to the holding of such meeting.

15.

Any member of the Committee may participate in the meeting of the Committee by means of conference telephone or other communication equipment, and the member participating in a meeting pursuant to this paragraph shall be deemed, for purposes hereof, to be present in person at the meeting.

16.

The Board and the Committee may, from time to time, appoint any person who need not be a member, to act as a secretary at any meeting.

17.

The Committee may invite such officers, directors and employees as it may see fit, from time to time, to attend meetings of the Committee.

18.

Any matters to be determined by the Committee shall be decided by a majority of votes cast at a meeting of the Committee called for such purpose; actions of the Committee may be taken by an instrument or instruments in writing signed by all of the members of the Committee, and such actions shall be effective as though they had been decided by a majority of votes cast at a meeting of the Committee called for such purpose.

19.

In the absence of the Chairman of the Committee, the members of the Committee shall appoint an acting Chairman.

20.

A copy of the minutes of each meeting of the Committee shall be provided to each member of the Committee and to each director in a timely fashion and the Committee shall report to the Board periodically, but no less than once annually.

IV.

RESPONSIBILITIES AND DUTIES

To fulfill its responsibilities and duties:

Financial Reporting

21.

the Committee shall review the Trust's annual and quarterly financial statements, including the Trust s disclosures under **Management Discussion and Analysis** , with management and the Trust s external auditors to gain reasonable assurance that the statements are accurate, complete, represent fairly the Trust's financial position and performance and are in accordance with Canadian (and if applicable, the United States of America) GAAP and report thereon to the Board before such financial statements are approved by the Board;

22.

the Committee shall receive from the Trust s external auditors reports on the results of their audit or review, respectively, of the annual and quarterly financial statements;

23.

the Committee may receive from management a copy of the representation letter provided to the Trust s external auditors and receive from management any additional representations required by the Committee;

24.

the Committee may review with management and, if appropriate, recommend approval to the Board of news releases and reports to Unitholders containing financial information before they are issued by the Trust and review generally with management the nature of the financial information and earnings guidance provided to analysts and rating agencies; and

25.

the Committee may review and, if appropriate, recommend approval to the Board of prospectuses, material change disclosures of a financial nature, management discussion and analysis, annual information forms and similar disclosure documents to be issued by the Trust.

Accounting Policies

26.

the Committee may review with management and the Trust s external auditors the appropriateness of the Trust's accounting policies, disclosures, reserves, key estimates and judgments, including changes or variations thereto and to obtain reasonable assurance that they are in compliance with GAAP; and report thereon to the Board; and

27.

the Committee may review with management and the Trust s external auditors the quality of earnings of the Trust's underlying accounting policies, key estimates, judgments and reserves.

Risk and Uncertainty

28.

acknowledging that it is the responsibility of the Board, in consultation with management, to identify the principal business risks facing the Trust, to determine the Trust's tolerance for risk and to approve risk management policies, the Committee may focus on financial risk and gain reasonable assurance that financial risk is being effectively managed or controlled by:

(a)

reviewing with management the Trust's tolerance for financial risks;

(b)

reviewing with management its assessment of the significant financial risks facing the Trust;

(c)

reviewing with management the Trust's policies and any proposed changes thereto for managing those significant financial risks; and

(d)

reviewing with management its plans, processes and programs to manage and control such risks;

29.

the Committee may review with management policies and compliance therewith that require significant actual or potential liabilities, contingent or otherwise, to be reported to the Board in a timely fashion;

30.

the Committee may review with management foreign currency, interest rate and commodity price risk mitigation strategies, including the use of derivative financial instruments;

31.

the Committee may review with management the adequacy of insurance coverage maintained by the Trust; and

32.

the Committee may review with management, the Trust s external auditors and the Trust's legal counsel, any legal claim or other contingency, including tax assessments, which could have a material effect upon the financial position or operating results of the Trust and the manner in which these matters have been disclosed in the financial statements.

Financial Controls and Control Deviations

33.

the Committee may review the plans of management with the Trust s external auditors to gain reasonable assurance of the comprehensiveness and co-ordination of the combined evaluation of the Trust s internal financial controls to identify significant deficiencies or material weaknesses in the quality, adequacy and effectiveness of those controls; and

34.

the Committee may receive regular reports from management and the Trust s external auditors on all significant deviations or indications/detection of fraud and the corrective activity undertaken in respect thereto.

Compliance with Laws and Regulations

35.

the Committee may review regular reports from management and others (e.g. external auditors, external and internal counsel) with respect to the Trust's compliance with laws and regulations and any legal matters that may have a material impact on the Trust, including:

(a)

tax and financial reporting laws and regulations;

(b)

legal withholding requirements;

(c)

environmental protection laws and regulations; and

(d)

other laws and regulations and any other legal matters (including the status of pending litigation) that may expose directors to liability;

36.

the Committee may review with management reports from the Reserve Committee with respect to matters having a potential material financial impact;

37.

the Committee may review with management the status of the Trust's tax returns and those of its subsidiaries;

38.

the Committee may review with management the organization, responsibilities, plans, results, budget and staffing of the Trust s legal and compliance function;

39.

the Committee may review with management, and any outside professionals as the Committee considers appropriate, the effectiveness of the Trust s disclosure control and procedures;

40.

the Committee may review with management, and any outside professionals as the Committee considers appropriate, important trends and developments in financial reporting practices and requirements and their effect on the Trust s financial statements;

41.

the Committee may obtain reports from management and the Trust s external auditors regarding compliance with all applicable legal and regulatory requirements, including the U.S. Foreign Corrupt Practices Act; and

42.

the Committee shall with management prepare the report for the Trust s proxy statement that would be required by the Securities and Exchange Commission were the Trust a U.S. company.

Relationship with Independent External Auditors

43.

the Committee shall recommend to the Board the nomination of the Trust s external auditors and have direct responsibility for the appointment, compensation and oversight of the work of the external auditors;

44.

the Committee shall have the sole authority to pre-approve all audit and non-audit services not prohibited by applicable law or the rules of the Toronto Stock Exchange or the American Stock Exchange to be provided by the Trust s external auditors including the remuneration and the terms of engagement;

45.

the Committee shall review the performance of the Trust s external auditors annually or more frequently as required;

46.

the Committee may receive annually from the Trust s external auditors an acknowledgement in writing that Unitholders, as represented by the Board and the Committee, are their primary client;

47.

the Committee may review with the lead audit partner whether any of the audit team members receive any discretionary compensation from the audit firm with respect to non-audit services performed by the Trust s external auditors;

48.

the Committee may obtain and review with the lead audit partner and a more senior representative of the Trust s external auditor, annually or more frequently as the Committee considers appropriate, a report by the external auditors describing: the external auditor s internal quality-control procedures; any material issues raised by the most recent internal quality-control review, or peer review, of the external auditor, or by any inquiry or investigation by governmental professional or other regulatory authorities, within the preceding five years respecting independent audits carried out by the external auditor, and any steps taken to deal with these issues; and (to assess the external auditor s independence) all relationships between the external auditors and the Trust;

49.

the Committee may review the experience, qualifications and performance of the senior members of the Trust s external auditor team;

50.

the Committee may pre-approve the hiring of any employee or former employee of the Trust's external auditors who was a member of the Trust s external audit team during the preceding three fiscal years and pre-approve the hiring of any employee or former employee of the external auditors (within the preceding three fiscal years) for senior positions within the Trust regardless of whether that person was a member of the

Trust s audit team;

51.

the Committee may receive from the Trust s external auditors, and review with the external auditors, a report describing critical accounting policies and practices used in preparing the Trust s financial statements, all alternative treatments of financial information that were discussed with management, their ramifications, and the external auditors' preferred treatment and other material written communications between management and the external auditors, in addition to reviewing with the external auditors any audit problems or difficulties and management s response;

52.

the Committee may review with the external auditors the scope of the audit, the areas of special emphasis to be addressed in the audit, the extent to which the external audit can be co-ordinated with management and the materiality levels that the external auditors propose to employ;

53.

the Committee may meet regularly with the external auditors in the absence of management to determine, inter alia, that no management restrictions have been placed on the scope and extent of the audit examinations by the external auditors or the reporting of their findings to the Committee; and

54.

the Committee may establish effective communication processes with management and the external auditors to assist the Committee to monitor objectively the quality and effectiveness of the relationship among the external auditors, management and the Committee.

Other Responsibilities

55.

the Committee may periodically review the form, content and level of detail of financial reports to the Board;

56.

the Committee may approve annually the reasonableness of the expenses of the Chairman of the Board and the President and Chief Executive Officer;

57.

the Committee may after consultation with the Chief Financial Officer and the external auditors, gain reasonable assurance, at least annually, of the quality and sufficiency of the Trust's accounting and financial personnel and other resources;

58.

the Committee may review with management and the lead audit partner of the Trust s external auditors the scope, planning and staffing of the proposed audit for the upcoming year;

59.

the Committee may review, in advance, the appointment of the Trust's senior financial executives;

60.

the Committee may investigate any matters that, in the Committee's discretion, fall within the Committee's duties;

61.

the Committee may review reports from management, the external auditors, and/or the Chairs of other Committees on their review of the Trust's policies on political donations and commissions paid to suppliers or others;

62.

the Committee shall establish procedures for the receipt, retention and treatment of complaints received by the Trust regarding accounting, internal accounting controls, or auditing matters, and the confidential, anonymous submission by employees of the Trust of concerns regarding questionable accounting or auditing matters or fraudulent activities;

63.

the Committee may provide oversight to the disclosure committee on behalf of the Board; and

64.

the Committee may perform such other functions as may from time to time be assigned to the Committee by the Board.

V.

GENERAL

65.

In discharging its duties under this mandate and charter, each member of the Committee shall be entitled to rely in good faith upon:

(a)

financial statements of the Trust (which are the responsibility of management) represented to him or her by an officer or in a written report of the external auditors to present fairly the financial position and results of the Trust in accordance with generally accepted accounting principles;

(b)

any report of a lawyer, accountant, engineer, appraiser or other person whose profession lends credibility to a statement made by any such person; and

(c)

the integrity of those persons and organizations within and outside the Trust from whom he or she receives information, and the accuracy of the financial and other information provided to the Committee by such persons or organizations.

66.

In discharging its duties under this mandate and charter, each member of the Committee shall be obliged only to exercise the care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. Nothing in this mandate and charter is intended, or may be construed, to impose on any member of the Committee a standard of care or diligence that is in any way more onerous or extensive than the standard to which all Board members are subject. The essence of the Committee's duties is monitoring and reviewing to gain reasonable assurance (but not to ensure) that the Fundamental Activities are being conducted effectively and that the Financial Reporting Objective is being met and to enable the Committee to report thereon to the Board.

67.

The Committee shall have full access to books, records, facilities and personnel of the Trust and shall have the authority to retain independent counsel and other advisors, as it deems necessary to carry out its duties.

68.

The Trust shall furnish the Committee with appropriate funding, as determined by the Committee, for payment of compensation to the external auditors and to any advisors employed by the Committee.

69.

The Committee shall conduct an annual performance self-evaluation and shall report to the entire Board the results of the self-evaluation. The Committee shall assess the adequacy of this mandate and charter on an annual basis and recommend any changes to the Board.

70.

From time to time, as requested by the Board, the Committee shall review the description of the Committee's mandate and charter and activities to be included in the Trust's statement of corporate governance practices.

EXHIBIT 2

Managements Discussion for Analysis

for the year ended December 31, 2004

MANAGEMENT DISCUSSION & ANALYSIS

SPECIAL NOTES

The following Management Discussion and Analysis (MD&A) of financial results should be read in conjunction with the audited Consolidated Financial Statements of Petrofund Energy Trust (Petrofund or the Trust) for the fiscal years ended December 31, 2004, and 2003 presented later in this report. All the oil and natural gas properties are held by Petrofund Corp. (PC) a wholly owned subsidiary of the Trust. This commentary is based on information available to March 1, 2005, which is the date of the auditor s report. Additional information (including Petrofund s annual information form) can be obtained on Sedar at www.sedar.com or on the Trust s website at www.petrofund.ca.

All amounts are stated in Canadian dollars unless otherwise noted. Where amounts and volumes are expressed on a barrel of oil equivalent (boe) basis, gas volumes have been converted to barrels of oil at 6,000 cubic feet per barrel (6 mcf/bbl). 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.

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 generally accepted accounting principles (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.

Management uses certain key performance indicators and industry benchmarks such as operating netbacks ("netbacks"), finding, development and acquisition costs ("FD&A"), and total capitalization to analyze financial and operating performance. These performance indicators and benchmarks as presented do not have any standardized meaning prescribed by Canadian GAAP and therefore may not be comparable with the calculation of similar measures for other entities.

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.

2004 HIGHLIGHTS/OVERVIEW

The Trust paid out cash distributions of $169.5 million or $1.92 per unit in 2004 a decrease of 8% from the $2.09 per unit paid in 2003.

The Trust s payout ratio for the year was 73% (2003 70%), 67% in the fourth quarter of 2004.

Net income decreased 15% to $74.4 million.

The Trust generated cash flow of $236.2 million, an increase of 26% over 2003.

Average production on a boe basis increased 11% to 31,429 boe/d in 2004 and to 36,025 boe/d in the fourth quarter.

Average prices were relatively strong, up 15% on a boe basis from the prior year; however the strengthening of the Canadian dollar offset part of the oil price increase.

Petrofund acquired interests in various long-life oil and gas properties for $606.8 million as a result of the purchase of Ultima Energy Trust (Ultima) and the Central Alberta PNG Partnership and 1024373 Alberta Ltd. (Central Alberta acquisition) and other minor properties. The properties added proved plus probable reserves of 40.7 million boe.

Petrofund continued an active development drilling and farmout program, investing $77.9 million on development drilling, facilities and other costs. During the year 165 wells were drilled at an overall success rate of 98%. These activities added production at $22,000 per boe/d. The combined result of the acquisition and development programs was to add 46.2 million boe s of reserves and replace 400% of 2004 production.

Petrofund ended 2004 with a strong balance sheet with long-term debt outstanding equivalent to 76% of annualized 4th quarter 2004 cash flow.

The Trust had a balanced production profile which averaged 42% natural gas and 58% oil and liquids in the fourth quarter of 2004.

The weighted average Trust units outstanding increased from 61.0 million to 88.2 million.

The Trust market capitalization as at December 31, 2004, was approximately $1.6 billion (2003 $1.4 billion).

CASH DISTRIBUTIONS

For the years ended December 31,	**2004**	**2003**	**2002**
Distributions paid per unit	$ 1.92	$ 2.09	$ 1.71

Trust unitholders who held their units throughout 2004 received cash distributions of $1.92 per unit as compared to $2.09 per unit in 2003 and $1.71 in 2002. For 2005, the Trust distributed $0.16 per unit in January $0.16 per unit for February, and has indicated $0.16 per unit for March.

The Trust generated cash flow available for distribution of $231.5 million in 2004 as compared to $180.7 million in 2003. A total of $79.9 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 $79.9 million represents 35% of cash flow for the year. A total of $169.5 million was paid out in distributions representing a payout ratio of 73% versus 70% in 2003. In the fourth quarter, the Trust generated cash flow available for distribution of $71.1 million before deducting $15.0 million for capital expenditures and paid out $47.7 million in distributions for a payout ratio of 67%. For a detailed analysis of cash flow available for distribution and distributions paid refer to Note 12 to the Consolidated Financial Statements.

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 31,429 boe/d in 2004 an increase of 11% over average production volumes of 28,418 boe/d in the previous year. The majority of the increase was due to the acquisition of Ultima purchased for $563.1 million in the second quarter of 2004, which combined with PC s development drilling program was also mainly responsible for the increase in production to 36,025 boe/d in the fourth quarter of 2004. The Central Alberta acquisition also added 363 boe/d to the fourth quarter of 2004. The increase in production from 25,782 boe/d in 2002, to 28,418 boe/d in 2003 was due mainly to the acquisition of NCE Energy Trust on May 31, 2002.

For the years ended December 31,	**2004**	**2003**	**2002**
Daily Production			
Oil (bbls)	15,084	12,454	11,162
Natural gas (mmcf)	84.5	83.3	76.9
Natural gas liquids (bbls)	**2,262**	**2,079**	**1,808**
Total (boe 6:1)	31,429	28,418	25,782

PRICING & PRICE RISK MANAGEMENT

Revenues from the sale of crude oil, natural gas, and natural gas liquids and sulphur increased 27% to $517.1 million in 2004 from $406.3 million in 2003 due to a 11% increase in production and a 15% increase in prices on a boe basis.

