Exemption Order # 82-5166

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Computershare

600, 530-8th Avenue S.W., Calgary, AB T2P 3S8 Tel.: (403) 267-6800 Fax: (403) 267-6598

March 12, 2004

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SUPPL

Alberta Securities Commission
British Columbia Securities Commission
The Manitoba Securities Commission
Office of the Administrator, New Brunswick
Securities Commission of Newfoundland
Nova Scotia Securities Commission
Ontario Securities Commission
Registrar of Securities, Prince Edward Island
Commission des valeurs mobilieres du Quebec
Saskatchewan Securities Commission
Toronto Stock Exchange

Dear Sirs:

Subject: APF Energy Trust

We advise the following with respect to the upcoming Meeting of Unitholders for the subject Trust:

1.	Meeting Type	:	Annual General
2.	Security Description of Voting Issue	:	Trust Units
3.	CUSIP Number	:	001 85T 202
4.	Record Date	:	April 16, 2004
5.	Meeting Date	:	May 18, 2004
6.	Meeting Location	:	Calgary, Alberta

PROCESSED
MAR 23 2004
THOMSON FINANCIAL

Yours truly,

COMPUTERSHARE TRUST COMPANY OF CANADA

"signed by"

Laura Leong
Corporate Trust Officer
Corporate Trust Department
Direct Dial No. (403) 267-6893
Fax: (403) 267-6598

dlw 3/23

Exemption Order # 82-5166

APF ENERGY

04 MAR 23 AM 7:21

NEWS RELEASE

TSX: AY.UN
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APF Energy Trust announces distribution of $0.175 per unit

March 18, 2004 - APF Energy Trust announces it is maintaining its monthly distribution of $0.175 per unit. Payment will be made on April 15, 2004 to unitholders of record on March 31, 2004. The ex-distribution date is March 29, 2004.

Certain statements in this material may be "forward-looking statements" including outlook on oil and gas prices, estimates of future production, estimated completion dates of acquisitions and construction and development projects, business plans for drilling and exploration, estimated amount and timing of capital expenditures and anticipated future debt levels and royalty rates. Information concerning reserves contained in this material may also be deemed forward-looking statements as such estimates involve the implied assessment that the resources described can be profitably produced in the future. These statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated by APF. This news release is not for distribution in the U.S. The Toronto Stock Exchange has neither approved nor disapproved of the contents of this news release.

For Further Information Please Contact

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APF ENERGY

04 MAR 23 AM 7:21

NEWS RELEASE **TSX: AY.UN; AY.DB**

APF CLARIFIES TAX TREATMENT OF DISTRIBUTIONS FOR U.S. UNITHOLDERS

February 23, 2004 - The following information is being provided to assist individual U.S. Unitholders of APF Energy Trust ("APF") in reporting distributions received from APF for the calendar year 2003. After consulting with its tax advisors, APF understands that the 2003 distributions paid by APF to non-corporate Unitholders who are U.S. residents or citizens should be treated as "Qualified Dividends" under the Jobs and Growth Tax Relief Reconciliation Act of 2003, and generally should be eligible for the reduced U.S. dividend tax rate.

APF is currently in the process of calculating its current and accumulated earnings and profits (in accordance with U.S. tax principles), which should enable U.S. Unitholders to determine the taxable percentage of the distributions paid to them. Detailed information for distributions paid in 2003 and prior years will be posted on the APF website (www.apfenergy.com). APF anticipates this information will be available by the beginning of March

APF has been advised that "Qualified Dividends" should be reported on Line 9b of the U.S. Federal individual income tax return unless the fact situation of the U.S. individual Unitholder determines otherwise. Commentary on page 23 of the IRS 2003 Form 1040 instruction booklet with respect to "Qualified Dividends" provides examples of individual situations where the dividends would not be "Qualified Dividends". Where, due to individual situations, the dividends are not "Qualified Dividends", the amount should be reported on Schedule B - Part 11 - Ordinary Dividends, Line 9a of your U.S. federal income tax return.

This information is not exhaustive of all possible U.S. income tax considerations, but is provided as a general guideline and is not intended to be legal or tax advice to any particular holder of APF Energy Trust units. Holders of APF Energy Trust units should consult their own legal and tax advisors as to their particular tax consequences of holding APF Energy Trust units.

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APF ENERGY

04 MAR 23 AM 7:21

NEWS RELEASE

TSX: AY.UN; AY.DB

APF ANNOUNCES TAX TREATMENT OF DISTRIBUTIONS

February 19, 2004 - APF Energy Trust ("APF") announces that for Canadian tax purposes, cash distributions paid to Unitholders in the 2003 taxation year were 78.814% taxable and 21.186% tax deferred ("return of capital").

The information contained herein is based on APF's understanding of the Canadian Income Tax Act and is provided for general information only. Unitholders are advised to consult their personal tax advisors with respect to their particular circumstances.

FOR CANADIAN TAXPAYERS

The table below sets out the cash distributions received in 2003 by unitholders and indicates what portion of each distribution is taxable as income and what is tax deferred as a return of capital. The distribution declared by APF in December 2003 was received by unitholders in January 2004 and is not included in the calculation of a unitholder's 2003 taxable income. Please note that columns may not add due to rounding.

TAX INFORMATION

Record Date	Payment Date	Taxable Amount Box 26 (Other Income)	Tax-Deferred Amount (Return of Capital)	Total Cash Distribution Paid
December 31, 2002	January 15, 2003	$0.1261	$0.0339	$0.1600
January 31, 2003	February 15, 2003	$0.1261	$0.0339	$0.1600
February 28, 2003	March 15, 2003	$0.1301	$0.0349	$0.1650
March 31, 2003	April 15, 2003	$0.1458	$0.0392	$0.1850
April 30, 2003	May 15, 2003	$0.1458	$0.0392	$0.1850
May 31, 2003	June 15, 2003	$0.1576	$0.0424	$0.2000
June 30, 2003	July 15, 2003	$0.1576	$0.0424	$0.2000
July 31, 2003	August 15, 2003	$0.1576	$0.0424	$0.2000
August 29, 2003	September 15, 2003	$0.1576	$0.0424	$0.2000
September 30, 2003	October 15, 2003	$0.1379	$0.0371	$0.1750
October 31, 2003	November 15, 2003	$0.1379	$0.0371	$0.1750
November 30, 2003	December 15, 2003	$0.1379	$0.0371	$0.1750
Total Paid During 2003 Taxation Year		**$1.7181**	**$0.4619**	**$2.1800**

Units held within an RRSP, RRIF, or DPSP

No amount should be reported on the 2003 individual Income Tax Return ("T1") in respect of trust units held in a Registered Retirement Savings Plan (RRSP), Registered Retirement Income Fund (RRIF), or Deferred Profit Sharing Plan (DPSP).

Units held outside an RRSP, RRIF, or DPSP

Registered unitholders who held trust units outside an RRSP, RRIF, or DPSP will receive a T3 Supplementary Slip for 2003 ("T3") and must report the taxable portion of such distributions as "other income" in Box 26 of their T3. Unitholders who held units through intermediaries such as investment advisers will be receiving T3s from those intermediaries.

Adjusted Cost Base Reduction

The Adjusted Cost Base ("ACB") is used in calculating capital gains or losses on the disposition of trust units held as capital property by a unitholder. As set out above, the ACB of each trust unit is reduced by the portion of distributions considered a return of capital and accordingly is not reported on a T3. Should a taxpayer's ACB be reduced below zero, that negative amount is deemed to be a capital gain of the individual and the ACB is deemed to be nil. That capital gain must be reported on Schedule 3 of the unitholder's T1.

APF investors who participated in the $10.00 per Trust Unit initial public offering in December 1996 who still hold the Trust Units at December 31, 2003 have an ACB of $3.529 per Trust Unit. This value adjusts for the cumulative return of capital of $6.471 as provided in the table below.

