PETROFUND ENERGY TRUST
Form 6-K
May 12, 2005

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: May 2005
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: May 12, 2005 By: /s/ Hugo Potts
Hugo St J. A. Potts, Esq.
Corporate Secretary

EXHIBIT

Exhibit	Description of Exhibit
1.	**First Quarter Report dated May 10, 2005.**

EXHIBIT 1

News Release

Calgary - May 10, 2005

Petrofund Energy Trust (*TSX: PTF.UN; AMEX: PTF*)
Announces Results for the First Quarter of 2005

Petrofund Energy Trust is pleased to provide its results for the first quarter of 2005. Key items from the quarter include:

- Average production of 35,234 boe per day, a 32% increase over the first quarter of last year.

- Cash flow increased 49% over the first quarter of 2004 to $73 million, due primarily to additional production from the Ultima acquisition, development drilling and higher commodity prices.

- First quarter payout ratio remained at 67%, identical to the previous quarter, and a 6% change from 73% in the first quarter of 2004.

- Operating costs for the quarter, which include a prior period adjustment of $0.79 per boe, increased to $10.09 per boe due to increasing industry costs. This was a 23% increase over first quarter of last year.

- General and administrative costs down 12% from last year to $1.15 per boe.

- The Trust exited the quarter with a 1.0:1.0 debt to cash flow ratio based on annualized first quarter cash flow.

- Invested $48 million in drilling and development activities resulting in 73 wells with a 97% success rate. Partially as a result of this success, the Trust is announcing a 33% increase in its 2005 development budget from $90 million to $120 million.

Petrofund's first quarter report is presented below:

[Missing Graphic Reference]
1st Quarter Report

for the three months ended March 31, 2005

FINANCIAL HIGHLIGHTS

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

		2005		2004	Variance
INCOME STATEMENT					
Oil and natural gas sales	$	154,768	$	99,699	55%
Cash flow (1)	$	72,959	$	49,047	49%
Per unit (2)	$	0.73	$	0.67	9%
Per boe	$	23.01	$	20.26	14%
Cash distributions paid per unit	$	0.48	$	0.48	-%
Net income	$	19,243	$	7,629	152%
Net income per unit					
Basic	$	0.19	$	0.10	90%
Diluted	$	0.19	$	0.10	90%
UNITS AND EXCHANGEABLE SHARES OUTSTANDING (2)					
Weighted average		100,603		73,674	37%
Diluted		100,644		73,872	36%
At period-end		100,746		73,682	37%
BALANCE SHEET					
Working capital (deficit) (3)	$	(59,531)	$	(56,093)	(6)%
Property, plant and equipment, net	$	1,259,248	$	883,191	43%
Long-term debt	$	239,237	$	90,040	166%
Unitholders' equity	$	992,882	$	615,952	61%
MARKET CAPITALIZATION, as at March 31	$	1,777,156	$	1,278,390	39%
TOTAL CAPITALIZATION, as at March 31 (3),(4)	$	2,075,924	$	1,424,523	46%
TRUST UNIT TRADING (TSX: PTF.UN)					
High	$	19.33	$	19.24	-%
Low	$	15.50	$	14.56	6%
Close	$	17.64	$	17.35	2%
Average daily volumes		264		204	29%
TRUST UNIT TRADING (AMEX: PTF)					
High	$	16.05	$	14.96	7%

Low	$	12.66	$ 10.95	16%
Close	$	14.62	$ 13.22	11%
Average daily volumes		643	633	2%

(1) Cash flow before net changes in non-cash operating working capital balances (Non-GAAP measure, see special notes in the Management Discussion and Analysis).
(2) See Note 2 to Interim Consolidated Financial Statements.
(3) Excludes net unrealized losses on commodity contracts.
(4) Total capitalization equals market capitalization plus net debt.

OPERATIONAL HIGHLIGHTS

(thousands of Canadian dollars, except per unit amounts)

DAILY PRODUCTION	**2005**	**2004**	**Variance**
Oil (bbls)	18,238	11,579	58%
Natural gas (mcf)	88,271	77,925	13%
Natural gas liquids (bbls)	2,283	2,040	12%
BOE (6:1)	35,234	26,607	32%
Total production (mboe)	3,171	2,421	31%
PRODUCTION PROFILE			
Oil	52%	44%	
Natural gas	42%	48%	
Natural gas liquids	6%	8%	
PRICES			
Oil (per bbl)	$ 54.74	$ 42.50	29%
Natural gas (per mcf)	$ 6.97	$ 6.76	3%
Natural gas liquids (per bbl)	$ 46.04	$ 37.06	24%
BOE (6:1)	$ 48.79	$ 41.15	19%
Cash operating netback per BOE	$ 25.45	$ 22.71	12%
LEASE OPERATING COSTS	$ 32,010	$ 19,829	(61)%
Cost per boe	$ 10.09	$ 8.19	(23)%
GENERAL AND ADMINISTRATIVE COSTS	$ 3,639	$ 3,138	(16)%
Cost per boe	$ 1.15	$ 1.30	12%

SPECIAL NOTES

As discussed per the February 2005 notice of the annual meeting, Peter N. Thomson did not stand for re-election, as director, at the April 13, 2005 meeting of the Unitholders.

As announced in March 2005, Mr. Edward J. Brown joined on April 1, 2005 as Vice President, Finance. Mr. Brown was subsequently appointed Chief Financial Officer on May 1, 2005, upon the retirement of Vince P. Moyer.

Management Discussion & Analysis
three months ended March 31, 2005

The following Management Discussion and Analysis (MD&A) of financial results should be read in conjunction with the unaudited Consolidated Financial Statements of Petrofund Energy Trust ("Petrofund" or the "Trust") for the three months ended March 31, 2005 and the December 31, 2004 audited consolidated financial statements and management's discussion and analysis included in the Petrofund Energy Trust 2004 annual report. All the oil and natural gas properties are held by Petrofund Corp. ("PC") a wholly owned subsidiary of the Trust. This commentary is based on information available to May 10, 2005. Additional information (including Petrofund's annual information form) can be obtained on Sedar at www.sedar.com or on the Trust's website at www.petrofund.ca.

All amounts are stated in Canadian dollars unless otherwise noted. Where amounts and volumes are expressed on a barrel of oil equivalent ("boe") basis, gas volumes have been converted to barrels of oil at 6,000 cubic feet per barrel (6 mcf/bbl). BOEs may be misleading, particularly if used in isolation. A BOE conversion of 6 mcf/1 bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

NON GAAP MEASURES

Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian generally accepted accounting principles ("GAAP") and may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flows or operating profits for the period, nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital.