Crude oil sales increased to $269.6 million in 2004 from $178.0 million in 2003 due to a 21% increase in production from 12,454 bbl/d in 2003 to 15,084 bbl/d in 2004 and a 25% increase in the oil price. Oil production in the fourth quarter averaged 18,508 boe/d. The average WTI oil price increased from $31.04 US/bbl in 2003 to $41.40 US/bbl in 2004 or 33%, however, the Canadian par price at Edmonton

increased only 22% from $43.14/bbl to $52.54/bbl due to the significant strengthening of the Canadian dollar relative to the U.S. dollar which averaged $0.770 in 2004 versus $0.716 in 2003. The average Canadian wellhead price received by Petrofund increased from $39.16/bbl in 2003 to $48.83/bbl in 2004.

About 60% of the Trust s crude production was sold directly to refiners in 2004 with the balance being delivered to marketers. Petrofund intends to maintain this sales mix in 2005.

Crude differentials widened considerably in Western Canada during 2004 though Petrofund was shielded from the deterioration in these differentials due to its high quality portfolio. Petrofund s differential to Edmonton postings before hedging decreased to $3.71/bbl in 2004 from $4.23/bbl in 2003. Heavy oil differentials are expected to remain weak but the expectation is for more stable differentials for the lighter and medium sour crudes comprising the bulk of the Trust s portfolio (98% light and medium crudes). Petrofund does however, expect its overall differential from Edmonton to increase in 2005.

Natural gas sales increased to $212.6 million in 2004 from $201.5 million in 2003 due to a 1% increase in production and a 4% increase in the average prices received from $6.63/mcf in 2003 to $6.87/mcf in 2004. The monthly AECO price per mmbtu increased from $6.70 in 2003 to $6.79 in 2004. Production volumes averaged 84.5 mmcf/d in 2004 and 90.1 mmcf/d in the fourth quarter compared to 83.3 mmcf/d in 2003. Petrofund sold 30% of its production in 2004 to aggregators at netback pricing, down from 34% in 2003. Netbacks from these markets are below those otherwise available to the Trust at AECO; however, the average aggregator discount to AECO for Petrofund improved in 2004 by $0.34/mcf. The Trust sold the remaining 70% of its production on daily and monthly spot market pricing in Alberta, Saskatchewan and British Columbia.

Sales of natural gas liquids and sulphur increased to $34.9 million in 2004 from $26.8 million in 2003 as production increased to 2,262 bbl/d in 2004 (4th quarter-2,502) from 2,079 bbl/d in 2003. The average price increased from $35.05/bbl in 2003 to $41.96/bbl in 2004. The majority of the Trust s NGLs (90%) are sold to one buyer under one-year contract terms at market sensitive pricing with the remainder widely distributed among an number of buyers. The Trust has optimized netbacks by aggregating its NGL production with a single buyer. Alberta NGL netbacks lagged crude oil during the year in a pattern similar to the prior year but pricing was stable over the period with no periods of extreme weakness. The condensate market in Western Canada was exceptionally tight in the fourth quarter with prices trading well in excess of WTI. Petrofund expects pricing for 2005 to remain strong for all its NGLs and condensate.

Crude oil accounted for 48% of production in 2004 (2003 44%, 2002 43%), while natural gas constituted 45% of production in 2004 (2003 49%, 2002 50%). Natural gas liquid volumes accounted for 7% of total production in all three years. The Trust continues to maintain a balance between oil and natural gas production.

Average prices received for the year ended December 31,	**2004**	**2003**	**2002**
Oil (per bbl) (1)	$ 48.83	$ 39.16	$ 36.91
Natural gas (per mcf) (1)	6.87	6.63	4.08
Natural gas liquids (per bbl) (1)	41.96	35.05	28.69
Weighted average (6:1)	**$ 44.93**	**$ 39.15**	**$ 30.17**

[(1)] Prices are before realized gains/losses on commodity contracts and before transportation costs which were previously deducted from oil and natural gas prices and are now disclosed separately on the income statement. Prices previously reported for prior years have been restated.

Production Revenue (millions)		**2004**		**2003**		**2002**
Oil	$	269.6	$	178.0	$	150.4
Natural gas		212.6		201.5		114.6
Natural gas liquids & sulphur		34.9		26.8		18.8
Total	$	517.1	$	406.3	$	283.8

The Trust has a formal risk management policy which permits the risk management committee to use specified price risk management strategies for up to 40% 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 eighteen months 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. By doing this 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, 2004, Petrofund had 18.2 mmcf/d of natural gas and 4,250 bbl/d of crude oil hedged for calendar year 2005. A summary of the hedged volumes and prices by quarter is shown in the following table (see note 15 to the Consolidated Financial Statements for a detailed disclosure of all derivative financial instruments and their corresponding mark-to-market values):

		Average Volumes (mcf/d)			
Natural Gas	**2005**	**Q1**	**Q2**	**Q3**	**Q4**
Collars	15,791	18,950	18,948	18,948	6,316
Three way collars	2,369	9,475	-	-	-
Total mcf/d	**18,160**	**28,425**	**18,948**	**18,948**	**6,316**
		Average Prices ($/mcf)			
Collar ceiling price	$ 9.74	$12.75	$ 8.73	$ 8.73	$ 8.73
Collar floor price	6.31	6.23	6.33	6.33	6.33
Three way ceiling price	8.97	8.97	-	-	-
Three way floor price	5.80	5.80	-	-	-
Three way floor	$ 4.75	$ 4.75	$ -	$ -	$ -

	Average Volumes (bbl/d)				
Oil	**2005**	**Q1**	**Q2**	**Q3**	**Q4**
Three way collars	3,750	3,000	4,000	4,000	4,000
Floors	500	2,000	-	-	-
Total bbl/d	**4,250**	**5,000**	**4,000**	**4,000**	**4,000**
	Average Price ($/bbl)				
Three way ceiling price	$ 43.30	$ 38.31	$ 43.76	$ 45.56	$ 45.56
Three way floor price	34.28	31.10	35.34	35.34	35.34
Three way floor	29.70	26.85	30.65	30.65	30.65
Floor price	$ 50.49	$ 50.49	$ -	$ -	$ -

Alberta Power

Petrofund has 2.0 MW/h of power hedged at a fixed price of $44.50/MW throughout 2005.

As at February 11, 2005, Petrofund entered into the following additional hedges (not included in the table above):

1)

A three way collar for April 1, 2005 to October 31, 2005, for 4,737 mcf/d of natural gas (at AECO) with strikes at the $4.75-$5.80-$7.92/mcf levels (the price is collared between $5.80 and $7.92/mcf level unless prices dip below $4.75/mcf);

2)

A three way collar for November 1, 2005 to March 31, 2006, for 4,737 mcf/d of natural gas (at AECO) with strikes at the $5.65-$6.70-$10.55/mcf levels (the price is collared between $6.70 and $10.55/mcf level unless prices dip below $5.65/mcf);

3)

A three way collar for January 1, 2006, to March 31, 2006, for 1,000 bbl/d of crude (WTI) with strikes at the $42.07-$48.08-$63.71/Cdn. per bbl levels (the price is collared between $48.08 and $63.71/bbl level unless prices dip below $42.07/Cdn. per bbl);

4)

A collar for April 1, 2005 to June 30, 2005, for 1,000 bbl/d of crude (WTI) between $48.08 and $66.11/Cdn. per bbl.

All foreign exchange calculations in this section of the report (including those immediately above) incorporate the Bank of Canada US dollar rate at the close on December 31, 2004, of $1.202 C$:US$.

LOSS ON COMMODITY CONTRACTS

	2004	**2003**	**2002**
Realized losses	$ (42,491)	$ (7,755)	$ (8,668)
Change in fair value		-	-
Fair value, beginning of year	(6,771)	-	-

Fair value of Ultima contracts acquired	(5,584)	-	-
	(12,355)	-	-
Less fair value, end of year	(11,318)	-	-
Change in fair value of financial instruments	1,037	-	-
Amortization of negative fair value at			

6

January 1, 2004	(7,258)	-	-
Total non-cash adjustments	(6,221)	-	-
Total	$ (48,712)	$ (7,755)	$ (8,668)

ROYALTIES

	2004	**2003**	**2002**
Royalties (millions)	$ 100.2	$ 84.8	$ 50.4
Average royalty rate (%)	19.4	20.9	17.8
$/boe	$ 8.71	$ 8.18	$ 5.36

Royalties, which include crown, freehold and overrides paid on oil and natural gas production, increased to $100.2 million in 2004 from $84.8 million in 2003 net of the Alberta Royalty Credit (ARC). Royalties, as a percentage of revenues before hedging losses, decreased to 19.4% of revenues in 2004 from 20.9% of revenues in 2003 as the average royalty rates on the properties acquired from Ultima were lower than the existing Petrofund properties. The average royalty rate was lower at 17.8% in 2002 reflecting the low gas prices in that year. The gas royalty rate increases with price.

EXPENSES

	2004	**2003**	**2002**
Expenses (millions)			
Lease operating	$ 103.6	$ 91.3	$ 74.8
Transportation	5.9	5.5	4.5
General & administrative	14.4	13.0	15.5
Management fee	-	-	4.7
Net interest	$ 5.8	$ 8.7	$ 8.3
Expenses per boe			
Lease operating	$ 9.01	$ 8.80	$ 7.95
Transportation	0.51	0.53	0.48
General & administrative	1.26	1.26	1.65
Management fee	-	-	0.50
Net interest	$ 0.51	$ 0.84	$ 0.88

Lease Operating

Oil and gas lease operating expenses increased to $103.6 million in 2004 from $91.3 million in 2003 (2002 - $74.8 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 $9.01 in 2004 from $8.80 in 2003 (2002 - $7.95).

The most significant contributor to the higher operating costs in each year was general industry increases for all types of services including surface and downhole well repair costs and facility maintenance work.

Transportation Costs

Transportation costs were previously deducted from sales. Due to a change in accounting presentation, sales revenues have been increased by the transportation amounts with the costs disclosed as a separate item. Transportation costs ranged between $0.48/boe and $0.53/boe in the three year period.

General & Administrative ("G&A")

G&A costs on a boe basis were $1.26 per boe in 2004 and 2003 as compared to $1.65 per boe in 2002. General and administrative costs, net of overhead recoveries, increased to $14.4 million in 2004 from $13.0 million in 2003 (2002 - $15.5 million). G&A costs in 2004 included $778,000 relating to the reclassification of units, which was deferred indefinitely in December 2004, and $212,000 for external costs associated with compliance with Section 404 of the Sarbanes-Oxley Act (SOX 404) which equates to $ 0.09 per boe.

G&A costs in 2004 also include $1.5 million of compensation expense related to the restricted unit plan ("RUP") and the long-term incentive plan ("LTIP") which were approved on February 17, 2004, on the recommendation of the Human Resources and Compensation Committee. The compensation expense is based on the unit price of the Trust units at December 31, 2004, of $15.61 per unit.

The plans authorize the Trust to grant restricted units to directors, officers, employees or consultants of the Trust or any of its subsidiaries. The units vest over time and upon vesting may be redeemed by the holder for cash or units under the RUP and for units only under the LTIP. Upon vesting, the plan participant is entitled to receive cash, based on the weighted average trading price of the units for the last twenty days prior to the vesting date plus accrued distributions or units including additional units for accrued distributions. The estimated fair value of the units and the cash to be issued is expensed in the consolidated statement of operations over the vesting period. As the cash and the value of the Trust units to be issued is dependent upon future Trust unit prices, the expense recorded may fluctuate over time. These plans replace the unit incentive (option) plan. No options have been issued under the unit incentive (option) plan since 2002.

Management Fees/ Internalization of Management

No management, acquisition or disposition fees were payable in 2004 and 2003 and no future fees will be paid due to the internalization of management. In 2002 management fees of $4.7 million were paid to the previous manager. The cost of the internalization to Petrofund was $30.9 million, including of the issue of 1,939,147 exchangeable shares (refer to Notes 5 and 9 of the Consolidated Financial Statements).

Financing Costs

Interest and other financing costs decreased to $5.8 million in 2004 from $8.7 million in 2003 (2002 - $8.3 million), due to the decrease in the average loan balance outstanding and a decrease in the average prime loan rate from 4.7% in 2003 to 4.0% in 2004. The average loan outstanding in 2004 was $157.5 million versus $180.7 million in 2003.

The bank loan outstanding at December 31, 2004, was $214.4 million as compared to $109.7 million at the end of the previous year.

DEPLETION, DEPRECIATION & ACCRETION

Depletion, depreciation and accretion expense increased to $153.1 million in 2004 from $118.3 million in 2003 (2002 - $103.3 million) due to the increase in production and an increase in the depletion rate. The rate per boe increased to $13.31 in 2004 from $11.41 in 2003 (2002 - $10.97). The increase in the rate over the three years reflects the increasing cost of acquisitions. The unproved properties are included in the depletion and depreciation expense calculation.

INCOME 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 the Trust s 100% owned subsidiary, Petrofund Corp. at the end of the year. The Federal Large Corporations Tax rate is being reduced in stages over a period of five years commencing in 2004, so that by 2008, the tax will be eliminated.

Capital taxes of $3.3 million in 2004 (2003 - $2.5 million), (2002 - $2.1 million) 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 Petrofund Corp s assets and their respective accounting carrying cost. Future income taxes were increased by $7.9 million due to the Central Alberta acquisition. This liability arose as the purchase price of the assets was in excess of its tax pools. Future income taxes were decreased by $12.7 million on the purchase of Ultima. The reduction in this liability arose as the value of the tax pools exceeded the purchase price of the operating subsidiary of Ultima. Future income tax expense was $7.1 million in 2004, as compared to recoveries of $44.2 million in 2003 and $14.0 million in 2002 resulting in a remaining future income tax liability of $81.4 million at December 31, 2004. The provision for deferred income tax expense in 2004 reflects the utilization of loss carryforwards in the operating subsidiary of the Trust. The future income tax recovery in 2003 was increased by $36.7 million to reflect reductions in the Federal and Alberta income tax rates announced in that year.

NET INCOME

For the years ended December 31,		**2004**		**2003**		**2002**
Net income	$	74,359	$	87,276	$	25,518
Net income per Trust unit						
Basic	$	0.84	$	1.43	$	0.51
Diluted	$	0.84	$	1.43	$	0.51

Net income decreased to $74.4 million in 2004 from the $87.3 million reported in 2003 (2002 - $25.5). Net income for the year ended December 31, 2003 was reduced by $30.9 million for management internalization costs and increased by $36.7 million for future income tax rate reductions.

Net income before taxes increased from $11.5 million in 2002 to $43.6 million in 2003 mainly due to a 14% increase in production and a 29% increase in prices on a boe basis. The increase in net income before taxes from $43.6 million in 2003 to $82.0 million in 2004 was the result of a 11% increase in production and a 15% increase in prices on a boe basis. Total costs, excluding the internalization of management, increased $0.41 on a boe basis from 2002 to 2003 and $1.80 from 2003 to 2004. The increase from 2003 to 2004 was mainly due to the higher depletion rate due to the Ultima acquisition.

