PETROFUND ENERGY TRUST
Form 6-K
February 17, 2006

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 6-K

REPORT OF FOREIGN ISSUER PURSUANT TO RULE 13A-16 OR 15D-16 OF THE SECURITIES EXCHANGE ACT OF 1934

For the month of: February 2006

Commission File Number: 00-115124

PETROFUND ENERGY TRUST

(Name of Registrant)

Barclay Centre

600 444 7Avenue SW

Calgary, Alberta

Canada T2P 0X8

(Address of Principal Executive Offices)

Indicate by check mark whether the registrant files or will file annual reports under cover of Form 20-F or Form 40-F:

Form 20-F _____

Form 40-F __X__

Indicate by check mark whether the registrant by furnishing 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:

Yes ______

No __**X**__

If Yes is marked, indicate below the file number assigned to the registrant in connection with Rule 12g3-2(b): N/A

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

PETROFUND ENERGY TRUST

Date: February 15, 2006

By:

signed _Hugo S^tJ. A. Potts_

Hugo S^tJ. A. Potts, Esq.

Corporate Secretary

EXHIBIT

Exhibit	Description of Exhibit
1.	**2005 Year-End Report dated February 14, 2006.**

EXHIBIT 1

444 - 7th Avenue S.W.
Suite 600
Calgary, Alberta
T2P 0X8
Telephone: (403) 218-8625
Fax: (403) 269-5858

News Release

CALGARY February 14, 2006

Petrofund Energy Trust (*TSX: PTF.UN; AMEX: PTF*)

Reports Financial and Reserve Results for 2005

Petrofund Energy Trust is pleased to present its year end financial results for 2005 as well as selected information from its independent engineering reserve report. Attractive commodity prices coupled with the results from our active drilling and acquisition programs contributed to our highly positive 2005 results.

Key accomplishments in 2005 include:

-

Production increased 18% in 2005 to an annual average production of 36,991 boepd. Fourth quarter average production reached 39,178 boepd. These significant increases were largely due to very successful drilling and development programs coupled with five strategic acquisitions throughout the year.

-

Annual cash flow increased 68% in 2005 to $398 million, and net income increased 183% to $211 million. This was due to the additional production and a 28% increase in Petrofund s average 2005 realized price to $57.71 per boe.

-

Our payout ratio in 2005 was 51% compared to 73% in 2004. This enabled the trust to fund 100% of its drilling and development program internally. The 37% of cash flow that was used to fund drilling and development resulted in the trust replacing over 90% of its annual production decline. The remaining 12% of cash flow was used toward debt reduction, which ultimately funded a portion of the trust s 2005 acquisitions.

-

Total net capital expenditures by the trust surpassed $700 million in 2005. This resulted in the addition of 33.2 million boe of proved plus probable gross reserves replacing almost 300% of annual 2005 production. These capital programs contributed to an increase in the trust s overall proved plus probable gross reserves base to 162.3 mmboe at the end of the year.

-

Petrofund s reserve life index at the end of 2005 is 11.0 years, marking the 10th consecutive year this indicator has been greater than 10 years.

-

The trust achieved very positive results on a per unit basis in 2005. The 2005 exit production rate on a per unit basis was held essentially flat compared to the 2004 exit rate. Also, the trust s 2005 year end proven plus probable gross reserves per unit was only down about 2% over 2004 year end results, and the trust still paid out $202 million in distributions to unitholders.

-

The trust continued its established trend of financial conservatism ending the year with a net debt to cash flow ratio of 0.8:1.0 based on annualized fourth quarter 2005 cash flow (which only includes one month of production from the assets acquired when the trust acquired Kaiser Energy Ltd. Kaiser).

-

Amidst significant industry cost pressure, general and administrative costs, including all cash and non-cash charges, were $1.27 per boe of production in 2005 verses $1.26 in 2004. Due to the high industry activity and cost pressures throughout the sector, operating costs increased 16% to $10.49 per boe.

-

Unit liquidity continued to increase in 2005 with average combined AMEX and TSX trading volumes averaging 769,000 units per day verses 692,000 in 2004. In addition, over the course of the year our unit price increased 31% closing at $20.49 on the TSX on December 31, 2005. If distributions are included, the total 2005 return is 44%.

The strong performances Petrofund achieved in 2005 are clearly indicated in our year end results and the trust is well positioned for future successes as it enters 2006 with:

-

a low and conservative payout ratio

-

a healthy balance sheet

-

a deep and diversified prospect inventory (including low risk opportunities from Kaiser s properties)

-

long life properties with a top quartile low corporate average decline

-

a balanced oil and gas production split

-

very capable, knowledgeable and proven people

Petrofund will be conducting a conference call and webcast for analysts and investors on Wednesday, February 15, 2006 at 9:00 am Mountain Standard Time (11:00 am Eastern Standard Time) to discuss our 2005 year-end results. Interested parties are invited to participate by calling 1-888-458-1598 and entering the pass code 8412449#. The call will also be available via webcast which may be accessed on Petrofund s website at www.petrofund.ca. The webcast will be accessible for replay through the website for the next 30 days.

Petrofund s financial results for the period ending December 31, 2005 are presented in the following excerpt from our 2005 annual report. Selected information and details of the foregoing from Petrofund s independent engineering reserve report are also included after the financial results.

FINANCIAL HIGHLIGHTS

(thousands of Canadian dollars and units, except per unit amounts and as indicated)

For the years ended December 31,	2005	2004	Variance
INCOME STATEMENT			
Oil and natural gas sales [5]	$779,630	$517,081	51 %
Cash flow [1]	$398,003	$236,245	68 %
Per unit basic and diluted [2]	$3.84	$2.68	43 %
Per boe	$29.48	$20.54	44 %
Cash distributions paid per unit	$1.95	$1.92	2 %
Payout ratio [6]	51%	73%	(30) %
Net income	$210,668	$74,359	183 %
Net income per unit			
Basic	$2.03	$0.84	142 %
Diluted	$2.03	$0.84	142 %
UNITS AND EXCHANGEABLE SHARES OUTSTANDING [2]			
Weighted average	103,660	88,169	18 %
Diluted	103,724	88,292	17 %
At year-end	117,561	100,451	17 %
BALANCE SHEET			
Working capital (deficit) [3]	$31,897	$(49,310)	165 %
Property, plant and equipment, net	$1,777,922	$1,246,694	43 %
Total assets	$2,267,119	$1,486,412	53 %
Long-term debt	$462,783	$214,414	116 %
Unitholders equity	$1,385,343	$1,026,526	35 %
MARKET CAPITALIZATION, as at December 31	$2,408,816	$1,568,036	54 %
TOTAL CAPITALIZATION, as at December 31 [3], [4]	$2,839,702	$1,831,760	55 %
TRUST UNIT TRADING (TSX: PTF.UN)			
High ($CDN)	$23.31	$19.24	21 %
Low ($CDN)	$15.50	$14.52	7 %
Close ($CDN)	$20.49	$15.61	31 %
Average daily volumes	210	216	(3) %
TRUST UNIT TRADING (AMEX: PTF)			
High ($US)	$19.88	$14.96	33 %
Low ($US)	$12.66	$10.95	16 %
Close ($US)	$17.64	$13.04	35 %
Average daily volumes	559	476	17 %

(1)

Cash flow before net changes in non-cash operating working capital

(Non-GAAP measure, see special notes in the Management s Discussion and Analysis).

(2)

See Note 9 to the Consolidated Financial Statements.

(3)

Excludes net unrealized gains/losses on commodity contracts.

(4)

Total capitalization equals market capitalization plus net debt

(Non-GAAP measure, see special notes in the Management s Discussion and Analysis).

(5)

Prices and revenue are before realized gains/losses on commodity contracts and before transportation costs.

(6)

Cash distributions paid divided by cash flow before capital reinvestment.

OPERATIONAL HIGHLIGHTS

(thousands of Canadian dollars, except per unit amounts and as indicated)

For the years ended December 31,	**2005**	**2004**	**Variance**	
DAILY PRODUCTION				
Oil (bbls)	18,264	15,084	21	%
Natural gas (mmcf)	98.1	84.5	16	%
Natural gas liquids (bbls)	2,383	2,262	5	%
BOE (6:1)	36,991	31,429	18	%
Total annual production (mboe)	13,501	11,503	17	%
PRODUCTION PROFILE				
Oil	49%	48%		
Natural gas	45%	45%		
Natural gas liquids	6%	7%		
AVERAGE PRICES (1)				
Oil (per bbl)	$	$		
	61.54	48.83	26	%
Natural gas (per mcf)	$	$		%
	9.02	6.87	31	
Natural gas liquids (per bbl)	$	$		
	52.98	41.96	26	%
Per BOE (6:1)	$	$		%
	57.71	44.93	28	
CASH OPERATING NETBACK PER BOE (2)	$	$		
	32.05	23.01	39	%
PROVEN PLUS PROBABLE RESERVES (3)				
Crude oil (millions of barrels)	88.5	86.0	3	%
Natural gas (billions of cubic feet)	388.7	283.7	37	%
Natural gas liquids (millions of barrels)	9.0	8.3	10	%
Millions of barrels of oil equivalent at 6:1	162.3	141.6	15	%
LEASE OPERATING COSTS	$	$		
	141,578	103,610	(37)	%
Cost per boe	$	$		%
	10.49	9.01	(16)	
GENERAL AND ADMINISTRATIVE COSTS	$	$	(19)	%

	17,174	14,441		
Cost per boe	$	$		%
	1.27	1.26	(1)	

(1)

Prices and revenue are before realized gains/losses on commodity contracts and before transportation costs.

(2)

Cash operating netback per BOE is calculated as the selling price less the cash cost of hedging less royalties, net of ARC, lease operating costs and transportation costs, by product, divided by the total production volumes in each period. For details by product type see the section Net Income in the Management s Discussion and Analysis.

(3)

Reserves at December 31, 2005, and 2004 are based on total proved plus probable gross reserves (as defined in National Instrument 51-101 (NI 51-101)), being working interest reserves prior to deduction of royalties.

Management s Discussion & Analysis

SPECIAL NOTES

The following Management s 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, 2005 and 2004 included in this 2005 annual report. All oil and natural gas properties are held by Petrofund Corp. (PC) and Petrofund Ventures Trust (PVT), wholly owned subsidiaries of the Trust. This commentary is based on information available to, and is dated, February 14, 2006. Additional information (including Petrofund s annual information form AIF), when filed, 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/1 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. Reserves at December 31, 2005, and 2004 are based on total proved plus probable gross reserves (as defined in National Instrument 51-101 (NI 51-101)), being working interest reserves prior to deduction of royalties.

NON GAAP MEASURES

The Trust uses adjusted cash flow (before changes in non-cash operating working capital and before capital reinvestment) to analyze operating performance and leverage. Adjusted cash flow (before changes in non-cash operating working capital) and adjusted cash flow before capital reinvestment before changes in working capital and before settlement of asset retirement obligations as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles (Canadian GAAP) and may not be comparable with the calculation of similar measures for other entities. Cash flow (before changes in non-cash operating working capital) and cash flow from operations before changes in working capital and before settlement of asset retirement obligations 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 provided by operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow (before changes in non-cash operating working capital) and cash flow from operations before changes in working capital and before settlement of asset retirement obligations are based on cash flow from operating activities before changes in non-cash operating working capital or before changes in non-cash working capital and before settlement of asset retirement obligations, as applicable.

The Trust also uses net debt . Net debt as presented does not have any standardized meaning prescribed by Canadian GAAP and may not be comparable with the calculation of similar measures for other entities. Net debt as used by the Trust is calculated as bank debt and any working capital deficit excluding the current portion of derivative contracts.

The Trust also uses payout ratio as cash distributions paid divided by cash flow before capital reinvestment. Payout ratio as presented does not have any standardized meaning prescribed by Canadian GAAP and may not be comparable with the calculation of similar measures for other entities.

Cash operating netback per BOE is calculated as the selling price less the cash cost of hedging less royalties, net of Alberta Royalty Credit (ARC), lease operating costs and transportation costs, by product, divided by the total production volumes in each period. For details by product type see the section Net Income in the Management s Discussion and Analysis.

The Trust 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.

These measures should be given careful consideration by the reader.

FORWARD-LOOKING STATEMENTS

Certain statements contained in this annual report constitute forward-looking statements. The use of any of the words anticipate , continue , estimate , expect , may , project , should , believe and similar expressions are inte forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking statements. The Trust and PC believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct and such forward-looking statements included in this annual report should not be unduly relied upon. These statements speak only as of the date of this annual report.

In particular, this annual report contains forward-looking statements pertaining to the following:

- the size of the Trust s oil and natural gas reserves;
- projections of market prices and costs;
- anticipated distributions on units of the Trust and the payout ratio;
- capital expenditures and the timing thereof;
- supply and demand for oil and natural gas;
- the Trust s expectations with respect to acquisitions and the properties obtained thereunder;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions and development; and
- treatment under governmental regulatory regimes.

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

- volatility in market prices for oil and natural gas;

- liabilities inherent in oil and gas operations;
- uncertainties associated with estimating reserves;
- competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and processing problems; and
- the other factors described under Business Risks in this annual report and in the AIF.

These factors should not be construed as exhaustive. Except as required by applicable securities laws, neither the Trust nor PC undertakes any obligation to publicly update or revise any forward-looking statements.

2005 HIGHLIGHTS

The Trust paid out cash distributions of $1.95 per unit in 2005, compared to $1.92 per unit in 2004 (2003 - $2.09 per unit). Petrofund has since paid/distributed $0.20 per unit for January 2006, announced distributions of $0.20 per unit for February and based on current commodity prices and market conditions has indicated distributions of $0.20 per unit for March 2006.

The Trust s payout ratio for 2005 was 51% compared to 73% in 2004 (2003 70%). The lower payout ratio enabled the Trust to fund 100% of its 2005 development expenditures from retained cash flow before capital reinvestment.

The Trust generated cash flow before non-cash operating working capital of $398.0 million in 2005, an increase of 68% over 2004. This increase reflects increased average production and higher prices. Net income increased to $210.7 million in 2005 versus $74.4 million in 2004. The net income also includes an unrealized (non-cash) gain on commodity contracts of $6.3 million in 2005 versus an unrealized (non-cash) loss on commodity contracts of $6.2 million in 2004 as well as a future income tax recovery of $6.7 million in 2005 versus $7.1 million expense in 2004.

Average production on a boe basis increased 18% to 36,991 boe/d in 2005 from 31,429 boe/d in 2004. The change in production reflects PC s development drilling program, the acquisition of Ultima Energy Trust (Ultima) in June 2004, the Central Alberta acquisitions in November 2004 and the 2005 acquisitions listed later in this section, offset by natural production decline.

Average prices in 2005 were up 28% on a boe basis from the prior year and were $57.71 per boe for 2005 compared to $44.93 per boe in 2004.

Petrofund has a strong balance sheet with a net debt to cash flow ratio as at December 31, 2005, of 1.1:1.0 based on 2005 cash flow before non-cash operating working capital.

On November 16, 2005 Petrofund entered into an agreement to acquire 100% of Kaiser Energy Ltd. (Kaiser), effective December 1, 2005. Kaiser held (or held prior to the completion of the acquisition by Petrofund), either directly or indirectly, interests in Canadian Acquisition Limited Partnership (Canadian Partnership) and certain properties to be transferred to Kaiser (collectively, the Kaiser Entities). Petrofund added $489.7 million to oil and gas properties (excluding non-cash negative working capital of $14.9 million, future income taxes of $157.2 million and asset retirement obligations of $4.9 million). This acquisition added approximately 5,400 boepd production to the Trust and working interest reserves additions of 20 million boe on a proved plus probable basis.

In 2005, Petrofund further acquired interests in various oil and gas properties for $74.0 million (excluding non-cash negative working capital assumed of $4.8 million, future income taxes of $10.4 million and asset retirement obligations of $1.2 million), which includes the purchase of Northern Crown Petroleums Ltd. (Northern Crown), Tahiti Gas Ltd. (Tahiti) and property interests in the Turin and Joarcam areas. These acquisitions added approximately 1,650 boepd of production to the Trust. Petrofund s internal estimate of reserves acquired, at the time of acquisition, was 4.6 million boe on a proved plus probable basis.

The Trust has a balanced production profile which averaged 45% natural gas and 55% oil and liquids for the fiscal year ended December 31, 2005.

The Trust completed a bought deal financing of 4.15 million Trust units, raising gross proceeds of $75.7 million ($71.4 million net) in the second quarter of 2005. The Trust also completed a bought deal financing of 12.5 million Trust units, raising gross proceeds of $250 million ($237 million net) in the fourth quarter of 2005. The weighted average number of Trust units/Exchangeable shares outstanding increased from 88.2 million in 2004 to 103.7 million in 2005. As at December 31, 2005 there were 117.6 million Trust units/Exchangeable shares outstanding.

The Trust s total capitalization as at December 31, 2005, was approximately $2.8 billion ($1.8 billion as at December 31, 2004).

CASH DISTRIBUTIONS

For the years ended December 31,	**2005**	**2004**	**2003**
	$	$	$
Distributions paid per unit	1.95	1.92	2.09

Trust unitholders who held their units in 2005 received aggregate cash distributions of $1.95 per unit as compared to $1.92 per unit in 2004 (2003 - $2.09 per unit). For 2006, the Trust distributed $0.20 per unit in January, has announced a distribution of $0.20 per unit for February, and has indicated a distribution of $0.20 per unit for March.

Petrofund focuses on the ability to maintain distribution levels. As part of this strategy, the Trust has lowered its payout ratio over the past two years in response to increasing oil and gas prices which currently exceed historical highs. At the same time, the Trust has allocated a higher percentage of cash flow for capital reinvestment. Petrofund monitors the distribution payout with respect to forecasted funds flow, debt levels and pending plans. The level of cash retained has historically varied between 10% and 30% of annual funds flow; however, Petrofund adjusts the payout levels in an effort to balance the desire for distributions with the requirement to maintain a prudent capital structure. To reflect the treatment of capital expenditures funded from cash flow, the Trust has modified the calculation of Distributions payable to Unitholders by applying the portion of capital expenditures funded from cash flow rather than an estimated amount as a reduction of Distributions payable up to the amount available for such purposes. Any remaining cash flow continues to be shown as Distributions payable to Unitholders at the end of the period.