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

FORWARD-LOOKING STATEMENTS

This disclosure includes statements about expected future events and/or financial results that are forward-looking in nature and subject to substantial risks and uncertainties. For those statements, Petrofund claims the protection of the safe harbor for forward-looking statements provisions contained in the U.S. Private Securities Litigation Reform Act of 1995. Petrofund cautions that actual performance will be affected by a number of factors, many of which are beyond its control. These include general economic conditions in Canada and the United States; industry conditions including changes in laws and regulations; changes in

income tax regulations; increased competition; and fluctuations in commodity prices, foreign exchange and interest rates. In addition, there are numerous risks and uncertainties associated with oil and natural gas operations and the evaluation of oil and natural gas reserves. As a result, future events and results may vary substantially from what Petrofund currently foresees.

A more complete discussion of the various factors that may affect future results is contained in Petrofund's recent filings with the Securities and Exchange Commission and Canadian securities regulatory authorities.

RESULT SUMMARY

FIRST QUARTER 2005 VERSUS FOURTH QUARTER 2004

The Trust generated cash flow of $73.0 million or $0.73 per unit in the first quarter of 2005 compared to $72.3 million or $0.72 per unit in the fourth quarter of 2004. The Trust maintained monthly cash distributions of $0.16 per unit and a payout ratio of 67% in the first quarter of 2005.

The first quarter of 2005 was one of the most active quarters in its history for Petrofund's drilling and development activities. Total expenditures for the quarter were $48.4 million. These activities will provide new production in the second and third quarters of 2005, as discussed further in the Operational Highlights.

Daily production volumes in the first quarter of 2005 of 35,234 boe were slightly below fourth quarter volumes of 2004 of 36,025 boe. This decrease resulted from the natural production decline and the temporary shut in of production at one minor property, but was partially offset by production additions from development activities.

Net income of $19.2 million in the first quarter of 2005 decreased from $50.9 million in the fourth quarter of 2004 mainly due to a change of $50.2 million in non-cash adjustments on commodity contracts. The Trust recognized an unrealized (non-cash) commodity adjustment of $23.8 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 accounting standard governing price risk management activity. In addition, the future income tax recovery in the first quarter of 2005 was $12.7 million compared to $774,000 expense in the fourth quarter of 2004.

The cash loss on commodity contracts during the first quarter of 2005 was $8.2 million compared to a $14.1 million loss in the fourth quarter of 2004.

Royalties were 20% of revenue in the first quarter of 2005, compared to 20% for the three months ended December 31, 2004.

Lease operating costs increased to $10.09/boe in the first quarter of 2005 from $8.82/boe in the fourth quarter of 2004. The most significant contributor to the higher operating costs in the first quarter of 2005 versus 2004 was general industry increases for all types of services including surface and downhole well repair costs and facility maintenance work. Costs in the first quarter of 2005 included prior year adjustments from operators of $2.5 million or $0.79 per boe.

HIGHLIGHTS OF THE THREE MONTHS ENDED MARCH 31, 2005

The Trust paid out cash distributions of $0.48 per unit in the first quarter of 2005 as compared to $0.48 per unit in the first quarter of 2004.

The Trust's payout ratio for the three months ended March 31, 2005 was 67% remaining the same as the fourth quarter of 2004 and compared to 73% in the first quarter of 2004.

Net income increased 152% to $19.2 million in the first quarter of 2005 versus $7.6 million in the first quarter of 2004.

The Trust generated cash flow of $73.0 million, an increase of 49% over the first quarter of 2004.

Average production on a boe basis increased 32% to 35,234 boe/d in the first quarter of 2005 from 26,607 boe/d in the first quarter of 2004.

Average prices in the first quarter of 2005 were up 19% on a boe basis from the same period the prior year.

Petrofund has a strong balance sheet with a net debt to cash flow ratio of 1.0:1.0 of annualized first quarter 2005 cash flow.

The Trust has a balanced production profile which averaged 42% natural gas and 58% oil and liquids in the first quarter of 2005.

The weighted average Trust units outstanding increased from 73.7 million in the first quarter of 2004 to 100.6 million in the first quarter of 2005.

The Trust market capitalization as at March 31, 2005, was approximately $1.8 billion ($1.3 billion March 31, 2004).

OPERATIONAL HIGHLIGHTS

Petrofund had an active drilling program in the first quarter of 2005, with 73 wells drilled. The program consisted of 70 working interest wells (23.2 net) and three farmout wells resulting in 50 gas wells, 20 oil wells, one service well and two dry and abandoned wells for an overall 97% success rate. Following is a summary of properties where significant activity occurred.

July Lake, British Columbia

Petrofund finished drilling four wells of a five well program in the shortened winter drilling season. The wells were all successful horizontal Jean Marie gas wells and Petrofund has 100% working interest in all the wells. A pipeline gathering system and compressor station were completed before break-up resulting in all four wells commencing production at quarter end. It is expected these wells will provide approximately 5.5 mmcf/d new production to Petrofund in the second quarter of 2005.

Turin, Alberta

At the Turin property in southern Alberta, Petrofund commenced a 10 well drilling program in February. At quarter end, six wells had been drilled (4.75 net) resulting in four oil wells, one gas well and one unproductive well. The wells are currently being completed and new production facilities are under construction to tie the wells into existing treating facilities. The unproductive wellbore may be utilized as a water injection well. Expected production increase from the five wells is approximately 200 boe/d net to Petrofund and is scheduled to come on stream in May 2005.

Three Hills Creek, Alberta

Petrofund participated in the drilling of 26 wells (9.1 net) as part of the ongoing CBM (coalbed methane) development in this area. Testing of the wells is underway and facilities are currently being installed to bring the production on stream in the third quarter of 2005. Petrofund's net share of this production is expected to be 750 mcf/d.

Weyburn, Saskatchewan

In the Weyburn Unit, 11 horizontal infill wells (2.3 net) were drilled in the first quarter of 2005. Eight of these 11 wells were re-entries, where additional horizontal legs are drilled from existing welbores. Petrofund's net production from these wells of 250 boe/d will be seen during the second quarter of 2005.

Border, British Columbia

Nine Bluesky-Gething gas wells (0.8 net) were drilled in the Border "B" Unit this winter. Production from the new wells will help offset the natural production decline from the reservoir and maintain gas throughput at the Border gas plant. Petrofund's net production from these wells totals 1.0 mmcf/d.

Fort Saskatchewan, Alberta

A production optimization review of the low pressure gas gathering system for our Beaverhill Lake Viking Gas Unit (95% WI) resulted in the installation of a 750 hp booster compressor giving an immediate gain of 400 mcf/d and allowing a significant further expected increase in ultimate recovery as the upgrade will be capable of taking the entire field to much lower pressures.

The upgrade has also allowed the Lindbrook facility to handle new production from a 100% WI deep gas well that started production in March at 500 mcf/d and will also allow opportunities for custom processing.

Cherhill, Alberta

The central oil treating facility at Cherhill was expanded in March to increase produced water handling capability. This expansion has allowed Petrofund to restart several high water-cut oil wells that were shut in due to lack of capacity. Petrofund will also now be able to upsize the pumps on several producing oil wells and expects to realize a total gain of 150 bbl/d of oil production during the second quarter of 2005.