HISTORICAL TAX INFORMATION

Payment Period	Taxable Amount Per Unit (Other Income)	Tax Deferred Amount Per Unit (Return of Capital)	Cash Distribution Per Unit for Tax Purposes	Taxable Percentage	Tax Deferred Percentage
2003	$1.718	$0.462	$2.180	78.814%	21.186%
2002	$1.143	$0.657	$1.800	63.517%	36.483%
2001	$1.741	$1.304	$3.045	57.175%	42.825%
2000	$1.181	$0.719	$1.900	62.137%	37.863%
1999	$0.526	$1.029	$1.555	33.826%	66.174%
1998	$0.453	$1.387	$1.840	24.625%	75.375%
1997	$0.597	$0.913	$1.510	39.536%	60.464%

FOR NON-RESIDENT UNITHOLDERS

The following information is provided for general information only. Investors are encouraged to seek advice from a qualified tax advisor in their country of residence to obtain guidance with respect to the appropriate tax treatment of their distributions.

U.S. Residents Invested in APF

The Tax Treaty between Canada and the U.S. allows for a reduction to the 25% withholding tax for U.S. residents. The current rate after the reduction is prescribed at 15% with some U.S. taxpayers being eligible for a foreign tax credit with respect to the Canadian withholding taxes paid. U.S. investors may also seek a refund of Canadian withholding tax related to amounts withheld on non-taxable distributions (from a Canadian tax perspective) from Canada Customs and Revenue Agency by filing Form NR7-R, Application for Refund of Non-Resident Tax Withheld.

APF is deemed to be a Corporation for U.S. tax purposes. U.S. tax rules state that no portion of the distribution will be considered a tax-deferred return of capital unless the trust computes its current and accumulated earnings and profits in accordance with U.S. income tax principles. A current and accumulated earnings and profits calculation has not been performed by APF in the past; therefore distributions paid to U.S. investors in 2003 are 100% taxable to U.S. residents as a dividend. Registered Unitholders will receive a form NR4 from the Transfer Agent, Computershare Trust Company of Canada. Non-registered Unitholders (units held by a brokerage firm or other intermediary) will receive a form NR4 from the brokerage firm or other intermediary.

Certain statements in this material may be "forward-looking statements" including outlook on oil and gas prices, estimates of future production, estimated completion dates of acquisitions and construction and development projects, business plans for drilling and exploration, estimated amounts and timing of capital expenditures and anticipated future debt levels and royalty rates. Information concerning reserves contained in this material may also be deemed to be forward-looking statements as such estimates involve *the implied assessment that the resources described can be profitably produced in the future. These statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated by APF. This news release is not for distribution to U.S. newswire services or for distribution in the U.S. The Toronto Stock Exchange has neither approved nor disapproved of the contents of this news release.*

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APF ENERGY 04 MAR 23 AM 7:21

NEWS RELEASE

TSX: AY.UN; AY.DB

APF ENERGY TRUST RELEASES 2003 FINANCIAL RESULTS AND OIL AND NATURAL GAS RESERVES SUMMARY

March 11, 2004 - APF Energy Trust ("APF" or the "Trust") is pleased to release its 2003 financial and operating results and a summary of its recently completed independent engineering report. The evaluation of the oil and natural gas reserves was prepared in accordance with National Instrument 51-101("NI 51-101").

Highlights for the Year

- Outstanding returns: APF generated an annual total return of 50%, bringing the average annual return since inception in late 1996 to 22%, placing APF among the sector's best long-term performers.

- Strong distributions: APF paid out $2.18 per unit, a 21% increase over 2002 distributions. At December 31, 2003, APF's cumulative distributions since inception totaled $179 million or $13.83 per unit. For 2003, approximately 21% of the distribution was tax deferred as a return of capital.

- Increased reserves: Net proved plus probable reserve additions, including acquisitions, amounted to 15.1 million barrels of oil equivalent ("boe"), representing 332% of annual production.

- Increased liquidity: Through a public offering and three corporate acquisitions, APF issued 10.68 million units during 2003. Average daily trading volumes increased by 137% over 2002 levels to 163,000 units per day. The total value of APF units traded during 2003 was $463 million.

- Growing cash flow and earnings: APF generated $83.3 million of operating cash flow ($2.69 per unit) and $43.0 million ($1.32 per unit) of earnings, representing a 26% and 140% increase respectively from per-unit amounts in 2002.

- Active drilling program: APF participated in the drilling of 164 gross wells (64.83 net) with a 100% success rate. Capital expenditures of $33.6 million, or 40% of cash flow, were directed to development and optimization initiatives, with the results replacing 82% of annual production.

- Increased production: Average daily production volumes increased by 46% to 12,463 boe, with 55% leveraged to oil.

- Synergistic acquisitions: APF executed on $167 million of acquisitions, adding to the Trust's inventory of drilling prospects, particularly in its core gas areas in southern and central Alberta.

Summary of Operating & Financial Results

Financial	3 Months Ended December 31		12 Months Ended December 31	
($000, except per unit/boe amounts)	2003	2002	2003	2002
Revenue	39,110	29,380	165,457	94,021
Per unit[a]	$ 1.15	$ 1.32	$ 5.34	$ 4.59
Operating cash flow[b]	16,039	7,112	83,326	43,788
Per unit[a]	$ 0.47	$ 0.32	$ 2.69	$ 2.14
Net earnings	(3,110)	(942)	43,048	11,365
Per unit[d]	$ (0.09)	$ (0.04)	$ 1.32	$ 0.55
Distributions	17,822	10,246	68,713	37,766
Per unit[a]	$ 0.525	$ 0.46	$ 2.195	$ 1.81
Operating costs per boe	$ 7.97	$ 6.84	$ 7.12	$ 6.35
Operating netbacks per boe	$ 18.15	$ 20.60	$ 22.11	$ 17.83
Bank debt	98,000	88,000	98,000	88,000
Market				
Units outstanding (000)				
End of period	34,074	22,942	34,074	22,942
Weighted average - basic	33,907	22,270	30,970	20,470
Weighted average - fully diluted	38,577	22,320	35,641	20,528
Trading				
High ($)	$ 12.67	$ 10.71	$ 12.67	$ 11.19
Low ($)	$ 11.45	$ 9.00	$ 9.30	$ 9.00
Close ($)	$ 12.54	$ 9.79	$ 12.54	$ 9.79
Average daily volumes	123,000	84,300	163,000	68,700

Operating				
Daily production (average)				
Oil (bbl)	6,499	6,001	6,472	5,307
Gas (mcf)	36,929	19,776	33,799	18,488
NGL (bbl)	474	187	358	144
Total (boe)[c]	13,128	9,484	12,463	8,532
Commodity prices (Cdn$)				
Oil (per bbl)	$ 31.66	$ 35.80	$ 34.46	$ 33.66
Gas (per mcf)	$ 5.41	$ 4.74	$ 6.32	$ 3.83
NGL (per bbl)	$ 31.37	$ 30.63	$ 31.82	$ 25.15
Average (boe)[c]	$ 32.03	$ 33.14	$ 35.95	$ 29.65
Drilling (gross wells)				
Gas	31	25	80	62
Oil	15	5	60	40
CBM	19	-	19	-
Other	-	1	5	7
Total	65	31	164	109

a) Based on the basic weighted average trust units outstanding for the period.
b) Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Cash flow as presented is not intended to represent operating cash flow 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 and accrued interest on convertible debentures.
c) BOE's may be misleading, particularly if used in isolation. In accordance with NI 51-101, a BOE conversion ratio for natural gas of 6 Mcf: 1 bbl has been used which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.
d) Net income in the basic per trust unit calculation had been reduced by interest accrued on the convertible debentures.

Financial and Operating Results

Production

Production volumes were 46% higher in 2003, due primarily to the acquisitions of Hawk Oil Inc. ("Hawk"), Nycan Energy Corp. ("Nycan") and CanScot Resources Ltd. ("CanScot"). Natural production declines were partially offset by production increases from successful development drilling programs at Queensdale, Macoun and Tatagwa in southeast Saskatchewan and at Paddle River, Redwater and Countess in Alberta. A $40 million capital expenditure budget has been established for 2004 and is expected to maintain production levels at the 2003 exit rate of approximately 13,000 boe/d.

	2003	2002	% Change
Crude oil (bbl/d)	6,472	5,307	22
Natural gas (mcf/d)	33,799	18,488	83
NGL (bbl/d)	358	144	149
Total (boe/d)	12,463	8,532	46

Production split	2003	2002	% Change
Oil & NGLs	55%	64%	-14
Natural Gas	45%	36%	25

APF's production mix was 55% crude oil and NGL's and 45% natural gas. Crude oil was sold under 30 day evergreen contracts while approximately 25% of natural gas production was sold to aggregators pursuant to long-term contracts, with the remaining 75% sold on the spot market.