Operating Netbacks 2004	**Oil $/bbl**	**Gas $/mcf**	**NGL $ /bbl**	**Total $ /boe**
Selling price		$		$
	$ 48.83	6.87	$ 41.96	44.93
Cash cost of hedging	(7.38)	(0.06)	-	(3.69)
Net selling price	41.45	6.81	41.96	41.24
Royalties, net of ARC	8.22	1.48	10.98	8.71
Operating	11.07	1.16	7.96	9.01
Transportation	0.25	0.13	0.44	0.51
Operating netback	$ 21.91	$4.04	$ 22.58	$ 23.01

Operating Netbacks 2003	Oil $/bbl	Gas $/mcf	NGL $ /bbl	Total $ /boe
Selling price	$ 39.16	$ 6.63	$ 35.05	$ 39.15
Cash cost of hedging	(1.00)	(0.11)	-	(0.75)
Net selling price	38.16	6.52	35.05	38.40
Royalties, net of ARC	6.32	1.60	9.80	8.18
Operating	11.23	1.13	7.89	8.80
Transportation	0.25	0.13	0.39	0.53
Operating netback	$ 20.36	$ 3.66	$ 16.97	$ 20.89

Operating Netbacks 2002	Oil $/bbl	Gas $/mcf	NGL $ /bbl	Total $ /boe
Selling price	$ 36.91	$ 4.08	$ 28.69	$ 30.17
Cash cost of hedging	(2.10)	-	-	(0.92)
Net selling price	34.81	4.08	28.69	29.25
Royalties, net of ARC	5.56	0.82	7.40	5.36
Operating	10.35	1.01	6.36	7.95
Transportation	0.13	0.13	0.39	0.48
Operating netback	$ 18.77	$ 2.12	$ 14.54	$ 15.46

QUARTERLY AND ANNUAL FINANCIAL DATA

($millions, except per unit amounts)	Net Oil and Natural Gas Sales (1)	Net Income	Net income per Unit (2) Basic	Diluted
2004				
First quarter	$ 81.1	$ 7.6	$ 0.10	$ 0.10
Second quarter	89.9	0.8	0.01	0.01
Third quarter	119.9	15.1	0.15	0.15
Fourth quarter	125.9	50.9	0.51	0.51
	$ 416.8	$ 74.4	$ 0.84	$ 0.84
2003				
First quarter	$ 91.4	$ 32.6	$ 0.60	$ 0.60
Second quarter	77.9	15.3	0.26	0.26
Third quarter	75.4	15.1	0.23	0.23
Fourth quarter	76.8	24.3	0.35	0.35
	$ 321.5	$ 87.3	$ 1.43	$ 1.43
2002				
First quarter	$ 44.1	$ 1.3	$ 0.03	$ 0.03
Second quarter	56.5	8.7	0.18	0.18
Third quarter	59.5	10.0	0.18	0.18
Fourth quarter	73.3	5.5	0.10	0.10
	$ 233.4	$ 25.5	$ 0.49	$ 0.49

(1)

Net after royalties

(2)

Net income per unit numbers are calculated quarterly and annually and therefore do not add.

For the years ended December 31,		**2004**		**2003**		**2002**
Total assets	$	1,486,412	$	962,528	$	909,093
Total long-term debt	$	214,414	$	110,315	$	219,218

Summary of Fourth Quarter Results

Three months ended December 31,		**2004**		**2003**	**% change**
Daily production volumes					
Oil (bbls) 13,645 18,508					36
Natural gas (mmcf)		90.1		80.3	12
Natural gas liquids (bbls)		**2,502**		**2,185**	**15**
BOE (6:1)		36,025		29,211	23
Average prices					
Oil (per bbl)	$	50.96	$	36.07	41
Natural gas (per mcf)		7.12		5.87	21
Natural gas liquids (per bbl)		**48.20**		**34.86**	**38**
BOE (6:1)	$	47.33	$	35.60	33

Three months ended December 31,		**2004**		**2003**	**% change**
Production revenue ($ millions)	$	156.9	$	95.8	64
Royalties ($ millions)		31.2		19.0	(64)
Transportation costs ($ millions)		1.6		1.4	(18)
Operating expenses ($ millions)		29.2		24.8	(18)
cost per boe		8.82		9.22	3
General and administrative ($ millions)		4.2		2.9	(45)
cost per boe	$	1.27	$	1.10	(15)

Revenues increased 64% to $156.9 million in the fourth quarter of 2004 from $95.8 million in the fourth quarter of 2003. Average daily production was up 23%, from 29,211 boe/d to 36,025 boe/d and prices were up 33% on a boe basis to $47.33/boe in 2004, from $35.60/boe in 2003. The change in production reflects the acquisition of Ultima in June of 2004, PC s development drilling program and the Central Alberta acquisition.

Royalties were 20% of revenue in the fourth quarter of 2004 and 2003. Operating costs were $8.82/boe in the fourth quarter of 2004 as compared to $9.22/boe in the same period of 2003. General and administrative costs increased to $1.27/boe from $1.10/boe, due to $738,000 or $0.22/boe relating to the planned reclassification of units and SOX 404 compliance.

CAPITAL EXPENDITURES

Acquisitions

During the year, PC incurred $606.8 million for the Ultima, the Central Alberta, and other minor acquisitions, and acquired 40.7 million boe of proved plus probable reserves. The properties acquired were heavily weighted to oil and had a reserve life index of 11.2 years.

On June 16, 2004, Petrofund acquired all the assets and assumed all liabilities of Ultima for an aggregate cost of $563.1 million consisting of 26.4 million Petrofund Trust units valued at $17.12 per unit, the assumption of debt and negative working capital of $119.7 million and transaction costs incurred by Petrofund of $1.9 million. On November 10, 2004, the Central Alberta acquisition was purchased for $27.7 million in cash and an additional $8.9 million was added to oil and natural gas and property interests for future income taxes and asset retirement obligations. In addition, other minor property interests were acquired.

Development Activities

During the year PC incurred $77.9 million drilling and development activities as compared to $71.4 million in 2003. A total of 165 wells were drilled, of which 66 were gas, 92 oil, 5 service wells and 2 dry and abandoned for an overall success rate of 98%. These activities added 3,500 boe/d of production at an average cost of $22,000 per boe/d and offset more than half of the decline in existing production.

Farmout Activities

During 2004, Petrofund entered into 26 separate farmout/option agreements with various industry partners on properties and related expenditures that did not meet Petrofund s investment criteria. These deals resulted in the drilling of 32 wells and 11 re-entries on Petrofund s undeveloped lands. The approximate cost of these expenditures, net to Petrofund s interest and paid for by various third parties, was $8.1 million. This drilling yielded 30 gas wells, 9 oil wells and 4 dry holes.

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 interest for each well which generally equates to 50% of its pre-farmout interest.

Disposition of Properties

During 2004, Petrofund disposed of minor properties for net proceeds of $1.0 million. During 2003, Petrofund disposed of approximately five million boe of proven plus probable reserves for $33.5 million. In 2002 $30.0 million of properties were sold at an average price of $8.95 per boe. 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.

A summary of capital expenditures for the last three years is as follows (in millions):

For the years ended December 31,		2004		2003		2002
Property acquisitions (1) (2)	$	606.8	$	115.6	$	218.5
Property dispositions		(1.0)		(33.5)		(30.0)
Net acquisitions		605.8		82.1		188.5
Finding and development costs:						
Land & seismic		2.2		2.5		2.8
Drilling & completion		35.3		42.5		22.2
Well equipping		10.6		7.9		6.7
Tie-ins		5.4		5.2		2.7
Facilities		13.3		8.4		3.2
CO2 purchases		8.4		3.5		3.2
Other		2.7		1.4		-
Total		77.9		71.4		40.8
Total net capital expenditures	$	683.7	$	153.5	$	229.3

(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.

(2)

Includes goodwill of $180.3 million.

ASSET RETIREMENT FUND

At the end of the year, PC had $7.1 million set aside in cash to fund future abandonment costs. This cash fund was increased by $0.15/boe produced in 2004 as compared to $0.075/boe in prior periods. In addition the Ultima reserve fund of $1.5 million was added to the Trust on the consolidation of the entity into Petrofund in June 2004. 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. PC performs well reclamation and abandonments, flare pit remediation work, etc. on a routine basis to proactively address environmental concerns. Petrofund incurred $4.6 million for abandonment and reclamation projects in 2004 compared to $4.7 million in 2003 and $2.2 million in 2002. PC expects to spend a further $4.0 million to $5.0 million on reclamation and abandonment work in 2005 which will reduce cash flow available for distribution.

GOODWILL

The goodwill balance of $180.3 million resulted from the Ultima and the Central Alberta acquisitions. The amount was determined based on the excess of total consideration paid plus the future income tax liability less the fair value assigned to the assets.

Accounting standards require that the goodwill balance be assessed for impairment at least annually and if impairment exists that it be charged to income in the period in which the impairment occurs. The Trust has determined that there was no goodwill impairment as of December 31, 2004.

DEBT

PC s borrowing base was increased to $325 million, in conjunction with the acquisition of Ultima. As at December 31, 2004, the amount outstanding on the credit facility was $214.4 million with $110.6 million available to finance future activities.

The revolving period on the syndicated facility ends on June 29, 2005, 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.

LIQUIDITY AND CAPITAL RESOURCES

The working capital deficit was $49.3 million at December 31, 2004, an increase of $19.3 million from the $30.0 million deficit as at December 31, 2003. The 2004 deficit excludes net unrealized losses on commodity contracts. Current assets decreased $8.1 million from 2003 to 2004 as accounts receivable at December 31, 2003, included $22.4 million due on the sale of properties which was collected in early 2004. Accounts receivable and payables are higher in general due to the increase in the size of the Trust especially in the second half of the year due to the acquisition of Ultima. The major part of the increase

of $24.3 million in payables is due to a general increase in joint venture payables and the capital expenditure accrual due to an active drilling program in the fourth quarter. The decrease in distributions payable of $17.9 million is due to the increase in cash flow withheld to fund capital expenditures, including the Weyburn lease obligation.

During 2004 the Trust generated cash flow of $236.2 million and paid out $169.5 million in distributions. The excess of $66.7 million was used to fund part of the Trust's capital expenditure program.

Total long-term debt and capital leases increased $104.1 million from $110.3 million at December 31, 2003, to $214.4 million at the end of the current year due to the assumption of debt on the Ultima acquisition, the cost of development activities and the Central Alberta acquisition. The current limit on the facility is $325 million. The banking syndicate is currently reviewing the borrowing base and indications are that it will be increased.

The major changes in total long- term debt were due to:

For the years ended December 31,		**2004**		**2003**
Cash flow from operating activities	$	236.2	$	187.6
Proceeds received from issuance of Trust units		4.5		214.0
Net change in non-cash working capital balances		33.5		6.4
Distributions paid		(169.5)		(127.3)
Expenditures on oil & natural properties, net		(107.8)		(153.5)
Assumption of Ultima debt, net of cash		(100.6)		-
Asset retirement reserve		(1.7)		(0.8)
Redemption of exchangeable shares		(1.8)		(2.8)
Capital lease repayments		(0.4)		(9.3)
(Increase) decrease in cash		2.9		(3.7)
Internalization of management contract		-		(8.0)
Miscellaneous		0.6		6.3
	$	(104.1)	$	108.9

The ratio of long-term debt to annualized fourth quarter cash flow was 0.8:1.0.

In the absence of an equity issue, long-term debt will increase in 2005 due to the capital expenditure program which is expected to be in the $90 million range (excluding acquisitions) of which approximately one half will be funded from cash flow. If the Trust is successful in completing one or more significant acquisitions in 2005 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.

Capitalization Analysis

($ thousands, except per unit and percent amounts)		**2004**		**2003**		**2002**
Working capital (deficiency)	$	(60,295)	$	(30,006)	$	(6,909)
Bank debt		214,414		109,707		212,253
Capital lease obligation		-		608		6,965
Net debt obligation	$	274,709	$	140,321	$	226,127
Units outstanding and issueable						
for Exchangeable Shares		100,451		73,628		54,108
Market Price at December 31,	$	15.61	$	18.79	$	10.85

Market capitalization	$ 1,568,036	$ 1,383,465	$ 587,069

Total capitalization	$ 1,842,745	$ 1,523,786	$ 813,196
Net debt as a percentage of total capitalization	14.9%	9.2%	27.8%
Cash flow	$ 236,246	$ 187,585	$ 112,570
Net debt to cash flow	1.2:1.0	0.7:1.0	2.0:1.0

Total capitalization as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

UNITHOLDERS EQUITY

The weighted average Trust units/exchangeable shares outstanding are as follows:

For the twelve months ended December 31,	**2004**	**2003**	**2002**
Basic	88,169,339	61,010,105	49,921,523
Diluted	88,292,020	61,153,027	49,967,648

Trust units/exchangeable shares outstanding:			
As at December 31,	**2004**	**2003**	**2002**
Trust units outstanding	99,511,576	72,688,577	54,108,420
Trust units issuable for exchangeable shares (*Note 10*)	939,147	939,147	-
	100,450,723	73,627,724	54,108,420

The Trust had 99,511,576 Trust units outstanding at December 31, 2004, compared to 72,688,577 Trust units at the end of 2003. The increase in Trust units from December 31, 2004 to March 1, 2005, the date of the MD&A, was minimal. The weighted average number of Trust units outstanding including Exchangeable Shares, was 88,169,339 Trust units for 2004 as compared to 61,010,105 for 2003. In April 2003, 1,939,147 Exchangeable Shares and 100,244 Trust units were issued in connection with the internalization transaction. During 2003, 906,635 Exchangeable Shares were converted into 1,000,000 Trust units and 181,041 were redeemed for cash leaving 851,471 Exchangeable Shares outstanding at year end which were convertible into 939,147 Trust units. During 2004, 94,823 Exchangeable Shares were redeemed for cash leaving 756,648 Exchangeable Shares outstanding at December 31, 2004, which can be converted at the option of the unit holder into 939,147 Trust units.

On June 16, 2004, the Trust issued 26.4 million units for the purchase of Ultima issued at a deemed price of $17.12 per unit. In May 2003, 9.2 million units were issued at a price of $10.60 per unit and in December 2003, 6.6 million units were issued at a price of $16.20 per unit.

During the year, 332,733 options (2003 1,673,404) were exercised for the same number of Trust units generating proceeds of $3.8 million in 2004 and $20.5 million in 2003. (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. In 2004 184,982 (2003 - 316,785) units were issued under the DRIP plan at an average price of $16.24 per Trust unit (2003 - $13.21) for total proceeds of $3.0 million in 2004 and $4.2 million in 2003. (Note 8).

TAXABILITY OF DISTRIBUTIONS

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.

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 2004 distributions paid out during the period January to May were determined to be 84.300% ordinary income and the remaining 15.700% was considered a return of capital. Those distributions paid out during the period June to December 2004 were determined to be 72.364% ordinary income and the remaining 27.636% was considered 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 2004, 35.372% of distributions to U.S. unitholders was dividend income and 64.628% was a return of capital. The tax liability of distributions is expected to increase significantly in 2005.

NON-RESIDENT OWNERSHIP

In March of 2004, the Government of Canada announced proposed amendments to the *Income Tax Act* (Canada) (the Tax Act) that would have eliminated an exemption which the Trust relies upon to qualify as a mutual fund Trust for the purpose of the Tax Act as a result of the nature of the assets of the Trust. With this exemption removed, Petrofund would have been required to bring its non-resident ownership below 50% by January 1, 2007 in order to maintain its tax status as a mutual fund Trust.

In September 2004, draft amendments to the Tax Act giving effect to the foregoing were released by the Government of Canada (the Draft Amendments). The Draft Amendments would have deleted the requirement that a Trust not be considered to be established and maintained primarily for the benefit of non-residents of Canada in order to qualify as a mutual fund Trust. Such Draft Amendments instead introduced a requirement that non-residents of Canada not hold more than 50% of the issued units of the Trust, calculated on a fair market value basis, and that such level of ownership be attained by January 1, 2007.

In view of this information and the continuing rapid increase in Petrofund s non-resident ownership percentage, Petrofund s Board of Directors elected to propose to unitholders a reclassification of the Trust s capital structure designed to prevent further migration of ownership of the Trust to non-residents. The reclassification of Petrofund s Trust units was overwhelmingly approved by unitholders at a special meeting on November 16, 2004. Implementation, which is subject to the Board s discretion, was scheduled for December 16, 2004.

On December 6, 2004, the Government of Canada announced changes to the 2004 Budget in a Notice of Ways and Means motion which did not include the previously proposed amendments to the Tax Act relating to non-resident ownership of mutual fund Trusts. As such, the restrictions announced earlier in the year regarding non-resident ownership and the associated deadlines were removed. In response to these changes, Petrofund announced on December 8, 2004, that it would not proceed with the reclassification of its Trust units.

Prior to the initial March 2004 announcement, Petrofund qualified as a mutual fund Trust under the Tax Act and the current version of the Government s proposed 2004 Budget preserves this status. However, the government has indicated that further discussions will be pursued with the private sector to establish whether an alternative proposal can be devised that would achieve its tax revenue objectives. At this time the government has not provided any further clarity or associated time frames regarding this matter. Further updates on this subject will be provided if and when the government moves forward on this issue.