Ferrier, Alberta

Compression was installed to increase production capacity at the Ferrier gas plant. A workover and tie-in of a standing well, along with continued optimization should increase production by approximately 1.5 mmcf/d.

Armisie, Alberta

The Armisie field was shut in for approximately eight weeks during the first quarter of 2005 due to restrictions at the gas processing plant that handles the Armisie solution gas and non associated gas. This restriction is not likely to reoccur. Petrofund lost approximately 400 boe/d production during the shut-in.

CASH DISTRIBUTIONS

For the three months ended March 31,	**2005**	**2004**
Distributions paid per unit	$0.48	$0.48

Trust unitholders who held their units throughout first quarter of 2005 received cash distributions of $0.48 per unit as compared to $0.48 per unit in 2004. For 2005 the Trust distributed $0.16 per unit in April, has announced $0.16 per unit for May, and has indicated $0.16 per unit for June.

The Trust generated cash flow available for distribution before reserve for capital expenditures in the first quarter of 2005 of $71.7 million. The Trust paid out $47.9 million in distributions representing a payout ratio of 67%.

For the 12 months ended March 31, 2005, the Trust generated cash flow available for distribution of $255.3 million, and allocated $87.4 million for investment in development drilling and other projects. Distributions of $182.5 million were paid out, representing a payout ratio of 71%. For a detailed analysis of cash flow available for distribution and distributions paid refer to Note 7 to the Interim Consolidated Financial Statements.

RESULTS OF OPERATIONS

PRODUCTION

In accordance with Canadian practice, production volumes and reserves are reported on a working interest basis, before deduction of Crown and other royalties, unless otherwise indicated.

Production volumes averaged 35,234 boe/d in the first quarter of 2005, an increase of 32% over average production volumes of 26,607 boe/d in the first quarter of 2004. The change in production reflects the acquisition of Ultima in

June of 2004, PC's development drilling program and the Central Alberta acquisition in November 2004.

For the three months ended March 31,	**2005**	**2004**
Daily Production		
Oil (bbls)	18,238	11,579
Natural gas (mcf)	88,271	77,925
Natural gas liquids (bbls)	2,283	2,040
Total (boe 6:1)	35,234	26,607

PRICING & PRICE RISK MANAGEMENT

Revenues from the sale of crude oil, natural gas, and natural gas liquids and sulphur increased 55% to $154.8 million in the first quarter of 2005 from $99.7 million in the first quarter of 2004 due to a 31% increase in production and a 19% increase in prices on a boe basis.

Crude oil sales increased to $89.9 million in the first quarter of 2005 from $44.8 million in the first quarter of 2004 due to a 58% increase in production from 11,579 bbl/d in the first quarter of 2004 to 18,238 bbl/d in the first quarter of 2005 and a 29% increase in the oil price. The average WTI oil price increased from $35.14 US/bbl in 2004 to $49.84 US/bbl in the first quarter of 2005 or 42%; however, the Canadian par price at Edmonton increased only 35% from $45.60/bbl to $61.45/bbl due to the significant strengthening of the Canadian dollar relative to the U.S. dollar which averaged $0.82 in the first quarter of 2005 versus $0.76 in the first quarter of 2004. The average Canadian wellhead price received by Petrofund increased from $42.50/bbl in the first quarter of 2004 to $54.74/bbl in the first quarter of 2005. Petrofund's differential from Edmonton par was $3.10/bbl in the first quarter of 2004 versus $6.71/bbl in the first quarter of 2005 as quality differentials for medium crudes have increased.

Natural gas sales increased to $55.4 million in the first quarter of 2005 from $48.0 million in the first quarter of 2004 due to a 13% increase in production and a 3% increase in the average prices received from $6.76/mcf in the first quarter of 2004 to $6.97/mcf in the first quarter of 2005. The monthly AECO price per mmbtu increased from $6.61 in the first quarter of 2004 to $6.69 in the first quarter of 2005. Production volumes averaged 88.3 mmcf/d in the first quarter of 2005 compared to 77.9 mmcf/d in the first quarter of 2004.

Sales of natural gas liquids and sulphur increased to $9.5 million in the first quarter of 2005 from $6.9 million in the first quarter of 2004 as production increased to 2,283 bbl/d in the first quarter of 2005 from 2,040 bbl/d in the first quarter of 2004. The average price increased from $37.06/bbl in the first quarter of 2004 to $46.04/bbl in the first quarter of 2005.

Average prices received for the three months ended March 31,	**2005**	**2004**
Oil (per bbl) [(1)]	$ 54.74	$ 42.50
Natural gas (per mcf) [(1)]	6.97	6.76
Natural gas liquids (per bbl) [(1)]	46.04	37.06
Weighted average (6:1)	$ 48.79	$ 41.15

(1) Prices are before realized gains/losses on commodity contracts and before transportation costs.

Production Revenue ($ millions)	**2005**	**2004**
Oil	$ 89.9	$ 44.8
Natural gas	55.4	48.0
Natural gas liquids & sulphur	9.5	6.9
Total	$ 154.8	$ 99.7

The Trust has a formal risk management policy which permits the risk management committee to use specified price risk management strategies for up to 40% of crude oil, natural gas and NGL production including: fixed price contracts; costless collars; the purchase of floor price options; and other derivative financial instruments to reduce price volatility and ensure minimum prices for a maximum of eighteen months beyond the current date. The program is designed to provide price protection on a portion of the Trust's future production in the event of adverse commodity price movement, while retaining significant exposure to upside price movements. By doing this, the Trust seeks to provide a measure of stability to cash distributions as well as ensure Petrofund realizes positive economic returns from its capital development and acquisition activities.

As at March 31, 2005, Petrofund had 24.7 mmcf/d of natural gas and 5,000 bbl/d of crude oil hedged for remainder of 2005. A summary of the hedged volumes and prices by quarter is shown in the following table (see Note 8 to the Interim Consolidated Financial Statements for a detailed disclosure of all derivative financial instruments and their corresponding mark-to-market values):

Average Volumes (mcf/d)

		2005			**2006**	
Natural Gas	**2005**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**
Fixed	3,158	4,737	4,737	-	-	-
Collars	15,790	18,948	18,948	9,474	4,737	-
Three way collars	5,790	4,737	4,737	7,895	9,474	-
Total mcf/d	**24,738**	**28,422**	**28,422**	**17,369**	**14,211**	-

Average Prices ($/mcf)

Fixed price	$ 7.06	$ 7.07	$ 7.06	$ -	$ -	$ -
Collar ceiling price	9.81	8.73	8.73	11.98	13.61	-
Collar floor price	6.54	6.33	6.33	6.96	7.28	-
Three way ceiling price	8.78	7.92	7.92	10.49	11.77	-
Three way floor price	5.96	5.80	5.80	6.28	6.52	-
Three way floor short	$ 4.91	$ 4.75	$ 4.75	$ 5.23	$ 5.47	$ -