Commodity Prices and Hedging

The benchmark West Texas Intermediate ("WTI") oil price averaged US$31.06 per bbl in 2003, 19% higher than the 2002 average of US$26.10. Crude oil prices in Canada are based on the WTI reference price, adjusted for transportation, differentials and foreign exchange. The price received by APF is based upon the refiners' posted price, less transportation and adjustments for APF's product quality relative to the posted price and adjusted for hedging. APF's oil price after hedging averaged $34.46 per bbl in 2003, compared to $33.66 per bbl in 2002, an increase of 2%. Canadian oil prices were negatively impacted by an average 11% decrease in the value of the U.S. dollar versus the Canadian dollar during 2003. The NYMEX futures contracts for the remainder of 2004 suggest crude oil prices will exceed 2003 levels during 2004.

APF's realized natural gas price after hedging for 2003 averaged $6.32 per mcf, 65% higher than the average realized price of $3.83 per mcf in 2002. This is consistent with the increase in the benchmark AECO price in Alberta, which increased by an average of 63% from 2002 levels. APF expects gas prices during 2004 to remain consistent with or exceed 2003 levels as supply concerns dominate the market.

Prices - After Hedging		2003		2002	% Change
Crude oil (Cdn$/bbl)	$	34.46	$	33.66	2
Natural gas (Cdn$/mcf)		6.32		3.83	65
NGL (Cdn$/bbl)		31.82		25.15	27
Total (Cdn$/boe)	$	35.95	$	29.65	21

Reference Pricing		2003		2002	% Change
WTI (US$/bbl)	$	31.06	$	26.10	19
AECO gas (Cdn$/mcf)	$	6.67	$	4.08	63
Foreign exchange (US$/Cdn$)	$	1.401	$	1.570	-11

APF actively manages risk by entering into hedging contracts to protect revenues from fluctuations in commodity prices, thereby ensuring that a portion of the year's distributions, based on certain commodity price assumptions, are protected. Due to stronger than budgeted oil prices during 2003, hedging activities reduced revenues by $3.56 million and the realized oil price by $1.61 per bbl. With respect to gas, APF's realized price was improved by a modest $0.02 per mcf. At the time of printing, APF had the following hedges in place.

Current Hedging Position

Period	Commodity	Type of Contract	Average Daily Quantity	Average Hedged Price
March 2004	Crude oil	Swap	3,000 bbls	US$30.76/bbl
March 2004	Natural gas	Swap	10,000 GJ	Cdn$7.19/GJ
March 2004	Natural gas	Physical	2,000 mmbtu	US$7.00/mmbtu
April to June 2004	Crude oil	Swap	2,500 bbls	US$30.78/bbl
April to June 2004	Natural gas	Swap	10,333 GJ	Cdn$5.76/GJ
April to June 2004	Natural gas	Swap	1,000 mmbtu	US$5.19/mmbtu
July to September 2004	Crude oil	Swap	2,167 bbls	US$29.58/bbl
July to September 2004	Natural gas	Swap	10,000 GJ	Cdn$5.75/GJ
July to September 2004	Natural gas	Swap	1,000 mmbtu	US$5.19/mmbtu
October to December 2004	Crude oil	Swap	1,833 bbls	US$30.45/bbl
October to December 2004	Natural gas	Swap	3,333 GJ	Cdn$5.75/GJ
October to December 2004	Natural gas	Swap	333 mmbtu	US$5.19/mmbtu
January 2005	Crude oil	Swap	500 bbls	US$31.47/bbl

In addition to commodity hedging, APF has also entered into foreign currency hedge contracts in order to mitigate currency risk. The Trust has hedged US$20 million of revenue at a rate of Cdn$1.3317 or US$0.7509 for calendar 2004.

Revenues

Revenues, net of hedging transactions, increased 76% to $165 million in 2003, due to a combination of higher production volumes and higher commodity prices.

(000 except per boe amounts)	2003	% of Total	2002	% of Total
Crude oil sales	$ 85,193	51	$ 69,390	74
Natural gas sales	77,747	47	25,534	27
NGL sales	4,157	3	1,320	1
Hedging	(3,565)	-2	(3,899)	-4
Other	1,925	1	1,676	2
Total revenue	165,457	100	94,021	100
Per boe	$ 36.37		$ 30.19	

Royalties

Royalties per barrel of oil equivalent produced were 19% higher in 2003, consistent with the increase in commodity prices during the year. Royalties as a percentage of revenues were essentially unchanged.

(000 except per boe amounts)	2003	2002	% Change
Crown royalties	$ 19,364	$ 10,905	78
Freehold royalties	10,193	6,323	61
Overriding royalties	2,916	1,479	97
Total royalties	32,473	18,707	74
% of revenue after hedging	19.6%	19.9%	-1
Per boe	$ 7.14	$ 6.01	19

Operating Costs

Operating costs increased 12% in 2003 to $7.12 per boe, due primarily to initial field optimization costs on newly acquired properties and higher energy costs. Continued high energy costs and generally higher field costs associated with APF's current property portfolio are expected to negate any operating efficiencies initiated to reduce operating costs in 2004.

(000 except per boe amounts)		2003		2002	% Change
Operating costs	$	32,370	$	19,748	64
Per boe	$	7.12	$	6.35	12

Netbacks

Higher commodity prices offset increased royalty and operating costs during 2003 resulting in operating netbacks of $22.11 per boe, a 24% increase from 2002.

(per boe)		2003		2002	% Change
Net revenue (after hedging)	$	36.37	$	30.19	20
Royalties		(7.14)		(6.01)	19
Operating costs		(7.12)		(6.35)	12
Netback	$	22.11	$	17.83	24

General and Administrative Costs

General and administrative costs increased 116% in absolute terms over 2002, and 48% per boe produced. The increase is due primarily to costs associated with the increase in staffing levels from recent corporate and property acquisitions and the cost of the company's short-term incentive plan ("STIP").

The STIP was created to encourage and reward outstanding employee performance and to ensure that the interests of both the unitholders and employees were aligned. The STIP enables all employees to participate in a bonus pool, provided APF generates at least a 10% total annual return. Total annual return is calculated as distributions paid during the year plus or minus the change in unit price compared to the previous year-end. When the 10% total return threshold is met, a portion of net operating income ("NOI") is allocated to the bonus pool and shared by all employees. The total return on APF units for the year ended December 31, 2003 was 50%. Based on this total return, the bonus pool under the STIP for the year was $3.35 million (2002 - $nil). Senior employees, including officers, may also be eligible to receive performance bonuses based on criteria applicable to each individual's responsibilities. Excluding the STIP, general and administrative costs per boe for the year ended December 31, 2003 were $1.47.

APF's success at finding and developing oil and gas reserves is due to its ability to recruit highly competent individuals with strong technical skill sets. Accordingly, APF's compensation structure is designed to provide employees with a competitive base package and the potential to enhance the base, provided unitholders experience strong returns.

(000 except per boe amounts)		2003		2002	% Change
General and administrative	$	10,023	$	4,635	116
Per boe	$	2.20	$	1.49	48

Compensation Expense

During 2003, as part of APF's long-term incentive plan, 1,538,250 trust unit incentive rights (2002 – 441,233) were issued to employees and directors, at prices ranging from $9.67 to $11.54 per trust unit (2002 - $9.73 to $10.80). The exercise price of the rights is adjusted downward over time by the amount, if any, that quarterly distributions exceed 2.5 % of the net book value of property, plant and equipment. The rights have a 10 year term and vest in one-third increments on the first, second and third anniversaries of their grant. Rights to purchase 1,824,330 trust units at an average adjusted exercise price of $9.09 were outstanding at December 31, 2003. These rights have an average remaining contractual life of 9.3 years and expire at various dates to September 2013. There were 47,221 rights exercisable at December 31, 2003 (2002 – nil).

APF has prospectively adopted the CICA Handbook Section 3870 – "Stock Based Compensation". Under the transitional adoption rules, companies that prospectively adopt at December 31, 2003 are only required to recognize compensation expense for those options granted during 2003, with proforma disclosure of options granted during 2002.