Based on information available to the Trust, Petrofund estimates that non-resident ownership was approximately 66% as of January 14, 2005. While there are no longer any restrictions or deadlines on Petrofund pertaining to non-resident ownership levels, the Trust will continue to provide non-resident ownership level updates on a quarterly basis.

CONTRACTUAL OBLIGATIONS

The following is a summary of the Trust's contractual obligations due in the next five years and thereafter:

		Payment due by Period			
Contractual Obligations	**Total**	**less than one year**	**1 3 years**	**4 5 years**	**after 5 years**
(millions of dollars)					
Long-term debt [1]	$ 214.4	$ -	$ -	$ -	$ 214.4
Capital lease obligations	0.6	0.6	-	-	-
Operating leases	21.2	2.0	4.4	4.8	10.0
Purchase obligations [2]	142.0	16.3	28.2	26.6	70.9
Asset retirement obligation [3]	116.5	3.1	6.7	9.7	97.0
RUP, LTIP's [4]	1.3	0.8	0.4	-	0.1
Total	$ 496.0	$ 22.8	$ 39.7	$ 41.1	$ 392.4

(1)

Approval to extend the revolving period must be obtained from the banking syndicate on an annual basis; however it has been extended every year since the inception of the facility.

(2)

These amounts represent estimated commitments of $113.2 million for CO2 purchases and $28.8 million for processing fees with respect to PC s 21% interest in the Weyburn unit.

(3)

These amounts represent the undiscounted future reclamation and abandonment costs that are expected to be incurred over the life of the properties based on current costs.

(4)

Based on the current estimate of payments to be made on the vesting dates.

OFF-BALANCE SHEET ARRANGEMENTS

The Trust has no off-balance sheet financing arrangements.

RELATED PARTY TRANSACTIONS

During 2002 Petrofund paid NCE Petrofund Management Corp. (NCEP Management), the Previous Manager, a management fee of $4.7 million, investment fees of $1.3 million and disposition fees of $116,000. During 2002 Petrofund also paid NCE Management Services Inc. (NMSI) $11.7 million for accounting and administrative services, which is included in general and administrative expenses, $838,000 for project services and evaluation services, which has been capitalized to oil and gas properties and $300,000 for marketing and other related equity issue costs. Due to the internalization of management no fees were payable after 2002 and accounting and administrative costs were paid directly by Petrofund. The contract with NMSI was terminated. NMSI and NCEP were both beneficially owned by John Driscoll, a director of PC (Refer to Note 4 and Note 9 of the Consolidated Financial Statements).

FINANCIAL REPORTING AND REGULATORY UPDATE

There have been several changes in the financial reporting and securities regulatory environment in 2004 and 2003 that have impacted the Trust. The following new and amended standards impacted the financial statements in 2004 and in some cases resulted in restatements of comparable numbers for 2003 and 2002.

FULL COST ACCOUNTING GUIDELINES

Effective December 31, 2003, Petrofund adopted Section 3063, Impairment of Long-Lived Assets (S.3063). S.3063 which establishes standards for the recognition, measurement and disclosure of the impairment of long-lived 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 application of the impairment test for companies following the full cost method of accounting for oil and natural gas activities is included in Accounting Guideline 16, (AcG-16) Oil and Gas Accounting Full Cost AcG-16 was issued in September 2003. Effective January 1, 2004, impairment is recognized if the carrying value of the oil and natural gas royalty and property interests exceeds the sum of the undiscounted cash flows expected to result from the Trust s proved reserves based on future prices, adjusted for contract prices and quality differentials. If impairment is indicated, the amount is measured by comparing the carrying value of the oil and natural gas royalty and property interests to the estimated net present value of future cash flows from proved plus probable reserves. The present value of the future cash flow is based on the Trust s risk-free interest rate. Any excess carrying value above the net present value of the Trust s future cash flows would be recorded in depletion, depreciation and accretion expense as a permanent impairment. This differs from the previous cost recovery ceiling test that used undiscounted cash flows and constant prices and costs less general and administrative, financing costs, and income taxes. There was no write-down of the Trust s oil and gas royalty and property interests under either method in 2004, or 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, as noted below.

HEDGING RELATIONSHIPS

Effective January 1, 2004, Petrofund adopted Accounting Guideline 13, Hedging Relationships (AcG-13) AcG-13 establishes certain conditions under which 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. 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 recorded the fair value of the derivative financial instruments in the amount of $6.8 million as a liability on the balance sheet. The change in the fair value from January 1, 2004 has been recorded in the income statement on a separate line as loss on commodity contracts. This line item also includes realized gains and losses on the derivative financial instruments which were previously recorded in oil and gas sales.

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, Petrofund adopted Section 3110, Asset Retirement Obligations which requires liability recognition for retirement obligations associated with 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. The accrued reclamation and abandonment liabilities on the balance sheet which were calculated on a unit of production basis were reversed January 1, 2004. Oil and gas properties were increased and a liability was set up for the amount calculated under the new standard. The 2004 accounting follows the new standard and the comparative numbers for 2003 and prior periods have been restated.

The impact of this standard was 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) increased to $34.4 million at December 31, 2003, from $16.8 million and the liability at December 31, 2002, increased to $34.5 million from $15.3 million. The effect on the income statement was to increase (decrease) net income before income taxes by $1.5 million in 2003 (2002 - $1.1 million, 2001 - $(0.9) million).

CONTINUOUS DISCLOSURE OBLIGATIONS

Effective March 31, 2004, the Trust and all reporting issuers in Canada were subject to new disclosure requirements as per National Instrument 51-102 Continuous Disclosure Obligations . This new instrument was effective for fiscal years beginning on or after January 1, 2004. The Instrument shortened the time frame for filing of annual and interim financial statements, MD&A and the Annual Information Form (AIF). The Instrument also provides enhanced disclosure requirements in the MD&A and AIF. Under this new instrument, it is no longer 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.

STANDARDS OF DISCLOSURE FOR OIL AND GAS ACTIVITIES

Effective September 30, 2003, the regulatory authorities in Canada implemented National Instrument NI 51-101, "Standards of Disclosure for Oil and Gas Activities", which is effective for fiscal years that include or end on December 31, 2003. The instrument imposes more standardized guidelines for the evaluation and disclosure of reserve estimates and related oil and natural gas disclosures. Standardized definitions for the calculation of net asset value, netbacks and finding and development costs are included in the instrument.

DISCLOSURES OF GUARANTEES

Effective January 1, 2003, the Trust is required to disclose the nature, terms and estimated fair value of guarantees in the notes to the financial statements in accordance with Accounting Guideline 14 (AcG 14). This standard has no impact on the financial statements in 2004 or 2003 and has not resulted in any disclosure in the Notes to the Consolidated Financial Statements.

OTHER

On November 5, 2004, the Emerging Issues Committee of the Canadian Institute of Chartered Accountants (CICA) issued EIC-149, Accounting for retractable or mandatorily redeemable shares. The abstract deals with the issue of whether retractable or mandatorily redeemable shares should be classified as a liability or equity. Petrofund Energy Trust issues units which are retractable by the unitholders from time to time at the lesser of 95% of the simple average of the market prices of the units for the ten day trading period commencing immediately after the retraction date and the closing market price on the retraction date. Petrofund has concluded the Trust units issued meet all of the criteria necessary to continue to classify them as equity.

Accounting Guideline 15, AcG-15, consolidation of Variable Interest Entities is effective for the first quarter of 2005. We do not expect it to have any impact on Petrofund s Financial Statements. A number of other guidelines were issued by the Emerging Issues Committee during 2004, most of which are not applicable or will have little or no impact on the 2005 financial statements. EIC 151, Exchangeable Securities confirms that the accounting adopted for recording the Exchangeable Shares issued in 2003 and subsequent redemptions and conversions is appropriate given that they are not transferable.

The Accounting Standards Board (AcSB) issued three exposure drafts in March 2003 entitled Financial Instruments Recognition and Measurement , Comprehensive Income and Hedges , which parallel many of the U.S. rules relating to accounting for financial instruments and comprehensive income. These standards which were planned for implementation in years beginning on or after October 1, 2005 were rescheduled for implementation for years on or after October 1, 2006. On January 27, 2005, the AcSB issued the new standard for accounting for financial instruments which is effective for annual and interim periods beginning on or after October 1, 2006. Petrofund has not assessed the potential impact of this standard on its financial statements at this time.

The AcSB also issued an exposure draft in March 2004 on subsequent events that will replace Section 3820 of the CICA handbook. In September 2003 an exposure draft was issued on changes in Accounting Policies and Estimates and Errors which was also effective January 1, 2005. These exposure drafts did not have a material effect on the financial statements.

Other accounting standards issued by the CICA during the year ended December 31, 2004, are not expected to affect the Trust at this time.

Included in Note 19 to the Consolidated Financial Statements is a discussion of the differences between Canadian and U.S. generally accepted accounting principles.

<u>MANAGEMENT AND FINANCIAL REPORTING SYSTEMS</u>

The Trust has established procedures and internal control systems in place to ensure timely and accurate preparation of management, financial and other reports. Disclosure controls are in place to ensure all ongoing statutory reporting requirements are met and material information is disclosed on a timely basis. The President and CEO and Senior Vice-President and Chief Financial Officer, individually, sign

certifications that the financial statements together with the other financial information included in the regulatory filings fairly present in all material respects the financial condition, results of operation, and cash flows as of the dates and for the periods presented.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates. These estimates include:

(a)

estimated production revenues, royalties and operating costs as at a specific reporting date but for which actual revenues and costs have not yet been received.

(b)

estimated capital expenditures on projects that are in progress.

(c)

estimated depletion, depreciation, and accretion that are based on estimates of oil and gas reserves that the Trust expects to recover in the future.

(d)

estimated fair values of derivative contracts that are subject to fluctuation depending upon underlying commodity prices and foreign exchange rates.

(e)

estimated value of asset retirement obligations that are dependent upon estimates of future costs and timing of expenditures.

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, depreciation and accretion 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 assess the borrowing base for the Trust's credit facilities. Revision or changes in the reserve estimates can have either a positive or negative impact on net income or the borrowing base of the Trust.

All estimates are prepared by qualified individuals who have knowledge of operations and related activities. Prior estimates are compared to actual results to confirm or improve accrual procedures and to make more informed decisions on future estimates.

SARBANES - OXLEY ACT OF 2002

In August 2002 the United States government passed into law the Sarbanes-Oxley Act of 2002 (the Sarbanes-Oxley Act) in an effort to strengthen corporate governance and restore investor confidence. This legislation is wide ranging and establishes new or enhanced reporting standards for all U.S. public company boards, management and public accounting firms. As Petrofund's securities are listed on the American Stock Exchange (AMEX), it is subject to compliance with the Sarbanes Oxley Act.

Beginning with fiscal year-end December 31, 2006, Petrofund is required to comply with Section 404 of the Act and include in its annual reports filed with the U.S. Securities and Exchange Commission a report from management on internal control over financial reporting, including a statement as to whether or not the Trust s internal control over financial reporting is effective. Management s report will also include a statement that the independent chartered accountants firm that audited the financial statements included in

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the Trust s annual report has issued an attestation report on management s assessment of the Trust s internal control over financial reporting.

Beginning in the first quarter of 2007, Petrofund must make quarterly evaluations of changes to internal control over financial reporting and report on any significant changes or deficiencies.

Section 302 of the Act together with corresponding U.S. Securities and Exchange Commission rules currently require the principal executive and financial officer, to make quarterly and annual certifications with respect to the Trust s internal control over disclosure controls and procedures. In 2007, the certifications will also include internal control over financial reporting.

Petrofund initiated work on meeting the requirements of Section 404 of the Sarbanes-Oxley Act in the second quarter of fiscal 2004 and has established a clear methodology and project timeline to meet compliance by the legislated compliance dates.

To date, all of Petrofund s major processes have been re-documented to more clearly address and encompass the rigor of the Sarbanes-Oxley Act. A comprehensive evaluation has begun which focuses on confirming the overall design effectiveness of Petrofund s internal controls over financial reporting. Concurrently, a thorough testing program is being created to establish the effectiveness of individual controls. Petrofund anticipates full internal testing procedures to be completed mid-second quarter of 2005. An independent audit by Petrofund s external auditors will begin early in the third quarter of 2005.

BUSINESS RISKS

VOLATILITY IN 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 significantly 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: 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.

RESERVE ESTIMATES

The value of the Trust Units depends upon, among other things, the reserves attributable to PC s properties. The reserves and recovery information contained in PC s independent reserve evaluation is only an estimate. The actual production and ultimate reserves from the properties may be greater or less than the estimates prepared by the independent reserve evaluator. The reserve report was prepared using certain commodity price assumptions that are described in the notes to the reserve tables. If lower prices for crude oil, natural gas liquids and natural gas are realized by the Trust, the present value of estimated future net cash flows for the Trust s reserves would be reduced and the reduction could be significant.

DEPLETION OF RESERVES

The Trust has certain unique attributes which differentiate it from other oil and natural gas industry participants. Distributions by the Trust, absent commodity price increases or cost effective acquisition and development activities, will decline. As the Trust will not be reinvesting the majority of its cash flow, absent acquisitions 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 dependant upon its

success in exploiting its reserve base and acquiring additional reserves. 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.

FOREIGN EXCHANGE RATES

World oil prices are quoted in U.S. dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate that fluctuates over time. A material increase in the value of the Canadian dollar which occurred from 2003 to 2004 negatively affected the Trust s net production revenue. The Canadian dollar averaged US $0.77 in 2004 versus US $0.71 in 2003. The increase in the exchange rate for the Canadian dollar and future Canadian/U.S. exchange rates will affect future distributions and the future value of the Trust s reserves as determined by independent evaluators.

OPERATIONAL RISKS

PC s operations are subject to all of the risks normally associated with drilling for and the production and transportation of oil and natural 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 which cannot be insured against or which we may elect not to insure because of high premium costs or other reasons. (See Environmental and Safety Risks).

Continuing production from a property, and to some extent the marketing of production there-from, are largely dependent upon the ability of the operator of the property. Operating costs on most properties have increased over recent years. To the extent the operator fails to perform these functions properly, revenue may be reduced. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Trust to certain properties. PC markets and hedges its oil and natural gas production with a number of counterparties and therefore is subject to the risk that these parties may not be able to meet all their commitments under these contracts. A reduction of the distributions could result in such circumstances.

COMPETITION

There is strong competition relating to all aspects of the oil and natural 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. There are numerous Trusts in the oil and natural gas industry that are competing for the acquisition of properties with longer life reserves and with exploitation and developmental opportunities. As a result of the increasing competition, it may be more difficult to acquire reserves on beneficial terms.

ASSESSMENTS OF THE VALUE OF ACQUISITIONS

Acquisitions of resource issuers and resource assets are 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 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 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, and these 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.

ENVIRONMENTAL AND SAFETY RISKS

The oil and natural gas industry is subject to extensive environmental and safety regulations 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 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. In such an event, these environmental obligations would be funded out of PC s cash flow and could therefore reduce distributable income payable to Unitholders. In addition, the December 1997, Kyoto Protocol with respect to the reduction of greenhouse gases has been ratified by Canada. Although it is not possible at this time to assess the potential impacts on the business and operations of the Trust, they could be significant.

CREDIT FACILITY RESTRICTIONS ON DISTRIBUTIONS

Petrofund Corp. has a revolving borrowing base credit facility with a syndicate of banks (the Lenders). Under the terms of this facility, the revolving period is set at 364 days and renewed annually. To effect a renewal, no earlier than 90 days and no later than 60 days prior to the end of the existing period, Petrofund requests, from the Lenders, an extension for a further 364 period. In the event the Lenders elect not to extend the revolving period, no payments are required to be made to non-extending Lenders for a period of one year. However, during that year, Petrofund Corp. will be required to maintain certain minimum balances on deposit with the syndicate agent. At the end of the one year period, the entire amount becomes due and payable. If this event were to occur, it is likely that Petrofund Corp. would be forced to suspend royalty payments to Petrofund Energy Trust, which, in turn, would be unable to make distributions to unitholders. The revolving period has been extended each year by the Lenders since the inception of the Trust.