Average Volumes (bbl/d)

	2005	**2006**

Oil	**2005**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**
Collared	1,000	1,000	1,000	1,000	2,000	-
Three way collars	4,000	4,000	4,000	4,000	1,000	1,000
Total bbl/d	**5,000**	**5,000**	**5,000**	**5,000**	**3,000**	**1,000**
			Average Price ($/bbl)			
Collar ceiling price	$ 67.76	$66.53	$68.77	$ 67.98	$ 78.63	$ -
Collar floor price	49.99	48.38	50.80	50.80	52.62	-
Three way ceiling price	45.24	44.03	45.85	45.85	64.11	71.67
Three way floor price	35.57	35.57	35.57	35.57	48.38	50.80
Three way floor short	$ 30.85	$30.85	$30.85	$ 30.85	$ 42.34	$ 44.76

		2005			**2006**	
Alberta Power	**2005**	**Q2**	**Q3**	**Q4**	**Q1**	**Q2**
Fixed MW/h	2.0	2.0	2.0	2.0	-	-
Fixed price ($/MWh)	$44.50	$44.50	$44.50	$44.50	-	-

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.

As at May 10th, 2005 Petrofund had entered into the following additional hedge (not included in the table above):

1) Collar for April 1, 2006-June 30, 2006 for 1,000 bbl/d of crude (WTI) between $57.45 and $84.67/bbl levels.

Petrofund has no volumes hedged after June 30, 2006. All foreign exchange calculations in this section of the report incorporate the Bank of Canada US dollar rate at the close on March 31, 2005 of CDN $1.2096:US$. For a complete listing of all hedge transaction details please see Note 8 to the Interim Consolidated Financial Statements.

LOSS ON COMMODITY CONTRACTS (in $ thousands)

For the three months ended March 31,		**2005**		**2004**
Realized losses	$	(8,166)	$	(4,900)
Change in fair value				
Fair value, beginning of period		(11,318)		(6,771)
Less fair value, end of period		(35,090)		(16,901)
Change in fair value of financial instruments		(23,772)		(10,130)
Amortization of deferred commodity contracts		(59)		(2,461)
Total non-cash adjustments		(23,831)		(12,591)
Total	$	(31,997)	$	(17,491)

ROYALTIES

For the three months ended March 31,	**2005**	**2004**
Royalties ($ millions)	$31.8	$18.6
Average royalty rate (%)	20	19
$/boe	$10.04	$7.67

Royalties, which include crown, freehold and overrides paid on oil and natural gas production, increased to $31.8 million in the first quarter of 2005 from $18.6 million in the first quarter of 2004, net of the Alberta Royalty Credit (“ARC”). Royalties, as a percentage of revenues before hedging losses, increased to 20% of revenues in the first quarter of 2005 from 19% of revenues in the first quarter of 2004.

EXPENSES

For the three months ended March 31,	**2005**	**2004**
Expenses ($ millions)		
Lease operating	$ 32.0	$ 19.8
Transportation	2.0	1.4
General & administrative	3.6	3.1
Financing costs	2.1	0.9
Expenses per boe		
Lease operating	$ 10.09	$ 8.19
Transportation	0.64	0.56
General & administrative	1.15	1.30
Financing costs	0.67	0.37

Lease Operating

Oil and gas lease operating expenses increased to $32.0 million in the first quarter of 2005 from $19.8 million in the first quarter of 2004 due to the additional wells on production and the increase in costs on a boe basis. Operating costs on a boe basis increased to $10.09 in the first quarter of 2005 from $8.19 in the first quarter of 2004.

The most significant contributor to the higher operating costs in the first quarter of 2005 versus 2004 was general industry increases for all types of services including surface and downhole well repair costs and facility maintenance work. In addition, costs in the first quarter of 2005 include prior year adjustments from operators of $2.5 million or $0.79 per boe.

Transportation Costs

Transportation costs on a boe basis were $0.64 in the first quarter of 2005 as compared to $0.56 in the first quarter of 2004, which reflects the higher transportation costs associated with the Ultima properties.

General & Administrative ("G&A")

G&A costs on a boe basis were $1.15 per boe in the first quarter 2005 as compared to $1.30 per boe in the same period 2004. General and administrative costs, net of overhead recoveries, increased to $3.6 million in 2005 from $3.1 million in 2004. G&A costs in the first quarter of 2005 included $74,000 relating to the external costs associated with compliance with Section 404 of the Sarbanes-Oxley Act (“SOX 404”) and $74,000 for the reclassification of units, which equates to $ 0.05 per boe.

Financing Costs

Interest and other financing costs increased to $2.1 million in the first quarter of 2005 from $906,000 in the first quarter of 2004 due to the increase in the average loan balance outstanding, offset by a decrease in the average prime loan rate from 4.305% in first quarter of 2004 to 4.25% in the first quarter of 2005. The average loan outstanding in the first quarter of 2005 was $233.2 million versus $89.8 million in the first quarter of 2004.

The bank loan outstanding at March 31, 2005, was $239.2 million as compared to $214.4 million at December 31, 2004.

DEPLETION, DEPRECIATION & ACCRETION

Depletion, depreciation and accretion expense increased to $43.7 million in the first quarter of 2005 from $29.5 million in first quarter of 2004 due to the increase in production and an increase in the depletion rate. The rate per boe increased to $13.78 in the first quarter of 2005 from $12.20 in the first quarter of 2004. The increase in the rate over 2004 reflects the increasing cost of acquisitions. Unproved properties are included in the depletion and depreciation expense calculation.

INCOME TAXES

Current taxes consist of the Federal Large Corporations Tax and some minor amounts relating to income taxes of corporate entities acquired. The Federal Large Corporations Tax is based primarily on the debt and equity balances of the Trust's 100% owned subsidiary, Petrofund Corp. as at March 31, 2005. The Federal Large Corporations Tax rate is being reduced in stages over a period of five years commencing in 2004, so that by 2008, the tax will be eliminated.

Capital taxes of $787,000 in the first quarter of 2005 (2004 - $737,000) are primarily the Saskatchewan Capital Tax and Resource Surcharge, which is based upon gross revenues earned in Saskatchewan.

Future income tax liabilities arise due to the differences between the tax basis of Petrofund Corp's assets and their respective accounting carrying cost. The future income tax recovery in the first quarter of 2005 was $12.7 million compared to $443,000 expense in the first quarter of 2004 as a result of an increase in non-cash commodity contract losses.

NET INCOME

For the three months ended March 31,	**2005**	**2004**
Net income ($000's)	$ 19,243	$ 7,629
Net income per Trust unit		
Basic	$ 0.19	$ 0.10
Diluted	$ 0.19	$ 0.10

Net income before taxes decreased from $8.1 million in the first quarter of 2004 to $6.6 million in the first quarter of 2005 mainly due to a 61% increase in lease operating costs, a 48% increase in depletion offset by a 55% increase in revenues. Production was up 31% and prices increased 19% on a boe basis.