(000 except per boe amounts)		2003		2002	% Change
Compensation expense	$	1,241	$	-	100
Per boe	$	0.27	$	-	100

Capital Expenditures, Acquisitions and Dispositions

Net capital expenditures, including net property and corporate acquisitions, were $191 million in 2003 ($101 million in 2002). Of the total, $33.6 million was incurred for drilling and completions, geological, geophysical and production facilities expenditures, as APF continues to develop its asset base, with the remaining $158 million attributable to net property and corporate acquisitions. The 2003 corporate acquisitions of Hawk, Nycan and CanScot totalled $137.6 million, accounting for 72% of net capital expenditures during the year.

(000)		2003		2002	% Change
Corporate acquisitions	$	137,622	$	62,143	121
Property acquisitions		26,928		27,958	-4
Land acquisitions		2,310		616	275
Seismic		1,070		497	115
Drilling and completion		24,287		15,890	53
Production facilities		7,749		3,684	110
Other		494		908	-46
Subtotal	$	200,460	$	111,696	79
Dispositions		(9,284)		(10,569)	-12
Net capital expenditures	$	191,176	$	101,127	89

Net Earnings

Earnings were up 279% to $43.0 million or $1.32 per trust unit ($1.21 diluted) in 2003 compared to $11.4 million or $0.55 per trust unit ($0.55 diluted) in 2002. The increase is attributable to both increases in production and commodity prices received throughout 2003.

Cash Distributions

Cash distributions for 2003 were $68.7 million, or $2.195 per trust unit, compared to $37.8 million or $1.81 per trust unit in 2002. During 2003, APF funded $9.3 million of capital expenditures from cash flow (2002 – $5.1 million), resulting in a payout ratio of 87% (2002 – 88%) . For 2004, APF intends to maintain its historical policy of retaining a portion of available cash flow to fund capital expenditures and development initiatives, with a target range of 15% to 20%.

Distribution Reinvestment Plan

On November 20, 2003, the Trust announced the adoption of a Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan (the "DRIP"), effective for monthly distributions payable on and following December 15, 2003. The DRIP allows eligible Unitholders to direct that their monthly cash distributions be reinvested in additional trust units at 95% of the average market price (as defined in the DRIP) on the applicable distribution date.

The DRIP includes a feature which allows eligible Unitholders to elect, under the premium distribution component, to have these additional trust units delivered to a designated broker in exchange for a premium cash distribution equal to 102% of the cash distribution that such Unitholders would have otherwise been entitled to receive on the applicable distribution date.

The DRIP also allows those unitholders who participate in either the distribution reinvestment component or the premium distribution component to purchase additional trust units directly from APF for cash at a purchase price equal to the average market price (with no discount) in minimum amounts of $1,000 per remittance and up to $100,000 aggregate amount of remittances by a unitholder in any calendar month, all subject to an overall annual limit of 2% of the outstanding trust units.

Liquidity and Capital Resources

At December 31, 2003, APF had a revolving term credit facility in the amount of $150 million, with a borrowing base of $150 million, of which $98 million was drawn. The facility may be drawn down or repaid at any time, and there are no scheduled repayment terms.

On July 3, 2003, APF closed a $50.0 million 9.40% Convertible Unsecured Subordinated Debenture offering. At December 31, 2003, the balance of convertible debentures, net of conversions, was $48.8 million including accumulated interest of $2.3 million.

At December 31, 2003, APF had a working capital deficit of approximately $10.2 million, compared to a working capital surplus of $0.4 million at December 31, 2002. The primary reasons for the working capital deficiency at December 31, 2003 are the significant increase in development drilling activity at December 31, 2003, resulting in higher capital expenditure accruals, along with the accrual for the STIP and provision for the semi-annual payment of debenture interest due January 31, 2004. Subsequent to year-end, APF raised $55.2 million through an equity issue, proceeds from which were used to fund the working capital deficit and pay down long term debt.

Unitholders' Equity

At December 31, 2003, APF had 34.1 million trust units outstanding (2002 – 22.9 million) and a market capitalization of approximately $427.1 million (2002 – $224.6 million).

In February 2003, APF issued 3.99 million trust units at $9.45 per trust unit for the acquisition of Hawk Oil.

In April 2003, APF issued 5.35 million trust units at $10.40 per trust unit for gross proceeds of $55.7 million. Proceeds from this issue were used to finance the purchase of Nycan and to reduce bank debt.

In June 2003, APF issued 50,000, 9.4% convertible, unsecured subordinated debentures at $1,000 per debenture, to fund the acquisition of assets at Swan Hills and to reduce bank debt.

In September 2003, APF issued 1.34 million trust units at $11.50 per trust unit for the acquisition of CanScot.

In December 2003, APF issued 140,710 trust units pursuant to the new Premium Distribution Reinvestment Plan for proceeds of $1.60 million ($nil in 2002).

During 2003, 199,005 trust units (61,777 in 2002) were issued pursuant to the trust unit incentive plan for total proceeds of $1.75 million ($0.5 million in 2002). An additional 107,998 units were issued during the year upon conversion of debentures.

On February 4, 2004, APF closed an issue of 4.76 million trust units at a price of $11.60 per unit for gross proceeds of $55.3 million. The proceeds of this offering were used to fund working capital and pay down long term debt.

OIL AND GAS RESERVES SUMMARY

All of APF's Canadian reserves were evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ"), while coalbed methane ("CBM") reserves in the United States were evaluated by McDaniel & Associates Consultants Ltd. ("McDaniel"). Both reports were prepared effective January 1, 2004. All reserves were evaluated in accordance with the new standard, NI 51-101.

NI 51-101 replaced the former National Policy 2-B ("NP 2-B"). Under the new instrument, the total proved reserves are to reflect a 90% confidence level; that is, nine times out of ten, actual reserves recovered should exceed the estimated proved reserves. The proved plus probable reserves are to reflect a 50% or greater confidence level and are effectively meant to be the "best estimate" of the company's reserves. This compares to the previous definition of "likelihood of existence" under NP 2-B. The following reserves summary has been prepared comparing the new proved plus probable, P-50, reserves to previous proved plus risk adjusted (50%) probable reserves, which were commonly referenced as "established reserves" under NP 2-B.

The following table summarizes the Company Interest Reserves assigned in the GLJ and McDaniel reports. Company Interest Reserves are defined as working interest reserves (before the deduction of royalties) plus royalty interest reserves. Additional information required under NI 51-101 will be included in the Annual Information Form to be filed for fiscal 2003 and will be available on the company's website at www.apfenergy.com in the near future.

	Reserve Volumes at January 1, 2004				Reserve Values[f] at January 1, 2004		
	Natural Gas	Oil[e]	NGLs	Total	Net Present Value ($mm) at:		
Reserve Category	(bcf)	(mbbl)	(mbbl)	(mboe)	0%	10%	12%
Proved producing	65.8	12,869	818	24,652	321.8	229.3	217.9
Total proved	72.7	16,800	979	29,895	388.6	257	242.3
Proved + probable	99.2	22,638	1,151	40,322	512.4	316.5	295.6

e) Sum of light, medium and heavy volumes
f) All evaluations have been stated prior to any provision for income taxes and general and administrative costs. The estimated reserve values disclosed do not represent fair market value.

Both reports were prepared using the GLJ January 1, 2004 price forecast, which estimated the price of West Texas Intermediate ("WTI") oil to average US$29.00 per barrel during 2004 and US$26.00 per barrel in 2005. No value was assigned to APF's Canadian CBM reserves.

GLJ Forecast at January 1, 2004			Edmonton	
	Exchange	WTI Oil	Light Oil	Alberta Gas
Year	US$/Cdn$	US$/bbl	Cdn$/bbl	Cdn$/mmbtu
2004	0.75	$29.00	$37.75	$5.85
2005	0.75	$26.25	$33.75	$5.15
2006	0.75	$25.00	$32.50	$5.00
2007	0.75	$25.00	$32.50	$5.00
2008 - 2014	0.75	$25.00	$32.50	$5.00
Escalate thereafter		1.5%/yr	1.5%/yr	1.5%/yr

In addition, GLJ has evaluated APF's undeveloped land, assigning a value of $19.1 million.

APF's company interest proved plus probable reserves increased by 26% in 2003 through a combination of drilling additions and acquisitions. Drilling activity and improved recoveries added 3.7 million boe of new company interest reserves on a proved plus probable basis, with the balance of APF's development and optimization efforts resulting in probable, undeveloped and non-producing reserves being moved into the producing category. Reserve additions replaced 82% of the 4.5 million boe APF produced in 2003, before technical revisions.