In addition from time to time, the Lenders have the right to review the borrowing base of Petrofund Corp s properties. If the borrowings exceed the redetermined borrowing base, on 60 days notice from the lender, Petrofund Corp is required to reduce its borrowing to the redetermined borrowing base. If, during the 60 day period, borrowings exceed the borrowing base by less than five percent, Petrofund Corp. is permitted to make a cash payment to the Trust for one normal monthly distribution to unitholders. However, if the excess borrowings are greater than five percent, no distributions are permitted.

TAXABILITY OF PETROFUND CORP

At the current time, there is no income tax payable by PC; however this situation could change depending upon the level of cash flows, within PC, the amount paid by PC to the Trust and the tax deductions generated within PC. Cash flow that is not paid to the Trust and subsequently distributed to unitholders is retained in PC and creates taxable income in PC. PC uses its available tax deductions from its development program and other deductions on property acquisitions that are not transferred to the Trust through the sale of a royalty to reduce its taxable income. If the tax deductions are not sufficient to reduce taxable income to nil PC could be liable for current income taxes. The amount of any current taxes payable would reduce cash available for distribution.

In addition, there is always legislative risk that could occur because of potential changes in current tax law that may erode the value of current and past tax positions. For example, the Federal Government has proposed certain changes relating to the deductibility of interest that could affect the operating corporation (PC). As well the Saskatchewan Government is proposing changes to the Saskatchewan Corporation Capital Tax Surcharge. These and any other changes could adversely affect the taxability of our operating subsidiary and the amount of cash flow distributed to unitholders.

ACCESS TO CAPITAL MARKETS

In the normal course of making capital investments to maintain and expand the oil and natural gas reserves of the Trust, additional Trust units are issued from treasury which may result in a decline in production per Trust unit and reserves per Trust unit. To the extent that external sources of capital, 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 PC is required to use cash flow to finance capital expenditures or property acquisitions, to pay debt service charges or to reduce debt, the level of distributable income will be reduced.

SENSITIVITY ANALYSIS

Below is a table that shows sensitivities to pre-hedging cash flow as a result of product price and operational changes that can significantly affect cash flow and results of operations. The table is based on actual 2004 prices received and average fourth quarter production volumes of 36,025 boe/d. 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.

			$/unit
	Change	**$000s**	**per year**
Price per barrel of oil (1)	$ 1.00 U.S.	$ 7,860	$0.078
Price per mcf of natural gas (1)	$0.25 CDN.	$ 6,289	$0.063
US/CDN exchange rate	$ 0.01	$ 4,025	$ 0.040
Interest rate on debt ($200 million)	1%	$ 2,140	$ 0.021
Oil production volumes (1)	100 bbl/day	$ 1,461	$ 0.015
Gas production volumes (1)	1 mmcf/day	$ 1,918	$ 0.019

1) After adjustment for estimated royalties.

OUTLOOK FOR 2005

The level of cash flow for 2005 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 2004 and this trend is expected to continue in 2005. 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. The Trust 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 2005 moderated the net effect of these prices on Petrofund s cash flow. The WTI U.S. price increased 33% to $41.40/bbl in 2004 from $31.04 in 2003; however, as the (US/CDN) exchange rate averaged $0.770 in 2004 as compared to $0.716 in 2003 the par price at Edmonton was up only 22%. The Trust expects the Canadian dollar to remain strong throughout 2005.

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 positions appear elsewhere in this report.

PETROFUND ENERGY TRUST

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 compliance with the corporate governance standards outlined by the Toronto Stock Exchange (TSX).

Petrofund s Board of Directors is composed of individuals who all have experience relevant to the Trust s operations and understand the complexities of the Trust s business environment. The Board of Directors actively strives to include a diversity of backgrounds, perspectives, and skills among its members. In 2004, the Board increased in size by two directorships as a result of the Ultima transaction which closed in June. This increase was done with a view to increase overall effectiveness and improve decision making.

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 nine members. Seven of the nine 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 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 exceptions of Mr. Errico (the Trust s current President and Chief Executive Officer) and Mr. Driscoll (the Trust s former President and Chief Executive Officer), 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 Reserve Committee, and the Audit Committee. Committees have formal written mandates approved by the Board of Directors. 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 Cowan (Chairperson), Art Dumont and Peter 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. The Governance Committee 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 Governance Committee s mandate is the responsibility for considering and proposing nominations to the Board, should such nominations be required. The Committee reviews director compensation at least annually, and recommends changes as it sees fit to the Board for its approval.

AUDIT COMMITTEE

The Audit Committee comprises James Allard (Chairperson), Frank Potter, Peter Thomson and Gary Lee. The Committee oversees, among other things, Petrofund's finances, accounting and financial reporting practices and controls. All listed committee members possess the requisite financial skills necessary to qualify them as committee directors. Additionally, James 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 his lengthy career.

HUMAN RESOURCES & COMPENSATION COMMITTEE

The Human Resources & Compensation Committee comprises Frank Potter (Chairperson), Sandra Cowan and Wayne 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.

RESERVE AUDIT COMMITTEE

The Reserve Audit Committee comprises Wayne Newhouse (Chairperson), James Allard and Art Dumont. The Committee oversees the integrity of Petrofund s reserve estimates. The Reserves Audit Committee has the responsibility of overseeing the integrity of Petrofund s reserve estimates. Contained within the Reserve 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. The Committee 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.

CODE OF ETHICS AND WHISTLE BLOWER POLICY

Petrofund is committed to conducting its business in a responsible and ethical manner. To support this commitment, Petrofund has instituted a formal Code of Business Ethics and a Whistleblower Policy. These formalized documents are distributed to all officers, employees and contractors working for Petrofund. Each officer, employee or contractor is required to sign an acknowledgement and compliance letter stating that they have read, understand and will comply with these policies.

Specifically, the Code of Business Ethics clearly outlines the fundamental principles to which all officers, and employees and contractors are expected to adhere in the conduct of Petrofund s business. Fundamental principles of appropriate business conduct have been established, consistent with the core values and management philosophy of Petrofund, that are to be pursued by all officers, employees and contractors of the Trust.

The Whistleblower Policy describes Petrofund s principles and practices through which all officers, employees and contractors may report any concerns regarding the manner in which Petrofund conducts its business. Additionally, this policy outlines the means through which Petrofund will provide a safe, secure and confidential venue for staff to voice concerns about the Trust and its financial or operational processes. The Trust employs anonymous reporting methods easily accessible to all employees and consultants to help ensure anonymity and open access to those seeking to report such incidents. When required, senior management, as well as the Board of Directors through the Chairman of the Audit Committee participate in the review and investigation of the reported incidents.

EXHIBIT 3

Audited Consolidated Financial Statements

dated December 31, 2004 and 2003

and for the years ended

December 31, 2004, 2003 and 2002

Management s Report

These financial statements are the responsibility of the management of Petrofund Corp. (Management). They have been prepared in accordance with Canadian generally accepted accounting principles using Management s best estimates and judgments, where appropriate.

Management is responsible for the reliability and integrity of the financial statements, notes to the financial statements and other financial information contained in this report. Estimates are sometimes necessary in the preparation of these statements because a precise determination of some assets and liabilities depends on future events. Management has based these estimates on careful judgments and believes they are properly reflected in the accompanying financial statements. Management is also responsible for maintaining a system of internal controls designed to provide reasonable assurance that assets are safeguarded and that accounting systems provide timely, accurate and reliable financial information.

The Board of Directors of Petrofund is responsible for ensuring that Management fulfils its responsibilities for financial reporting and internal controls. The Board meets with Management to ensure that Management s responsibilities are fulfilled, to review financial statements and to recommend approval of the financial statements. An independent auditor appointed by the unitholders, Deloitte & Touche LLP, has audited the financial statements of Petrofund in accordance with Canadian generally accepted auditing standards and has provided an independent professional opinion.

(signed) Jeffery E. Errico

(signed) Vince Moyer

Jeffery E. Errico

Vince Moyer

President & CEO

Senior Vice-President, Finance &CFO

Calgary, Alberta, Canada

March 1, 2005

REPORT OF INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS

To the Unitholders of Petrofund Energy Trust:

We have audited the consolidated balance sheet of Petrofund Energy Trust (an Ontario open-ended investment Trust) as at December 31, 2004 and 2003 and the consolidated statements of operations and accumulated earnings and cash flows for each of the years in the three year period ended December 31, 2004. 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, 2004 and 2003 and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2004 in accordance with Canadian generally accepted accounting principles.

The Trust is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audit included consideration of internal control over financial reporting as basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Trust s internal control over financial reporting. Accordingly we express no such opinion.

Calgary, Alberta, Canada

(signed) Deloitte & Touche LLP

March 1, 2005

Independent Registered Chartered Accountants

Consolidated Balance Sheet
(thousands of dollars)

As at December 31,	**2004**	**2003**
		(Restated *Note 3)*
Assets		
Current assets		
Cash	$ -	$ 2,182
Accounts receivable	37,713	48,268
Deferred loss on commodity contracts (*Note 3(b)*)	517	-
Commodity contracts (*Notes 3(b) and 15*)	3,281	-
Prepaid expenses	10,847	10,036
Total current assets	52,358	60,486
Asset retirement reserve fund *(Note 13(b))*	7,053	3,779
Goodwill (*Notes 4(a) and (b)*)	180,307	-
Oil and natural gas royalty and property interests, at cost less accumulated depletion and depreciation of $632,668 (2003 - $482,349) (*Note 4)*	1,246,694	898,263
	$ 1,486,412	$ 962,528
Liabilities and Unitholders' Equity		
Current liabilities		
Bank overdraft	$ 733	$ -
Accounts payable and accrued liabilities *(Note 18)*	60,961	36,684
Current portion of capital lease obligations (*Note 7*)	608	356
Deferred gain on commodity contracts (*Note 3(b)*)	184	-
Commodity contracts (*Note 3(b) and 15)*	14,599	-
Distributions payable to Unitholders (*Note 12*)	35,568	53,452
Total current liabilities	112,653	90,492
Long-term debt *(Note 6*)	214,414	109,707
Capital lease obligations (*Note 7*)	-	608
Future income taxes (*Note 16)*	81,411	79,065
Asset retirement obligations (*Note 3(a) and 13(a))*	51,408	34,363
Total liabilities	459,886	314,235
Commitments (*Note 17*)	-	-
Unitholders' equity		
Unitholders' capital *(Note 8*)	1,477,963	1,020,677
Exchangeable shares *(Note 10*)	10,518	10,518
Accumulated earnings	272,612	198,253
Accumulated cash distributions *(Note 12*)	(734,567)	(581,155)
Total unitholders' equity	1,026,526	648,293
	$ 1,486,412	$ 962,528

Signed on behalf of Petrofund Energy Trust by Petrofund Corp.:

(signed) Jeffery E. Errico
Jeffery E. Errico, Director

(signed) James E. Allard
James E. Allard, Director

The accompanying notes to Consolidated Financial Statements are an integral part of this consolidated balance sheet.

Consolidated Statement of Operations and Accumulated Earnings
(thousands of dollars, except per unit amounts)

For the years ended December 31,	**2004**	**2003**	**2002**
		(Restated *Note 3)*	(Restated *Note 3)*
Revenues			
Oil and natural gas sales (*Note 3(c)*)	$ 517,081	$ 406,346	$ 283,853
Royalties	(100,230)	(84,804)	(50,427)
Loss on commodity contracts (*Note 3(b)*)	(48,712)	(7,755)	(8,668)
	368,139	313,787	224,758
Expenses			
Lease operating	103,610	91,251	74,774
Transportation costs (*Note 3(c)*)	5,862	5,482	4,516
Management fee (*Note 5(a)*)	-	-	4,728
Financing costs	5,849	8,748	8,291
General and administrative (*Notes 5 and 9*)	14,441	13,047	15,514
Capital taxes	3,261	2,454	2,137
Depletion, depreciation and accretion	153,079	118,307	103,251
Internalization of management contract (*Note 9*)	-	30,850	-
	286,102	270,139	213,211
Income before provision for income taxes	82,037	43,648	11,547
Provision for (recovery of) income taxes (*Note 16*)			
Current	539	569	38
Future	7,139	(44,197)	(14,009)
	7,678	**(43,628)**	**(13,971)**
Net income	74,359	87,276	25,518
Accumulated earnings, beginning of year	199,200	113,396	89,017
Retroactive application of change in accounting policy *(Note 3(a))*	(947)	(2,419)	(3,558)
Accumulated earnings, beginning of year as restated	198,253	110,977	85,459
Accumulated earnings, end of year	$ 272,612	$ 198,253	$ 110,977
Net income per Trust unit (*Note 8*)			
Basic	$ 0.84	$ 1.43	$ 0.51
Diluted	$ 0.84	$ 1.43	$ 0.51

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,	**2004**	**2003**	**2002**
		(Restated *Note 3*)	(Restated *Note 3*)
Cash provided by (used in) operating activities			
Net income	$ 74,359	$ 87,276	$ 25,518
Add items not affecting cash:			
Depletion, depreciation and accretion	153,079	118,307	103,251
Commodity contracts	6,221	-	-
Future income taxes	7,139	(44,197)	(14,009)
Actual abandonment costs incurred (*Note 13*)	(4,553)	(4,651)	(2,190)
Internalization of management contract (*Note 9*)	-	30,850	-
	236,245	187,585	112,570
Net change in non-cash operating working capital balances	33,525	6,410	(30,938)
Cash provided by operating activities	269,770	193,995	81,632
Financing activities			
Bank loan	(5,700)	(102,546)	83,470
Distributions paid (*Note 12*)	(169,493)	(127,325)	(85,218)
Redemption of exchangeable shares *(Note 10)*	(1,803)	(2,792)	-
Capital lease repayments	(356)	(9,305)	(11,366)
Issuance of Trust units (*Note 8)*	4,479	214,002	55,821
Advances to affiliates (*Note 5*)	-	-	948
Cash provided by (used in) financing activities	(172,873)	(27,966)	43,655
Investing activities			
Asset retirement reserve (*Note 13*)	(1,725)	(776)	(706)
Acquisition of property interests	(108,841)	(186,956)	(158,516)
Proceeds on disposition of properties	1,043	33,466	30,019
Cash acquired on acquisition (*Note 4*)	9,711	-	427
Internalization of management contract (*Note 9*)	-	(8,009)	-
Cash used in investing activities	(99,812)	(162,275)	(128,776)
Net change in cash	(2,915)	3,754	(3,489)
Cash (bank overdraft), beginning of year	2,182	(1,572)	1,917
Cash (bank overdraft), end of year	$ (733)	$ 2,182	$ (1,572)
Interest paid during the year	$ 5,393	$ 8,885	$ 8,016
Income taxes paid during the year	$ 409	$ 842	$ 1,281

The accompanying notes to Consolidated Financial Statements are an integral part of these consolidated statements.

Notes to Consolidated Financial Statements

December 31, 2004, 2003 and 2002

(thousands of dollars, except per unit amounts)

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). The name of the Trust was changed to Petrofund Energy Trust effective November 1, 2003, from NCE Petrofund. On the same date the name of NCE Petrofund Corp. was changed to Petrofund Corp. Active operations commenced March 3, 1989. The beneficiaries of the Trust are the holders of the Trust units (Unitholders).

The Trust s primary source of income is the 99% net royalties granted to the Trust by PC and by Petrofund Ventures Trust, (PVT), formerly Ultima Ventures Trust. The royalty is equal to production revenue from the properties owned by the subsidiaries less operating costs, general and administrative costs, debt service charges (including principal and interest) and taxes payable.

PC acquires, manages and disposes of petroleum and natural gas properties for its own account and holds the legal interest to all properties owned beneficially by PVT, and grants the royalties to the Trust. The royalties granted to the Trust effectively transfer substantially all of the economic interest in the oil and gas properties to the Trust.

2. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

The Consolidated Financial Statements have been prepared by the management of PC following Canadian generally accepted accounting principles (GAAP). The impact of significant differences between Canadian GAAP and U.S. GAAP in these Consolidated Financial Statements is disclosed in Note 19. 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, Petrofund Corp., Petrofund Ventures Trust, 1518274 Ontario Ltd., NCE Management Services Inc. (NMSI), which previously 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)

Revenue recognition

Revenue from the sale of oil and natural gas is recognized at time of sale when title to the products transfers to the purchasers based on volumes delivered and contractual delivery points and prices.