During 2005, the Trust generated cash flow available for distribution before capital reinvestment of $394.2 million (2004 - $231.5 million). The Trust paid out $202.3 million (2004 - $169.5 million) in distributions representing a payout ratio of 51% (2004 73%). In the fourth quarter, the Trust generated cash flow available for distribution of $125.3 million before deducting $88.0 million for capital expenditures and paid out $55.5 million in distributions for a payout ratio of 44%. For a detailed analysis of cash flow available for distributions refer to Note 8 to the Consolidated Financial Statements.

CASH DISTRIBUTION PAID HISTORY (1)

Cash distributions comprise a return of capital portion (tax deferred) and a return on capital portion (taxable). The return of capital component reduces the cost basis of the trust units held, as described below. For additional information, please see our website at www.petrofund.ca.

Calendar Year	**Distributions** (2)	**Taxable Portion**	**Return of Capital**
	$	$	$
1989 to 1996	20.8950	-	20.8950
1997	2.3700	-	2.3700
1998	1.4400	-	1.4400
1999	1.8300	-	1.8300
2000	3.9900	2.4633	1.5267
2001	4.2400	2.6771	1.5629
2002	1.7100	0.9365	0.7735
2003	2.0900	1.0706	1.0194
2004	1.9200	1.4849	0.4351
2005	1.9500 (3)	1.9184	0.0316
	$	$	$
Cumulative	42.4350	10.5508	31.8842

(1)

Applies to unitholders who are residents of Canada and hold their units as capital property.

(2)

Based on cash distributions paid in the calendar year and adjusted for unit splits.

(3)

Petrofund estimates that approximately 98% of cash distributions paid in 2005 to Canadian unitholders. U.S. unitholders will also be taxable. Any non-taxable amounts will be treated as a tax deferred return of capital. Actual taxable amounts may vary depending on actual distributions and are dependent upon production, commodity prices and funds flow experienced throughout the year.

For U.S. taxpayers, the taxable portion of the cash distribution is considered to be a dividend for U.S. tax purposes. For most U.S. taxpayers this should be a Qualified Dividend eligible for the reduced tax rate. The non-taxable portion of the cash distribution is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss arising from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as gains.

This is a general guideline and not intended to be legal advice to any particular holder or potential holder of units of the Trust. This information is not exhaustive of all possible U.S. income tax considerations. Unitholders or potential unitholders of the Trust should consult their own legal and tax advisers as to the particular tax consequences of holding their Trust units.

CASH FLOW

($000 s)	**2005**	**2004**	**2003**
	$	***$***	$
Cash provided by operating activities	***337,223***	***243,652***	192,163
Increase (decrease) in non-cash working capital	60,780	(7,***407***)	(4,578)
Cash flow before non-cash operating working capital	398,003	236,245	187,585
Redemption of exchangeable shares	(1,154)	(1,803)	(2,792)
Asset retirement reserve fund	(2,025)	(1,725)	(776)
Capital lease repayment	(608)	(356)	(3,305)
Amortization of the cost of commodity contracts	-	(821)	-
Cash flow before capital reinvestment	$	***$***	$
	394,216	***231,540***	180,712

MONTHLY CASH DISTRIBUTIONS

Actual cash distributions paid for per Trust unit along with relevant payment dates for 2005, 2004 and 2003 are as follows:

Record Date (1)	Payment Date (1)	**2005**	**2004**	**2003**
		$	$	$
January 17	January 31	0.16	0.16	0.15
February 14	February 28	0.16	0.16	0.16
March 16	March 31	0.16	0.16	0.17
April 15	April 29	0.16	0.16	0.17
May 16	May 31	0.16	0.16	0.18
June 16	June 30	0.16	0.16	0.18
July 15	July 29	0.16	0.16	0.18
August 17	August 31	0.16	0.16	0.18
September 16	September 30	0.16	0.16	0.18
October 17	October 31	0.17	0.16	0.18
November 16	November 30	0.17	0.16	0.18
December 14	December 30	0.17	0.16	0.18
		$	$	$
		1.95	1.92	2.09

(1) Dates relate to 2005 only.

RESULTS OF OPERATIONS

FOURTH QUARTER 2005 VERSUS FOURTH QUARTER 2004

The Trust generated cash flow of $126.1 million or $1.17 per unit in the fourth quarter of 2005 compared to $72.3 million or $0.72 per unit in the fourth quarter of 2004. The Trust increased monthly cash distributions to $0.17 per unit in the fourth quarter of 2005. The Trust s payout ratio of 44% in the fourth quarter of 2005 compared to a payout ratio of 67% in the fourth quarter of 2004.

The fourth quarter of 2005 was an active quarter for Petrofund with the acquisition of Kaiser, plus ongoing drilling and development activities. Total capital expenditures for the quarter were $508.4 million. These activities provided new production in the fourth quarter of 2005, as discussed further in the Operational Highlights.

Average daily production volumes in the fourth quarter of 2005 of 39,178 boe were above the fourth quarter of 2004 volumes of 36,025 boe. This increase resulted from acquisitions and development activities in 2005 partially offset by the natural production decline.

Net income increased to $100.1 million in the fourth quarter of 2005 compared to $50.8 million in the fourth quarter of 2004. Revenues increased 53% which reflects an increase of 40% in prices on a boe basis and a 9% increase in production. The increase in revenue has partly been offset by a $11.9 million loss on commodity contracts and an increase of $12.4 million in depletion expense. The Trust recognized an unrealized (non-cash) commodity gain of $31.6 million versus an unrealized (non-cash) commodity gain of $26.4 million in the fourth quarter of 2004. Both adjustments were a result of the mark-to-market fair value accounting. In addition, the future income tax in the fourth quarter of 2005 was a recovery of $2.5 million compared to $774,000 expense in the fourth quarter of 2004, due to an increase in commodity contract losses and other tax related asset balances.

The cash loss on commodity contracts during the fourth quarter of 2005 was $11.9 million compared to a $14.1 million loss in the fourth quarter of 2004.

Royalties were 21% of revenue in the fourth quarter of 2005, compared to 20% for the fourth quarter of 2004.

Lease operating costs on a unit basis increased to $10.64/boe in the fourth quarter of 2005 from $8.82/boe in the fourth quarter of 2004. Costs for repairs and maintenance continue to increase as a result of high levels of activity in the upstream sector.

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.

Annual production volumes averaged 36,991 boe/d in 2005, an increase of 18% over average production volumes of 31,429 boe/d in 2004. The change in production reflects, PC s development drilling program, the acquisition of Ultima in June 2004, the Central Alberta PNG Partnership and 1024373 Alberta Ltd. (Central Alberta acquisition) acquisition in November 2004, the Turin area acquisition in January 2005, the Northern Crown and Tahiti acquisitions in May 2005, the Joarcam area acquisition in July 2005, the Kaiser acquisition in December 2005 and positive prior period adjustments (136 boe/d), partially offset by natural production decline.

For the years ended December 31,	**2005**	**2004**	**2003**
Daily Production			
Oil (bbls)	18,264	15,084	12,454
Natural gas (mmcf)	98.1	84.5	83.3
Natural gas liquids (bbls)	**2,383**	**2,262**	**2,079**
Total (boe 6:1)	36,991	31,429	28,418

PRICING & PRICE RISK MANAGEMENT

Revenues from the sale of crude oil, natural gas, and natural gas liquids and sulphur increased 51% to $779.6 million in 2005 from $517.1 million in 2004 due to a 17% increase in production and a 28% increase in prices on a boe basis.

Crude oil sales increased to $410.2 million in 2005 from $269.6 million in 2004 due to a 21% increase in production from 15,084 bbl/d in 2004 to 18,264 bbl/d in 2005 and a 26% increase in the oil price received. The average WTI oil price increased from U.S. $41.40/bbl in 2004 to U.S. $56.56/bbl in 2005 or 37%; however, the Canadian par price at Edmonton increased only 31% from $52.54/bbl to $68.72/bbl due to the significant strengthening of the Canadian dollar relative to the U.S. dollar which averaged 0.83 in 2005 versus 0.77 in 2004. The average Canadian wellhead price received by Petrofund increased to $61.54/bbl in 2005 from $48.83/bbl in 2004.

About 60% of the Trust s crude production was sold directly to refiners in 2005 with the balance being delivered to marketers. Petrofund intends to maintain this sales mix in 2006.

Crude differentials widened considerably in Western Canada during 2005 though Petrofund was partly shielded from the deterioration in these differentials due to its high quality portfolio. Petrofund s differential to Edmonton postings before hedging increased to $7.18/bbl in 2005 from $3.71/bbl in 2004 (2003 - $3.98/bbl). 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 (97% light and medium crudes). Petrofund does, however, expect its overall differential from Edmonton to increase in 2006.

Natural gas sales increased to $322.9 million in 2005 from $212.6 million in 2004 due to a 16% increase in production and a 31% increase in the average prices received from $6.87/mcf in 2004 to $9.02/mcf in 2005. The monthly AECO price per mmbtu increased from $6.79 in 2004 to $8.48 in 2005. Production volumes averaged 98.1 mmcf/d in 2005 compared to 84.5 mmcf/d in 2004. Petrofund sold 32% of its production in 2005 to aggregators at netback pricing, up from 30% in 2004. 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 2005 by $0.24/mcf. The Trust sold the remaining 68% of its production on daily and monthly spot market pricing in Alberta, Saskatchewan and British Columbia. Petrofund intends to maintain this sales mix in 2006.

Sales of natural gas liquids and sulphur increased to $46.5 million in 2005 from $34.9 million in 2004 as production increased to 2,383 bbl/d in 2005 from 2,262 bbl/d in 2004. The average price increased from $41.96/bbl in 2004 to $52.98/bbl in 2005. The majority of the Trust s NGLs (88%) are sold to one buyer under one-year contract terms at market sensitive pricing with the remainder widely distributed among any 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 2006 to remain strong for its NGLs and condensate.

Crude oil accounted for 49% of production in 2005 (2004 48%, 2003 44%), while natural gas constituted 45% of production in 2005 (2004 45%, 2003 49%). Natural gas liquid volumes accounted for 6% of total production in 2005 (2004 and 2003 7%). The Trust continues to maintain a balance between oil and natural gas production.

Average prices received for the years ended December 31,	**2005**	**2004**	**2003**
	$	$	$
Oil (per bbl) (1)	61.54	48.83	39.16
Natural gas (per mcf) (1)	9.02	6.87	6.63
Natural gas liquids (per bbl) (1)	52.98	41.96	35.05
	$	**$**	**$**
Weighted average per BOE (6:1)	**57.71**	**44.93**	**39.15**

(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)	**2005**	**2004**	**2003**
	$	$	$
Oil	410.2	269.6	178.0
Natural gas	322.9	212.6	201.5
Natural gas liquids & sulphur	46.5	34.9	26.8
	$	$	$
Total	**779.6**	517.1	406.3

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 to ensure Petrofund realizes positive economic returns from its capital development and acquisition activities.

As at December 31, 2005, Petrofund had 27.6 mmcf/d of natural gas and 4,500 bbl/d of crude oil hedged for the remainder of 2006 (approximately 25% of production). A summary of the hedged volumes and prices in place at December 31, 2005, 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	**2006**	**Q1**	**Q2**	**Q3**	**Q4**
Collars	20,132	14,211	28,422	28,422	9,474
Three way collars	5,132	9,474	4,737	4,737	1,579
Floors	2,369	9,474	-	-	-
Total mcf/d	27,633	33,159	33,159	33,159	11,053

		Average Price ($/mcf)			
Natural Gas	**2006**	**Q1**	**Q2**	**Q3**	**Q4**
	$	$	$	$	$
Collar ceiling price	13.51	16.29	12.58	12.58	12.58
Collar floor price	8.82	8.09	9.06	9.06	9.06
Three way ceiling price	9.69	11.77	8.99	8.99	8.99
Three way floor price	7.17	6.52	7.39	7.39	7.39

	$	$	$	$	$
Three way floor short	5.92	5.47	6.07	6.07	6.07

		Average Volumes (bbl/d)			
Oil	**2006**	**Q1**	**Q2**	**Q3**	**Q4**
Collared	4,000	5,000	5,000	4,000	2,000
Three way collars	500	1,000	1,000	-	-
Total bbl/d	**4,500**	**6,000**	**6,000**	**4,000**	**2,000**

		Average Price ($/bbl)			
Oil	**2006**	**Q1**	**Q2**	**Q3**	**Q4**
	$	$	$	$	$
Collar ceiling price	87.22	85.54	88.62	88.52	86.18
Collar floor price	58.92	56.29	58.73	59.61	61.06
Three way ceiling price	65.28	61.64	68.91	-	-
Three way floor price	47.69	46.52	48.85	-	-
	$	$	$	$	$
Three way floor short	41.87	40.71	43.03	-	-

Alberta Power	**2006**	**Q1**	**Q2**	**Q3**	**Q4**
Fixed, MW/h	2.0	2.0	2.0	2.0	2.0
	$	$	$	$	$
Fixed price ($/MWh)	57.00	57.00	57.00	57.00	57.00

Three-way Collars

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

After December 31, 2005 and as at February 14, 2006, Petrofund entered into the following additional hedges (not included in the table above):

(1)

A collar for July 1, 2006 to December 31, 2006, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $75.50/bbl.

(2)

A swap for April 1, 2006 to October 31, 2006 for 4.7 mmcf/d of natural gas at $9.49/mcf, at AECO pricing.

(3)

A collar for October 1, 2006 to December 31, 2006, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $84.75/bbl.

(4)

A collar for January 1, 2007 to March 31, 2007, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $82.55/bbl.

(5)

A collar for July 1, 2006 to September 30, 2006, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $86.00/bbl.

(6)

A collar for October 1, 2006 to December 31, 2006, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $90.00/bbl.

(7)

A collar for January 1, 2007 to March 31, 2007, for 1,000 bbl/d of crude (WTI) between $US $55.00 and $US $90.25/bbl.

(8)

A collar for November 1, 2006 to March 31, 2007, for 4.7 mmcf/d of natural gas at $9.45 and $12.86/mcf, at AECO pricing.

Petrofund has no sales volumes hedged after March 31, 2007. All foreign exchange calculations in this section of the report incorporate the Bank of Canada U.S. dollar rate at the close on December 31, 2005 of CDN $1.163:U.S. $1.

ROYALTIES

For the years ended December 31,	2005	2004	2003
	$	$	$
Royalties (millions)	155.8	100.2	84.8
Average royalty rate (%)	20.0	19.4	20.9
	$	$	$
$/boe	11.54	8.71	8.18

Royalties, which include crown, freehold and overrides paid on oil and natural gas production, increased to $155.8 million in 2005 from $100.2 million in 2004 (2003 $84.8 million) net of the Alberta Royalty Credit (ARC). Royalties, as a percentage of revenues before hedging losses, increased to 20% of revenues in 2005 from 19.4% of revenues in 2004 (2003 20.9%).

EXPENSES

For the years ended December 31,	2005	2004	2003
Expenses (millions)			
	$	$	$
Lease operating	141.6	103.6	91.3
Transportation costs	8.1	5.9	5.5
General & administrative	17.2	14.4	13.0
Financing costs	10.6	5.8	8.7
Expenses per boe			
	$	$	$
Lease operating	10.49	9.01	8.80
Transportation costs	0.60	0.51	0.53
General & administrative	1.27	1.26	1.26
Financing costs	0.79	0.51	0.84

Lease Operating

Operating costs for 2005 were up 16% to $10.49 per boe compared to $9.01 per boe in 2004 (2003 $8.80). Costs for repairs and maintenance continue to increase as a result of the high level of activity in the upstream sector.

The most significant contributor to the higher per unit operating costs to date in 2005 has been a general industry increase for all types of services and supplies including surface and downhole well repair and maintenance costs and facility maintenance work. In addition, the current high product price environment is driving average operating costs higher because marginal, higher cost properties continue to generate positive cash flow at higher than historical per unit costs and, as a result, remain on production longer. The Trust anticipates lease operating costs in 2006 will continue to increase at a rate similar to that of 2005.

Transportation Costs

Transportation costs on a boe basis were $0.60 in 2005 as compared to $0.51 in 2004 (2003 - $0.53), reflecting general increases in trucking costs of clean oil.

General & Administrative ("G&A") Costs

General and administrative costs for 2005, were $17.2 million compared to $14.4 million in 2004 (2003 - $13.0 million). Costs were $1.27 per boe in 2005 compared to $1.26 per boe in 2004 (2003 - $1.26 per boe). G & A costs in 2005 include $3.6 million of compensation expense related to the restricted unit plan (RUP) and the long-term incentive plan (LTIP) compared to $1.5 million in 2004. The compensation expense is based on the unit price of the Trust units at December 31, 2005, of $20.49 per unit (December 31, 2004 $15.61 per unit). See Notes 13 and 14 of the Consolidated Financial Statements for details of the Trust s incentive plans.

G & A costs in 2005 include $370,000 or $0.03 per boe for external costs associated with Section 404 of the Sarbanes Oxley Act (SOX 404) compared to $212,000 in 2004 or $0.09 per boe.

The Trust expects its per boe G&A costs to increase by approximately 20% in 2006, which mainly reflects increases in employee compensation expenses.

Financing Costs

Financing costs and increases in loan balances as noted below reflect funding of expenditures associated with PC s active property acquisitions, and drilling and development programs.

Interest and other financing costs for 2005, increased to $10.6 million in 2005 compared to $5.8 million in 2004 (2003 - $8.7 million), which reflects the increase in the average loan balance outstanding in 2005 of $270.1 million from $157.5 million in 2004 and an increase in the average prime loan rate from 4.0% in 2004 to 4.4% in 2005. Net debt as a percentage of total capitalization is 15.2% in 2005 compared to 14.9% in 2004 (2003 9.2%).

The bank loan outstanding at December 31, 2005, was $462.8 million as compared to $214.4 million at December 31, 2004. An amount of $248.3 million of debt was incurred in the fourth quarter of 2005 which was mainly incurred to finance the acquisition of Kaiser. At December 31, 2005, 100% of PC s debt was based on floating interest rates.