The Trust recognized a net loss on commodity contracts of $32.0 million in the first quarter of 2005 compared to $17.5 million in the first quarter of 2004. The unrealized (non-cash) loss on commodity contracts was $23.8 million in the first quarter of 2005 compared to $12.6 million in the first quarter of 2004.

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

Total cash netbacks increased by $23.9 million. On a boe basis cash netbacks were up to $23.35 in the first quarter of 2005 from $20.72 in the first quarter of 2004.

Total Cash Netbacks	**2005**	**2004**
Operating netback	$ 25.45	$ 22.71
Financing costs	0.67	0.37
General and administrative	1.15	1.30
Capital and current taxes	0.28	0.32
Total cash netback per BOE	$ 23.35	$ 20.72

As a result of the changes discussed above, net income increased to $11.6 million in the first quarter of 2005 from the $7.6 million reported in the first quarter of 2004.

Operating Netbacks 2005	**Oil $/bbl**	**Gas $/mcf**	**NGL $ /bbll**	**Total $ /boe**	
Selling price	$ 54.74	$ 6.97	$ 46.04	$ 48.79	
Cash cost of hedging	(5.02)	-	-		(2.57)
Net selling price	49.72	6.97	46.04	46.22-	
Royalties, net of ARC	10.13	1.62	11.50	10.04-	
Operating	12.00	1.32	9.03	10.09-	
Transportation	0.58	0.13	0.50	0.64-	
Operating netback	$ 27.01	$ 3.90	$ 25.01	$ 25.45 -	

Operating Netbacks 2004	**Oil $/bbl**	**Gas $/mcf**	**NGL $ /bbl**	**Total $ /boe**	
Selling price	$ 42.50	$ 6.76	$ 37.06	$ 41.15	
Cash cost of hedging	(4.91)	-	-		(2.02)
Net selling price	37.59	6.76	37.06	39.13	
Royalties, net of ARC	6.43	1.37	11.11	7.67	
Operating	11.94	0.84	6.79	8.19	
Transportation	0.22	0.15	0.41	0.56	
Operating netback	$ 19.00	$ 4.40	$ 18.75	$ 22.71	

QUARTERLY FINANCIAL DATA

($ millions, except per unit amounts)	**Net Oil and Natural Gas Sales [1]**	**Net Income**	**Net income per Unit Basic**	**Diluted**
2005				
First quarter	$ 122.9	$ 19.2	$ 0.19	$ 0.19
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
2003				
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

(1) Net after royalties

CAPITAL EXPENDITURES

Acquisitions

During the three months ended March 31, 2005, PC spent $6.3 million to acquire minor property interests in the Turin area, as compared to $1.1 million in the first quarter of 2004.

Development Activities

During the three months ended March 31, 2005, PC incurred $48.4 million drilling and development activities as compared to $12.6 million in the three months ended March 31, 2004. A total of 73 wells were drilled, of which 50 were gas, 20 oil, 1 service well and 2 dry and abandoned for an overall success rate of 97%.

A summary of capital expenditures for the period is as follows (in $ thousands):

For the three months ended March 31,	**2005**	**2004**
Property acquisitions [(1)]	$ 6,251	$ 1,090
Development expenditures:		
Land & seismic	3,969	607
Drilling & completion	22,398	5,686
Well equipping	5,051	1,198
Tie-ins	4,351	1,081
Facilities	8,716	2,546
CO2 purchases	3,818	1,458
Other	87	40
Total	48,390	12,616
Total net capital expenditures	$ 54,641	$ 13,706

(1) The property acquisition totals exclude non-cash future income tax adjustments for the difference between the cost and tax basis is of assets acquired by way of corporate acquisitions.

ASSET RETIREMENT FUND

As at March 31, 2005, PC had $7.5 million set aside in cash to fund future abandonment costs. This cash fund 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 $1.1 million for these activities in the first quarter of 2005 compared to $1.2 million in the first quarter of 2004. PC expects to spend a further $5 million to $6 million on reclamation and abandonment work in 2005.

GOODWILL

The goodwill balance of $180.3 million arose as a result of the Ultima and Central Alberta acquisitions in 2004. 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 goodwill impairment as of March 31, 2005.

DEBT

As at March 31, 2005, the amount outstanding on the credit facility was $239.2 million, with $85.8 million available to finance future activities prior to the increase in the borrowing base.

On April 29, 2005, PC's borrowing base was increased to $415 million and the revolving period on the syndicated facility of $390 million was extended for a further 364 day period ending on April 28, 2006. In the event that the revolving bank line is not extended at the end of the 364 day revolving period, no payments are required to be made to non-extending lenders during the first year of the term period. However, Petrofund will be required to maintain certain minimum balances on deposit with the syndicate agent.

LIQUIDITY AND CAPITAL RESOURCES

The working capital deficit was $59.5 million at March 31, 2005, an increase of $10.2 million from the $49.3 million deficit as at December 31, 2004. The March 31, 2005 and December 31, 2004 deficits excludes net unrealized losses on commodity contracts. Current assets increased $7.4 million from $48.6 million at December 31, 2004 to $56.0 million at March 31, 2005. Current liabilities increased $17.6 million from $97.9 million at December 31, 2004 to $115.5 million at March 31, 2005. This increase in liabilities reflects an increase in the capital expenditures in the quarter and an increase in distributions payable to Unitholders.

During first quarter of 2005 the Trust generated cash flow of $73.0 million and paid out $47.9 million in distributions. The excess of $25.0 million was used to partially fund the Trust's capital expenditure program.

Total long-term debt increased to $239.2 million at March 31, 2005, from $214.4 million at December 31, 2004, due to the cost of development activities.

The banking syndicate reviewed the borrowing base in conjunction with its review of the independent engineering report as at December 31, 2004 and increased the limit on the facility to $415 million from $325 million effective April 29, 2005.

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

For the three months ended March 31, ($ thousands)		**2005**		**2004**	
Cash flow	$	72,959	$	49,047	
Proceeds received from issuance of Trust units		4,190		907	
Net change in non-cash working capital balances		(7,132)		25,846	
Distributions paid		(47,894)			(34,910)
Expenditures on oil & natural properties, net		(54,641)			(13,706)
Asset retirement reserve		(476)			(363)
Redemption of exchangeable shares		(387)			(451)
Capital lease repayments		(406)			(86)
(Increase) decrease in cash		8,964			(6,415)
	$	(24,823)	$	19,869	

In the absence of an equity issue, long-term debt will increase in 2005 due to the capital expenditure program which is expected to be in the $120 million range (excluding acquisitions) of which a significant portion is expected to be funded from cash flow. If the Trust is successful in completing one or more significant acquisitions in 2005 these would be financed by further utilization of the credit facility or a combination of additional bank borrowing and a possible equity issue of treasury units.