(c)

Goodwill

Goodwill is recognized on a corporate acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired company. The goodwill balance is not amortized but instead is assessed for impairment at each reporting period. Impairment is determined based on the fair value of reporting entity (the consolidated Trust) compared to the book value of the reporting entity. Any impairment will be charged to the earnings in the period in which the fair value of the reporting entity is below the book value. If the fair value of the consolidated Trust is less than the book value, impairment is measured by allocating the fair value of the consolidated Trust to the identifiable assets and liabilities as if the Trust had been acquired in a business combination for a purchase price equal to its fair value. The excess of the fair value of the consolidated Trust over the amounts assigned to the identifiable assets and liabilities is the fair value of the goodwill. Any excess of the book value of goodwill over this implied fair value of goodwill is the impairment amount. Impairment is charged to earnings in the period in which it occurred.

(d)

Oil and natural 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 natural gas royalty and property interests and equipment are capitalized. General and administrative costs and interest are not capitalized.

The provision for depletion and depreciation is 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.

Prior to 2004 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 was 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, impairment is recognized if the carrying value of the oil and natural gas royalty and property interests exceeds the sum of the undiscounted cash flows expected to result from the Trust s proved reserves based on future prices, adjusted for contract prices and quality differentials. If impairment is indicated, the amount is measured by comparing the carrying value of the oil and natural gas royalty and property interests to the estimated net present value of future cash flows from proved plus probable reserves. The present value of the future cash flow is based on the Trust s risk-free interest rate. Any excess carrying value above the net present value of the Trust s future cash flows would be recorded in depletion, depreciation and accretion expense as a permanent impairment.

The Trust performed its impairment test at December 31, 2004 based on the undiscounted value of future net cash flows associated with its proved reserves using the following bench mark commodity prices:

	Fx	WTI	Edmonton Light	AECO
	$US/$Cdn	$US/Bbl	$Cdn/Bbl	Spot $/mmbtu
2005	$ 0.82	$ 42.00	$ 50.25	$ 6.60
2006	0.82	40.00	47.75	6.35
2007	0.82	38.00	45.50	6.15
2008	0.82	36.00	43.25	6.00
2009	0.82	34.00	40.75	6.00
2010-2015 Average	0.82	33.50	40.08	6.10

(e)

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.

(f)

Future income taxes

The Trust follows the liability method of accounting for income taxes. Under this method future 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 substantially enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period 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.

(g)

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.

(h)

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.

In 2003 the Trust 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 had 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 2004 for the options issued in 2002 was $924,000 (2003 $2.0 million). Net income would have been reduced by these amounts and net income per Trust unit would have decreased by $0.01 in 2004 (2003 - $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.

(i)

Restricted Unit Plan ("RUP") and Long-term Incentive Plan ("LTIP")

On February 17, 2004, the Board of Directors approved the adoption of the RUP and LTIP which authorizes the Trust to issue units to directors, officers, employees, or consultants of the Trust or any of its subsidiaries. The units, plus accrued distributions, vest over time and upon vesting may be redeemed by the holder for cash or units under the RUP and for units only under the LTIP. The units are issued, or the cash paid out, on the vesting dates based upon the weighted average trading prices of the units for the last 20 trading days prior to the vesting dates. The estimated value of the units to be issued, or the cash to be paid out, is charged to expense over the vesting periods of the grants.

The number of units granted but not vested at December 31, 2004 were:

Year of vesting	Number of units
2005	51,776
2006	20,620
2007	3,570
Thereafter	6,616

3. CHANGE IN ACCOUNTING POLICIES

(a) Asset retirement obligations

Effective January 1, 2004, the Trust retroactively adopted the new Canadian accounting standard for accounting for Asset Retirement Obligations ("ARO"). This standard 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 expected 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 in a manner consistent with the depletion and depreciation of the related assets.

Previously, the Trust recognized a provision for future site reclamation and abandonment ("SR&A") costs calculated on the unit-of-production method over the life of the petroleum and natural gas properties based on total estimated proved reserves and an estimated future liability.

The Trust has estimated the net present value of its total ARO to be $51.4 million as at December 31, 2004, (December 31, 2003 - $34.4 million) based on a total future liability of $116.5 million, (December 31, 2003 - $85.5 million). These payments are expected to be made over the next 35 years. The Trust's credit adjusted risk free rate of 6.5 per cent and an inflation rate of 1.5 per cent were used to calculate the present value of the ARO.

Net income before income taxes for the twelve months ended December 31, 2004 increased by $4.5 million ($2.6 million after tax) as a result of adopting this policy, with negligible impact on net income of $0.03 per unit.

The impact of this standard was 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) increased to $34.4 million at December 31, 2003, from $16.8 million and the liability at December 31, 2002, increased to $34.5 million from $15.3 million. The effect on the income statement was to increase (decrease) net income before income taxes by $ 1.5 million in 2003 (2002 - $1.1 million, 2001 - $(0.9) million).

The impact of this change on the balance sheet is as follows:

				Change in Accumulated Earnings			
December 31, 2003, Restatement	**Net PP&E**	**Future Tax**	**ARO Liability**	**Prior 2002**	**2002**	**2003**	**Total**
	$	$	$	$	$	$	$
Balance, beginning of period	879,633	77,005	16,846	- -		-	199,200
Initial fair value of ARO liability	32,771	-	32,771	-	-	-	-
Depletion expense	(14,141)	-	-	(9,698)	(2,279)	(2,164)	(14,141)
Accretion expense	-	-	10,230	(5,791)	(2,195)	(2,244)	(10,230)
Previously recorded SR&A provision expense	-	-	(25,484)	13,428	5,856	6,200	25,484
Future income tax adjustment_	-	2,060	-	(1,497)	(243)	(320)	(2,060)
Change in accounting policies	18,630	2,060	17,517	(3,558)	1,139	1,472	(947)
	$	$	$	$	$	$	$
Balance, beginning of period as Restated	898,263	79,065	34,363	(3,558)	1,139	1,472	198,253

The effect on basic and diluted earning per Trust unit for 2003 and 2002 is $0.02.

(b) Financial instruments

In December 2001, the Canadian Institute of Chartered Accountants ("CICA") issued Accounting Guideline 13, "Hedging Relationships" ("AcG-13"), effective for 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. Petrofund adopted 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.

All outstanding derivative instruments as of January 1, 2004 have been recorded as assets or liabilities, as appropriate, at fair value. The net negative fair value of the contracts at January 1, 2004, of $6.8 million plus costs incurred on the acquisition of the derivative instruments in the amount of $0.8 million are being amortized to expense over the remaining term of the contracts. The total amount of $7.6 million less $7.3 million amortized to expense in the twelve months ended December 31, 2004, or $0.3 million, has been recorded as a current asset or liability, as appropriate, on the balance sheet as deferred loss/gain on the commodity contracts at December 31, 2004.

The negative fair value of the commodity contracts at December 31, 2004, of $11.3 million has been recorded on the balance sheet as "commodity contracts" under assets or liabilities, as appropriate. The positive change in the fair value of the contracts from January 1, 2004, to December 31, 2004, of $1.0 million plus the amortized amount of $8.6 million is recorded in the income statement on a separate line as loss on commodity contracts". The line item also includes realized losses on commodity contracts of $42.5 million which in previous years were deducted from oil and natural gas sales. The comparative numbers for 2003 and 2002 represent realized losses on commodity contracts which were previously netted against oil and natural gas sales.

Deferred Commodity Contracts	**Jan 1, 2004**	**Amortized to Expense**	**Dec 31, 2004**
Current Asset			
Deferred loss	$ 8,075	$ (7,558)	$ 517
Cost of deferred commodity contracts	820	(820)	-
	8,895	(8,378)	517
Current Liability			
Deferred gain	(1,304)	1,120	(184)
	$ 7,591	$ (7,258)	$ 333

Commodity Contracts	**Jan 1, 2004**	**Ultima Acquisition**	**Change in Fair Value**	**Dec 31, 2004**
Current Asset				
Commodity contracts	$ 1,304	$ -	$ 1,977	$ 3,281
Current Liability				
Commodity contracts	(8,075)	(5,584)	(940)	(14,599)
	$ (6,771)	$ (5,584)	$ 1,037	$ (11,318)

(c)

Transportation Costs

CICA Handbook Section 1100, "Generally Accepted Accounting Principles", is effective for fiscal years beginning on or after October 1, 2003. This standard focuses on what constitutes Canadian generally accepted accounting principles and its sources, including the primary sources of generally accepted accounting principles. In prior years, it had been industry practice to record oil and natural gas sales net of related transportation costs. In accordance with the new accounting standard, oil and natural gas sales are now reported before transportation costs with separate disclosure in the consolidated statement of operations of transportation costs. Petroleum and natural gas sales and transportation costs both increased by $5.9 million in 2004 by $5.5 million in 2003 and by $4.5 million in 2002. This change in classification has no impact on net income and the comparative figures have been reclassified to conform to the presentation adopted for the current period.

4. ACQUISITIONS

(a) Ultima Energy Trust (Ultima)

On June 16, 2004, Petrofund acquired 100% of the issued and outstanding units of Ultima Energy Trust for 0.442 of a Petrofund unit on a tax-free rollover basis. The value assigned to each Petrofund unit was $17.12 based on the weighted average trading price of the Trust units for the period commencing five days before and ending five days after the acquisition was announced. Petrofund issued 26.4 million Trust units valued at $452.8 million which were distributed to former unitholders of Ultima and incurred $1.9 million in transaction costs. Of the total acquisition cost of $563.1 million, $385.0 million was allocated to oil and gas royalty and property interests and $178.1 million to goodwill, which is not deductible for tax purposes.

A summary of the net assets acquired is as follows:

		$000's
Current assets	$	22,244
Asset retirement reserve		1,549
Goodwill		178,110
Oil and gas royalty and property interests		384,987
Current liabilities		(17,791)
Long-term debt		(110,407)
Asset retirement obligations		(16,672)
Future income taxes		12,725
	$	454,745

If the acquisition had occurred on January 1, 2003 the following pro forma results would have been realized by the Trust in 2004 and 2003:

(000s except per unit amounts)		2004 (unaudited)		2003
Revenue	$	588,137	$	524,960
Net income	$	80,622	$	65,266
Net income per Trust unit	$	0.80	$	0.75

(b)

Central Alberta PNG Partnership and 102437 Alberta Ltd.

On November 10, 2004, Petrofund acquired 100% of the outstanding shares of Central Alberta PNG Partnership and 1024373 Alberta Ltd., for $27.7 million in cash.

A summary of the net assets acquired is as follows:

	$ 000's
Goodwill	$2,197
Oil and gas properties	34,404
Asset retirement obligations	(944)
Future income taxes	(7,932)
	$27,725

If the acquisition had occurred on January 1, 2003 the following pro forma results would have been realized by the Trust in 2004 and 2003:

(000's except per unit amounts)	**2004**	**2003**
	(unaudited)	
Revenue	$ 521,265	$ 412,961
Net income	$ 74,870	$ 88,584
Net income per Trust unit	$ 0.85	$ 1.45

(c)

Solaris Oil & Gas Inc.

On February 7, 2003, Petrofund 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 an outstanding bank loan.

A summary of the net assets acquired is a follows:

		$000's
Working capital	$	(813)

Oil and gas properties		13,219
Bank loan		(370)
Future income taxes		(4,676)
	$	7,360

(d)

NCE Energy Trust

On May 30, 2002, Petrofund acquired NCE Energy Trust (Energy) for 0.2325 of a Trust unit for each Energy 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.

A summary of the net assets acquired is as follows:

		$000s
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 Energy to pay down the bank debt of Energy.

5. RELATED PARTY TRANSACTIONS

(a) Management, advisory and administration agreement (prior to 2003)

PC, NCEP Management, the Previous Manager, and the Trust 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. NCEP Management was beneficially owned by John Driscoll, a director of PC. During 2002, the Previous Manager was paid a management fee equal to 3.25% of net operating income plus the Alberta Royalty Credit. In addition, the Previous Manager received an investment fee of 1.5% of the purchase cost of all properties purchased by PC other than replacement properties, and a disposition fee equal to 1.25% of the sale price of properties sold. During 2002, the Previous Manager received a management fee from PC of $4.7 million. In addition, the Previous Manager received investment fees of $1.3 million, which were capitalized as part of the acquisitions, and disposition fees of $116,000, which reduced the proceeds of disposition. Due to the internalization of management, no fees were paid after 2002 (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 exceeded 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 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 was the sole beneficial shareholder of NMSI. During 2002, PC paid NMSI $11.7 million for accounting and administrative services, which is included in general and administrative expenses and $838,000 for project sourcing and evaluation services, which have been capitalized to oil and gas properties. In addition, PC reimbursed NMSI $300,000 for marketing and other related equity issue costs. The amounts for general and administrative expenses paid to NMSI were subject to the same limitations noted for the Previous Manager in (a) above.

6. LONG-TERM DEBT

Under the loan agreements, PC has a revolving working capital operating facility of $25 million and a syndicated facility of $300 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. The prime interest rate at December 31, 2004 was 4.25% as at December 31, 2004, there was no amount outstanding under the working capital facility and $214.4 million outstanding under the syndicated facility.

The revolving period on the syndicated facility ends on June 29, 2005, 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 $500 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.

7. CAPITAL LEASE OBLIGATIONS

Capital lease obligations relate to equipment leases on three booster compressors and a gas sales line. The future minimum lease payments under the capital leases are as follows:

		$000s
2005	$	621
Total minimum lease payments		621
Less imputed interest at rates ranging from 7.37% to 8.425%		(13)
Obligation under capital leases - current	$	608

8. TRUST UNITS

Authorized: unlimited number of Trust units	**Number of Units**		**$000s**
Issued			
December 31, 2002	54,108,420	$	794,352
Issued for cash	15,800,000		204,440
Issued for internalization of management contact (*Note 9*)	100,244		1,123
Exchangeable shares converted (*Note 10*)	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
Issued for the Ultima acquisition (*Note 4(a)*)	26,449,102		452,807
Options exercised	332,733		3,771
Unit Purchase Plan	4,365		70
Unit Incentive Plan	36,799		638
December 31, 2004	99,511,576	$	1,477,963

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 or previously issued units of the Trust that are purchased in the open market and, secondly, to purchase for cash newly issued units directly from the Trust.

For the years ended December 31,	**2004**	**2003**	**2002**
Distributions reinvested to acquire previously issued units (000s)	$2,934	$4,095	$3,387
Price per unit	$16.24	$13.20	$12.15
Number of units acquired	180,617	310,276	278,797
Distributions reinvested to acquire newly issued units	$70	$89	$126
Price per unit	$15.96	$13.65	$12.36
Number of units acquired	4,365	6,509	10,184

The weighted average Trust units/exchangeable shares outstanding are as follows:

For the twelve months ended December 31,	**2004**	**2003**	**2002**
Basic	88,169,339	61,010,105	49,921,523
Diluted	88,292,020	61,153,027	49,967,648

The diluted numbers include all dilutive instruments.

Trust units/exchangeable shares outstanding:

As at December 31,	**2004**	**2003**	**2002**
Trust units outstanding	99,511,576	72,688,577	54,108,420
Trust units issuable for exchangeable shares (*Note 10*)	939,147	939,147	-
	100,450,723	73,627,724	54,108,420

9.

INTERNALIZATION OF MANAGEMENT CONTRACT

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 $		**000s**
Issuance of 1,939,147 exchangeable shares to the shareholder of the Previous Manager	$	21,718
Cash payment for the repayment of indebtedness owing by the Previous Manager		3,400
Issuance of 100,244 units to executive management		1,123
Cash payment to executive management		780
Cash payment for distributions on exchangeable shares and Trust units from		

January 1 to April 30, 2003,		1,326
Transaction costs		2,503
Total Purchase Price	$	30,850

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 January 1, 2004, Sentry no longer provides any services to Petrofund or 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.

10. EXCHANGEABLE SHARES

The number of Exchangeable Shares to be issued in connection with the internalization of the management contract (Note 9) 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 cannot transfer or sell the Exchangeable Shares, but 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 2004 94,823 (2003 - 181,041) Exchangeable Shares were redeemed for $1.8 million (2003 - $2.8 million) in cash.