DEPLETION, DEPRECIATION & ACCRETION

Depletion, depreciation and accretion expense increased to $202.8 million in 2005 from $153.1 million in 2004 (2003 - $118.3 million) due to the increase in production and an increase in the depletion rate. The rate per boe increased to $15.02 in 2005 from $13.31 in 2004 (2003 - $11.41). The increase in the rate over 2004 and into 2005 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, PC as at December 31, 2005. The Federal Large Corporations Tax rate is being reduced in stages so that by 2008 the tax will be eliminated.

Capital taxes of $3.9 million in 2005 (2004 $3.3 million, 2003 $2.5 million) relate primarily to the Saskatchewan Capital Tax and Resource Surcharge, which is based upon gross revenues earned in Saskatchewan. On March 23, 2005, Saskatchewan Finance passed its 2005 budget that included an amendment to subject trusts to the Corporation Capital Tax Resources Surcharge (Resource Surcharge) effective April 1, 2005. Previously, the resource surcharge did not apply to resource trusts and, therefore, Petrofund Ventures Trust (PVT), a 100% owned subsidiary of the Trust, which holds certain Saskatchewan properties, was not previously impacted by the resource surcharge. The resource surcharge is calculated based on a rate applicable to working interest oil and natural gas revenue earned in Saskatchewan at a rate of 3.6 percent on revenue from wells drilled prior to October 1, 2002 and a rate of two percent on revenue from wells drilled on or after October 1, 2002. PVT cash flow has been reduced by approximately $550,000 over the last three quarters of 2005.

Future income tax liabilities arise due to the differences between the tax basis of PC s assets and their respective accounting carrying cost. The future income tax expense in 2005 was a recovery of $6.7 million compared to $7.1 million expense in 2004 (2003 $44.2 million recovery) due to an increase in deferred tax assets, primarily asset retirement obligations.

NET INCOME

For the years ended December 31,		2005		2004		2003
Net income (millions)	$		$		$	

	210.7	74.4	87.3
Net income per Trust unit			
	$	$	$
Basic	2.03	0.84	1.43
		$	**$**
Diluted	**2.03**	0.84	**1.43**

Net income before taxes increased from $82.0 million in 2004 to $205.1 million in 2005 mainly due to a 51% increase in revenues reflected by a 17% increase in production and a 28% increase in prices on a boe basis and reduced net losses on commodity contracts. These increases have been offset partially by a 37% increase in lease operating costs and a 33% increase in depletion, depreciation and accretion expense.

The Trust recognized a net loss on commodity contracts of $34.5 million in 2005 compared to $48.7 million loss in 2004. The unrealized (non-cash) gain on commodity contracts was $6.3 million 2005 compared to a $6.2 million loss in 2004.

The increase in depletion is due to increased production and the increase in the depletion rate reflects the increasing cost of acquisitions.

Total cash netbacks increased by $159.6 million for 2005 compared to the same period in 2004. On a boe basis, cash netbacks were up to $29.61 in 2005 from $20.91 in 2004 (2003 - $18.50).

Total Cash Netbacks	**2005**	**2004**	**2003**
	$	$	$
Cash operating netback	32.05	23.01	20.89
Financing costs	0.79	0.51	0.84
General and administrative	1.27	1.26	1.26
Capital and current taxes	0.38	0.33	0.29
	$	$	$
Total cash netback per BOE	29.61	20.91	18.50

As a result of the changes discussed above, net income increased to $210.7 million in 2005 from the $74.4 million reported in 2004.

Cash Operating Netbacks 2005	**Oil $/bbl**	**Gas $/mcf**	**NGL $/bbl**	**Total $/boe**
	$	$	$	$
Selling price	61.54	9.02	52.98	57.71
Cash cost of hedging	(5.48)	(0.14)	-	(3.03)
Net selling price	56.06	8.88	52.98	54.68
Royalties, net of ARC	10.83	2.01	13.42	11.54
Lease operating	12.97	1.31	9.39	10.49
Transportation costs	0.48	0.12	0.52	0.60
	$	$	$	$
Cash operating netback	31.78	5.44	29.65	32.05

Cash 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
Lease operating	11.07	1.16	7.96	9.01

Transportation costs	0.25	0.13	0.44	0.51
	$	$	$	$
Cash operating netback	21.91	4.04	22.58	23.01

Cash 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
Lease operating	11.23	1.13	7.89	8.80
Transportation costs	0.25	0.13	0.39	0.53
	$	$	$	$
Cash operating netback	20.36	3.66	16.97	20.89

CAPITAL EXPENDITURES

Acquisitions

On November 16, 2005 Petrofund entered into an agreement to acquire Kaiser for $485 million, effective December 1, 2005, which added approximately 5,400 boepd of production with reserves of 20 million boe on a proved plus probable basis. Kaiser s assets also include 55,000 net acres of highly prospective undeveloped land on which Petrofund has already identified 166 (net) low to medium risk development drilling opportunities. These projects are expected to contribute positively to Petrofund s production in 2006 and thereafter.

In addition, PC spent $32.7 million to acquire Northern Crown effective May 10, 2005, $23.4 million to acquire Tahiti effective May 1, 2005, $6.3 million to acquire property interests in the Turin area effective January 1, 2005 and $11.8 million to acquire property interest in the Joarcam area effective July 1, 2005. These acquisitions added approximately 1,650 boepd of production to the Trust. On these acquisitions, Petrofund s internal estimate of reserves acquired, at the time of acquisition, was 4.6 million boe on a proved plus probable basis.

Dispositions

During 2005, PC disposed of minor properties for net proceeds of $871,000, which included one non-core area in the Acheson area of Alberta for $863,000.

Development Activities

During 2005, PC incurred $145.3 million in drilling and development activities compared to $76.7 million in 2004 (2003 - $71.4 million) before asset retirement obligations (ARO) capitalized. A total of 301 wells were drilled; 282 working interest wells (82.6 net) and 19 farmout wells, of which 175 were gas, 118 oil, 5 service wells and 3 were dry and abandoned for an overall success rate of 99%.

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

For the years ended December 31,	**2005**	**2004**	**2003**	
	$	$	$	
Corporate and property acquisitions [1]	561.1	32.1	115.6	
Property dispositions	(0.9)	(1.0)	(33.5	)
Total corporate and property acquisitions - cash	560.2	31.1	82.1	
Development expenditures:				
Land & seismic	8.5	2.2	2.5	
Drilling & completion	68.9	35.3	42.5	
Well equipping	10.4	10.6	7.9	
Tie-ins	14.3	5.4	5.2	
Facilities	24.9	13.3	8.4	
CO_2 purchases	17.7	8.4	3.5	
Other	0.6	1.5	1.4	
Total development expenditures - cash	145.3	76.7	71.4	
Total net capital expenditures cash	705.5	107.8	153.5	

Corporate acquisitions - non-cash [(2)]	178.5	570.0	4.7
Current year ARO capitalized	15.2	1.2	2.3
	$	$	$
Total capital expenditures [(3)]	899.2	679.0	160.5

(1)

The corporate and property acquisition totals exclude the impact of non-cash items on corporate acquisitions such as future income taxes and ARO.

(2)

Includes non-cash items such as: Trust units issued, working capital assumed, future income tax adjustments for the difference between the cost and tax basis of assets acquired and asset retirement obligations recognized for corporate acquisitions.

(3)

Includes change in oil and natural gas royalty and property interest and goodwill.

The Trust is planning a capital program of $200 million for 2006 however, the Trust may change its level of expenditure as it identifies and executes on more of the opportunities within its existing properties.

ASSET RETIREMENT RESERVE FUND

As at December 31, 2005, PC had $9.1 million set aside in a segregated cash reserve to fund future abandonment costs. This cash fund is currently being built up at a rate of $0.15/boe produced, which is in place to fund significant future reclamation costs, such as the decommissioning of a major facility. PC performs well reclamation and abandonments, flare pit remediation work, etc. on a routine basis, which reduces cash flow available for distribution to proactively address environmental concerns. Petrofund incurred $3.5 million for these activities in 2005 compared to $4.6 million in 2004. PC expects to spend a further $4.0 million on reclamation and abandonment work in 2006.

GOODWILL

The goodwill balance of $349.5 million arose as a result of the Ultima and Central Alberta acquisitions in 2004 and the Kaiser Entities, the Northern Crown and Tahiti acquisitions in 2005. The goodwill balance was determined based on the excess of total consideration paid plus the future income tax liability less the fair value of the assets acquired in each transaction.

Accounting standards require that the goodwill balance be assessed for impairment at least annually or more frequently if events or changes in circumstances indicate that the balance might be impaired. If such an impairment exists, it would be charged to income in the period in which the impairment occurs. The Trust has determined that there was no indication of goodwill impairment as of December 31, 2005.

LONG-TERM DEBT

In April 2005, PC extended its syndicated loan facility increasing its borrowing base to $415 million from $390 million. In December 2005, concurrent with the Kaiser acquisition, the borrowing base was increased to $590 million. As at December 31, 2005, the amount outstanding on PC s credit facility was $462.8 million, with $127.2 million available to finance future activities. See Note 6 of the Consolidated Financial Statements for further details on Long-Term Debt.

LIQUIDITY AND CAPITAL RESOURCES

Working capital was $31.9 million at December 31, 2005, an increase of $81.2 million from the $49.3 million deficit as at December 31, 2004. The December 31, 2005 and December 31, 2004 working capital exclude net unrealized gains/losses on commodity contracts. Current assets increased $80.2 million from $48.6 million at December 31, 2004 to $128.8 million at December 31, 2005. Current liabilities of $97.9 million at December 31, 2004 compare to $96.9 million at December 31, 2005. This slight decrease in liabilities reflects a decrease in distributions payable to Unitholders in 2005 offset by an increase in trade payables.

In June 2005, the Trust completed a bought deal financing of Trust units, raising gross proceeds of $75.7 million ($71.4 million net). A total of 4.15 million Trust units were issued at $18.25 per unit. The net proceeds were used to pay down debt and fund capital expenditures.

In December 2005, the Trust completed a bought deal financing of Trust units raising gross proceeds of $250 million ($237 million net). A total of 12.5 million Trust units were issued at $20.00 per unit. The net proceeds were used to fund the acquisition of Kaiser.

Total long-term debt increased to $462.8 million at December 31, 2005, from $214.4 million at December 31, 2004, due to the funding of acquisitions and development activities.

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

For the years ended December 31,	**2005**	**2004**	**2003**
($millions)			
	$	$	$
Cash flow before non-cash operating working capital	398.0	236.2	187.6
Net proceeds received from issuance of Trust units	315.0	4.5	214.0
Net change in non-cash working capital balances	(39.2)	33.5	6.4
Distributions paid	(202.3)	(169.5)	(127.3)
Expenditures on oil & natural gas properties, net	(705.5)	(107.8)	(153.5)
Assumption of debt, net of cash on acquisitions	29.0	(100.6)	-
Asset retirement reserve fund	(2.0)	(1.7)	(0.8)
Redemption of exchangeable shares	(1.1)	(1.8)	(2.8)
Capital lease repayments	(0.6)	(0.4)	(9.3)
Net (increase) decrease in cash and cash equivalents	(39.7)	2.9	(3.7)
Internalization of management contract	-	-	(8.0)
Miscellaneous	-	0.6	6.3
	$	$	$
Total changes long-term debt	(248.4)	(104.1)	108.9

The ratio of long-term debt at December 31, 2005, based on 2005 cash flow before non-cash operating working capital was 1.1:1.0.

In the absence of an equity issue, long-term debt is expected to increase in 2006 due to the capital expenditure program which is expected to be approximately $200 million (excluding acquisitions) of which a significant portion will be funded from cash flow. If the Trust is successful in completing one or more major acquisitions in 2006, 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.

The Trust anticipates it will continue to have adequate liquidity to fund future working capital and planned capital expenditures during 2006 primarily through cash flow from operations and utilization of our credit facility.

Capitalization Analysis

($000 s, except per unit and percent amounts)	**2005**	**2004**	**2003**
	$	$	$
Working capital (deficiency) [1]	31,897	(49,310)	(30,006)
Bank debt	462,783	214,414	109,707
Capital lease obligation	-	-	608
	$	$	$
Net debt obligation	430,886	263,724	140,321

Units outstanding and issuable for Exchangeable Shares at year end	117,561	100,451	73,628
Market Price at December 31,	$ 20.49	$ 15.61	$ 18.79
Market capitalization	$ 2,408,816	$ 1,568,036	$ 1,383,465
Total capitalization	$ 2,839,702	$ 1,831,760	$ 1,523,786
Net debt as a percentage of total capitalization	15.2%	14.9%	9.2%
Cash flow before non-cash operating working capital	$ 398,003	$ 236,245	$ 187,585
Net debt to cash flow	1.1:1.0	1.1:1.0	0.7:1.0

(1) Working capital (deficiency) excludes net unrealized gains/losses on commodity contracts.

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,	**2005**	**2004**	**2003**
Basic	103,660,178	88,169,339	61,010,105
Diluted	103,723,937	88,292,020	61,153,027

Trust units/exchangeable shares outstanding:

As at December 31,	**2005**	**2004**	**2003**
Trust units outstanding	117,172,421	99,511,576	72,688,577
Trust units issuable for exchangeable shares (*Note 10*)	388,147	939,147	939,147
	117,560,568	100,450,723	73,627,724

The Trust had 117,172,421 Trust units outstanding at December 31, 2005 compared to 99,511,576 Trust units at the end of 2004. The weighted average number of Trust units outstanding including Trust units issuable for Exchangeable Shares, was 103,660,178 Trust units in 2005 as compared to 88,169,339 for 2004. During the year ending December 31, 2005, 427,248 Exchangeable Shares were exchanged for 551,000 Trust units and 46,375 were redeemed for cash leaving 388,025 Exchangeable Shares outstanding at December 31, 2005 which are exchangeable into 388,147 Trust units.

On June 14, 2005, the Trust issued 4.15 million Trust units for gross proceeds of $75.7 million ($71.4 million net) at a deemed price of $18.25 per unit. On December 15, 2005, 12.5 million Trust units were issued at a price of $20.00 per unit with gross proceeds of $250 million ($237 million net).

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 weight 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.

On June 16, 2004, the Trust issued 26.4 million units for the purchase of Ultima 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 units.

During the year, 418,424 options (2004 - 332,733, 2003 - 1,673,404 options) were exercised for the same number of Trust units generating proceeds of $5.9 million in 2005 (2004 - $3.8 million, 2003 - $20.5 million). (For details of options exercised and outstanding at the end of the year refer to Note 14 of the Consolidated Financial Statements.)

FINANCIAL INSTRUMENTS

The net negative fair value of the commodity contracts at December 31, 2005 of $4.6 million has been recorded on the balance sheet as commodity contracts under assets or liabilities, as appropriate. The negative change in the fair value of the contracts, December 31, 2005 of $34.5 million (2004 - $48.7 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 $40.9 million for 2005 compared to $42.5 million for 2004.

	January 1,	**Amortized**	**December 31,**
Deferred Commodity Contracts ($000 s)	**2005**	**to Expense**	**2005**
Current Asset			

Deferred loss	$	$	$
	517	(517)	-
Current Liability			
Deferred gain	(184)	184	-

	$	$	$
	333	(333)	-

Commodity Contracts ($000 s)	**January 1, 2005**	**Change in Fair Value**	**December 31, 2005**
Current Asset			
Commodity contracts	$ 3,281	$ (1,375)	$ 1,906
Current Liability			
Commodity contracts	(14,599)	8,053	(6,546)
	$ (11,318)	$ 6,678	$ (4,640)

The following is a summary of the gain (loss) on commodity contracts for 2005:

($000 s)	**Crude Oil & Liquids**	**Natural Gas**	**Electricity**	**2005 Total**	**2004 Total**	**2003 Total**
Realized cash gain (loss) on contracts	$ (36,554)	$ (4,851)	$ 514	$ (40,891)	$ (42,491)	$ (7,755)
Unrealized gain (loss) on contracts	10,462	(4,764)	647	6,345	(6,221)	-
Gain (loss) on commodity contracts	$ (26,092)	$ (9,615)	$ 1,161	$ (34,546)	$ (48,712)	$ (7,755)

NON-RESIDENT OWNERSHIP

Based on information available to the Trust, Petrofund estimated that non-resident ownership was approximately 70% as of January 31, 2006. There are to the knowledge of Petrofund, at this time, no significant changes pending or proposed to the Income Tax Act (Canada) (the Tax Act) that could impact Petrofund s qualification as a mutual fund trust under the Tax Act.

In order for Petrofund to qualify as a 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 endeavor 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 the purposes of the requirements of these provisions, should qualify as a mutual fund trust under the current provisions of the Tax Act.

Accordingly, there are to the knowledge of Petrofund, at this time, no restrictions or deadlines on Petrofund pertaining to non-resident ownership levels. However, the Trust will continue to provide non-resident ownership level updates on a quarterly basis and will continue to monitor any developments in this area.

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		**less than**	**1 3**	**4 5**	**after**
(millions)	**Total**	**one year**	**years**	**years**	**5 years**
	$	$	$	$	$
Long-term debt (1), (5)	462.8	-	-	-	462.8
Operating leases	17.7	2.1	4.4	4.6	6.6
Purchase obligations (2)	135.7	15.0	26.5	26.6	67.6
Asset retirement obligation (3)	217.4	4.0	7.7	11.1	194.6
RUP, LTIP s(4)	4.9	1.6	2.9	0.1	0.3
	$	$	$	$	
Total	838.5	22.7	41.5	42.4	$ 731.9

(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 $108.6 million for CO_2 purchases and $27.1 million for processing fees with respect to PC s interest in 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.

(4)

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

(5)

Interest expense of approximately $21.0 million per year has been excluded from the above table.

OFF-BALANCE SHEET ARRANGEMENTS

The Trust had no off-balance sheet financing arrangements in the last competed financial year.

RELATED PARTY TRANSACTIONS

The Trust had no related party transactions in the last completed financial year.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in accordance with GAAP requires management to make certain judgments and estimates. The Trust follows the full cost method of accounting for its oil and natural gas activities as described in Note 2 of the Consolidated Financial Statements. 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.

(f)

estimated fair value of acquired company s assets and liabilities are dependent on the estimated value of oil and natural gas properties. Determining fair value of these properties involves estimating oil and natural gas reserves and future prices of oil and natural gas.