Company interest proved plus probable reserve additions, including acquisitions, amounted to 15.1 million boe replacing 332% of annual production. With an increased inventory of undrilled opportunities, APF is in the first quarter of its most active capital expenditure program, with an estimated $40 million to be spent in 2004, 85% of which has been designated for drilling and development.

Reserve Reconciliation

On a proved plus probable basis, APF had negligible technical revisions, amounting to -2%. In the Proved Developed Producing ("PDP") category, revisions amounted to -8%. Almost 39% of the total revisions to PDP reserves were attributable to a non-operated 6.86% interest in the Pembina Cardium Unit No. 9, with the balance allocated over APF's remaining properties.

With respect to acquisitions, APF was assigned 12.1 million boe of Proved plus Probable reserves for transactions completed in 2003.

Company Interest Reserve Reconciliation Summary	**Proved Producing**	**Total Proved[g]**	**Total Proved Plus Probable[h,i]**
Light, medium and heavy oil (mbbl)			
Opening balance, December 31, 2002	14,911	16,684	19,760
Drilling	969	1,166	1,431
Improved recovery	78	78	465
Tech revisions/new standards	(1,721)	(1,221)	(45)
Acquisitions	2,373	4,114	5,560
Dispositions	(1,378)	(1,659)	(2,171)
Production	(2,362)	(2,362)	(2,362)
Closing balance, December 31, 2003	**12,869**	**16,800**	**22,638**
Gas (bcf)			
Opening balance, December 31, 2002	50.51	59.44	68.29
Drilling	7.38	6.76	9.73
Improved recovery	0.93	0.79	0.84
Tech revisions/new standards	(1.23)	(4.96)	(3.63)
Acquisitions	20.72	23.26	36.66
Dispositions	(0.17)	(0.25)	(0.34)
Production	(12.34)	(12.34)	(12.34)
Closing balance, December 31, 2003	**65.80**	**72.70**	**99.20**
NGLs (mbbl)			
Opening balance, December 31, 2002	636	768	847
Drilling	15	43	62
Improved recovery	31	0	1
Tech revisions/new standards	(49)	(74)	(65)
Acquisitions	316	372	437
Dispositions	-	-	-
Production	(131)	(131)	(131)
Closing balance, December 31, 2003	**818**	**979**	**1,151**
Oil Equivalent (mboe)			
Opening balance, December 31, 2002	23,965	27,359	31,990
Drilling	2,213	2,336	3,114
Improved recovery	264	209	606
Tech revisions/new standards	(1,976)	(2,122)	(718)
Acquisitions	6,141	8,362	12,107
Dispositions	(1,406)	(1,701)	(2,228)
Production	(4,549)	(4,549)	(4,549)
Closing balance, December 31, 2003	**24,652**	**29,895**	**40,322**

columns may not add due to rounding

g) Under NI 51-101, Proved reserves are those which can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

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

i) 2002 reserve estimates were evaluated in accordance with the standards of National Policy 2-B which has now been replaced by NI 51-101. Reconciliation for Proved + Probable includes prior year Probable reserves risked at 50% (established reserves).

Consolidated Balance Sheets

(unaudited)
As at December 31, 2003 and 2002

	2003 $000	2002 $000
Assets		
Current assets		
Cash	1,381	950
Accounts receivable	27,542	21,111
Other current assets	3,506	2,779
	32,429	24,840
Site restoration fund (note 6)	2,342	784
Goodwill (note 7)	48,230	11,476
Property, plant and equipment (note 5)	401,286	260,527
	484,287	297,627
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	36,711	16,943
Due to APF Energy Management Inc. (note 14)	-	3,923
Cash distribution payable	5,963	3,565
	42,674	24,431
Future income taxes (note 13)	64,222	39,625
Long-term debt (note 8)	98,000	88,000
Site restoration liability (note 6)	10,410	6,227
	215,306	158,283
Unitholders' Equity		
Unitholders' investment account (note 9)	324,317	214,405
Contributed surplus (note 10)	1,241	-
Accumulated earnings	78,637	35,589
Accumulated cash distributions (note 4)	(179,363)	(110,650)
Convertible debentures (note 12)	46,466	-
Accumulated interest on convertible debentures	(2,317)	-
	268,981	139,344
	484,287	297,627

Contingencies and commitments (note 17)

Consolidated Statements of Operations and Accumulated Earnings

(unaudited)
For the years ended December 31, 2003 and 2002

(in thousands of dollars, except per unit data)	2003 $	2002 $
Revenue		
Oil and gas	163,532	92,345
Royalties expense, net of ARTC	(32,473)	(18,707)
Other	1,925	1,676
	132,984	75,314
Expenses		
Operating	32,370	19,748
General and administrative (note 14)	10,023	4,635
Stock-based compensation expense (note 10)	1,241	-
Management fee (note 14)	-	1,976
Interest on long-term debt	4,171	2,834
Depletion, depreciation and amortization	50,417	30,201
Site restoration	3,327	2,087
Capital and other taxes	2,720	1,901
Internalization of management contract (note 14)	-	7,297
	104,269	70,679
Income before income taxes and minority interest	28,715	4,635
Recovery of future income taxes (note 13)	14,333	7,133
Income before minority interest	43,048	11,768
Minority interest (note 14)	-	403
Net income	43,048	11,365
Accumulated earnings – Beginning of year	35,589	24,224
Accumulated earnings – End of year	78,637	35,589
Net income per unit – basic	1.32	0.55
Net income per unit – diluted	1.21	0.55

Consolidated Statements of Cash Flows

(unaudited)

For the years ended December 31, 2003 and 2002

	2003 $000	2002 $000
Cash provided by (used in)		
Operating activities		
Net income for the year	43,048	11,365
Items not affecting cash		
Depletion, depreciation and amortization	50,417	30,200
Minority interest	-	403
Future income taxes	(14,333)	(7,133)
Internalization of management contract	-	7,037
Stock-based compensation expense	1,241	-
Site restoration	3,327	2,087
Site restoration expenditures (note 6)	(374)	(171)
	83,326	43,788
Net change in non-cash working capital items		
Accounts receivable	1,016	(7,994)
Other current assets	(398)	(328)
Accounts payable and accrued liabilities	9,138	6,537
Due to related party / APF Management	(3,923)	(1,088)
Cash distribution payable	2,398	1,227
	8,231	(1,646)
Site restoration fund contribution	(1,558)	(754)
Cash distributions	(68,713)	(37,766)
	21,286	3,622
Investing activities		
Purchase of Hawk Oil	(3,456)	-
Purchase of Nycan Energy	(34,287)	-
Purchase of CanScot Resources	(20,516)	-
Purchase of Kinwest	-	(17,361)
Additions to property, plant and equipment	(33,601)	(20,979)
Purchase of oil and natural gas properties	(29,238)	(28,574)
Proceeds on sale of properties	9,284	10,569
Changes in non-cash working capital-investing items	2,961	(560)
	(108,853)	(56,905)
Financing activities		
Issue of units for cash	57,272	32,250
Issue of units for cash upon exercise of stock options	1,749	554
Unit issue costs	(3,467)	(1,861)
Convertible debentures – net of costs	47,681	-
Interest on convertible debentures	(2,317)	-
(Repayment)/proceeds on issue of long-term debt – net	(12,920)	21,650
Distribution to 1% minority interest	-	(403)
	87,998	52,190
Change in cash during the year	431	(1,093)
Cash – Beginning of year	950	2,043
Cash – End of year	1,381	950

Supplemental information (note 16)

Notes to Consolidated Financial Statements

(unaudited)
December 31, 2003 and 2002

The objective and integrity of data in these financial statements, including estimates and judgements relating to matters not concluded by year-end, are the responsibility of management of APF Energy Trust ("Trust"). In management's opinion, the financial statements have been properly prepared within reasonable limits of materiality and within the framework of the Trust's accounting policies.

1 Basis of presentation

APF Energy Trust (the "Trust")

The Trust is an open-end investment trust under the laws of the Province of Alberta.

APF Energy Inc. ("Energy")

Energy was incorporated and organized for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties, including certain initial properties and granting a royalty thereon to the Trust.

APF Energy Limited Partnership ("LP")

LP was formed for the purpose of acquiring, developing, exploiting and disposing of oil and natural gas properties and granting a royalty thereon to the Trust.