On December 17, 2003, 906,635 Exchangeable Shares were converted to 1,000,000 Trust units at an exchange rate of 1.10298. At December 31, 2004, 756,648 Exchangeable Shares were outstanding, at an exchange ratio of 1.24119 per Trust Unit. (2003 851,471 Exchangeable Shares at an exchange ratio of 1.20297 per Trust unit).

Issued and Outstanding	**Number of Shares**		**$000s**
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
Redemption of shares	(94,823)		-
Balance, December 31, 2004	756,648		10,518
Exchangeable ratio, end of year	1.24119		-
Exchangeable for Trust units	939,147	$	10,518

11. UNIT INCENTIVE PLAN

A summary of the status of the Unit Incentive Plan as of December 31, 2004, 2003 and 2002 and changes during the years then ended is presented below. No options have been issued under the plan since 2002 as the plan has been replaced by the restricted unit plan and the long-term incentive plan. The Trust units reserved for issuance under the unit incentive plan have been reduced to the number of options outstanding.

For the years ended December 31,		**2004**		**2003**		**2002**
	Units	Weighted Average Exercise Price	Units	Weighted Average Exercise Price	Units	Weighted Average Exercise Price
Options outstanding, beginning of year	799,122	$ 12.93	3,028,280	$ 13.21	1,840,190	$ 15.92
Issued	-	-	-	-	1,468,100	10.65
Forfeited	(16,933)	14.42	(555,754)	16.82	(272,044)	16.66
Exercised	(332,733)	11.13	(1,673,404)	12.88	(7,966)	10.65
Options outstanding before reduction of exercise price	449,456	16.97	799,122	14.74	3,028,280	13.31
Reduction of exercise price	-	(3.12)	-	(1.81)	-	(0.10)
Options outstanding, end of year	449,456	$ 13.85	799,122	$ 12.93	3,028,280	$ 13.21
Options exercisable, end of year	449,456	$ 13.85	440,656	$ 15.36	1,593,681	$ 14.10

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 natural 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, 2004:

Number of Units	**Exercise Price**	**Reduced Exercise Price**	**Expiry Date**
4,689	$ 15.00	N/A	May 8, 2005
258,000	$ 19.35	$ 15.53	January 30, 2006
81,901	$ 17.25	$ 14.08	April 4, 2006
8,400	$ 14.71	$ 12.61	July 20, 2006
96,466	$ 10.65	$ 9.23	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 and income and debt repayments from PC. An overall analysis is as follows:

For the period ended	**Cash Distribution Date**	**2004**	**2003**	**2002**
November 30	January 31	$ 0.16	$ 0.15	$ 0.15
December 31	February 28	0.16	0.16	0.15

January 31	March 31	0.16	0.17	0.13
February 28	April 30	0.16	0.17	0.13
March 31	May 31	0.16	0.18	0.14
April 30	June 30	0.16	0.18	0.14

May 31	July 31	0.16	0.18	0.14
June 30	August 31	0.16	0.18	0.14
July 31	September 30	0.16	0.18	0.14
August 31	October 31	0.16	0.18	0.15
September 30	November 30	0.16	0.18	0.15
October 31	December 31	0.16	0.18	0.15
Cash Distributions per Trust unit		$ 1.92	$ 2.09	$ 1.71

Reconciliation of Distributions Accruing to Unitholders

(thousands of dollars)

For the years ended December 31,	**2004**	**2003**	**2002**
Distributions payable, beginning of year	$ 53,452	$ 30,065	$ 12,188
Distributions accruing during the year			
Cash flow provided by operating activities	269,770	193,995	81,632
Net change in non-cash operating working capital balance	(33,525)	(6,410)	30,938
Amortization of the cost of commodity contracts	(821)	-	-
Redemption of exchangeable shares	(1,803)	(2,792)	-
Proceeds on disposition of property interests	-	-	946
Asset retirement reserve	(1,725)	(776)	(706)
Less capital lease repayment (2)	(356)	(3,305)	(5,366)
Cash flow before capital reinvestment	231,540	180,712	107,444
Weyburn capital lease obligations (4)	(34,931)	-	-
Capital expenditures	(45,000)	(30,000)	(10,000)
Total distributions accruing during the year	151,609	150,712	97,444
NCE Energy Trust cash flow (1)	-	-	5,651
Total distributable income for the year	151,609	150,712	103,095
Distributions paid	(169,493)	(127,325)	(85,218)
Distributions payable, end of year (3)	$ 35,568	$ 53,452	$ 30,065

(1) Remaining undistributed cash flow of NCE Energy Trust on May 30, 2002, (see Note 4(d)).

(2) Net of $6 million refinanced by the increase in the bank loan in 2003 and 2002 respectively.

(3) It is expected that a portion of this amount will be used to fund capital expenditures.

(4) This amount was included in long-term debt assumed on the Ultima acquisition.

Accumulated Cash Distributions

	2004	**2003**	**2002**
Accumulated cash distributions, beginning of year	$ 581,155	$ 427,651	$ 330,207
Distributions accruing during the year	151,609	150,712	97,444
Redemption of exchangeable shares	1,803	2,792	-
Accumulated cash distributions, end of year	$ 734,567	$ 581,155	$ 427,651

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13. ASSET RETIREMENT OBLIGATIONS AND RESERVE FUND

(a)

Asset Retirement Obligations

The total future asset retirement obligation was estimated by management based on the Trust's net ownership interest in wells and facilities and the estimated timing of the costs to be incurred in future periods. The following reconciles the Trust's outstanding ARO for the periods indicated:

For the period ended December 31,	**2004**	**2003**	**2002**
Balance at beginning of year	$ 16,846	$ 15,298	$ 11,632
Initial fair value of ARO liability	32,771	30,497	29,777
Accretion expense	10,230	7,986	5,790
Previous recorded SR&A provision	(25,484)	(19,284)	(13,427)
Balance as at January 1, 2004, 2003 and 2002			
as restated	34,363	34,497	33,772
Increase in liabilities during the year	1,222	2,273	720
Accretion expense during the year	2,760	2,244	2,195
Actual costs incurred during the year	(4,553)	(4,651)	(2,190)
Ultima and Central Alberta acquisitions (Note 4)	17,616	-	-
Balance at end of year	$ 51,408	$ 34,363	$ 34,497

(b)

Asset Retirement Reserve Fund

PC maintains a cash reserve to finance large and unusual oil and natural gas property reclamation and abandonment costs by withholding distributions accruing to Unitholders. At December 31, 2004, the cash reserve was $7.1 million (2003 - $3.8 million). In 2004 PC increased the cash reserve by withholding $1.7 million (2003 - $776,000, 2002 - $706,000) from distributions accruing to Unitholders. Ultima s ARO reserve of $1.5 million (Note 4) was also added to the fund on the consolidation of the entity into Petrofund in June 2004. In addition, routine ongoing reclamation and abandonment costs of $4.6 million in 2004 (2003 - $4.7 million, 2002 - $2.2 million) were incurred and deducted from distributions accruing to Unitholders.

Previously this cash fund was being built up at a rate of $0.075/boe produced. Effective January 1, 2004, this was increased to $0.15/boe produced.

14. FINANCIAL INSTRUMENTS

The Trust is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. A variety of instruments are used by the Trust to reduce its exposure to fluctuations in the commodity prices. The Trust is exposed to losses in event of default by the counterparties of these derivative instruments. The Trust manages this risk by diversifying its derivative portfolio with a number of financially sound counterparties.

The Trust s financial instruments consist of cash, accounts receivable and payable, bank overdraft, long-term debt, capital lease obligation, distributions payable to unitholders and commodity contracts. As at December 31, 2004, the carrying value of the cash, bank overdraft, accounts receivable and payable and distribution payments to unitholders approximated their fair value due to their short-term nature. The

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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 at December 31, 2004, had a negative fair value of $11.3 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.

Substantially all of the Trust s accounts receivable are due from customers in the oil and gas industry and are subject to normal industry credit risk. The carrying value of accounts receivable reflects management s assessment of their realizable value. The Trust is also exposed to fluctuations in interest rates as the rate on its borrowings fluctuate with changes in the prime interest rate.

15.

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 economic hedges, and the related unrealized gains or losses at December 31, 2004, are summarized separately below:

Natural Gas	**Term**	**Volume mcf/d**	**Price $/mcf**	**Delivery Point**	**Unrealized Gain $000 s**
Three way collar	November 1, 2004 to March 31, 2005	9,475	$4.74-$5.80-$8.97	AECO	$ 97
Collar	November 1, 2004 to March 31, 2005	9,475	$6.23-$10.82	AECO	261
Collar	November 1, 2004 to March 31, 2005	9,475	$6.23-$14.67	AECO	297
Collar	April 1, 2005 to October 31, 2005	4,737	$6.33-$8.44	AECO	471
Collar	April 1, 2005 to October 31, 2005	4,737	$6.33-$9.60	AECO	604
Collar	April 1, 2005 to October 31, 2005	4,737	$6.33-$8.44	AECO	471
Collar	April 1, 2005 to October 31, 2005	4,737	$6.33-$8.44	AECO	471
Total					$ 2,672

Oil	Term	Volume bbl/d	Price $/bbl	Delivery Point	Unrealized Gain (Loss) $000 s
Three way collar	January 1, 2005 to December 31, 2005	1,000	$24.04-$28.85-$34.86	Edmonton	$ (6,021)
Three way collar	January 1, 2005 to December 31, 2005	1,000	$28.85-$32.23-$40.64	Edmonton	(4,139)
Three way collar	January 1, 2005 to December 31, 2005	1,000	$27.65-$32.21-$39.44	Edmonton	(4,425)
Floor	January 1, 2005 to March 31, 2005	1,000	$46.88	Edmonton	78
Three way collar	April 1, 2005 to June 30, 2005	1,000	$42.07-$48.08-$60.10	Edmonton	(14)
Floor	January 1, 2005 to March 31, 2005	1,000	$54.09	Edmonton	337
Three way collar	July 1, 2005 to December 31, 2005	1,000	$42.07-$48.08-$67.31	Edmonton	128
Total					$ (14,056)

Three-way Collars

A three-way collar is transacted by selling a call to create a cap, buying a put to create a floor, and then selling a put below the floor. For example, a three-way collar of $35 - $40 - $50 would result in the following prices received. For market prices between the cap and floor ($40-$50), Petrofund receives the market price. For market prices between the two puts ($35-$40), Petrofund receives market price plus the difference between the puts of $5.

All the oil hedges are at U.S. WTI prices and have been converted to Canadian dollars at the year-end exchange rate of $1.202 C$:US$.

Electricity	Term	Volume MW/h	Price $/MWh	Delivery Point	Unrealized Gain $000 s
Fixed Price	January 1, 2004 to December 31, 2005	2.0	$44.50	Alberta Power Pool	$ 66

The gains or losses are recognized on a monthly basis over the terms of the contracts.

16. INCOME TAXES

The future income tax liability (asset) includes the following temporary differences:

As at December 31,		**2004**		**2003**		**2002**
Oil and gas properties	$	78,411	$	79,065	$	121,566
Resource allowance		-		-		(2,980)
	$	78,411	$	79,065	$	118,586

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,	**2004**	**2003**	**2002**
Income before income tax provision	$ 82,037	$ 43,648	$ 11,547
Income tax provision computed at statutory rates	$ 31,886	$ 17,782	$ 4,877
Effect on income tax of:			
Income attributed to the Trust	(23,031)	(41,468)	(24,435)
Internalization of management contract	-	12,568	-
Non-deductible crown charges, net of Alberta Royalty Credit	20,031	24,190	17,055
Resource allowance	(19,138)	(20,730)	(15,045)
Capital taxes	1,267	1,000	831
Income tax rate reductions on opening balances	-	(36,688)	-
Effect of change in corporate tax rate	(898)	-	-
Attributed royalty income deductible for provincial taxes	(2,274)	-	-
Temporary differences in resource allowance	-	-	(19)
Other	(165)	(282)	2,765
Provision for (recovery of) income taxes	$ 7,678	$ (43,628)	$ (13,971)

The petroleum and natural gas properties and facilities owned by the Subsidiaries have a tax basis of $213.7 million (2003 - $232.7 million; 2002- $212 million) available for future use as deductions from taxable income. Included in this tax basis are non-capital loss carry forwards of $18.3 million (2003 - $43.6 million; 2002 - $34.0 million), which expire in various years through 2010.

17. COMMITMENTS

In the normal course of operations, the Trust provides indemnifications that are often standard contractual terms to counterparties in transactions such as purchase and sale contracts, service agreements, director/officer contracts and leasing transactions. These indemnification agreements may require Petrofund to compensate the counterparties for costs incurred as a result of various events, including environmental liabilities, changes in (or in the interpretation of) laws and regulations, or as a result of litigation claims or statutory sanctions that may be suffered by the counterparty as a consequence of the transaction. The terms of these indemnification agreements will vary based upon the contract, the nature of which prevents the Trust from making a reasonable estimate of the maximum potential amount that could be required to pay to counterparties. Historically, the Trust has not made any significant payments under such indemnifications and no amounts have been accrued in the accompanying Consolidated Financial Statements with respect to these indemnification guarantees.

The following is a summary of the Trust's contractual obligations due in the next five years and thereafter:

		Payment due by Period			
Contractual Obligations	**Total**	**less than one year**	**1 3 years**	**4 5 years**	**after 5 years**
(millions of dollars)					
Capital lease obligations	$ 0.6	$ 0.6	$ -	$ -	$ -
Operating leases (2)	21.2	2.0	4.4	4.8	10.0
Purchase obligations (1)	142.0	16.3	28.2	26.6	70.9
Total	$ 163.8	$ 18.9	$ 32.6	$ 31.4	$ 80.9

(1)

These amounts represent commitments of $113.2 million for CO2 purchases and $28.8 million for processing fees with respect to PC s 21% interest in the Weyburn unit.

(2)

Operating lease expense was $1.3 million in 2004 (2003 $1.4 million, 2002 - $2.1 million)

18. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

For the years ended December 31,		**2004**		**2003**
Capital accrual	$	16,850	$	12,295
Joint venture and trade payables		22,165		14,842
Other		21,946		9,547
Total	$	60,961	$	36,684

19. 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)

Under U.S. GAAP, the carrying value of oil and gas royalty and property interests, net of future income taxes, is limited to the present value of after tax future net revenue from proven reserves excluding future asset retirement costs, discounted at 10% (based on prices and costs at the balance sheet date), plus the lower of cost and fair value of unproven properties. Where the amount of an impairment test write-down under

Canadian GAAP differs from the amount of the write-down under U.S. GAAP, the charge for depletion, depreciation and accretion will differ in subsequent years.

(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)

Prior to the Trust adopting AcG-13 for Canadian GAAP purposes, a difference existed in that U.S. GAAP accounting and reporting standards required 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. In 2004, for Canadian GAAP purposes, Petrofund applied the fair value method of accounting for all derivative transactions.

U.S. GAAP hedge accounting treatment allows unrealized gains and losses on cash flow hedges 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. For 2003 and 2004 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, 2004, 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. No options have been granted since 2002. Effective January 1, 2003, the Trust accounts for compensation expense for options awarded on or after January 1, 2003, based on the fair value method of accounting as described in Note 2.

For U.S. GAAP purposes, the Unit Incentive Plan has been accounted for as 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.

(e)

On January 1, 2003 Petrofund adopted the U.S. reporting requirements for ARO through a cumulative effect adjustment in the Consolidated Statement of Operations. Petrofund adopted the equivalent Canadian standard for ARO on January 1, 2004 as described in Note 3. These standards are consistent except for the method of implementation and the adoption date.

(f)

The Trust presents oil and natural gas sales and royalty amounts gross in the Consolidated Statement of Operations. These line items would be combined and presented net in a statement of operations prepared in accordance with U.S. GAAP. This difference does not result in an adjustment to the financial results as reported under Canadian GAAP.

(g)

An income statement prepared in accordance with U.S. GAAP segregates operating and non-operating expenses in the statement of operations. Management fees, financing costs and internalization of the management contract would be presented in the non-operating section of the statement of operations. This difference does not result in an adjustment to the financial results as reported under Canadian GAAP.

(h)

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. In 2004, the Trust adopted AcG-14 Disclosure of Guarantees for Canadian GAAP. There are no guarantees outstanding at December 31, 2004 or 2003, other than as disclosed in note 17.