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. Reserve estimates are prepared by an independent qualified reserves evaluator appointed by the Board. An independent committee of the Board, the Reserve s Audit and EH& S committee oversees the integrity of the Trust s reserves.

FINANCIAL REPORTING AND REGULATORY UPDATE

Redeemable or Retractable Shares

On November 5, 2004, the CICA issued EIC-149 Accounting for Retractable or Mandatorily Redeemable Shares that lists specific criteria required to be met in order for entities to reflect trust units and exchangeable shares as either a liability or equity in their financial statements The trust units and exchangeable shares meet the required criteria to be reflected as Unitholders equity and no additional presentation or disclosure is required.

Financial Instruments Recognition and Measurement

On January 27, 2005, the Accounting Standard s Board (AcSB) issued CICA Handbook section 3855 Financial Instruments Recognition and Measurement , CICA Handbook section 3861 Financial Instruments-Disclosure and Presentation , CICA Handbook section 1530 Comprehensive Income and CICA handbook section 3865 Hedges that deal with the recognition and measurement of financial instruments and comprehensive income. The new standards are intended to harmonize Canadian standards with United States and International accounting standards and are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. These new standards will impact the Trust in future periods and the resulting impact will be assessed at that time.

Non-Controlling Interest

On January 19, 2005, the CICA issued EI-151 Exchangeable Securities Issued by Subsidiaries of Income Trusts which states that exchangeable securities issued by a subsidiary of an income trust should be reflected as either non-controlling interest or debt on the consolidated balance sheet unless they meet certain criteria. The exchangeable shares issued by Petrofund Corp., a wholly owned corporate subsidiary of the Trust, are not publicly traded and therefore are not considered, by EIC-151.

EIC-151, Exchangeable Securities, has previously confirmed that the accounting adopted for the recording of the Exchangeable Shares that were issued by a subsidiary of the Trust in 2003 and subsequent redemptions and conversions is appropriate given that they are not transferable.

OUTLOOK FOR 2006

The level of cash flow for 2006 will be affected by oil and gas prices, the Canadian U.S. 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 volatility in 2006 to date and this trend is expected to continue into 2006. The Trust is expected to continue to be active in the acquisition market. 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 expects prices for quality, long life assets to be at or near record levels. Petrofund expects to be an active participant in this market but success will be tempered by a commitment to maintain historic discipline and bid only at levels consistent with the best long term interest of our unitholders.

Acquisition activities will be complemented by an extensive drilling and farmout program that will be conducted on our existing land base.

Although product prices have remained at high levels, the strengthening of the Canadian dollar in the fourth quarter of 2005 moderated the net effect of these prices on Petrofund s cash flow. The WTI price increased 37% to U.S. $56.56/bbl in 2005 from U.S. $41.40/bbl in 2004; however, as the (U.S./CDN) exchange rate averaged 0.83 in

2005 as compared to 0.77 in 2004 the par price at Edmonton was up only 31%. The Trust expects the Canadian dollar to remain strong throughout 2006.

Petrofund pursues a well defined risk management program to help offset the effect of commodity 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. The risk management strategies and hedged positions are discussed under the header Pricing and Price Risk Management in this report.

CORPORATE DEVELOPMENTS

Petrofund Energy Trust added to the S&P/TSX Composite Index

Following market close on December 16, 2005 Petrofund was added to the S&P/TSX Composite Index at 50 per cent of its full float adjusted weight, resulting in Petrofund having a weighting of .08% in the Index. Standard & Poor s had previously announced it intended to include income trusts in the S&P/TSX Composite Index at 50 per cent of their full float adjusted weight on December 16, 2005 and at full weighting on the March 17, 2006 market close.

No Change to Tax Treatment of Income Trusts

On November 23, 2005, the federal government of Canada announced a reduction in personal income taxes on dividends and an end to the consultation process initiated on September 8, 2005 to review the tax treatment of income trusts and flow-through entities. The government did not announce any changes to the tax treatment of income trusts and flow-through entities.

The Trust s management believes that the announcement reflects the overwhelming consensus of submissions received during the consultation process to reduce personal income tax on corporate dividends to correct the long-standing problem of double taxation of dividends at the federal level. Petrofund appreciated the opportunity to participate in the consultation process and is pleased with the government s decision. The decision reduces the uncertainty surrounding income trust taxation and assists in leveling the playing field between corporations and trusts by establishing a better balance between the tax treatment of these entities.

Petrofund continues to express to the federal government the need for removal of the limitation of non-Canadian resident ownership of income trusts. Income trusts need access to global capital markets, similar to the access that corporations currently enjoy, to grow their businesses. This, we believe, is ultimately in the best interests of investors and the Canadian economy.

MANAGEMENT AND FINANCIAL REPORTING SYSTEMS

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 and procedures are in place to ensure all ongoing statutory reporting requirements are met and material information is disclosed on a timely basis. The President and Chief Executive Officer and 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. During 2005, there were no significant changes that would materially effect the internal controls over financial reporting.

Evaluation of Disclosure Control and Procedures

Our management, including our Chief Executive Officer and the Chief Financial Officer, have evaluated the effectiveness of the Trust s disclosure controls and procedures as of the end of the period covered by this report. Based on that evaluation, the Chief Executive Officer and the Chief Financial Officer have concluded that the Trust s disclosure controls are effective as of the end of the period covered by this annual report, in all material respects, after considering the control assertion statements and the guidance published within U.S. Securities and Exchange Commission Release No. 33-8124, Certification of Disclosures in Companies Quarterly and Annual Reports, and Canadian Securities Administrators Multilateral Instrument 52-109 Certification of Disclosures in Issuers Annual and Interim Fillings. There were no changes to our internal control over financial reporting during our last fiscal year that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Sarbanes-Oxley Update

On July 31, 2002, the United States Congress enacted the Sarbanes-Oxley Act (SOX) that applies to all companies reporting with the Securities and Exchange Commission (SEC). On March 2, 2005, the SEC announced a one year extension of the compliance date for all foreign private issuers that are accelerated filers. As a result of this extension, Petrofund is currently required to comply with Section 404 of the SOX legislation as of December 31, 2006. Section 404 requires that management identify, document, and assess internal control over financial reporting and issue an annual report on their assessment of its effectiveness. The Trust has implemented a comprehensive program for meeting the requirements of Section 404 by December 31, 2006.

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 and PVT 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 subsidiaries. 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 and PVT s properties. The reserves and recovery information contained in PC s and PVT 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 attributes which differentiate it from many 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 and PVT s reserves and production and, therefore, their cash flows will be highly dependant upon their success in exploiting their 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.

VARIATIONS IN INTEREST RATES AND FOREIGN EXCHANGE RATES

Variations in interest rates could result in a significant increase in the amount the Trust pays to service debt, resulting in a decrease in distribution to Unitholders.

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 2005 negatively affected the Trust s net production revenue. The Canadian dollar averaged US 0.83 in 2005 versus US 0.77 in 2004 versus 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.

CREDIT RISK

PC markets and hedges its and PVT s 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 distributions could result in such circumstances. Oil and natural gas sales revenue credit risk is managed by limiting the exposure to customers based on assigned credit ratings as well as limiting the maximum exposure to any single customer. Risk is further managed as sales revenue receivables are due and settled in the month following the sale. PC manages its exposure to credit risk under financial instruments, such as commodity derivatives and foreign exchange contracts, by selecting counterparties of high credit quality. Risk is also minimized through regular management review of potential exposure to, and credit ratings of such counterparties. PC has not experienced a significant loss on uncollected receivables from any customers or counterparties.

OPERATIONAL RISKS

PC s and PVT 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. PC currently operates approximately 50% of its total daily production. 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. A reduction of the distributions and possible reduction in capital could result in such circumstances.

EXPANSION OF OPERATIONS

The operations and expertise of management of the Trust are currently focused on conventional oil and natural gas production and development in Western Canadian Sedimentary Basin. In the future, the Trust may acquire oil and natural gas properties outside this geographic area. In addition, the Trust Indenture does not limit the activities of the Trust to oil and natural 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.

MARKETABILITY OF PRODUCTION

The marketability of PC s and PVT 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 and PVT 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 and PVT s control.

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 and PVT s 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 and PVT have established a reclamation fund for the purpose of funding their estimated future environmental and reclamation obligations based on their current knowledge, there can be no assurance that PC and PVT will be able to satisfy their actual future environmental and reclamation obligations. While PC and PVT have 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 and PVT maintain insurance coverage considered to be customary in the industry, they are not fully insured against certain environmental risks, either because such insurance is not available, or because of high premium costs. In particular, insurance against risks from environmental pollution occurring over time (compared to sudden and catastrophic damages) is not available. In such an event, these environmental obligations would be funded out of PC s and PVT s cash flows 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

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 and PVT. 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 and PVT 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 reminder, 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 favorable 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 and PVT s properties, and by those operators to PC, payments between any of these parties may also be delayed my 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.

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 endeavor 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 the 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.

TAXABILITY OF PETROFUND CORP

At the current time, there is no income tax payable by PC other than Large Corporate Tax; 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). 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.

<u>SENSITIVITY ANALYSIS</u>

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 2005 prices received for the fourth quarter of 2005 and 39,178 boe/d fourth quarter 2005 production volumes. 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	$000	$/unit per year
Price per barrel of oil*	$ 1.00 U.S. WTI	$ 7,457	$ 0.063
Price per mcf of natural gas*	$ 0.25 CDN	$ 7,556	$ 0.064
US/Cdn exchange rate	$ 0.01	$ 6,215	$ 0.053
Interest rate on debt ($463 million)	1%	$ 4,627	$ 0.039
Oil production volumes*	100 bbl/day	$ 1,846	$ 0.016
Gas production volumes*	1 mmcf/day	$ 3,268	$ 0.028

*After adjustment for estimated royalties.

PETROFUND ENERGY TRUST

CORPORATE GOVERNANCE

The relationship between the board of directors of PC (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. Strategic planning is fundamental to Petrofund and strategic planning is done collaboratively between the Board and Management. The Board oversees and monitors systems for managing business risk and regularly reviews strategic plans with Management. Petrofund is in full compliance with the corporate governance standards established under National Policy 58-201 entitled Corporate Governance Guidelines (NP 58-201).

The Board is composed of individuals all of who have experience relevant to the Trust s operations and understand the complexities of the Trust s business environment. The Board includes 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. At the April 2005, annual meeting one director did not stand for re-election, thereby reducing the number of directors to eight.

In addition to those matters which must be approved by the Board 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 eight members. All members of the Board, with the exception of Mr. Errico (the Trust s current President and Chief Executive Officer) are independent directors within the context and meaning outlined within NP 58-201. The responsibility for ensuring that individual directors are independent rests with the Board. The Board will ensure that Petrofund discloses on an annual basis the number of independent and non-independent directors.

ORIENTATION AND CONTINUING EDUCATION

Petrofund has instituted, under the auspices of the Governance Committee, a formal orientation and education program for new Board members in order to ensure that new directors are familiarized with Petrofund's business; including Petrofund's field operations, management, administration, policies and plans, and the procedures of the Board. New directors attend a one day session conducted by the Chief Executive Officer, which includes presentations from the other executive officers and senior personnel, and which covers the general structure of Petrofund, corporate strategies, acquisition and development projects, oil and gas operations, legal matters, financial matters, accounting matters, and investor relations. The directors are provided with a Board Orientation Manual containing written information and materials pertaining to the subjects covered in the orientation session, which is revised and updated on a regular basis by management. The Board is also encouraged to take part in site visits to wellsites and facility locations in the field to observe for themselves the standard and quality of

Petrofund s operations. In addition to the regular updates and revisions to the Board Orientation Manual, Petrofund encourages directors to attend, enrol, or participate in courses and/or seminars dealing with financial literacy, corporate governance, and related matters and has agreed to pay the cost of such courses and seminars.

COMMITTEES

The Board has four committees; the Governance Committee, the Audit Committee, the Human Resources & Compensation Committee and the Reserves Audit and EH&S Committee. All Board committees consist entirely of independent directors. Committees have formal written mandates approved by the Board. 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 for its approval. All committees have the right to retain independent advisors at the expense of Petrofund.

GOVERNANCE COMMITTEE

The Governance Committee is comprised of Sandra Cowan (Chairperson), Art Dumont and Frank Potter each of whom has been determined to be independent. The Committee has the responsibility for proposing new nominees to the Board, 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 is comprised of James Allard (Chairperson), Frank Potter and Gary Lee each of whom has been determined to be independent. 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 a financial expert, having served as Chief Executive Officer and Chief Financial Officer for several private and publicly traded companies throughout his lengthy career. The Committee meets with Petrofund s independent external auditors without management and does so a minimum of four times a year. The Committee has direct responsibility for the appointment, compensation and oversight of the external auditors. The Committee has sole authority to pre-approve all audit and non-audit services not prohibited by applicable law or rules of the stock exchanges (TSX and AMEX), including remuneration and terms of engagement.

HUMAN RESOURCES & COMPENSATION COMMITTEE

The Human Resources & Compensation Committee is comprised of Frank Potter (Chairperson), Gary Lee and Wayne Newhouse each of whom has been determined to be independent. 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.

Under the guidance of the Committee, each director performs a written annual appraisal of the CEO s performance against stated performance objectives formulated at the beginning of each year.

RESERVES AUDIT AND EH&S COMMITTEE

The Reserves Audit and EH&S Committee is comprised of Wayne Newhouse (Chairperson), James Allard and Art Dumont each of whom has been determined to be independent. The Reserves Audit and EH&S Committee has the responsibility of overseeing the integrity of Petrofund s reserve estimates. Contained within the Reserves Audit and EH&S Committee s 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 annually without management.

CODE OF BUSINESS ETHICS AND WHISTLEBLOWER 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 through the Chairman of the Audit Committee participate in the review and investigation of the reported incidents.

QUARTERLY and ANNUAL FINANCIAL DATA

(millions of Canadian dollars, except per unit amounts)

			Net income per unit [2]	
	Net Oil and Natural Gas Sales [1]	**Net Income**	**Basic**	**Diluted**
2005				
	$	$	$	$
First quarter	122.9	19.2	0.19	0.19
Second quarter	141.7	40.2	0.40	0.40
Third quarter	170.3	51.2	0.49	0.49
Fourth quarter	188.9	100.1	0.93	0.93
	$	$	$	$
	623.8	210.7	2.03	2.03
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

(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, ($000 s)	**2005**	**2004**	**2003**
Total assets	$	$	$

	2,267,119	1,486,412	962,528
Total long-term debt	$	$	$
	462,783	214,414	110,315

SUMMARY of FOURTH QUARTER RESULTS

Three months ended December 31,	**2005**	**2004**	**% change**	
Daily Production Volumes				
Oil (bbls)	18,856	18,508	2	
Natural gas (mmcf)	108.9	90.1	21	
Natural gas liquids (bbls)	2,164	2,502	(14	)
BOE (6:1)	39,178	36,025	9	
Average Prices [1]				
	$	$		
Oil (per bbl)	62.46	50.96	23	
Natural gas (per mcf)	11.78	7.12	65	

Natural gas liquids (per bbl)	65.46	48.20	36	
	$	$		
Per BOE (6:1)	66.44	47.33	40	
Operational Highlights				
	$	$		
Oil and natural gas sales ($ millions) [1]	239.6	156.9	53	
Royalties ($ millions)	50.7	31.2	(63)	
Transportation costs ($ millions)	1.8	1.6	(15)	
Operating expenses ($ millions)	38.3	29.2	(31)	
Costs per boe	10.64	8.82	(21)	
General and administrative ($ millions)	4.8	4.2	(14	)
	$	$		)
Costs per boe	1.34	1.27	(6	

(1)

Prices and revenue are before realized gains/losses on commodity contracts and before transportation costs.