Tika Energy Inc. ("Tika")

Tika is a wholly owned subsidiary of Energy and was incorporated in Wyoming for the purpose of acquiring, developing, exploiting and disposing of coalbed methane gas properties in the United States.

2 Significant accounting policies

Consolidation

These consolidated financial statements include the accounts of the Trust, Energy, LP and Tika and are referred to collectively as "APF".

Revenue recognition

Revenue associated with the sale of crude oil, natural gas, and natural gas liquids owned by the Trust are recognized when title passes from the Trust to its customers.

Goodwill

The Trust records goodwill relating to a corporate acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired company. Goodwill is stated at cost less impairment and is not amortized. The goodwill balance is assessed for impairment annually at year-end or as events occur that could indicate an impairment. Impairment is recognized based on the fair value of APF compared to the net book value of APF. 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 occurs.

Property, plant and equipment – oil and natural gas

APF follows the full cost method of accounting. All costs of acquiring oil and natural gas properties and related development costs are capitalized and accumulated in a cost centre. Maintenance and repairs are charged against earnings, and renewals and enhancements, which extend the economic life of the property, plant and equipment are capitalized.

Gains and losses are not recognized upon disposition of oil and natural gas properties unless such a disposition would alter the rate of depletion by 20% or more.

Ceiling test

The Trust places a limit on the aggregate carrying value of property, plant and equipment. An impairment is recognized if the carrying amount of the property, plant and equipment exceeds the sum of the undiscounted cash flows expected to result from the Trust's proved reserves. Cash flows are calculated based on third party quoted forward prices, adjusted for the Trust's contract prices and quality differentials.

The Trust determines if there is an impairment by comparing the carrying amounts of the property, plant and equipment to an amount equal to the fair value of the property, plant and equipment. Any excess carrying value above the fair value of the Trust's future cash flows would be recorded as a permanent impairment. The cost of unproved properties are excluded from the ceiling test calculation and is subject to a separate impairment test.

Depletion, depreciation and amortization

Depletion, depreciation and amortization of oil and natural gas assets including tangible equipment is calculated using the unit-of-production method based on the working interest share of total proven reserves before royalties. Reserves estimates are calculated in accordance with National Instrument 51-101 and relative volumes of petroleum and natural gas reserves and production, before royalties, are converted at the energy equivalent conversion ratio of six thousand cubic feet of natural gas to one barrel of oil.

Site restoration and abandonment

The provision for estimated site restoration costs is determined using the unit-of-production method. Actual site restoration costs are charged against the accumulated provision.

Other equipment

All other equipment is carried at cost and is depreciated over the estimated useful life of the assets at annual rates varying from 10% to 30%.

Joint ventures

Substantially all oil and natural gas production and exploitation activities are conducted jointly with others. Accordingly, the accounts reflect APF's proportionate interest in these activities.

Trust per unit calculations

The Trust has applied the treasury stock method to determine the dilutive effect of stock options and other dilutive instruments. Under the treasury stock method, only "in the money" dilutive instruments impact the diluted calculations.

Cash distributions declared per unit amount is based on actual distribution for units outstanding at the time of declaration.

Unit based compensation

APF has established a Trust Unit Incentive Rights Plan (the "Plan") for employees, independent directors and long-term consultants who otherwise meet the definition of an employee of APF. The exercise price of the rights granted under the Plan may be reduced in future periods in accordance with the terms of the Plan. The amount of the reduction cannot be reasonably estimated as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of amounts to be withheld from future distributions to unitholders to fund capital expenditures and the purchase and sale of property, plant and equipment. Therefore, it is not possible to determine a fair value for the rights granted under the Plan using a traditional option pricing model and compensation expense has been determined based on the intrinsic value of the rights at the date of exercise or at the date of the financial statements for unexercised rights.

The Trust has a Trust Unit Incentive Rights Plan which is described in note 10.

Compensation expense associated with rights granted under the Plan is deferred and recognized in earnings over the vesting period of the Plan with a corresponding increase or decrease in contributed surplus. Changes in the intrinsic value of unexercised rights after the vesting period are recognized in earnings in the period of change with a corresponding increase or decrease in contributed surplus. This method of determining compensation expense may result in large fluctuations, even recoveries, in compensation expense due to changes in the underlying Trust unit price. Recoveries of compensation expense will only be recognized to the extent of previously recorded cumulative compensation expense associated with rights exercised or outstanding at the date of the financial statements.

Consideration paid upon the exercise of the rights together with the amount previously recognized in contributed surplus is recorded as an increase in unitholders' capital. If Trust Units or Trust Unit options are repurchased from employees, the excess of the consideration paid over the carrying amount of the Trust Units or Trust Unit options cancelled is charged to accumulated earnings.

The Trust has not incorporated an estimated forfeiture rate for rights that will not vest, rather, APF accounts for actual forfeitures as they occur.

Cash distributions

Cash distributions are calculated on an accrual basis and are paid to the Unitholders based upon funds available for distribution.

Income taxes

The Trust is an inter vivos trust for income tax purposes. As such, the Trust is taxable on any taxable income which is not allocated to the Unitholders. The Trust intends to allocate all taxable income to Unitholders. Should the Trust incur any income taxes, the funds available for distribution will be reduced accordingly. Provision for income taxes is recorded in Energy at applicable statutory rates. Provision for income taxes is recorded in Energy using the liability method of accounting whereby the future income tax effect of any difference between the accounting and income tax basis of an asset or liability is booked.

Management estimates

The consolidated financial statements include certain management estimates that may require accounting adjustments based on future occurrences. The most significant estimates relate to depletion, depreciation and amortization and ceiling test calculations for capital assets including future abandonment liabilities as they are based on engineering reserve estimates and estimated future costs.

3 Change in accounting policies

Accounting Guideline 16

Effective December 2003, the Trust adopted AcG-16 "Oil and Gas Accounting – Full Cost", the new guideline issued by the Canadian Institute of Chartered Accountants which replaces AcG-5 "Full Cost Accounting in the Oil and Gas Industry".

There were no changes to net income, property, plant and equipment or any other reported amounts in the financial statements as a result of adopting this guideline.

Stock based compensation

APF elected to prospectively adopt amendments to CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" pursuant to the transitional provisions contained therein. Under this amended standard, APF must account for compensation expense based on the fair value of rights granted under its' unit-based compensation plan. As APF is unable to determine the fair value of the rights granted, compensation expense has been determined based on the intrinsic value of the rights at the grant date or at the date of the financial statements for unexercised rights as described in Note 2.

For rights granted in 2002, APF has elected to disclose pro forma results as if the amended accounting standard had been adopted retroactively. As a result of adopting this standard, net income for the year ended December 31, 2003 decreased by $1.2 million and contributed surplus increased by $1.2 million.

See Note 10 for additional information regarding the nature of the plan and the associated compensation expense.

4 Cash distributions and accumulated cash distributions

The following table is the calculation of cash distributions and accumulated cash distributions:

(in thousands of dollars, except as noted)	2003 $	2002 $
Oil and gas sales	163,532	92,345
Other	1,925	1,676
Gross overriding royalties and lessors' royalties	(13,109)	(7,802)
	152,348	86,219
Less		
Operating costs	32,370	19,748
General and administrative	9,362	4,317
Management fees	-	1,976
Debt service charges (including interest and principal)	4,171	2,834
Site restoration fund contribution	1,932	925
Capital and other taxes	2,720	1,901
Capital expenditures funded from cash flow	9,326	5,144
	59,881	36,845
Income subject to the royalty	92,467	49,374
99% of income subject to the royalty	91,542	48,880
Crown charges, net of Alberta Royalty Tax Credit	(19,851)	(10,796)
Interest on convertible debentures	(2,317)	-
General and administrative costs of the Trust	(661)	(318)
Cash available to be distributed	68,713	37,766
Cash distributed to date	62,750	34,201
Cash distribution payable	5,963	3,565
Actual cash distribution declared per unit ($)	2.195	1.810
Opening accumulated cash distributions	110,650	72,884
Distribution declared and paid	62,750	34,201
Distribution declared and payable	5,963	3,565
Closing accumulated cash distributions	179,363	110,650

5 Property, plant and equipment

	2003 $000	2002 $000
Property, plant and equipment	531,365	340,189
Accumulated depletion, depreciation and amortization	(130,079)	(79,662)
	401,286	260,527

The calculation of 2003 depletion, depreciation and amortization included an estimated $25.0 million (2002 – $16.7 million) for future development costs associated with proved undeveloped reserves and excluded $10.8 million (2002 – $7.9 million) for the estimated value of unproved properties and coalbed methane projects currently in the development stage. General and administration costs of $458,000 associated with coalbed methane projects have been capitalized (2002 – $nil).