(i)

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 Canadian GAAP.

Under U.S. GAAP, the Trust s bank overdraft would be presented as a financing activity rather than as a component of cash. Therefore, cash provided by (used in) financing activities under U.S. GAAP would be $(172,140) in 2004 (2003 ($29,538), 2002 $45,227).

The net change in non-cash operating working capital balances is comprised of the following:

(000 s)	**2004**	**2003**	**2002**
Accounts receivable	$ (977)	$ (6,317)	$ (24,727)
Due from affiliates	-	164	-
Prepaids and deposits	(1,812)	54	(5,506)
Accounts payable and accrued liabilities	36,314	14,677	(705)
Payable to affiliates	-	(2,168)	-
	$ 33,525	$ 6,410	$ (30,938)

(j)

In 2004, the FASB issued new and revised standards, all of which were assessed by Management to be not applicable to the Trust with the exception that in December 2004, the FASB issued SFAS No. 123R, Share Based Payments , which addresses the issue of measuring compensation cost associated with Share Based Payment plans. This statement requires that all such plans be measured at fair value using an option pricing model whereas previously certain plans could be measured using either a fair value method or an intrinsic value method. The revision is intended to increase the consistency and comparability of financial results by only allowing one method of application. This revised standard is effective for the first interim or annual period beginning on or after June 15, 2005. Management will assess the impact of this revised standard in 2005.

(k)

Under U.S. 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.

(l)

Under U.S. GAAP, redeemable equity instruments which are not mandatorily redeemable at a specific or determinable date must be presented as temporary equity and carried on the balance sheet at redemption value. Changes in redemption value between periods are charged or credited to retained earnings. Prior to 2004, the Trust accounted for its trust units as a component of permanent unitholders equity. This accounting was based on the assumption that the redemption feature embedded in the trust units was sufficiently restrictive to avoid classification as temporary equity under U.S. GAAP. The Trust has concluded that the restrictions on redemption are not substantive and the trust units must be presented as temporary equity and carried on the balance sheet at their redemption value. Consequently, the Trust has revised the 2003 and 2002 amounts presented under U.S. GAAP. Unitholders equity in 2003 and 2002 has decreased by $1,383,465 and $587,076 respectively, (including a decrease in retained earnings of $349,067 and an increase of $207,335 respectively) and temporary equity has increased by $1,383,465 and $587,076 respectively for the effect of this restatement.

The application of U.S. GAAP would have the following effects on net income as reported:

For the years ended December 31, ($000s)	**2004**	**2003**	**2002**
Net income as reported in consolidated		(Restated)	(Restated)
statement of operations	$ 74,359	$ 87,276	$ 25,518
Adjustments:			
Realized/ (unrealized) loss on derivatives	6,774	(6,774)	(563)
Compensation expense	1,991	(3,144)	(59)
Depletion and depreciation	14,584	23,263	23,170
Future income taxes	(7,518)	(3,505)	(7,985)
Net income, as adjusted, before cumulative effect of a change in accounting principle	90,190	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	90,190	94,697	40,081
Realized gain (loss) on derivatives, net of income tax expense (recovery) of $Nil (2003 - $330, 2002 $(1,113))	-	451	(1,483)
Comprehensive income	$ 90,190	$ 95,148	$ 38,598
Net income per unit, as adjusted before cumulative effect			
Basic	$ 1.02	$ 1.59	$ 0.80
Diluted	$ 1.02	$ 1.59	$ 0.80
Net income per unit, as adjusted after cumulative effect			
Basic	$ 1.02	$ 1.55	$ 0.77
Diluted	$ 1.02	$ 1.55	$ 0.77

Accumulated other comprehensive income:

For the years ended December 31, ($000s)	**2004**	**2003**	**2002**
Opening balance at January 1	$ -	$ (451)	$ 1,032
Unrealized gain (loss) on derivatives, net of income tax expense (recovery) of $Nil (2003 - $330, 2002 $(1,113))	-	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 ($000s)	As reported	Decrease	US GAAP
December 31, 2004			
Oil and gas royalty and property interests, net	$ 1,246,694	$ (161,218)	$ 1,085,476
Future income taxes	81,411	(46,992)	34,419
Temporary equity	-	1,568,036	1,568,036
Unitholders' equity	1,026,526	(1,682,262)	(655,736)
December 31, 2003 (as restated)			
Oil and gas derivative instruments	$ -	$ (6,774)	$ (6,774)
Oil and gas royalty and property interests, net	898,263	(175,802)	722,461
Future income taxes	79,065	(54,510)	24,555
Temporary equity	-	1,383,465	1,383,465
Unitholders' equity	648,293	(1,511,531)	(863,238)

The following presents the consolidated statement of unitholders equity and temporary equity for the three years ended December 31, 2004 under U.S. GAAP.

(000 s)	Accumulated Distributions	Retained Earnings	Accumulated Other Comprehensive Income	Total Unitholders' Equity	Temporary Equity
December 31, 2001	$ (330,207)	$ 70,359	$ 1,032	$ (258,816)	$ 501,739
Units issued		-	-	-	158,439
Commissions & issue costs		-	-	-	(4,190)
Options exercised		-	-	-	85
Unit purchase plan		-	-	-	126
Net income		40,081	-	40,081	-
Other comprehensive income on derivatives	-	-	(1,483)	(1,483)	-
Stock based compensation expense	-	-	-	-	59
Distribution accruing to unitholders	(97,444)	-	-	(97,444)	-
Change in redemption value		69,182	-	69,182	(69,182)
December 31, 2002	(427,651)	179,622	(451)	(248,480)	587,076
Units issued	-	-	-	-	205,563
Exchangeable shares issued	-	-	-	-	21,718
Redemption of exchangeable shares	(2,792)	-	-	(2,792)	-
Commission & issue costs	-	-	-	-	(11,001)
Options exercised	-	-	-	-	20,474
Unit purchase plan	-	-	-	-	89
Net income		94,697	-	94,697	-
	-	-	451	451	-

Other comprehensive income on derivatives

Stock based compensation expense	-	-	-	-	3,144
Distribution accruing to unitholders	(150,712)	-	-	(150,712)	-
Change in redemption value	-	(556,402)	-	(556,402)	556,402
December 31, 2003	(581,155)	(282,083)	-	(863,238)	1,383,465
Units issued	-	-	-	-	452,807
Redemption of exchangeable shares	(1,803)		-	(1,803)	-
Options exercised	-	-	-	-	3,771
Unit purchase plan	-	-	-	-	70
Unit incentive plan	-	-	-	-	638
Net income	-	90,190	-	90,190	-
Stock based compensation expense	-	-	-	-	(1,991)
Distribution accruing to unitholders	(151,609)	-	-	(151,609)	-
Change in redemption value		270,724	-	270,724	(270,724)
December 31, 2004	$ (734,567)	$ 78,831	$ -	$ (655,736)	$ 1,568,036

EXHIBIT 4

Disclosure Controls and Procedures

Petrofund Energy Trust

Form 40-F

CONTROLS AND PROCEDURES

Evaluation of disclosure controls and procedures. Our Chief Executive Officer and Chief Financial Officer have evaluated the effectiveness of our disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15-d-15(e)) as of the end of the period covered by this report. Management recognizes that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives, and in reaching a reasonable level of assurance, management necessarily is required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures. They concluded that, as of the end of the period covered by this report, our disclosure controls and procedures are effective at the reasonable assurance level, in ensuring that material information relating to the Trust and its consolidated subsidiaries would be made known to them by others within those entities, particularly during the period in which this report was being prepared.

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.

EXHIBIT 5

Audit Committee Financial Expert

Petrofund Energy Trust

Form 40-F

Petrofund Corp. s Board of Directors has determined that Mr. James Allard is an audit committee financial expert.

Petrofund Corp. s board of directors has determined that it has at least one audit committee financial expert serving on its audit committee. Mr. James Allard has been determined to be such audit committee financial expert and is independent; as that term is defined by the American Exchange s listing standards applicable to Petrofund Energy Trust. **[The SEC has stated that the designation of a person as an audit committee financial expert, does not impose on such person any duties, obligations or liability that are greater than those imposed on such person as a member of the audit committee and the board of directors in the absence of such designation and does not affect the duties, obligation or liability of any other member of the audit committee or board of directors.]**

James 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 publicly traded and private companies during that period. During the past five years, he has continued to serve on 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.

EXHIBIT 6

Code of Ethics

Petrofund Energy Trust

Form 40-F

Petrofund Energy Trust has adopted a code of ethics that applies to the President and Chief Executive Officer and Senior Vice-President and Chief Financial Officer. There has been no revision or waiver to such code of ethics. This code of ethics has been posted on the Trust s website at www.petrofund.ca.

EXHIBIT 7

Audit Committee Pre-Approval Policies and Procedures and Registrant s

Principal Accountant Fees and Services

Petrofund Energy Trust

Form 40-F

Under the audit "Committee Mandate and Charter", the Audit Committee has the sole authorization to pre-approve all audit and non-audit services. This authority has been delegated to the Chairman of the Audit committee who is independent of management and who reports all pre-approved audit and non-audit services to the other members of the committee on a quarterly basis. This delegation of authority is pursuant to the Trust's Audit Committee Mandate and Charter a resolution of the Trust's Audit Committee, which includes detailed descriptions of the particular services that may be approved, and requires that each Audit Committee member be informed of each service that is approved.

The following sets out the fees billed to the Trust by Deloitte & Touche LLP and its affiliates for professional services rendered in each of the years ended December 31, 2004 and 2003. During these years, Deloitte & Touche LLP was the Trust s only external auditor.

Category	**Year ended December 31,**	
	2004	**2003**
Audit Fees (1)	$ 246,103	$ 254,500
Tax Fees (2)	31,428	77,845
Total	$ 277,531	$ 332,345

(1) Audit fees relate to professional services rendered by Deloitte & Touche LLP for the audit for the Trust s annual financial statements, the review of the Trust s quarterly financial statements and procedures performed in connection with offering documents including the French translation of those documents.

(2) For professional services rendered by Deloitte & Touche LLP in connection with tax compliance and consultation on tax matters. The majority of the fees incurred in 2003 relate to the Internalization of Management which is disclosed in the Consolidated Income Statement and in Note 9 to the Consolidated Financial Statements.

There were no other fees paid to Deloitte & Touche LLP.

EXHIBIT 8

Consent of Gilbert Laustsen Jung Associates Ltd.

Petrofund Energy Trust

Form 40-F

We hereby consent to the use and reference to our name and reports evaluating Petrofund Corp. s oil and gas reserves as at December 31, 2004 and the information derived from our reports, as described or incorporated by reference in Petrofund Energy Trust s Annual Report on Form 40-F for the year ended December 31, 2004 filed with the United States Securities and Exchange Commission pursuant to the Securities Exchange Act of 1934, as amended.

Sincerely,

GILBERT LAUSTSEN JUNG

ASSOCIATES LTD.

(Signed) Wayne Chow

Name: Wayne Chow, P. Eng.

Title: Vice President

March 15, 2005

Calgary, Alberta, Canada

EXHIBIT 9

Consent of Deloitte & Touche LLP

Petrofund Energy Trust

Form 40-F

Consent of Independent Registered Charted Accountants

We consent to the use of our reports dated March 1, 2004, (which audit report expresses an unqualified opinion on the financial statements and includes Comments by Independent Registered Accountants on Canada-United States of America Reporting Differences relating to changes in accounting principles that have a material effect on the comparability of the financial statements, changes in accounting principles that have been implemented in the financial statements and a restatement of the financial statements) relating to the financial statements of Petrofund Energy Trust appearing in the Annual Report on Form 40-F of Petrofund Energy Trust for the year ended December 31, 2004.

(signed) Deloitte & Touche LLP

Independent Registered Chartered Accountants

Calgary, Alberta, Canada

March 15, 2005

EXHIBIT 10

Comments by Independent Registered Chartered Accountants

COMMENTS BY INDEPENDENT REGISTERED CHARTERED ACCOUNTANTS ON CANADA-UNITED STATES OF AMERICA REPORTING DIFFERENCES

The standards of the Public Company Accounting Oversight Board (United States) require the addition of an explanatory paragraph (following the opinion paragraph) when there are changes in accounting principles that have a material effect on the comparability of the financial statements and changes in accounting principles that have been implemented in the financial statements, such as the changes described in Note 3 to the consolidated financial statements of Petrofund Energy Trust.

The standards of the Public Company Accounting Oversight Board (United States) also require the addition of a explanatory paragraph (following the opinion paragraph) when there has been a restatement of the financial statements as described in Note 19 to the consolidated financial statements.

Our report to the unitholders dated March 1, 2005 is expressed in accordance with Canadian reporting standards, which do not require a reference in the auditors report to such changes in accounting principles as described in Note 3 or to such conditions and events as described in Note 19 when the changes, conditions and events are properly accounted for and adequately disclosed in the financial statements.

Calgary, Alberta, Canada

(signed) Deloitte & Touche LLP

March 1, 2005

Independent Registered Chartered Accountant

EXHIBIT 11

Certifications pursuant to

Exchange Act Rules

13a-15(f) and 15d-15(f))

CERTIFICATION

I, Jeffery E. Errico, certify that:

1.

I have reviewed this annual report on Form 40-F of Petrofund Energy Trust;

2.

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3.

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4.

The issuer s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a)

Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b)

Evaluated the effectiveness of the issuer s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c)

Disclosed in this report any change in the issuer s internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer s internal control over financial reporting; and

5.

The issuer s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer s auditors and the audit committee of the issuer s board of directors (or persons performing the equivalent functions):

(a)

All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer s ability to record, process, summarize and report financial information; and

(b)

Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer s internal control over financial reporting.

Date:

March 15, 2005

(signed) Jeffery E. Errico

Name:

Jeffery E. Errico
Title:

President and Chief Executive Officer

CERTIFICATION

I, Vince Moyer, certify that:

1.

I have reviewed this annual report on Form 40-F of Petrofund Energy Trust;

2.

Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3.

Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the issuer as of, and for, the periods presented in this report;

4.

The issuer s other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the issuer and have:

(a)

Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the issuer, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

(b)

Evaluated the effectiveness of the issuer s disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

(c)

Disclosed in this report any change in the issuer s internal control over financial reporting that occurred during the period covered by the annual report that has materially affected, or is reasonably likely to materially affect, the issuer s internal control over financial reporting; and

5.

The issuer s other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the issuer s auditors and the audit committee of the issuer s board of directors (or persons performing the equivalent functions):

(a)

All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the issuer s ability to record, process, summarize and report financial information; and

(b)

Any fraud, whether or not material, that involves management or other employees who have a significant role in the issuer s internal control over financial reporting.

Date:

March 15, 2005

(signed) Vince P. Moyer

Name:

Vince P. Moyer

Title:

Senior Vice-President Finance and Chief Financial Officer

EXHIBIT 12

Certifications pursuant to

Exchange Act Rule

13a-14(b) or Rule 15d-14(b)

CERTIFICATION
PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Petrofund Energy Trust (Petrofund) is filing its annual report on Form 40-F for the fiscal year ended December 31, 2004 (the Report) with the United States Securities and Exchange Commission.

I, Jeffery E. Errico, President and Chief Executive Officer of Petrofund, certify, pursuant to 18 U.S.C. section 1350, as enacted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1.

The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2.

The information contained in the Report fairly presents, in all material respects, the financial condition

and results of operations of Petrofund.

Dated: March 15, 2005

(signed) Jeffery E. Errico

Jeffery E. Errico
President and Chief Executive Officer

CERTIFICATION
PURSUANT TO 18 U.S.C. SECTION 1350, AS ENACTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

Petrofund Energy Trust (Petrofund) is filing its annual report on Form 40-F for the fiscal year ended December 31, 2004 (the Report) with the United States Securities and Exchange Commission.

I, Vince P. Moyer, Senior Vice-President, Finance and Chief Financial Officer of the Company, certify, pursuant to 18 U.S.C. section 1350, as enacted pursuant to section 906 of the Sarbanes-Oxley Act of 2002, that:

1.

The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

2.

The information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of Petrofund.

Dated: March 15, 2005

(signed) Vince P. Moyer
Vince P. Moyer
Senior Vice-President, Finance and
Chief Financial Officer