QUARTERLY REVIEW

(thousands of Canadian dollars and units, except per unit amounts and as indicated)

	2005				2004			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Daily Production								
Oil (bbls)	18,856	18,451	17,500	18,238	18,508	17,504	12,679	11,579
Natural gas (mcf)	108,948	97,825	96,951	88,271	90,089	90,119	79,741	77,925
Natural gas liquids (bbls)	2,164	2,730	2,353	2,283	2,502	2,427	2,074	2,040
BOE (6:1)	39,178	37,485	36,011	35,234	36,025	34,950	28,043	26,607
Average Prices (5)								
Oil (per bbl)	$ 62.46	$ 69.37	$ 59.18	$ 54.74	$ 50.96	$ 52.02	$ 47.01	$ 42.50
Natural gas (per mcf)	$ 11.78	$ 9.10	$ 7.65	$ 6.97	$ 7.12	$ 6.50	$ 7.13	$ 6.76
Natural gas liquids (per bbl)	$ 65.46	$ 50.36	$ 51.10	$ 46.04	$ 48.20	$ 43.68	$ 37.13	$ 37.06
Per BOE (6:1)	$ 66.44	$ 61.57	$ 52.69	$ 48.79	$ 47.33	$ 45.85	$ 44.27	$ 41.15
Operational Highlights								
Oil and natural gas sales (5)	$ 239,627	$ 212,404	$ 172,831	$ 154,768	$ 156,922	$ 147,489	$ 112,970	$ 99,699
Net oil and natural gas sales (1)	$ 188,920	$ 170,309	$ 141,722	$ 122,924	$ 125,866	$ 119,911	$ 89,953	$ 81,121
Cash flow (2)	$ 126,111	$ 111,122	$ 87,811	$ 72,959	$ 72,302	$ 65,075	$ 49,820	$ 49,047
Per unit - basic	$ 1.17	$ 1.06	$ 0.86	$ 0.73	$ 0.72	$ 0.65	$ 0.64	$ 0.67
- diluted	$ 1.17	$ 1.06	$ 0.86	$ 0.72	$ 0.72	$ 0.65	$ 0.64	$ 0.66
Per boe	$ 34.99	$ 32.22	$ 26.80	$ 23.01	$ 21.81	$ 20.24	$ 19.52	$ 20.26
Cash distribution paid	$	$	$	$	$	$	$	$

	55,452	50,150	48,793	47,894	47,734	47,684	39,165	34,910
Cash distribution paid per unit	$ 0.51	$ 0.48	$ 0.48	$ 0.48	$ 0.48	$ 0.48	$ 0.48	$ 0.48
Payout ratio [(6)]	44%	45%	56%	67%	67%	75%	80%	73%
Net income	$ 100,023	$ 51,209	$ 40,193	$ 19,243	$ 50,765	$ 15,147	$ 817	$ 7,629
Net income per unit - Basic	$ 0.93	$ 0.49	$ 0.40	$ 0.19	$ 0.51	$ 0.15	$ 0.01	$ 0.10
- Diluted	$ 0.93	$ 0.49	$ 0.40	$ 0.19	$ 0.51	$ 0.15	$ 0.01	$ 0.10
Cash operating netback per BOE [(7)]	$ 37.93	$ 34.67	$ 29.28	$ 25.45	$ 24.40	$ 22.57	$ 22.05	$ 22.71

	$	$	$	$	$	$	$	$
Lease operating costs	38,333	35,558	35,677	32,010	29,222	30,920	23,639	19,829
	$	$	$	$	$	$	$	$
Cost per BOE	10.64	10.31	10.89	10.09	8.82	9.62	9.26	8.19
	$	$	$	$	$	$	$	$
General & administrative costs	4,817	4,816	3,902	3,639	4,223	3,764	3,316	3,138
	$	$	$	$	$	$	$	$
Costs per BOE	1.34	1.40	1.19	1.15	1.27	1.17	1.30	1.30

QUARTERLY REVIEW - continued

(thousands of Canadian dollars and units, except per unit amounts and as indicated)

	2005				2004			
	Q4	**Q3**	**Q2**	**Q1**	**Q4**	**Q3**	**Q2**	**Q1**
Balance sheet								
Working capital (deficit) [3]	$ 31,897	$ 12,077	$ (47,812)	$ (59,531)	$ (49,310)	$ (24,229)	$ (13,884)	$(56,093)
Property, plant and equipment, net	$ 1,777,922	$ 1,297,522	$ 1,306,761	$ 1,259,248	$ 1,246,694	$ 1,230,636	$ 1,251,484	$883,191
Total assets	$ 2,267,119	$ 1,569,436	$ 1,575,524	$ 1,503,672	$ 1,486,412	$ 1,469,209	$ 1,507,276	$932,758
Long-term debt	$ 462,783	$ 244,499	$ 254,345	$ 239,237	$ 214,414	$ 199,474	$ 212,537	$90,040
Unitholders equity	$ 1,385,343	$ 1,084,746	$ 1,034,115	$ 992,882	$ 1,026,526	$ 1,031,226	$ 1,063,704	$615,952
Units and Exchangeable Shares Outstanding								
Weighted average	107,363	105,018	101,569	100,603	100,396	100,267	78,074	73,674
Diluted	107,415	105,039	101,593	100,644	100,466	100,353	78,229	73,872
At period end	117,561	105,046	105,014	100,746	100,451	100,344	100,190	73,682
Market Capitalization	$ 2,408,816	$ 2,397,156	$ 2,047,767	$ 1,777,156	$ 1,568,036	$ 1,595,476	$ 1,487,823	$1,278,390
Total Capitalization [3] [4]	$ 2,839,702	$ 2,629,578	$ 2,349,924	$ 2,075,924	$ 1,831,760	$ 1,819,179	$ 1,714,244	$1,424,523
Trust Unit Trading (TSX:PTF.UN)								
High ($CDN)	$ 23.17	$ 23.31	$ 19.97	$ 19.33	$ 17.15	$ 16.35	$ 18.08	$19.24
Low ($CDN)	$ 19.05	$ 19.30	$ 17.00	$ 15.50	$ 14.52	$ 14.62	$ 14.70	$14.56
Close ($CDN)	$ 20.49	$ 22.82	$ 19.50	$ 17.64	$ 15.61	$ 15.90	$ 14.85	$17.35
Average daily volumes	256	147	176	264	185	287	189	204
Trust Unit Trading (AMEX:PTF)								

High ($US)	$ 19.88	$ 19.85	$ 16.25	$ 16.05	$ 13.65	$ 12.83	$ 13.54	$14.96
Low ($US)	$ 16.10	$ 15.72	$ 13.62	$ 12.66	$ 12.16	$ 11.10	$ 10.95	$10.95
Close ($US)	$ 17.64	$ 19.64	$ 15.92	$ 14.62	$ 13.04	$ 12.60	$ 11.16	$13.22

Average daily volumes (7)	550	579	469	643	518	431	319	633

Net after royalties.

(2)

Cash flow before net changes in non-cash operating capital
(Non-GAAP measures, see special notes in Management s Discussion and Analysis).

(3)

Excludes net unrealized gains/losses on commodity contracts.

(4)

Total capitalization equals market capitalization plus net debt
(Non-GAAP measures, see special notes in Management s Discussion and Analysis).

(5)

Prices and revenue are before realized gains/losses on commodity contracts and before transportation costs.

(6)

Cash distributions paid divided by cash flow before capital reinvestment.

(7)

Cash operating netback per BOE is calculated as the selling price less the cash cost of hedging less royalties, net of ARC, lease operating costs and transportation costs, by product, divided by the total production volumes in each period.

Consolidated Balance Sheet

(thousands of Canadian dollars)

As at December 31,	**2005**	**2004**
ASSETS		
Current assets		
Cash and cash equivalents *(Note 18(b))*	$ 38,935	$ -
Accounts receivable *(Note 19)*	72,599	37,713
Deferred loss on commodity contracts	-	517
Commodity contracts (*Note 15)*	1,906	3,281
Prepaid expenses	17,217	10,847
Total current assets	130,657	52,358
Asset retirement reserve fund *(Note 7(b))*	9,078	7,053
Goodwill (*Notes 3 and 5*)	349,462	180,307
Oil and natural gas royalty and property interests (*Notes 4 and 5)*	1,777,922	1,246,694
	$ 2,267,119	$ 1,486,412
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities	$	$
Bank overdraft	-	733
Accounts payable and accrued liabilities *(Note 19)*	96,854	60,961
Current portion of capital lease obligations	-	608
Deferred gain on commodity contracts	-	184
Commodity contracts (*Note 15)*	6,546	14,599
Distributions payable to Unitholders (*Note 8*)	-	35,568
Total current liabilities	103,400	112,653
Long-term debt *(Note 6*)	462,783	214,414
Future income taxes (*Note 16)*	242,320	81,411
Asset retirement obligations (*Note 7(a))*	73,273	51,408
Total liabilities	881,776	459,886
Commitments and contingent liabilities *(Note 17)*		
Unitholders' equity		
Unitholders' capital *(Note 9*)	1,799,137	1,477,963
Exchangeable shares *(Note 10*)	4,347	10,518
Contributed surplus *(Note 11)*	1,021	-

Accumulated earnings	483,280	272,612
Accumulated cash distributions *(Note 8)*	(902,442)	(734,567)
Total unitholders' equity	1,385,343	1,026,526
	$	$
	2,267,119	1,486,412

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

Consolidated Statement of Operations and Accumulated Earnings

(thousands of Canadian dollars, except per unit amounts)

For the years ended December 31,	**2005**	**2004**	**2003**
REVENUES			
	$	$	$
Oil and natural gas sales	779,630	517,081	406,346
Royalties	(155,755)	(100,230)	(84,804)
Loss on commodity contracts	(34,546)	(48,712)	(7,755)
	589,329	368,139	313,787
EXPENSES			
Lease operating	141,578	103,610	91,251
Transportation costs	8,059	5,862	5,482
Financing costs	10,600	5,849	8,748
General and administrative	17,174	14,441	13,047
Capital taxes	3,938	3,261	2,454
Depletion, depreciation and accretion	202,839	153,079	118,307
Internalization of management contract (*Note 12*)	-	-	30,850
-			
286,102			
270,139	384,188	286,102	270,139
Income before provision for income taxes			
-			
82,037			
43,648	205,141	82,037	43,648
Provision for (recovery of) income taxes *(Note 16)*			
Current	1,184	539	569
Future	(6,711)	7,139	(44,197)
-			
7,678			
(43,628)	(5,527)	**7,678**	(43,628)
Net income	210,668	74,359	**87,276**
-			

74,359

87,276

Accumulated earnings, beginning of the year	272,612	198,253	110,977
	$	$	$
Accumulated earnings, end of the year	483,280	272,612	198,253
Net income per Trust unit (*Note 9)*			
	$	$	$
Basic	2.03	0.84	1.43
	$	$	$
Diluted	2.03	0.84	1.43

The accompanying notes to the Consolidated Financial Statements are an integral part of this consolidated statement.

Consolidated Statement of Cash Flows

(thousands of Canadian dollars)

For the years ended December 31,	**2005**		**2004 2003**
Cash provided by (used in):			
Operating activities			
	$	$	$
Net income	210,668	74,359	87,276
Add items not affecting cash:			
Depletion, depreciation and accretion	202,839	153,079	118,307
Unrealized (gains) losses on commodity contracts	(6,345)	6,221	-
Future income taxes	(6,711)	7,139	(44,197
Unit-based compensation	1,021	-	-
Actual abandonment costs settled (*Note 7(a)*)	(3,469)	(4,553)	(4,651)
Internalization of management contract (*Note 12*)			
-			
-			
30,850	-	-	30,850
(Increase) decrease in non-cash operating working capital *(Note 18)*	(60,780)	7,407	4,578
Cash provided by operating activities	337,223	243,652	192,163
Financing activities			
Long-term debt	248,369	(5,700)	(102,546)
Distributions paid (*Note 8*)	(202,289)	(169,493)	(127,325)
Redemption of exchangeable shares *(Note 10)*	(1,154)	(1,803)	(2,792)
Capital lease repayments	(608)	(356)	(9,305)
Issuance of Trust units, net (*Note 9)*	315,003	4,479	214,002
(Increase) decrease in non-cash financing working capital *(Note 18)*	388	(168)	168
Cash provided by (used in) financing activities	359,709	(173,041)	(27,798
Investing activities			
Asset retirement reserve fund *(Note 7(b))*	(2,025)	(1,725)	(776)
Corporate acquisitions *(Note 5)*	(542,819)	(28,960)	(8,549)
Property acquisitions	(18,241)	(3,093)	(107,023)
Property dispositions	871	1,043	33,466
Development expenditures	(145,262)	(76,788)	(71,384)
Cash acquired on acquisition (*Note 5*)	28,993	9,711	-

Internalization of management contract (*Note 12*)	-	-	(8,009)
Decrease in non-cash investing working capital *(Note 18)*	21,219	26,286	1,664
Cash used in investing activities	(657,264)	(73,526)	(160,611)
Net change in cash and cash equivalents	39,668	(2,915)	3,754
Cash and cash equivalents (bank overdraft), beginning of the year	(733)	2,182	(1,572)
	$	$	$
Cash and cash equivalents (bank overdraft), end of the year *(Note 18)*	38,935	(733)	2,182

The accompanying notes to the Consolidated Financial Statements are an integral part of this consolidated statement.

Notes to the Consolidated Financial Statements

December 31, 2005, 2004 and 2003

(thousands of Canadian dollars, except unit and per unit amounts and as indicated)

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 royalties are 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 in Canadian dollars 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 20. The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosures of contingencies at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Actual results could differ from those estimated. The following significant accounting policies are presented to assist the reader in evaluating these Consolidated Financial Statements.

(a)

Basis of Consolidation

The Consolidated Financial Statements include the accounts of the Trust and its wholly-owned subsidiaries, PC, PVT, Petrofund Alternative Energy Ltd., 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 or the Previous Manager), collectively, the Subsidiaries . NMSI and NCEP Management were acquired to effect the internalization of management and the exchangeable shares of PC are exchangeable into Trust units. (See Notes 10 and 12). All intercompany transactions have been eliminated.

(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 corporate acquisitions 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 recognized based on the fair value of reporting entity (the consolidated Trust) compared to the book value of the reporting entity. 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.

The provision for depletion and depreciation is computed using the unit-of-production method including future development costs based on the estimated gross proven oil and gas reserves and based on forecast prices and escalated costs. 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. Gas volumes are converted to barrels of oil at 6,000 cubic feet per barrel.

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.

(e)

Asset Retirement Obligation

The Trust recognizes as a liability the estimated fair value of the future retirement obligations associated with property, plant and equipment in the period in which it s incurred. The fair value is capitalized and amortized over the same period as the underlying asset. The Trust estimates the liability based on the estimated costs to abandon and reclaim its net ownership interest in all wells and facilities and the estimated timing of the costs to be incurred in future periods. This estimate is reviewed on a periodic basis and any changes are prospectively applied as an increase or decrease to the liability. As time passes, the change in net present value of the future retirement liability is recorded as accretion and is charged to earnings in the period. Actual costs incurred upon settlement of the liability are charged against the liability.

(f)

Financial Instruments

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 and electricity purchases. 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 Accounting Guideline 13 Hedging Relationships . Petrofund uses the fair value method of accounting for all derivative transactions. Fair values are determined based on third-party statements for the amounts that would be paid or received to settle these instruments prior to maturity and recorded on the balance sheet with changes in the fair value recorded in the statement of income as a gain (loss).

(g)

Distributions Payable to Unitholders

Distributions payable to Unitholders are equal to amounts declared and payable by the Trust. In 2004, the distributions payable were based on amounts received or receivable by the Trust on the cash distributions date, with income earned, but not received, distributed on the cash distribution date following receipt.

(h)

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 temporary 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.

(i)

Transportation Costs

Transportation costs associated with oil and natural gas sales are recognized when the product is delivered.

(j)

Unit-based Compensation

The Trust has three stock-based compensation plans: (i) the Restricted Unit Plan (RUP), (ii) the Long-Term Incentive Plan (LTIP) and (iii) the Trust Unit Incentive Plan (TUIP) which is being phased out. These plans are described in Notes 13 and 14 to the Consolidated Financial Statements.

(i)

Restricted Unit Plan

The RUP authorizes the Trust to issue units to directors, officers, employees or consultants. The RUP operates independently of the LTIP which is made available to the Chief Executive Officer (CEO), the Executive Vice-President (EVP), Senior Vice-President, Operations (SVP) and the Vice-President, Finance and Chief Financial Officer (CFO); however, these officers are also eligible to participate in the RUP. The units, plus accrued distributions, vest over time and upon vesting may be redeemed by the holder for cash or Trust units. The Trust units are issued, or cash paid out, on the vesting dates based on the weighted average trading prices of the Trust units for the last 20 days prior to the vesting dates.

As the RUP is settled in cash or units at the option of the holder, the associated compensation expense and the related liability is calculated as the excess of the quoted market value of the trust units over the exercise price of the units at each reporting period. The expense is amortized over the vesting period of three years.

(ii)

Long-Term Incentive Plan

The LTIP authorizes the Trust to issue units to the CEO, EVP, SVP and CFO. Directors and employees are not eligible to be issued units under the LTIP. The units, plus accrued distributions, vest over time and upon vesting may be redeemed by the holder for Trust units. One third of the LTIP award vests on the grant date, the remaining two thirds vests on the first and second anniversary date from the grant date.

As the LTIP is settled in equity, compensation expense is calculated as the fair value of the award at the date of grant. The Trust s LTIP is a full or whole share value grant. Under the plan, the eligible executives do not pay any consideration for this grant. Fair values are determined at the grant date, using an option pricing model. The compensation expense associated with these units is charged to earnings over the vesting period. The exercise of the units together with any amount previously recognized in contributed surplus is recorded as an increase in Unitholders capital.

(iii)

Trust Unit Incentive Plan

The TUIP 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.

The Trust accounts for stock options granted prior to 2003 based on the intrinsic value at the grant date, which does not result in a charge to earnings because the exercise price was equal to the market price at grant date. In 2003, the Trust prospectively adopted amendments to CICA 3870 Stock-Based Compensation and other Stock-based Payments. These amendments required the Trust to account for compensation expense for all awards granted on or after January 1, 2003, based on the fair value of the options at the grant date. The Trust has not granted any options since December 31, 2002 and therefore these amendments had no material impact on the Consolidated Financial Statements.

Consideration paid on the exercise of the options together with any amount previously recognized in contributed surplus is recorded as an increase in Unitholders capital.

(k)

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 and exchangeable shares outstanding for the period. Diluted per unit amounts reflect the potential dilution that would occur if options or LTIP units were exercised and Trust units were issued. The treasury stock method is used to determine the effect of dilutive instruments.

(l)

Cash and Cash Equivalents

Cash and cash equivalents include short-term, highly liquid investments with an original maturity of 90 days or less. They are recorded at cost and used to meet current operating activities and/or to reduce outstanding debt.

(m)

Exchangeable Shares

Exchangeable Shares are based on a ratio, which is adjusted each date that the Trust pays a distribution to its Unitholders. The Exchangeable Shares are not transferable and are presented as part of Unitholders equity.

(n)

Foreign Currency Translation

Monetary assets and liabilities denominated in a foreign currency are translated at the ratio of exchange in effect at the consolidated balance sheet date. Revenues and expenses are translated at the monthly average rates of exchange. Translation gains and losses are included in income in the period in which they arise.

3.

GOODWILL

The changes in the carrying amount of goodwill are as follows:

($000 s)	**2005**	**2004**
	$	$
Goodwill, January 1,	180,307	-
Goodwill acquired *(Note 5)*	169,155	180,307
	$	$
Goodwill, December 31,	349,462	180,307

4.

OIL AND NATURAL GAS ROYALTY AND PROPERTY INTERESTS (PP&E)

As at December 31, ($000 s)	**2005**	**2004**
	$	$
Oil and natural gas royalty and property interests, at cost	2,609,377	1,879,362
Accumulated depletion and depreciation	831,455	632,668
	$	$
Oil and natural gas royalty and property interests, net	1,777,922	1,246,694

Capitalized general and administrative expenses related to development activities of $2.3 million in 2005 (2004 - $1.0 million) is included in PP&E and the depletion and depreciation calculation includes future capital costs of $290.7 million at December 31, 2005 (2004 - $250.8 million) identified in our reserve report.

An impairment test calculation was performed on the Trust s oil and natural gas royalty property interests at December 31, 2005, in which the estimated undiscounted future net cash flows associated with proved reserves exceeded the carrying amount of the Trust s oil and natural gas royalty and property interests.