The Trust performed a ceiling test calculation at December 31, 2003 to assess the recoverable value of property, plant and equipment. The crude oil and natural gas futures prices are management's best estimates and are based on information obtained from third parties and were adjusted for commodity differentials specific to the Trust. Future prices were obtained for the period of 2004 to 2008 inclusive and then escalated based on escalation factors in the Trust's year-end independent reserves evaluation. Based on these assumptions shown below which are the present value of future net revenues from the Trust's proved plus probable reserves exceeded the carrying value of the Trust's property, plant and equipment at December 31, 2003.

Year	WTI Oil (US$/bbl)	Foreign exchange rate (US$/Cdn.$)	WTI Oil (Cdn.$/bbl)	AECO Gas (Cdn.$/mmbtu)
2004	30.18	0.77	39.43	5.72
2005	27.44	0.76	36.12	5.42
2006	26.67	0.75	35.33	5.27
2007	26.61	0.75	35.43	5.23
2008	26.78	0.75	35.77	5.18
2009 – 2014 (1)	-			-
Remainder (2)	1.5%			1.5%

(1) Percentage change represents the average for the period noted.

(2) Percentage change represents the change in each year after 2014 to the end of the reserve life.

6 Site restoration fund/liability

Energy and the LP are responsible for future site restoration costs on all properties. At December 31, 2003 the future undiscounted estimated costs for the site restoration liabilities were $31,198,000 (2002 – $29,858,000), of which $10,410,000 has been provided for. The current year expense charged to the provision was $3,327,000 (2002 – $2,087,000). Actual payments for abandonment in 2003 were $374,000 (2002 – $171,000).

A site restoration fund was established to fund future site reclamation and abandonment costs. Contributions to the site restoration fund during the year totalled $1,932,000 (2002 – $925,000) and have been deducted in calculating the income subject to the royalty.

Contributions to the site restoration fund are determined annually by management and are based on the average of the next three years expected site restoration expenses, as determined by the independent engineers.

7 Acquisitions

Effective February 5, 2003, Energy acquired all of the issued and outstanding shares of Hawk Oil Inc. ("Hawk Oil"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

	$000
Net assets acquired	
Bank overdraft	(5)
Other working capital	(629)
Property, plant and equipment	57,146
Goodwill	11,078
Debt assumed	(7,900)
Site restoration liability	(263)
Future income taxes	(18,266)
Total net assets acquired	41,161
Financed by	
Cash	2,856
Trust units issued (3,990,461 trust units)	37,710
Acquisition costs	595
Total consideration	41,161

Effective April 28, 2003, Energy acquired all of the issued and outstanding shares of Nycan Energy Corp. ("Nycan"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

	$000
Net assets acquired	
Cash	212
Other working capital	716
Property, plant and equipment	47,495
Goodwill	8,792
Debt assumed	(8,870)
Site restoration liability	(580)
Future income taxes	(13,266)
Total net assets acquired	34,499
Financed by	
Bank debt	34,374
Acquisition costs	125
Total consideration	34,499

Effective September 26, 2003, Energy acquired all of the issued and outstanding shares of CanScot Resources Limited ("CanScot"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

	$000
Net assets acquired	
Cash	156
Other working capital	22
Property, plant and equipment	32,980
Goodwill	16,884
Debt assumed	(6,150)
Site restoration liability	(388)
Future income taxes	(7,399)
Total net assets acquired	36,105
Financed by	
Bank debt	19,689
Trust units issued (1,342,004 trust units)	15,433
Acquisition costs	983
Total consideration	36,105

Effective May 30, 2002, Energy acquired all of the issued and outstanding shares of two private corporations, Kinwest Energy Inc. ("Kinwest") and Kinwest's joint venture partner (collectively the "Kinwest Acquisition"). The transaction has been accounted for as a business combination with the allocation of the purchase price and consideration paid as follows:

	$000
Net assets acquired	
Working capital	1,641
Property, plant and equipment	63,483
Goodwill	11,476
Debt assumed	(10,146)
Site restoration liability	(673)
Future income taxes	(15,410)
Total net assets acquired	50,371
Financed by	
Cash	13,042
Trust units issued (3,385,510 trust units)	36,056
Acquisition cost – due to related party	838
Acquisition costs	435
Total consideration	50,371

8 Long-term debt

	2003 $000	2002 $000
Bank loans	98,000	88,000

At December 31, 2003, APF had a $150.0 million revolving term credit facility with a syndicate of Canadian resident financial institutions. The facility may be drawn down or repaid at any time but there are no scheduled repayment terms. The debt bears interest based on a sliding scale tied to APF's debt to cash flow ratio, from a minimum of the bank's prime rate plus 0.125% to a maximum of the prime rate plus 1.625% (2002 – prime rate plus 1.5%) or where available, at Banker's Acceptances rates plus a stamping fee of 1.125% to 2.0% (2002 – 1.125% to 2.5%). The debt is secured by a $300.0 million demand debenture containing a first fixed charge on all the petroleum and natural gas assets of APF and an assignment of book debts and material gas contracts. At December 31, 2003, the interest rate was bank prime of 4.5% plus 0.125% (2002 – 4.5% plus 0.25%).

APF has the option to extend the revolving period for an additional 364 days by giving notice to the lenders no earlier than 180 days and no less than 90 days prior to the end of the revolving period. If the revolving period is not extended, the outstanding principal will be converted to a one-year non-revolving term loan commencing on the day immediately following the end of the then current revolving period. During the one-year term period, APF will pay 1/6th of the outstanding principal on the 180th day after the commencement of the one-year term period and 1/12th of the outstanding principal on the 90th day thereafter.

9 Unitholders' investment account

	2003		2002	
	Units	Amounts $000	Units	Amounts $000
Balance – Beginning of year	22,942,417	214,405	15,583,880	141,069
Issued to acquire Hawk Oil	3,990,461	37,710	-	-
Issued to acquire CanScot Resources	1,342,004	15,433	-	-
Issued to acquire Kinwest	-	-	3,385,510	36,056
Issued for cash	5,351,645	55,670	3,303,665	32,250
Cost of units issued	-	(3,467)	-	(1,861)
Distribution reinvestment program	140,710	1,602	-	-
Issued on conversion of debentures	107,998	1,215	-	-
Issued under management internalization	-	-	608,185	6,337
Issued on exercise of options/rights	199,005	1,749	61,177	554
Balance – End of year	34,074,240	324,317	22,942,417	214,405

The holders of Units are entitled to vote at any meeting of the Unitholders.

The per unit calculations are based on the weighted average number of units outstanding during the year of 30,970,093 units (2002 – 20,470,210 units). In computing diluted net income per unit, 334,077 units were added to the weighted average number of units outstanding during the year (2002 – 57,569) for the dilutive effect of employee options and rights to acquire trust units. In addition, 4,336,444 units were added (2002 – nil) for the dilutive effect of the convertible debentures for a total weighted average number of units for 2003 of 35,640,614 (2002 – 20,527,779).

Net income for 2003 has been adjusted by $2,317,000 (2002 – $nil) for the interest accrued on the convertible debenture for purposes of calculating basic earnings per unit.

In 1999, the Trust created a Unitholders' Rights Plan and authorized the issuance of one right in respect of each Unit outstanding. Each right would allow Unitholders in specified circumstances, to acquire, on payment of an exercise price of $50.00, the number of Units having an aggregate market price equal to twice the exercise price of the rights.

Effective with the December 2003 distribution, the Trust initiated a premium distribution reinvestment plan ("DRIP"). The DRIP permits eligible unitholders to direct their distributions to the purchase of additional units at 95% of the average market price as defined in the plan ("Regular DRIP").

The premium distribution component permits eligible unitholders to elect to receive 102% of the cash the unitholder would otherwise have received on the distribution date ("Premium DRIP"). Participation in the Regular DRIP and Premium DRIP is subject to proration by the Trust. Unitholders who participate in either the Regular DRIP or the Premium DRIP are also eligible to participate in the optional unit purchase plan as defined in the DRIP.