Capitalization Analysis

($ thousands, except per unit and percent amounts)		**2005**		**2004**	
Working capital (deficiency) [(1)]	$	(59,531)			$ (56,093)
Bank debt		239,237		89,838	
Capital lease obligation		-		202	
Net debt obligation	$	298,768	$	146,133	
Units outstanding and issuable for Exchangeable Shares		100,746		73,682	
Market Price at March 31,		17.64		17.35	
Market capitalization	$	1,777,156	$	1,278,390	
Total capitalization	$	2,075,924	$	1,424,523	
Net debt as a percentage of total capitalization		14%		10%	

[(1)] Excludes net unrealized losses on commodity contracts.

Based on annualized first quarter 2005 cash flow, Petrofund's net debt to cash flow ratio is 1.0:1.0.

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

UNITHOLDERS' EQUITY

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

For the three months ended March 31,	**2005**	**2004**
Basic	100,602,757	73,673,782
Diluted	100,644,186	73,872,208

Trust units/exchangeable shares outstanding:

As at March 31,	**2005**	**2004**
Trust units outstanding	100,206,640	72,743,253
Trust units issuable for exchangeable shares (*Note 3*)	539,147	939,147
	100,745,787	73,682,400

The Trust had 100,206,640 Trust units outstanding at March 31, 2005 compared to 72,743,253 Trust units at the end of March 31, 2004. The weighted average number of Trust units outstanding including Exchangeable Shares, was 100,745,787 Trust units for the first quarter of 2005 as compared to 73,682,400 for 2004. During the first quarter of 2005, 316,251 Exchangeable Shares were converted into 400,000 Trust units and 17,747 were redeemed for cash leaving 422,650 Exchangeable Shares outstanding at March 31, 2005 which are convertable into 539,147 Trust units.

FINANCIAL INSTRUMENTS

The net negative fair value of the commodity contracts at March 31, 2005 of $35.1 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, from January 1, 2005 to March 31, 2005 of $23.8 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 $8.2 million for three months ended March 31, 2005 compared to $4.9 million for three months ended March 31, 2004.

Deferred Commodity Contracts ($000’s)	**Jan 1, 2005**	**Amortized to Expense**	**Mar 31, 2005**
Current Asset			
Deferred loss	$ 517	$ (129)	$ 388
Current Liability			
Deferred gain	(184)	70	(114)
	$ 333	$ (59)	$ 274

Commodity Contracts ($000’s)	**Jan 1, 2005**	**Change in Fair Value**	**Mar 31, 2005**
Current Asset			
Commodity contracts	$ 3,281	$ (3,093)	$ 188
Current Liability			
Commodity contracts	(14,599)	(20,679)	(35,278)
	$ (11,318)	$ (23,772)	$ (35,090)

NON-RESIDENT OWNERSHIP

Based on information available to the Trust, Petrofund estimated that non-resident ownership was approximately 71% as of April 30, 2005. While there are, at present, no restrictions or deadlines on Petrofund pertaining to non-resident ownership levels, the Trust will continue to provide non-resident ownership level updates on a quarterly basis. Petrofund continues to monitor developments in this area.

OFF-BALANCE SHEET ARRANGEMENTS

The Trust has no off-balance sheet financing arrangements.

OUTLOOK FOR 2005

The level of cash flow for 2005 will be affected by oil and gas prices, the Canadian - US dollar exchange rate and the Trust's ability to add reserves and production in a cost effective manner. Both product prices and the exchange rate showed significant volatility in 2004 and this trend is expected to continue in 2005. The acquisition market is expected to continue to be active. 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 first quarter of 2005 moderated the net effect of these prices on Petrofund's cash flow. The WTI U.S. price increased 42% to $49.84/bbl in 2005 from $35.14/bbl in the first quarter of 2004; however, as the (US/CDN) exchange rate averaged $0.82 in 2005 as compared to $0.76 in the first quarter of 2004 the par price at Edmonton was up only 35%. The Trust expects the Canadian dollar to remain strong throughout 2005.

Petrofund pursues a well defined risk management program to help offset the effect of price fluctuations. This program utilizes collars as the main hedging tool but Petrofund also enters into fixed price transactions when commodity prices approach historic highs. To date, the Trust has not entered into any currency related transactions. A discussion of the risk management strategies and hedged positions appear elsewhere in this report.

SENSITIVITY ANALYSIS

Below is a table that shows sensitivities to pre-hedging cash flow as a result of product price and operational changes that can significantly affect cash flow and results of operations. The table is based on actual 2005 prices received for the first quarter of 2005 and production volumes of 35,000 boe/d. These sensitivities are approximations only and are not necessarily valid at other price and production levels. As well, hedging activities can significantly affect these sensitivities.

	Change	$000's	$/unit per year
Price per barrel of oil*	$ 1.00 US	$ 7,607	$ 0.075
Price per mcf of natural gas*	$ 0.25 CDN	$ 6,143	$ 0.061
US/Cdn exchange rate	$ 0.01	$ 4,681	$ 0.046
Interest rate on debt ($239 million)	1%	$ 2,390	$ 0.024
Oil production volumes*	100 bbl/day	$ 1,638	$ 0.016
Gas production volumes*	1 mmcf/day	$ 1,946	$ 0.019

* After adjustment for estimated royalties.

Consolidated Balance Sheet

(thousands of dollars) (unaudited)

As at March 31, 2005 and December 31, 2004		**2005**		**2004**	
Assets					
Current assets					
Accounts receivable	$	40,027	$	37,713	
Deferred loss on commodity contracts		388		517	
Commodity contracts (*Note 8)*		188		3,281	
Prepaid expenses		15,985		10,847	
Total current assets		56,588		52,358	
Asset retirement reserve fund *(Note 6(b))*		7,529		7,053	
Goodwill		180,307		180,307	
Oil and natural gas royalty and property interests, at cost less accumulated depletion and depreciation of $675,757 (2004 - $632,668)		1,259,248		1,246,694	
	$	1,503,672	$	1,486,412	
Liabilities and Unitholders' Equity					
Current liabilities					
Bank overdraft	$	9,697	$	733	
Accounts payable and accrued liabilities		61,280		60,961	
Current portion of capital lease obligations		202		608	
Deferred gain on commodity contracts		114		184	
Commodity contracts (*Note 8)*		35,278		14,599	
Distributions payable to Unitholders (*Note 7)*		44,364		35,568	
Total current liabilities		150,935		112,653	
Long-term debt *(Note 5*)		239,237		214,414	
Future income taxes		68,705		81,411	
Asset retirement obligations (*Note 6(a))*		51,913		51,408	
Total liabilities		510,790		459,886	
Unitholders' equity					
Unitholders' capital *(Note 2)*		1,486,633		1,477,963	
Exchangeable shares *(Note 3*)		6,038		10,518	
Accumulated earnings		291,855		272,612	
Accumulated cash distributions *(Note 7*)		(791,644)			(734,567)
Total unitholders' equity		992,882		1,026,526	