The Trust performed its impairment test at December 31, 2005, based on the undiscounted value of future net cash flows based on forecast prices and escalated costs associated with its proved reserves using the following bench mark commodity prices and foreign exchange rates:

	Fx	WTI	Edmonton Light	AECO Spot
	$US/$Cdn	$US/Bbl	$Cdn/Bbl	$/mmbtu
2006	0.85	57.00	66.25	10.60
2007	0.85	55.00	64.00	9.25
2008	0.85	51.00	59.25	8.00
2009	0.85	48.00	55.75	7.50
2010	0.85	46.50	54.00	7.20
2011-2016 Average	0.85	46.54	54.00	7.16
2017+	0.85	+2.0%/yr	+2.0%/yr	+2.0%/yr

5.

ACQUISITIONS

(a)

Acquisition of Kaiser Energy Ltd.

On November 16, 2005, Petrofund entered into an agreement to acquire 100% of Kaiser Energy Ltd. (Kaiser), effective December 1, 2005. Kaiser held, either directly or indirectly, interests in Canadian Acquisitions Limited Partnership and certain properties transferred to Kaiser.

Petrofund s total consideration for the Kaiser acquisition was $471.9 million which includes acquisition costs of $1.8 million and assumed debt and negative working capital of $14.9 million. Of the total cash consideration of $471.9 million, on a preliminary basis, $489.7 million was allocated to oil and natural gas royalty and property interest and $159.2 million to goodwill which is not deductible income for tax purposes.

A summary of the estimated net assets acquired is as follows:

		$000 s
	$	
Current assets (including cash of $32.3 million)		47,951
Goodwill		159,212
Oil and natural gas royalty and property interests		489,676
Current liabilities		(62,840)
Asset retirement obligations		(4,930)
Future income taxes		(157,201
	$	471,868

The consolidated financial statements reflect the operations of Kaiser from December 1, 2005. If the acquisition had occurred on January 1, 2004 the following pro forma results would have been realized by the Trust in 2005 and 2004:

($000 s except per unit amounts)	2005 (unaudited)	2004
Revenue	$ 97,216	$ 91,077
Net income (loss)	$ 8,309	$ (2,081)
Net income per Trust unit	$ 0.07	$ (0.02)

(b)

Acquisition of Northern Crown Petroleums Ltd.

On May 10, 2005, Petrofund acquired 100% of the outstanding shares of Northern Crown Petroleums Ltd. and its wholly owned subsidiary Spiral Resources Ltd. (collectively Northern Crown) for $32.7 million in cash and assumed debt and negative working capital of $4.8 million. Of the total acquisition costs of $32.7 million, $38.6 million was allocated to oil and natural gas royalty and property interest and $7.1 million to goodwill, which is not deductible for income tax purposes.

A summary of the net assets acquired is as follows:

	$000 s
	$
Current assets	1,733
Goodwill	7,122
Oil and natural gas royalty and property interests	38,556
Current liabilities (including bank overdraft of $3,368)	(6,550)
Asset retirement obligations	(756)
Future income taxes	(7,398)
	$ 32,707

The consolidated financial statements reflect the operations of Northern Crown from May 11, 2005. If the acquisition had occurred on January 1, 2004 the following pro forma results would have been realized by the Trust in 2005 and 2004:

($000 s except per unit amounts)	2005	2004
	(unaudited)	
Revenue	$ 4,192	$ 2,011
Net income (loss)	$ 1,282	$ (1,319)
Net income (loss) per Trust unit	$ 0.01	$ (0.01)

(c)

Acquisition of Tahiti Gas Ltd.

On May 31, 2005, Petrofund acquired 100% of the outstanding shares of Tahiti Gas Ltd. (Tahiti) for $23.4 million in cash and assumed debt and working capital of $23,000. Of the total acquisition costs of $23.4 million, $24.0 million was allocated to oil and natural gas royalty and property interest and $2.8 million to goodwill which is not deductible for income tax purposes.

A summary of the net assets acquired is as follows:

	$000 s
Current assets (including cash of $88)	$ 184
Goodwill	2,821
Oil and natural gas royalty and property interests	23,974

Current liabilities	(161)
Asset retirement obligations	(420)
Future income taxes	(3,021)
	$ 23,377

The consolidated financial statement reflects the operations of Tahiti from June 1, 2005. If the acquisition had occurred on January 1, 2004 the following pro forma results would have been realized in the Trust in 2005 and 2004:

($000 s except per unit amounts)	**2005**	**2004**
	(unaudited)	
Revenue	$ 390	$ 853
Net loss	$ (378)	$ (811)
Net loss per Trust unit	$ -	$ (0.01)

(d)

Ultima Energy Trust

On June 16, 2004, Petrofund acquired 100% of the issued and outstanding units of Ultima Energy Trust (Ultima) for 0.442 of a Petrofund unit for each Ultima unit on a tax-free rollover basis. The value assigned to each Petrofund unit issued 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 $454.7 million, $385.0 million was allocated to oil and natural gas royalty and property interests and $178.1 million to goodwill, which is not deductible for income 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 natural 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

The consolidated financial statements reflect the operations of Ultima from June 16, 2004. If the acquisition had occurred on January 1, 2003 the following pro forma results would have been realized in the Trust in 2004 and 2003:

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

(e)

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 natural gas royalty and property interests	34,404
Asset retirement obligations	(944)
Future income taxes	(7,932)
	$ 27,725

The consolidated financial statements reflect the operations of Central Alberta PNG Partnership and 1034373 Alberta Ltd. from November 11, 2004. 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

(f)

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 natural gas royalty and property interests		13,219
Bank overdraft		(370)
Future income taxes		(4,676)
		$ 7,360

6.

LONG-TERM DEBT

Under the loan agreements, as at December 31, 2005, PC, a wholly-owned subsidiary of the Trust, had a revolving working capital operating facility of $50 million and a syndicated facility of $540 million. Interest rates fluctuate under the syndicated facility with Canadian prime and U.S. base rates plus between 0 and 25 basis points, as well as with Canadian banker s acceptance and LIBOR rates plus between 75 basis points and 125 basis points, depending, in each case upon the Trust s debt to cash flow ratio. The Credit Facilities are secured by a $900 million debenture containing a first ranking security interest on all of PC s assets. In addition, the Credit Facilities requires each of the Trust, PVT and the subsidiaries of the Trust other than PC and PVT, to provide a guarantee of PC s indebtedness under the Credit Facilities that is secured by a $900 million debenture containing a first ranking security interest on their respective assets. The Canadian prime rate at December 31, 2005, was 5% with an effective date of December 7, 2005. As at December 31, 2005 and 2004, there was no amount outstanding under the working capital facility and $462.8 million (2004 - $214.4 million) was outstanding under the syndicated facility, with $127.2 million available to finance future activities.

The revolving period on the syndicated facility ends on April 28, 2006, 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, PC 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 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 Facilities are financed with Banker s Acceptances, resulting in a reduction in the stated bank loan interest rates.

7.

ASSET RETIREMENT OBLIGATIONS AND RESERVE FUND

(a)

Asset Retirement Obligations (ARO)

The total future asset retirement obligation was estimated by management based upon the Trust s share of estimated costs to reclaim and abandon the wells and facilities and the estimated timing of the costs to be incurred in future periods.

Total undiscounted ARO are $217.4 million as at December 31, 2005 (December 31, 2004 - $147.6 million). These payments are expected to occur over the next 35 years, with the majority of payments occurring between 10 and 20 years. The Trust s credit adjusted risk free interest rate of 6.5 percent (2004 6.5 percent) and an inflation rate of 2.0 percent (2004 1.5 percent) were used to calculate the present value of the ARO.

The following reconciles the Trust s outstanding ARO for the periods indicated:

($000 s)	2005	2004	2003
	$	$	$
Asset retirement obligations, January 1,	51,408	34,363	34,497
Increase in liabilities during the year	5,721	1,222	2,273
Revision to previously estimated cash flows	9,455	-	-
Accretion expense during the year	4,052	2,760	2,244
Actual costs settled during the year	(3,469)	(4,553)	(4,651)
Acquisitions additions during the year *(Note 5)*	6,106	17,616	-
	$	$	$
Asset retirement obligations, December 31, (b)	73,273	51,408	34,363

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 amounts which would otherwise represent distributions accruing to Unitholders. At December 31, 2005, the cash reserve was $9.1 million (December 31, 2004 - $7.1 million). In 2005, PC increased the cash reserve by withholding $2.0 million (2004 - $1.7 million, 2003 - $0.8 million) from distributions accruing to Unitholders. In addition, routine ongoing reclamation and abandonment costs of $3.5 million in 2005 (2004 - $4.6 million, 2003 $4.7 million) were incurred and deducted from distributions accruing to Unitholders.

8.

RECONCILIATION OF CASH FLOW AND DISTRIBUTIONS

Cash distributions are calculated in accordance with the Trust Indenture. To arrive at cash distributions, cash provided by operating activities before changes in non-cash working capital, is reduced by asset retirement reserve fund contributions, a portion of capital expenditures, debt repayments, Trust expenses, unit retraction or repurchases, if any, and all amounts paid into the asset retirement reserve fund. The portion of cash flow withheld to fund capital expenditures and to make debt repayments is at the discretion of the Board of Directors.

Reconciliation of Distributions Accruing to Unitholders

($000 s)	2005	2004	2003
	$	$	$
Distributions payable to Unitholders, January 1,	35,568	53,452	30,065
Distributions accruing during the year			
Cash provided by operating activities	337,223	243,652	192,163
Net change in non-cash operating working capital balances	60,780	(7,407)	(4,578)

Amortization of the cost of commodity contracts	-		(821)		-
Redemption of exchangeable shares	(1,154)	(1,803)		(2,792)	
Asset retirement reserve fund	(2,025)	(1,725)		(776)	
Capital lease repayment	(608)		(356)		(3,305)
Weyburn deferred capital obligation	-		(34,931)		-
Capital expenditures funded from cash flow	(227,495)		(45,000)		(30,000)
Total distributions accruing during the year	166,721		151,609		150,712
Distributions paid	(202,289)		(169,493)		(127,325)
	$		$		$
Distributions payable to Unitholders, December 31,	-		35,568		53,452

Accumulated Cash Distributions ($000 s)	2005	2004	2003
	$	$	$
Accumulated cash distributions, January 1,	734,567	581,155	427,651
Distributions accruing during the year	166,721	151,609	150,712
Redemption of exchangeable shares	1,154	1,803	2,792
	$	$	$
Accumulated cash distributions, December 31,	902,442	734,567	581,155

9.

TRUST UNITS

Authorized:unlimited number of Trust units	**Number of Units**	**$000 s**
Issued		
		$
Balance, December 31, 2003	72,688,577	1,020,677
Issued for the Ultima acquisition (Note 5(d))	26,449,102	452,807
Options exercised	332,733	3,771
Unit purchase plan	4,365	70
LTIP & RUP	36,799	638
Balance, December 31, 2004	99,511,576	1,477,963
Issued for cash	16,650,000	325,738
Exchangeable shares exchanged *(Note 10)*	551,000	6,171
Commissions and issue costs	-	(17,333)
Options exercised	418,424	5,889
Unit purchase plan	5,419	107
LTIP & RUP	36,002	602
		$
Balance, December 31, 2005	117,172,421	1,799,137

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,	**2005**	**2004**	**2003**
Distributions reinvested to acquire newly issued units ($000 s)	$	$	$

	107	70	89
	$	$	$
Price per unit	19.77	15.96	13.65
Number of units acquired	5,419	4,365	6,509

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

As at December 31,	**2005**	**2004**	**2003**
Basic	103,660,178	88,169,339	61,010,105
Diluted	103,723,937	88,292,020	61,153,027

The diluted amounts include all dilutive instruments.

Trust units/exchangeable shares outstanding:

As at December 31,	**2005**	**2004**	**2003**
Trust units outstanding	117,172,421	99,511,576	72,688,577
Trust units issuable for exchangeable shares *(Note 10)*	388,147	939,147	939,147
	117,560,568	100,450,723	73,627,724

10.

EXCHANGEABLE SHARES

The number of Exchangeable Shares issued in connection with the internalization of the management contract (Note 12) was determined based on a negotiated value of $12.17 per share as set out in the Trust s 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. The holder of the Exchangeable Shares is entitled to redeem for cash the number of shares equal to the cash distributions that would have been received had the Exchangeable Shares been exchanged for 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 2005, 46,375 (2004 94,823, 2003 181,041) Exchangeable Shares were redeemed for $1.2 million (2004- $1.8 million, 2003 - $2.8 million) in cash.

In 2005, 427,248 Exchangeable Shares were converted to 551,000 Trust units at an average exchange rate of 1.28965. At December 31, 2005, 283,025 Exchangeable shares were outstanding at an exchange ratio of 1.37142 per Trust Unit (2004 - 756,648 Exchangeable Shares, exchange ratio of 1.24119, 2003 851,471 Exchangeable Shares, exchange ratio of 1.20297).

Issued and Outstanding	Number of Shares	$000 s
		$
Balance, December 31, 2003	851,471	10,518
Redemption of shares	(94,823)	-
Balance, December 31, 2004	756,648	10,518
Redemption of shares	(46,375)	-
Exchanged for Trust Units [(1), (2)]	(427,248)	(6,171)
Balance, December 31, 2005	283,025	4,347
Exchangeable ratio, end of period	1.37142	-
		$
Exchangeable for Trust units	388,147	4,347

(1)

On March 7, 2005, 316,251 Exchangeable Shares were exchanged for 400,000 Trust units at an exchange rate of 1.26482.

(2)

On December 1, 2005, 110,997 Exchangeable Shares were exchanged for 151,000 Trust units at an exchange rate of 1.36040.

11.

CONTRIBUTED SURPLUS

($000 s)	2005	2004
	$	$
Contributed surplus, January 1,	-	-
Long-term incentive plan (non-cash expensed)	1,021	-
	$	$
Contributed surplus, December 31,	1,021	-

12.

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	**$000 s**
	$
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.

13.

RESTRICTED UNIT PLAN (RUP) AND LONG-TERM INCENTIVE PLAN (LTIP)

The number of units outstanding, excluded accrued distributions, is as follows:

	RUP		
	STAFF	**DIRECTORS**	**LTIP**
Balance, January 1, 2004	-	-	-
		-	
Granted	67,185	8,486	93,468
Units exercised	(20,370)	-	(62,312)
Forfeitures	(975)	-	-
	45,840	8,486	
Balance, December 31, 2004		8,486	31,156
Granted	102,480	7,925	61,245
Units exercised	(20,315)	-	(51,571)
Forfeitures	(23,700)	-	-
Balance, December 31, 2005	104,305	16,411	40,830

The fair value of the 2005 and 2004 LTIP grant was $1.1 million and $1.4 million respectively. The related expense is being recognized over a three year vesting period. The fair values have been determined using an option-pricing model with the following assumptions:

	2005	2004
Risk-free interest rate	3.49%	3.42%
Expected hold period to exercise	1.5 years	1.0 year

Volatility in market price of Trust units	17.07%	27.78%
Dividend yield	0%	0%

In 2005 and 2004, $1.9 million and $605,000 respectively was recorded as compensation expense with respect to the RUP for staff.

On July 1, 2005 each independent Director, other then the Chairman of the Board, received restricted units valued at $15,000. In addition, each director must take a minimum of 20% of the annual $30,000 retainer in restricted units for a minimum annual total of $21,000 in unit grants per year.

Directors were granted 6,697 restricted units on July 1, 2005 and in addition one director takes 100% of the annual retainer in restricted units. Total allocation of restricted units to directors in 2005 was 7,925 restricted units. Directors were granted 6,816 restricted units on July 1, 2004. On October 1, 2004 additional grants were made totalling 1,670 restricted units for a total 2004 allocation of 8,486 restricted units.

The total value of the grants to Directors including accrued distributions that was expensed was $248,000 and $140,000 in 2005 and 2004 respectively.

Vesting period of the units granted but not vested at December 31, 2005 are:

	Total	**2006**	**2007**	**2008**	**Thereafter**
RUP-Staff	104,305	45,915	29,795	28,595	-
RUP-Directors	16,411	-	1,393	1,580	13,438
LTIP	40,830	20,415	20,415	-	-
	161,546	66,330	51,603	30,175	13,438

14.

TRUST UNIT INCENTIVE PLAN

A summary of the status of the Trust Unit Incentive Plan as of December 31, 2005, 2004 and 2003 and changes during the years then ended is presented below. No options have been issued under the plan since July 25, 2002 as the plan has been replaced by the RUP and the LTIP. The Trust units reserved for issuance under the unit incentive plan have been reduced to the number of options outstanding. No further options will be issued and this plan will be terminated once all options outstanding are exercised or expire.

For the years ended December 31,		**2005**		**2004**		**2003**
	Units	Weighted Average Exercise Price	Units	Weighted Average Exercise Price	Units	Weighted Average Exercise Price
Options outstanding,		$		$		$
beginning of year	449,456	13.85	799,122	12.93	3,028,280	13.21
Forfeited	502	14.73	(16,933)	14.42	(555,754)	16.82
Exercised	(418,424)	14.08	(332,733)	11.33	(1,673,404)	12.88
Options outstanding before reduction of exercise price	31,534	15.08	449,456	16.97	799,122	14.74
Reduction of exercise price	-	(3.29)	-	(3.12)	-	(1.81)
Options outstanding,		$		$		$
end of year	31,534	11.79	449,456	13.85	799,122	12.93
Options exercisable,						

		$		$		$
end of year	31,534	11.79	449,456	13.85	440,656	15.36

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 and exercisable at December 31, 2005:

Number of Units	**Exercise Price**	**Reduced Exercise Price**	**Expiry Date**
13,000*	$ 19.35	$ 14.82	January 30, 2006
1,834	$ 17.25	$ 13.37	April 4, 2006
3,600	$ 14.71	$ 11.90	July 20, 2006
13,100	$ 10.65	$ 8.52	July 25, 2007

* Have been fully exercised prior to expiry date.

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 compensation expense under this method is presented in the following table:

	2005			**2004**			**2003**		
	Net Income	**Earnings per Unit Basic**	**Diluted**	**Net Income**	**Earnings per Unit Basic**	**Diluted**	**Net Income**	**Earnings per Unit Basic**	**Diluted**
As reported	$ 210,668	$ 2.03	$ 2.03	$ 74,359	$ 0.84	$ 0.84	$ 87,276	$ 1.43	$ 1.43
Pro forma adjustments	(469)	-	-	(924)	(0.01)	(0.01)	(1,998)	(0.03)	(0.03)
Pro forma net income	$ 210,199	$ 2.03	$ 2.03	$ 73,435	$ 0.83	$ 0.83	$ 85,278	$ 1.40	$ 1.40

15. FINANCIAL INSTRUMENTS

Financial instruments of the Trust carried on the consolidated balance sheet consist mainly of cash and cash equivalents, accounts receivable, asset retirement reserve fund, current liabilities, commodity contracts and long-term debt. As at December 31, 2005 and 2004, there were no significant differences between the carrying value of these financial instruments and their estimated fair value.

The Trust is subject to normal industry credit risk on its accounts receivable with customers and joint venture partners. The Trust mitigates these risks by maintaining credit management policies and by entering into sales contracts with entities of high credit rating. In addition, the Trust uses derivative financial instruments which may expose the Trust to credit risk with respect to default by the counterparties to these derivative contracts. This credit risk is controlled as the Trust limits its transactions to those counterparties that are financially sound.

The Trust is exposed to fluctuations in commodity prices for oil and natural gas. Commodity prices are affected by many factors including supply and demand, economic and political factors, weather and other conditions. Any movement in commodity process may impact the financial results of the Trust and cash distributions to unitholders. The Trust enters into various pricing mechanisms to reduce price volatility and establish minimum prices for a portion of its oil and gas production.

The Trust is exposed to fluctuations in interest rates as the long-term debt is based on floating interest rates.

The outstanding derivative financial instruments as at December 31, 2005 and the related unrealized gains or losses are summarized separately below:

Natural Gas	Term	Volume mcf/d	Price $/mcf	Delivery Point	Unrealized Gain (Loss) $000 s
Three way collar					$
	November 1, 2005 to March 31, 2006	4,737	$5.65-$6.70-$10.55	AECO	(499)
Three way collar	November 1, 2005 to March 31, 2006	4,737	$5.28-$6.33-$12.98	AECO	(86)
Collar	November 1, 2005 to March 31, 2006	4,737	$7.39-$13.72	AECO	(39)
Collar	November 1, 2005 to March 31, 2006	4,737	$7.39-$16.15	AECO	(18)
Collar	January 1, 2006 to March 31, 2006	4,737	$9.50-$19.00	AECO	98
Floor	November 1, 2005 to March 31, 2006	4,737	$8.44	AECO	50
Floor	November 1, 2005 to March 31, 2006	4,737	$8.44	AECO	51
Three way collar	April 1, 2006 to October 31, 2006	4,737	$6.07-$7.39-$8.99	AECO	(1,875)
Collar	April 1, 2006 to October 31, 2006	4,737	$7.39-$10.55	AECO	(1,017)
Collar	April 1, 2006 to October 31, 2006	4,737	$8.44-$11.35	AECO	(462)
Collar	April 1, 2006 to October 31, 2006	4,737	$8.44-$14.51	AECO	120
Collar	April 1, 2006 to October 31, 2006	4,737	$8.97-$14.78	AECO	332
Collar	April 1, 2006 to October 31, 2006	4,737	$10.55-$11.61	AECO	489
Collar	April 1, 2006 to October 31, 2006	4,737	$10.55-$12.66	AECO	732
					$
Total					(2,124)

Oil	Term	Volume bbl/d	Price $/bbl	Delivery Point	Unrealized Gain (Loss) $000 s
Three way collar					$
	January 1, 2006 to April 1, 2006	1,000	$40.71-$46.52-$61.64	Edmonton	(959)
Collar	January 1, 2006 to April 1, 2006	1,000	$48.85-$69.78	Edmonton	(361)
Three way collar	April 1, 2006 to June 30, 2006	1,000	$43.03-$48.85-$68.91	Edmonton	(729)
Collar	January 1, 2006 to March 31, 2006	1,000	$52.34-$81.41	Edmonton	(48)
Collar	January 1, 2006 to March 31, 2006	1,000	$58.15-$93.04	Edmonton	7
Collar	April 1, 2006 to June 30, 2006	1,000	$55.24-$81.41	Edmonton	(191)
Collar	April 1, 2006 to June 30, 2006	1,000	$58.15-$75.60	Edmonton	(318)
Collar	April 1, 2006 to June 30, 2006	1,000	$58.15-$88.39	Edmonton	(22)
Collar	April 1, 2006 to June 30, 2006	1,000	$58.15-$94.20	Edmonton	35
Collar	July 1, 2006 to September 30, 2006	1,000	$58.15-$75.60	Edmonton	(416)
Collar	July 1, 2006 to September 30, 2006	1,000	$58.15-$87.81	Edmonton	(90)
Collar	July 1, 2006 to September 30, 2006	1,000	$58.15-$93.91	Edmonton	4
Collar	October 1, 2006 to December 31, 2007	1,000	$58.15-$75.60	Edmonton	(474)
Collar	January 1, 2006 to March 31, 2006	1,000	$58.15-$79.69	Edmonton	(55)
Collar	January 1, 2006 to	1,000	$63.97-$103.51	Edmonton	229

	June 30, 2006				
Collar	July 1, 2006 to				
	December 31, 2006	1,000	$63.97-$96.76	Edmonton	311
					$
Total					(3,077)

Electricity	**Term**	**Volume MW/h**	**Price $/MHz**	**Delivery Point**	**Unrealized Gain $000 s**
Fixed Price					$
	January 1, 2006 to December 31, 2008	2.0	$57.00	Alberta Power Pool	561
					$
Total					561

16.

INCOME TAXES

The future income tax liability consists of the following temporary differences:

As at December 31, ($000 s)	**2005**	**2004**	**2003**
	$	$	$
Oil and natural gas properties	268,836	102,294	85,185
Commodity contracts	(1,560)	(3,461)	-
Asset retirement obligations	(24,956)	(17,422)	(6,120)
	$	$	$
Future income taxes	242,320	81,411	79,065

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, ($000 s)	**2005**	**2004**	**2003**
	$	$	$
Income before provision for income taxes	205,141	82,037	43,648
	$	$	$
Income tax provision computed at statutory rates	70,682	31,886	17,782
Effect on income tax of:			
Income attributed to the Trust	(76,832)	(23,031)	(41,468)
Internalization of management contract	-	-	12,568
Non-deductible crown charges,			
net of Alberta Royalty Credit	21,897	20,031	24,190
Resource allowance	(20,852)	(19,138)	(20,730)
Capital taxes	686	1,267	1,000
Income tax rate reductions on opening balances	-	-	(36,688)
Effect of change in corporate tax rate	(403)	(898)	-
Attributed royalty income deductible for			
provincial taxes	-	(2,274)	-
Other	(705)	(165)	(282)
	$	$	$
Provision for (recovery of) income taxes	(5,527)	7,678	(43,628)

The petroleum and natural gas properties and facilities owned by PC have a tax basis of $313.2 million (2004 - $213.7 million; 2003 - $232.7 million) available for future use as deductions from taxable income. Included in this tax basis are non-capital loss carry forwards of $18.2 million (2004 - $18.3 million; 2003 - $43.6 million), which expire in various years through 2010.

Royalty Trusts that meet certain criteria in the Canadian Income Tax Act qualify for special income tax treatment that permits a tax deduction by the trust for distributions paid to the trust s unitholders in addition to tax pool deductions available to the trust. Petrofund meets these requirements and has available resource tax pools for future tax deductions as at December 31, 2005, of $545.5 million.

17.

COMMITMENTS AND CONTINGENT LIABILITIES

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 be paid 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 Trust is involved in litigation and claims arising from the normal course of operations. Management is of the opinion that any resulting settlement would not materially affect the financial position or results of operations of the Trust.

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)					
	$	$	$	$	$
Long-term debt [1]	462.8	-	-	-	462.8
Operating leases	17.7	2.1	4.4	4.6	6.6
Purchase obligations [2]	135.7	15.0	26.5	26.6	67.6
Asset retirement obligation [3]	217.4	4.0	7.7	11.1	194.6
RUP, LTIP s [4]	4.9	1.6	2.9	0.1	0.3
	$	$	$	$	
Total	838.5	22.7	41.5	42.4	$ 731.9

(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 $108.6 million for CO_2 purchases and $27.1 million for processing fees with respect to PC s interest in 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.

(4)

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

18.

OTHER CASH FLOW DISCLOSURES

(a)

The net change in non-cash working capital balances comprises the following:

($000 s)	2005	2004	2003
	$	$	$
Accounts receivable	(65,514)	(977)	(6,317)
Due from affiliates	-	-	164
Prepaids and deposits	(6,370)	(1,812)	54
Accounts payable and accrued liabilities	32,711	36,314	14,677
Payable to affiliates	-	-	(2,168)
	$	$	$
	(39,173)	33,525	6,410
Relating to:			
	$	$	$
Operating activities	(60,780)	7,407	4,578
Financing	388	(168)	168
Investing	21,219	26,286	1,664
		$	$
	$ (39,173)	33,525	6,410

(b)

Cash and cash equivalents comprises the following:

($000 s)	2005	2004	2003
		$	$
Cash/(bank overdraft)	$ 8,935	(5,733)	(4,318)
Short-term investments	30,000	5,000	6,500
	$	$	$
Cash and cash equivalent/(bank overdraft)	38,935	(733)	2,182

(c)

Other cash flow information includes:

($000 s)	2005	2004	2003
	$	$	$
Interest paid during the year	9,843	5,393	5,393
	$	$	$
Income taxes paid during the year	311	409	409

19.

ACCOUNTS RECEIVABLE AND ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

(a)

Accounts receivable

For the years ended December 31, ($000 s)	2005	2004
		$
Revenue accrual	$ 43,209	25,106
Joint venture receivables	29,369	12,474
Other	21	133
		$
Accounts receivable	$ 72,599	37,713

(b)

Accounts payable

For the years ended December 31, ($000 s)	2005	2004
		$
Capital accrual	$ 17,611	16,850
Joint venture payables	49,443	16,179
Trade payables	1,289	5,986
RUP and LTIP payable	2,716	1,199
Other	25,795	20,747
		$
Accounts payable and accrued liabilities	$ 96,854	60,961

20.

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 deferred income taxes and inclusive of asset retirement obligation additions to oil and gas royalty and property interests excluding asset retirement costs, is limited to the present value of after tax future net revenue from proven reserves, 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. There were no additional impairments during 2005 or 2004. In addition, U.S. GAAP depletion is calculated based on constant prices in effect at year end.

(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. U.S. GAAP hedge accounting treatment allows the effective portion of unrealized gains and losses to be deferred in other comprehensive income (for the effective portion of the hedge) until such time as the forecasted transaction occurs and requires that an entity formally document, designate and assess effectiveness of derivative instruments that receive hedge accounting treatment.

(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. Beginning in 2004, for Canadian GAAP purposes, Petrofund applied the fair value method of accounting for all derivative transactions with the change in fair value of these contracts reported in income and no difference between U.S. GAAP and Canadian GAAP.

(d)

Prior to January 1, 2004, 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, 2005, 2004 and 2003 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 2003. No options have been granted since 2002, which would require, the Trust to account for compensation expense based on the fair value method of accounting.

For U.S. GAAP purposes, the Unit Incentive Plan is a variable compensation plan as the exercise price of the options is subject to downward revisions from time to time. Accordingly, compensation expense is determined as the excess of the market price of the Trust units over the adjusted exercise price of the options at each financial reporting date and is deferred and recognized in income over the vesting period of the options. After the options have vested, compensation expense is recognized in income in the period in which a change in the market price of the Trust units or the exercise price of the options occurs.

For 2005 and 2004 there are no significant differences that resulted in accounting for the LTIP or RUP under FAS123 for U.S. GAAP purposes.

(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 7. 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-operation expenses in the statement of operations. Management fees, financing costs and internalization of management contracts would be presented in the non-operating section of the statement of operations and retained earnings. This difference does not result in an adjustment to the financial results as reported under Canadian GAAP.

(h)

Prior to the Trust adopting AcG-14 Disclosure of Guarantors , a U.S. GAAP difference was created once the Financial Accounting Standards Board (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, 2003. There are no guarantees which would need to be recognized for U.S. GAAP purposes at December 31, 2005 or 2004.

(i)

Under U.S. GAAP, the Trust s bank overdraft would be presented as a financial activity rather than as a component of cash. Therefore, cash provided by (used in) financing activities under U.S. GAAP would be $358,976 in 2005 (2004 ($172,308), 2003 ($29,370)) which would need to be recognized for U.S. GAAP purposes. In addition, cash flow relating to derivative contracts would also be presented as investing activities.

(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 Statement of Financial Accounting Standard (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 fiscal year 2006. The Trust will evaluate the impact of this standard in 2006.

In addition, FAS 154, *Accounting Changes in Error Corrections*, changes the requirements for the accounting for and reporting of a change in accounting principle. The standard is effective for the Trust in fiscal 2006.

On January 27, 2005, the Accounting Standard s Board (AcSB) issued CICA Handbook section 3855 Financial Instruments Recognition and Measurement , CICA Handbook section 3861 Financial Instruments-Disclosure and Presentation , CICA Handbook section 1530 Comprehensive Income and CICA handbook section 3865 Hedges that deal with the recognition and measurement of financial instruments and comprehensive income. The new standards are intended to harmonize Canadian standards with United States and International accounting standards and are effective for annual and interim periods in fiscal years beginning on or after October 1, 2006. These new standards will impact the Trust in future periods and the resulting impact will be assessed at that time.

(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 9 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.

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

For the years ended December 31, **($000 s)**	**2005**	**2004**	**2003**
	$	$	$
Net income as reported under Canadian GAAP	210,668	74,359	87,276
Adjustments:			
Realized/(unrealized) loss on derivatives	-	6,774	(6,774)
Compensation expense	(464)	1,991	(3,144)
Depletion and depreciation	2,482	14,584	23,263
Deferred income taxes on above adjustments	(855)	(7,518)	(3,505)
Net income, as adjusted, before cumulative effect of a change in accounting principle	211,831	90,190	97,116
Cumulative effect of a change in accounting principle, net of income taxes	-	-	(2,419)

Net income, as adjusted, after cumulative effect	211,831	90,190	94,697
Unrealized gain (loss) on derivatives, net of income			
tax expense (recovery) of $Nil (2004 - $Nil 2003 $ (330))	-	-	451
	$	$	$
Comprehensive income	211,831	90,190	95,148

For the years ended December 31, **($000 s)**	**2005**	**2004**	**2003**
Net income per unit, as adjusted before cumulative effect			
	$	$	$
Basic	2.04	1.02	1.59
	$	$	$
Diluted	2.04	1.02	1.59
Net income per unit, as adjusted after cumulative effect			
	$	$	$
Basic	2.04	1.02	1.55
	$	$	$
Diluted	2.04	1.02	1.55

Accumulated other comprehensive income:

For the years ended December 31, **($000 s)**	**2005**	**2004**	**2003**
	$	$	$
Opening balance at January 1,	-	-	(451)
Unrealized gain (loss) on derivatives, net of income tax expense (recovery) of $Nil (2004 - $Nil, 2003 $ (330))	-	-	451
	$	$	$
Closing balance at December 31,	-	-	-

The application of U.S. GAAP would have the following effects on the consolidated balance sheet as reported:

As at ($000 s)	**As reported**	**Increase (Decrease)**	**U.S. GAAP**
December 31, 2005			
	$	$	$
Oil and natural gas royalty and property interests, net (Note 4)	1,777,922	(158,736)	1,619,186
Deferred income taxes	242,320	(46,137)	196,183
Temporary equity	-	2,409,837	2,409,837
Unitholders' equity	1,385,343	(2,522,436)	(1,137,093)
December 31, 2004			
	$	$	$
Oil and natural gas royalty and property interests, net (Note 4)	1,246,694	(161,218)	1,085,476
Deferred 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)

The following presents the consolidated statement of unitholders equity and temporary equity for the three years ended December 31, 2005 under U.S. GAAP.

($000 s)	Accumulated Distributions	Retained Earnings	Accumulated Other Comprehensive Income	Total Unitholders Equity	Temporary Equity
	$	$	$	$	$
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	-
Other comprehensive income - gain on derivatives	-	-	451	451	-
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

($000 s)	Accumulated Distributions	Retained Earnings	Accumulated Other Comprehensive Income	Total Unitholders Equity	Temporary Equity
	$	$	$	$	$
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
RUP & LTIP	-	-	-	-	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	(207,724)
December 31, 2004	(734,567)	78,831	-	(655,736)	1,568,036
Units issued	-	-	-	-	308,405
Redemption of exchangeable shares	(1,154)	-	-	(1,154)	-
Options exercised	-	-	-	-	5,889
Unit purchase plan	-	-	-	-	107
RUP & LTIP	-	-	-	-	602
Net income	-	211,831	-	211,831	-
Stock based compensation expense	-	-	-	-	1,485
Distribution accruing to unitholders	(166,721)	-	-	(166,721)	-
Temporary equity	-	(525,313)	-	(525,313)	525,313
	$	$	$	$	$
December 31, 2005	(902,442)	(234,651)	-	(1,137,093)	2,409,837

SUPPLEMENTARY OIL AND GAS INFORMATION FAS 69 (unaudited)

The tables in this section set forth oil and gas information prepared by the Registrant in accordance with U.S. disclosure standards, pertaining to FAS 69, Disclosure about Oil and Gas Producing Activities .

Standardized Measure of Discounted Future Net Cash Flows and Changes Therein

In calculating the standardized measure of discounted future net cash flows, year-end constant prices and cost assumptions were applied to Petrofund s annual future production from proved reserves to determine cash inflows. Future production and development costs are based on constant price assumptions and assume the continuation of existing economic, operating and regulatory conditions. Future income taxes are calculated by applying statutory income tax rates to future pre-tax cash flows after provision for the tax cost of the oil and natural gas properties based upon existing laws and regulations. The Trust is currently not taxable. The discount was computed by application of a 10 percent discount factor to the future net cash flows. The calculation of the standardized measure of discounted future net cash flows is based upon the discounted future net cash flows prepared by Petrofund s independent qualified reserves evaluators in relation to the reserves they respectively evaluated, and adjusted by Petrofund is to account for management s estimates of risk management activities, asset retirement obligations and future income taxes.