	$	1,503,672	$ 1,486,412

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

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

For the three months ended March 31,		**2005**		**2004**	
Revenues					
Oil and natural gas sales	$	154,768	$	99,699	
Royalties		(31,844)			(18,578)
Loss on commodity contracts		(31,997)			(17,491)
		90,927		63,630	
Expenses					
Lease operating		32,010		19,829	
Transportation costs		2,036		1,355	
Financing costs		2,131		906	
General and administrative		3,639		3,138	
Capital taxes		787		737	
Depletion, depreciation and accretion		43,702		29,546	
		84,305		55,511	
Income before provision for income taxes		6,622		8,119	
Provision for (recovery of) income taxes					
Current		85		47	
Future		(12,706)		443	
		(12,621)		**490**	
Net income		19,243		7,629	
Accumulated earnings, beginning of period		272,612		198,253	
Accumulated earnings, end of period	$	291,855	$	205,882	
Net income per Trust unit (*Note 2)*					
Basic	$	0.19	$	0.10	
Diluted	$	0.19	$	0.10	

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

Consolidated Statement of Cash Flows
(thousands of dollars) (unaudited)

For the three months ended March 31,	**2005**	**2004**
Cash provided by (used in):		
Operating activities		
Net income	$19,243	$7,629
Add items not affecting cash:		
Depletion, depreciation and accretion	43,702	29,546
Commodity contracts	23,831	12,591
Future income taxes	(12,706)	443
Actual abandonment costs incurred (*Note 6*)	(1,111)	(1,162)
	72,959	49,047
Net change in non-cash operating working capital balances	(7,132)	25,846
Cash provided by operating activities	65,827	74,893
Financing activities		
Bank loan	24,823	(19,869)
Distributions paid (*Note 7*)	(47,894)	(34,910)
Redemption of exchangeable shares *(Note 3)*	(387)	(451)
Capital lease repayments	(406)	(86)
Issuance of Trust units (*Note 2)*	4,190	907
Cash used in financing activities	(19,674)	(54,409)
Investing activities		
Asset retirement reserve (*Note 6(b))*	(476)	(363)
Property acquisitions	(6,251)	(1,090)
Development expenditures	(48,390)	(12,616)
Cash used in investing activities	(55,117)	(14,069)
Net change in cash (bank overdraft)	(8,964)	6,415
Cash (bank overdraft), beginning of period	(733)	2,182
Cash (bank overdraft), end of period	$ (9,697)	$8,597
Interest paid during the period	$ 2,148	$944
Income taxes paid during the period	$ 244	$55

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

Notes to Interim Consolidated Financial Statements
March 31, 2005 and 2004
(unaudited)
(tabular amounts in thousands of dollars, except per unit amounts)

1. INTERIM FINANCIAL STATEMENTS

These unaudited interim consolidated financial statements follow the same accounting policies and methods of their application as the most recent annual financial statements. The note disclosure requirements for annual financial statements provide additional disclosures to that required for interim financial statements. Accordingly, these interim financial statements should be read in conjunction with the audited consolidated financial statements of Petrofund Energy Trust ("Petrofund" or the "Trust") as at December 31, 2004 and 2003 and for each of the years in the three-year period ended December 31, 2004.

2. TRUST UNITS

Authorized: unlimited number of Trust units	**Number of Units**		**$000's**
Issued			
December 31, 2004	99,511,576	$	1,477,963
Exchangeable shares converted *(Note 3)*	400,000		4,480
Options exercised	270,324		3,799
Unit purchase plan	1,681		31
Unit incentive plan	***23,059***		***360***
March 31, 2005	100,206,640	$	1,486,633

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

For the three months ended March 31,	**2005**	**2004**
Basic	100,602,757	73,673,783
Diluted	100,644,186	73,872,208

The diluted amounts include all dilutive instruments.

Trust units/exchangeable shares outstanding:

As at March 31,	**2005**	**2004**
Trust units outstanding	100,206,640	72,743,253
Trust units issuable for exchangeable shares (*Note 3*)	539,147	939,147
	100,745,787	73,682,400

3. EXCHANGEABLE SHARES

Issued and Outstanding	Number of Shares	$000's
Balance, December 31, 2004	756,648	$ 10,518
Redemption of shares	(17,747)	-
Exchanged for Trust Units [1]	(316,251)	(4,480)
Balance, March 31, 2005	422,650	6,038
Exchangeable ratio, end of period	1.27563	-
Exchangeable for Trust units	539,147	$ 6,038

[1] On March 7, 2005, 316,251 Exchangeable Shares were converted to 400,000 Trust units at an exchange rate of 1.26482.

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

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

	RUP	LTIP	
Balance, December 31, 2004	51,426	31,156	
Units issued	(18,760)		(31,156)
Granted	93,510	61,245	
Forfeitures	(752)	-	
Balance, March 31, 2005	125,424	61,245	

The Trust recorded compensation expenses of $450,000 in the first quarter of 2005 (2004 - $267,000). The compensation expense was based on the March 31, 2005 unit price of $17.64, distributions of $0.48 per unit during the quarter and management's estimate of the number of RUP and LTIP units to be issued on maturity.

5. LONG-TERM DEBT

Under the loan agreements, as at March 31, 2005, Petrofund Corp. ("PC"), a wholly-owned subsidiary of the Trust had a revolving working capital operating facility of $25 million and a syndicated facility of $300 million. On April 29, 2005, PC increased its syndicated facility to $390 million, bringing PC's borrowing base to $415 million. Interest on the working capital loan is at prime and interest on the syndicated facility varies with PC's debt to cash ratio from prime plus 80 basis points or, at the Trust's option, banker's acceptances rates plus stamping fees. The prime rate at March 31, 2005 was 4.25%. As at March 31, 2005, there was no amount outstanding under the working capital facility and $239.2 million outstanding under the syndicated facility.

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 credit facility is secured by a debenture of $600 million pursuant to which a Canadian chartered bank, as principal and as agent for the other lenders, received a first ranking security interest on all of PC's assets.

The loan is the legal obligation of PC. While principal and interest payments are allowable deductions in the calculation of royalty income, the Unitholders have no direct liability to the bank or to PC should the assets securing the loan generate insufficient cash flow to repay the obligation.

Substantially all of the credit facility is financed with Banker's Acceptances, resulting in a reduction in the stated bank loan interest rates.

6. ASSET RETIREMENT OBLIGATIONS AND RESERVE FUND

(a) Asset Retirement Obligations ("ARO")

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

For the three months ended March 31, ($000's)	**2005**	**2004**	
Balance, at beginning of period	$ 51,408	$ 34,363	
Increase in liabilities during the period	1,003	215	
Accretion expense during period	613	554	
Actual costs incurred during the period	(1,111)		(1,162)
Balance, at end of period	$ 51,913	$ 33,970	

(b) Asset Retirement Reserve Fund

PC maintains a cash reserve to finance large and unusual oil and natural gas property reclamation and abandonment costs by withholding distributions accruing to Unitholders. At March 31, 2005, the cash reserve was $7.5 million (2004 - $4.1 million). In first quarter of 2005 PC increased the cash reserve by withholding $476,000 from distributions accruing to Unitholders. In addition, routine ongoing reclamation and abandonment costs of $1.1 million in the first quarter of 2005 (2004 - $1.2 million) were incurred and deducted from distributions accruing to Unitholders.