Petrofund cautions that the discounted future net cash flows relating to proved oil and gas reserves are an indication of neither the fair market value of the Registrant s oil and gas properties, nor of the future net cash flows expected to be generated from such properties. The discounted future cash flows do not include the fair market value of exploratory properties and probable or possible oil and gas reserves, nor is consideration given to the effect of anticipated future changes in crude oil and natural gas prices, development, asset retirement and production costs and possible changes to tax and royalty regulations. The prescribed discount rate of 10 percent may not appropriately reflect future interest rates.

Capitalized Costs Relating to Oil and Gas Producing Activities

($ thousands)

As at December 31,	**2005**	**2004**	**2003**
	$	$	$
Proved oil and gas properties	2,540,501	1,858,291	1,364,296
Unproved oil and gas properties	68,876	21,071	16,316
Total capital costs	2,609,377	1,879,362	1,380,612
Accumulated depletion and depreciation	990,191	793,886	658,151
	$	$	$
Net capitalized costs	1,619,186	1,085,476	722,461

Costs Incurred in Oil and Gas Property Acquisition,

Exploration and Development Activities

($ thousands)

For the years ended December 31, (1)	**2005**	**2004**	**2003**
Property acquisition costs (1)			

	$	$	$
Proved oil and gas properties	571,113	605,840	82,100
Unproved oil and gas properties	6,707	1,695	1,700
Exploration costs (2)	1,782	678	5,700
Development costs (3)	151,950	75,637	64,000
	$	$	$
Total	731,552	683,850	153,500

(3)

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.

Results of Operations for Producing Activities

($ thousands)

For the years ended December 31,	**2005**	**2004**	**2003**
	$	$	$
Oil and gas sales, net of royalties and commodity contracts	589,329	368,139	313,787
Lease operating costs and capital taxes	145,516	106,871	93,705
Transportation costs	8,059	5,862	5,482
Depletion, depreciation and accretion	200,357	138,495	95,044
Operating income	235,397	116,911	119,556
Income taxes [(1)]	1,184	539	569
	$	$	$
Results of operations	234,213	116,372	118,987

(1)

Petrofund is currently not taxable, current income tax disclosed for the years 2003 through 2005 represent Large Corporation Tax, which is calculated by reference to balance sheet items (debt and equity) and not by income items.

Reserve Quantity Information for the Year Ended December 31, 2004

Constant Prices and Costs

Net Proved Developed and Proved Undeveloped Reserves	**Light and Medium oil (mbbls)**	**Heavy Oil (mbbls)**	**Natural Gas (bcf)**	**Natural Gas Liquids (mbbls)**	**Barrels of Oil Equivalent (mboe**
December 31, 2003	37,793	750	164	4,036	69,957
Extensions	170	-	6	17	1,005
Improved recovery	567	45	9	56	2,090
Technical revisions	2,769	168	7	353	4,461
Discoveries	-	-	1	8	151
Acquisitions	23,163	-	21	594	27,305
Dispositions	-	-	-	-	(26)
Economic factors	36	4	1	9	138
Production	(4,757)	(95)	(24)	(596)	(9,482)
Change for year	21,947	122	20	441	25,737
December 31, 2004	59,740	872	184	4,477	95,694
Developed	45,871	872	176	4,161	80,245
Undeveloped	13,869	-	8	316	15,449
Total	59,740	872	184	4,477	95,694

Reserve Quantity Information for the Year Ended December 31, 2005

Constant Prices and Costs

Net Proved Developed and Proved Undeveloped Reserves	Light and Medium oil (mbbls)	Heavy Oil (mbbls)	Natural Gas (bcf)	Natural Gas Liquids (mbbls)	Barrels of Oil Equivalent (mboe
December 31, 2004	59,740	872	184	4,477	95,694
Extensions	47	-	4	16	698
Improved recovery	3,883	4	9	109	5,443
Technical revisions	682	(149)	(7)	(82)	(692)
Discoveries	16	-	1	1	149
Acquisitions	263	20	76	658	13,704
Dispositions	(282)	-	(1)	(29)	(325)
Economic factors	(86)	(3)	2	35	292
Production	(5,400)	(87)	(28)	(649)	(10,764)
Change for year	(878)	(215)	57	58	8,505
December 31, 2005	58,862	657	241	4,535	104,199
Developed	45,945	657	223	4,349	88,147
Undeveloped	12,918	-	18	186	16,052
Total	58,862	657	241	4,535	104,199

(1)

Definitions:

(a)

Net reserves are the remaining reserves of Petrofund after deduction of estimated royalties and including royalty interest.

(b)

Proved reserves are the estimated quantities of crude oil, natural gas and NGLs which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made.

(c)

Proved Developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

(d)

Proved Undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

(2)

Petrofund does not file any estimates of total net proved crude oil or natural gas reserves with any U.S. federal authority or agency other than the SEC.

Standardized Measure of Discounted Future Net Cash Flows

Relating to Proved Oil and Gas Reserves

($000 s)	**2005**	**2004**
	$	$
Future cash inflows	6,103,302	3,760,846
Future production costs	1,808,102	1,489,174
Future development costs	290,746	250,820
Undiscounted pre-tax cash flows	4,004,454	2,020,852
Future income taxes (1)	-	-
Future net cash flows	4,004,454	2,020,852
Less 10% annual discount factor	1,682,362	864,180
	$	$
Standardized measure of discounted future net cash flows	2,322,092	1,156,672

(1) Petrofund is currently not taxable.

Reconciliation of Changes in Net Present Values of Future Net Revenue

Discounted at 10% Per Year

Proved Reserves Constant Prices and Costs

($000 s)	**2005**	**2004**
	$	$
Standardized measure of discounted future net cash flows, beginning of year	1,156,672	814,427
Oil and gas sales during the period (1)	(481,790)	(312,752)
Changes due to prices, production costs and royalties related to forecast production (2)	1,001,636	132,927
Development costs during the period (3)	136,200	(77,900)
Changes in forecast development costs (4)	(178,330)	90,297
Changes resulting from extensions and improved recovery (5)	137,275	40,197
Changes resulting from discoveries (5)	3,521	1,962
Changes resulting from acquisitions of reserves (5)	317,374	320,784
Changes resulting from dispositions of reserves (5)	(6,933)	(334)
Accretion of discount (6)	115,667	81,443
Net change in income taxes (7)	-	-
Changes resulting from technical reserves revisions plus all other changes	120,800	65,621
	$	$
Standardized measure of discounted future net cash flows, end of year	2,322,092	1,156,672

(7)

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. Petrofund is currently not taxable.

RESERVES SUMMARY

Petrofund has received the results of an independent engineering evaluation of its oil and gas reserves conducted by GLJ Petroleum Consultants Ltd. (GLJ) and effective December 31, 2005. This evaluation is prepared in accordance with National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* (NI 51-101).

HIGHLIGHTS

The following year end highlights are based on forecast prices and escalated costs:

- Proved plus probable gross reserves are 162.3 million boe, an increase of 15% over last year.
- Acquisition activity added 23.9 million boe of proved plus probable gross reserves replacing actual 2005 production over 2 times.
- Development activity added 9.7 million boe of proved plus probable gross reserves.
- Reserve life index is 11.0 years based on proved plus probable gross reserves and the 2006 forecasted total proved production rate.

RESERVE SUMMARY 2005

Summary of Oil and Gas Reserves
as of December 31, 2005
Based on Forecast Prices and Escalated Costs

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total BOE's	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(mbbls)		(mbbls)		(mmcf)		(mbbls)		(mboes)	
Proved Reserves										
Producing	51,891	44,557	719	644	258,190	206,154	5,765	4,097	101,407	83,656
Developed Nonproducing	309	289	-	-	16,640	13,307	264	178	3,346	2,685
Undeveloped	15,139	13,166	-	-	21,695	17,742	275	187	19,030	16,310
Total Proved Reserves	67,338	58,011	719	644	296,526	237,203	6,304	4,462	123,783	102,651
Probable	20,202	17,265	267	237	92,146	73,972	2,680	2,046	38,507	31,876
Total Proved plus Probable	87,540	75,276	987	880	388,672	311,174	8,985	6,508	162,290	134,527

Summary of Oil and Gas Reserves
as of December 31, 2005
Based on Constant Prices Costs

	Light and Medium Oil		Heavy Oil		Natural Gas		Natural Gas Liquids		Total BOE's	
	Gross	Net	Gross	Net	Gross	Net	Gross	Net	Gross	Net
	(mbbls)		(mbbls)		(mmcf)		(mbbls)		(mboes)	
Proved Reserves										
Producing	53,129	45,663	733	657	262,751	209,898	5,888	4,175	103,541	85,478
Developed Nonproducing	300	282	-	-	16,607	13,277	261	175	3,329	2,669
Undeveloped	15,093	12,918	-	-	21,631	17,689	276	186	18,975	16,052
Total Proved Reserves	68,522	58,862	733	657	300,989	240,865	6,425	4,535	125,845	104,199
Probable	20,470	17,420	267	237	93,439	75,056	2,704	2,059	39,014	32,225
Total Proved plus Probable	88,992	76,282	1,000	895	394,428	315,920	9,129	6,594	164,859	136,424

NET PRESENT VALUE SUMMARY 2005

Petrofund s reserves were evaluated using GLJ s constant and forecast prices effective December 31, 2005. The before tax net present values shown below do not necessarily represent the fair market value of the reserves.

Net Present Value of Future Net Revenue Before Income Taxes
At of December 31, 2005
Based on Forecast Prices and Escalated Costs

		Discounted at the Rate of		
($millions)	**Undiscounted**	**10%**	**12%**	**15%**
Proved Reserves				
Producing	2,511.2	1,631.5	1,537.8	1,420.7
Developed Nonproducing	97.9	52.2	48.5	44.0
Undeveloped	442.0	189.9	164.5	134.0
Total Proved Reserves	3,051.1	1,873.6	1,750.8	1,598.7
Probable	1,129.8	409.7	356.0	295.3
Total Proved plus Probable	4,180.9	2,283.3	2,106.8	1,894.0

GLJ December 31, 2005 Price Forecast

Summary of Pricing Assumptions as of December 31, 2005
Forecast Prices

Year	Oil WTI (US$/bbl)	Oil Edmonton Par (C$/bbl)	Natural Gas AECO Spot (C$/mmbtu)	Exchange Rate ($US/$Cdn)	Inflation (%)
2006	57.00	66.25	10.60	0.85	2.0
2007	55.00	64.00	9.25	0.85	2.0
2008	51.00	59.25	8.00	0.85	2.0
2009	48.00	55.75	7.50	0.85	2.0
2010	46.50	54.00	7.20	0.85	2.0
2011	45.00	52.25	6.90	0.85	2.0
2012	45.00	52.25	6.90	0.85	2.0

2013	46.00	53.25	7.05	0.85	2.0
2014	46.75	54.25	7.20	0.85	2.0
2015	47.75	55.50	7.40	0.85	2.0
2016	48.75	56.50	7.55	0.85	2.0

Note: Prices escalate 2.0% in 2017 and thereafter

Net Present Value of Future Net Revenue Before Income Taxes
At of December 31, 2005
Based on Forecast Prices and Escalated Costs

		Discounted at the Rate of		
($millions)	**Undiscounted**	**10%**	**12%**	**15%**
Proved Reserves				
Producing	3,321.6	2,009.7	1,871.8	1,701.1
Developed Nonproducing	119.7	63.0	58.1	52.2
Undeveloped	563.2	249.4	217.2	178.4
Total Proved Reserves	4,004.5	2,322.1	2,147.1	1,931.7
Probable	1,401.5	517.1	448.8	371.1
Total Proved plus Probable	5,405.9	2,839.2	2,595.9	2,302.8

GLJ December 31, 2005 Constant Price

Summary of Pricing Assumptions as of December 31, 2005
Constant Prices

Oil WTI (US$/bbl)	Oil Edmonton Par (C$/bbl)	Natural Gas AECO Spot (C$/mmbtu)	Exchange Rate ($US/$Cdn)
61.04	68.27	9.71	0.8577

RESERVE RECONCILIATION

Reconciliation of Total Company Interest Reserves

Forecast Prices and Escalated Costs

	Light and Medium Oil	**Heavy Oil**	**Natural Gas**	**Natural Gas Liquids**	**Barrels of Oil Equivalent**
	Proved (mbbls)	Proved (mbbls)	Proved (bcf)	Proved (mbbls)	Proved (mboe)
December 31, 2004	66,417	996	230	6,150	111,975
Extensions	52	-	5	21	835
Improved Recovery	4,797	4	10	151	6,650
Technical Revisions	1,017	(180)	(10)	(185)	(1,044)
Discoveries	23	-	1	1	192
Acquisitions	288	21	96	973	17,274
Dispositions	(315)	-	-	(43)	(378)
Economic Factors	1,742	4	4	158	2,541
Production	(6,563)	(103)	(36)	(870)	(13,501)
December 31, 2005	67,457	741	300	6,357	124,544

	Light and Medium Oil	**Heavy Oil**	**Natural Gas**	**Natural Gas Liquids**	**Barrels of Oil Equivalent**
	Proved Plus Probable (mbbls)	Proved plus Probable (mbbls)	Proved plus Probable (bcf)	Proved plus Probable (mbbls)	Proved plus Probable (mboe)
December 31, 2004	84,921	1,231	287	8,324	142,235
Extensions	31	-	7	27	1,186
Improved Recovery	5,964	4	12	184	8,198
Technical Revisions	1,002	(204)	(15)	(212)	(1,966)
Discoveries	28	-	1	3	277
Acquisitions	416	77	132	1,444	23,928

Dispositions	(378)	-	-	(50)	(453)
Economic Factors	2,270	8	5	201	3,345
Production	(6,563)	(103)	(36)	(870)	(13,501)
December 31, 2005	87,690	1,013	393	9,051	163,248

Note: Company Interest Reserves are the sum of royalty interest (royalty interest reserves include lessor royalty and overriding royalty volumes derived only from other working interest owners) and working interest reserves before deduction of royalty burdens payable. **Company Interest Reserves are not Gross Reserves or Net Reserves as defined for purposes of NI 51-101.**

Reconciliation of Company Net Reserves

Constant Prices and Costs

	Light and Medium Oil	**Heavy Oil**	**Natural Gas**	**Natural Gas Liquids**	**Barrels of Oil Equivalent**
	Net Proved (mbbls)	Net Proved (mbbls)	Net Proved (bcf)	Net Proved (mbbls)	Net Proved (mboe)
December 31, 2004	59,740	872	184	4,477	95,694
Extensions	47	-	4	16	698
Improved Recovery	3,883	4	9	109	5,443
Technical Revisions	682	(149)	(7)	(82)	(692)
Discoveries	16	-	1	1	149
Acquisitions	263	20	76	658	13,704
Dispositions	(282)	-	-	(29)	(325)
Economic Factors	(86)	(3)	2	35	292
Production	(5,400)	(87)	(28)	(649)	(10,764)
December 31, 2005	58,862	657	241	4,536	104,199

	Light and Medium Oil	**Heavy Oil**	**Natural Gas**	**Natural Gas Liquids**	**Barrels of Oil Equivalent**
	Net Net Proved plus Probable (mbbls)	Net Proved plus Probable (mbbls)	Net Proved Plus Probable (bcf)	Net Proved plus Probable (mbbls)	Net Proved plus Probable (mboe)
December 31, 2004	76,059	1,082	229	6,219	121,578
Extensions	25	-	6	20	996
Improved Recovery	4,790	4	10	136	6,672
Technical Revisions	629	(168)	(10)	(116)	(1,402)
Discoveries	20	-	1	2	214
Acquisitions	386	70	105	965	18,942
Dispositions	(337)	-	-	(34)	(388)
Economic Factors	109	(6)	3	51	576

Production	(5,400)	(87)	(28)	(649)	(10,764)
December 31, 2005	76,282	895	316	6,594	136,424

Note: Company Net Reserves are Petrofund s interest (operating and non-operating) share after deduction of royalties obligations, plus Petrofund s royalty interest in reserves.

Additional details regarding Petrofund s reserves information will be included in our Annual Information Form, which is anticipated to available on our website and SEDAR by the end of March.

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

Petrofund Energy Trust is a Calgary based royalty trust that acquires and manages producing oil and gas properties in Western Canada. The Trust pays its Unitholders monthly cash distributions that are derived from the Trust s cash flow from these properties. Petrofund Energy Trust was founded in 1988 and was one of the first oil and gas royalty trusts in Canada.

Certain information regarding Petrofund Energy Trust in this news release including management's assessment of future production estimates, future plans and operations, reserve estimates, drilling inventory and wells to be drilled, timing of drilling and tie-in of wells, productive capacity of new wells, capital expenditures and the timing thereof, and other types of information, may constitute forwarding-looking statements under applicable securities laws and necessarily involve risks including, without limitation, risks associated with oil and gas exploration, development, exploitation, production, marketing and transportation, loss of markets, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other producers, inability to retain drilling rigs and other services, incorrect assessment of the value of acquisitions, failure to realize the anticipated benefits of acquisitions, delays resulting from or inability to obtain required regulatory approvals and ability to access sufficient capital from internal and external sources. As a consequence, actual results may differ materially from those anticipated in the forward-looking statements. Readers are cautioned that the foregoing list of factors is not exhausted. Additional information on these and other factors that were applied in drawing a conclusion or making a forecast or projection as reflected in the forward-looking information and that could cause actual results to differ materially from those anticipated in the forward-looking statements are included in reports on file with Canadian securities regulatory authorities and may be accessed through the SEDAR website (www.sedar.com) or at the Trust's website (www.petrofund.ca). Furthermore, the forward-looking statements contained in this news release are made as the date of this news release and the Trust does not undertake any obligation to update publicly or to revise any of the included forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

PETROFUND ENERGY TRUST

Jeffery E. Errico

President and Chief Executive Officer

For Petrofund Investor Relations:

Phone: (403) 218-4736

Fax: (403) 539-4300

Toll Free: 1-866-318-1767

E-mail: info@petrofund.ca

Website: www.petrofund.ca

For information regarding this press release:

Chris Dutcher

Director, Business Development

Phone: (403) 218-8625

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