7. DISTRIBUTIONS ACCRUING TO UNITHOLDERS

Under the terms of the Trust Indenture, the Trust makes monthly distributions within a specified period following the end of each month ("Cash Distribution Date"). Distributions are equal to amounts received by the Trust on the Cash Distribution Date less permitted expenses. Distributions to Unitholders coincide with cash receipts of royalty and income and debt repayments from PC. An overall analysis is as follows:

For the period ended	Cash Distribution Date	2005	2004
November 30	January 31	$ 0.16	$ 0.16
December 31	February 28	0.16	0.16
January 31	March 31	0.16	0.16
Cash Distributions per Trust unit		$ 0.48	$ 0.48

Reconciliation of Distributions Accruing to Unitholders
(thousands of dollars)

For the three months ended March 31,	**2005**	**2004**
Distributions payable, beginning of period	$ 35,568	$ 53,452
Distributions accruing during the period		
Cash flow provided by operating activities	65,827	74,893
Net change in non-cash operating working capital balance	7,132	(25,846)
Amortization of the cost of commodity contracts	-	(221)
Redemption of exchangeable shares	(387)	(451)
Asset retirement reserve	(476)	(363)
Capital lease repayment	(406)	(86)
Cash flow before capital reinvestment	71,690	47,926
Reserve for capital expenditures	(15,000)	(7,500)
Total distributions accruing during the period	56,690	40,426
Distributions paid	(47,894)	(34,910)
Distributions payable, end of period [(1)]	$ 44,364	$ 58,968

[(1)] It is expected that a portion of this amount will be used to fund capital expenditures in the future.

Accumulated Cash Distributions
(thousands of dollars)

For the three months ended March 31,	**2005**	**2004**
Accumulated cash distributions, beginning of year	$ 734,567	$ 581,155
Distributions accruing during the period	56,690	40,426

Redemption of exchangeable shares		387		451
Accumulated cash distributions, end of period	$	791,644	$	622,032

8. DERIVATIVE FINANCIAL INSTRUMENTS AND PHYSICAL CONTRACTS

The Trust enters into various pricing mechanisms to reduce price volatility and establish minimum prices for a portion of its oil and gas production. These include fixed-price contracts and the use of derivative financial instruments.

The outstanding derivative financial instruments, all of which constitute effective economic hedges, and the related unrealized gains or losses since inception of the contracts at March 31, 2005, are summarized separately below:

Natural Gas	Term	Volume mcf/d	Price $/mcf	Delivery Point	Unrealized Gain (Loss) $000's
Fixed	April 1, 2005 to June 30, 2005	4,737	$7.07	AECO	$(398)
Collar	April 1, 2005 to October 31, 2005	4,737	$6.33-$8.44	AECO	(418)
Collar	April 1, 2005 to October 31, 2005	4,737	$6.33-$9.60	AECO	(128)
Collar	April 1, 2005 to October 31, 2005	4,737	$6.33-$8.44	AECO	(418)
Collar	April 1, 2005 to October 31, 2005	4,737	$6.33-$8.44	AECO	(418)
Three way collar	April 1, 2005 to October 31, 2005	4,737	$4.75-$5.80-$7.92	AECO	(652)
Fixed	July 1, 2005 to September 30, 2005	4,737	$7.06	AECO	(607)
Three way collar	November 1, 2005 to March 31, 2006	4,737	$5.68-$6.70-$10.55	AECO	(467)
Three way collar	November 1, 2005 to March 31, 2006	4,737	$5.28-$6.33-$12.98	AECO	(233)
Collar	November 1, 2005 to March 31, 2006	4,737	$7.28-$13.61	AECO	40
Total					$(3,699)

Oil	Term	Volume bbl/d	Price $/bbl	Delivery Point	Unrealized Loss $000's
Three way collar	January 1, 2005 to December 31, 2005	1,000	$24.19-$29.03-$35.08	Edmonton	$ (10,025)
Three way collar	January 1, 2005 to December 31, 2005	1,000	$29.03-$32.43-$40.90	Edmonton	(8,214)
Three way collar	January 1, 2005 to December 31, 2005	1,000	$27.82-$32.42-$39.67	Edmonton	(8,570)
Three way collar	April 1, 2005 to June 30, 2005	1,000	$42.34-$48.38-$60.48	Edmonton	(760)
Collar	April 1, 2005 to June 30, 2005	1,000	$48.38-$66.53	Edmonton	(364)
Three way collar	July 1, 2005 to December 31, 2005	1,000	$42.34-$48.38-$67.74	Edmonton	(1,126)
Collar	July 1, 2005 to September 30, 2005	1,000	$50.80-$68.77	Edmonton	(476)
Collar	October 1, 2005 to December 31, 2005	1,000	$50.80-$67.98	Edmonton	(529)
Three way collar	January 1, 2006 to March 31, 2006	1,000	$42.34-$48.38-$64.11	Edmonton	(725)
Collar	January 1, 2006 to March 31, 2006	1,000	$50.80-$72.58	Edmonton	(325)
Collar	January 1, 2006 to March 31, 2006	1,000	$54.43-$84.67	Edmonton	(4)
Three way collar	April 1, 2006 to June 30, 2006	1,000	$44.76-$50.80-$71.67	Edmonton	(421)
Total					$(31,539)

Electricity	Term	Volume MW/h	Price $/MWh	Delivery Point	Unrealized Gain $000's
Fixed Price	February 1, 2004 to December 31, 2005	2.0	$44.50	Alberta Power Pool	$148

Derivative financial instruments and related hedge contracts involve a degree of credit risk, which the Trust controls through the use of financially sound counterparties. The gains or losses incurred are recognized on a monthly basis over the terms of the hedge contracts. All foreign exchange calculations in this section of the report incorporate the Bank of Canada US dollar rate at the close on March 31, 2005 of CDN $1.2096:US$.

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, which 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.

This news release may include statements about expected future events and/or financial results that are forward-looking in nature and subject to risks and uncertainties. For those statements, we claim the protection of the safe harbor for forward-looking statements provisions contained in the U.S. Private Securities Litigation Reform Act of 1995. Petrofund Energy Trust cautions that actual performance will be affected by a number of factors, many of which are beyond its control. Future events and results may vary substantially from what Petrofund Energy Trust currently foresees. Discussion of the various factors that may affect future results is contained in Petrofund Energy Trust's recent filings with the Securities and Exchange Commission and Canadian securities regulatory authorities.

In regards to barrels of oil equivalent (boe), 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.

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