10 Trust unit incentive rights plan

Pursuant to a Trust Unit Incentive Plan dated December 17, 1996 and amended February 1, 1998 (the "Plan"), employees, directors and long-term consultants may be granted options to acquire Units of the

Trust. The exercise price for each option was the market price of the Units at the time the option was granted. Options granted prior to February 1, 1998 vested immediately, while options granted on or after February 1, 1998 vest in one-third increments on the first, second and third anniversaries of their grant. The maximum term for options is five years. This Plan was terminated in 2001 and replaced with a new Trust Unit Incentive Rights Plan ("Rights Plan").

Under the Rights Plan, employees, directors and long-term consultants may be granted rights to purchase Units of the Trust. The initial exercise price of rights granted under the Rights Plan may not be less than the current market price of the Trust Units as of the date of the grant and the maximum term of each right is not to exceed ten years. The exercise price is to be adjusted downwards from time to time by the amount, if any, that distributions to Unitholders in any calendar quarter exceed a percentage of APF's net book value of property, plant and equipment, as determined by the Trust.

APF recorded compensation expense and contributed surplus of $1,241,000 for rights issued in 2003, based on the year-end unit price of $12.54.

For rights granted in 2002, APF has elected to disclose proforma results as if the amended accounting standard has been applied retroactively. For the year ended December 31, 2003, APF's net income would have decreased by $950,000 for the estimated compensation cost associated with rights granted under the plan between January 1 and December 31, 2002 as follows:

	2003 **$000**	**2002** **$000**
Net income as reported	43,048	11,365
Less: Compensation expense for rights issued in 2002	(950)	-
Pro forma net income	42,098	11,365
Basic net income per trust unit		
As reported	1.32	0.55
Proforma	1.28	0.55
Diluted net income per trust unit		
As reported	1.21	0.55
Proforma	1.18	0.55

No compensation expense has been recorded for 2002 as the adjusted exercise price of the rights exceeded APF's market price at December 31, 2002.

Net income in the basic per trust unit calculation has been reduced by interest on the convertible debentures of $2.3 million for purposes of calculating the basic net income.

11 Option plan

A summary of the status of the Plan as of December 31, 2003 and 2002 is as follows:

Trust Unit Options	2003 Units	2003 Weighted average price $	2002 Units	2002 Weighted average price $
Outstanding – Beginning of year	244,029	9.13	330,540	9.32
Granted	-	-	-	-
Exercised	(106,786)	8.55	(58,677)	9.05
Forfeited	(10,774)	9.42	(27,834)	11.62
Outstanding – End of year	126,469	9.59	244,029	9.13
Options exercisable – End of year	60,173	9.48	76,488	8.72

The following table summarizes options information under the Plan outstanding at December 31, 2003:

Range of Exercise prices $	Number outstanding December 31, 2003	Weighted average remaining contractual life (years)	Weighted average exercise price $	Number exercisable December 31, 2003	Weighted average price $
7.00 – 7.99	700	1.18	7.15	700	7.15
8.00 – 9.00	6,899	0.15	8.00	6,899	8.00
9.01 – 10.00	118,870	2.17	9.70	52,574	9.70
	126,469	2.10	9.59	60,173	9.48

Rights plan

During the year, the Trust granted 1,538,250 rights (2002 – 441,233) under the Rights Plan to employees and directors to purchase trust units at prices ranging from $9.67 to $11.54 (2002 – $9.73 to $10.80) per trust unit.

A summary of the Rights Plan at December 31, 2003 and 2002 is as follows:

	2003		2002	
	Number of rights	Weighted average price $	Number of rights	Weighted average price $
Balance – Beginning of year	429,333	9.37	-	-
Granted	1,538,250	9.78	441,233	9.86
Exercised	(92,219)	9.05	(2,500)	9.73
Cancelled	(51,034)	9.67	(9,400)	9.73
Balance before reduction of exercise price	1,824,330	9.72	429,333	9.86
Reduction of exercise price	-	0.63	-	0.49
Balance – End of year	1,824,330	9.09	429,333	9.37
Rights exercisable – End of year	47,221	8.58	-	-

The following table summarizes information about the Rights Plan as at December 31, 2003:

Range of Exercise prices $	Number outstanding December 31, 2003	Weighted average remaining contractual life (years)	Weighted average exercise price $	Number exercisable December 31, 2003	Weighted average price $
8.00 – 9.00	222,180	8.17	8.40	40,721	8.49
9.01 – 10.00	1,508,623	9.27	9.06	6,500	9.18
10.01 – 11.00	10,858	9.45	10.45	-	-
11.01 – 12.00	82,669	9.50	11.31	-	-
	1,824,330		9.09	47,221	8.58

12 Convertible debentures

On July 3, 2003, APF issued $50.0 million of unsecured subordinated convertible debentures ($47.7 million net of issue costs) with a 9.40% coupon rate maturing July 31, 2008. Interest is paid semi-annually on January 31 and July 31. The debentures may be converted into trust units at the option of the holder at a conversion price of $11.25 per trust unit prior to July 31, 2008 and may be redeemed by APF under certain circumstances. The debentures and related interest obligations have been classified as equity on the consolidated balance sheet as APF may elect to satisfy interest and principal obligations by the issuance of trust units. During the year, $1.2 million of convertible debentures were converted into 107,998 trust units.

13 Income taxes

Energy and the LP have approximately $70.0 million of unused tax pools at December 31, 2003 ($60.4 million - December 31, 2002) available to be used to offset future taxable income subject to certain restrictions of the *Income Tax Act*.

Energy had approximately $22.3 million in non-capital losses at December 31, 2003 ($15.3 million – December 31, 2002) of which approximately $945,000 expire in 2005 and the remainder through 2010.

The Unitholders are responsible for their own income taxes. Distributions will be a combination of taxable income and a return of capital in the year received. Generally, when the Trust has no taxable income prior to the deduction of distributions, distributions will not be taxable but will be a return of capital which reduces the Unitholders' adjusted cost base in those years.

	2003 $000	2002 $000
Income before income taxes	28,715	4,635
Statutory tax rate	42.75%	43.5%
Expected tax provision	12,276	2.016
Effect on income tax of		
Net income of the Trust	(21,002)	(12,603)
Resource allowance	(2,250)	(595)
Non-deductible crown charges	669	47
Internalization of management contract	-	3,174
Capital tax	1,163	827
Rate reduction	(3,717)	-
Other	(1,472)	-
Provision for future income taxes	(14,333)	(7,134)
The future tax recorded on the balance sheet results from		
Capital assets in excess of tax value	72,725	46,282
Future tax losses that are likely to be utilized	(8,503)	(6,657)
	64,222	39,625

Distributions paid are deducted from taxable income only to the extent needed to reduce taxable income in the Trust to zero. Generally, the distributions deducted for the Trust tax return are taxable income to the Unitholders.

Taxable income of the Trust is comprised of income from royalty, adjusted for crown royalties and resource allowance, less deductions for Canadian oil and natural gas property expense (COGPE), which is claimed at a rate of 10% on a declining balance basis and issue costs which are claimed at 20% per year on a straight-line basis. Any losses that occur in the Trust must be retained in the Trust and may be carried forward and deducted from taxable income for a period of seven years. The COGPE during 2003 resulted from the purchase of royalty interests.

The amount of COGPE and issue costs remaining in the Trust are approximately $122.3 million.

14 Related party transactions

Internalization of management

On December 18, 2002, Unitholders approved the acquisition of APF Energy Management Inc. (the "Manager"), effective January 1, 2003. Total consideration for the transaction consisted of a cash payment of $3.9 million and the issuance of 608,185 Trust Units to the shareholders of the Manager as detailed below:

	$000
Net assets acquired	
Cash	419
Working capital	629
Property, plant and equipment	4,512
Future income taxes	(1,917)
Internalization of management contract	7,297
Total net assets acquired	10,940
Total consideration	
Cash	3,923
Trust units issued	6,337
Transaction costs	680
Total purchase price	10,940

Although the transaction did not close until January 3, 2003, all of the major conditions, including unitholder and regulatory approval, had been obtained by December 31, 2002. Accordingly, the transaction was accounted for as if it had closed on December 31, 2002.

The consideration paid through the issue of Trust Units is partially subject to escrow restrictions. In the case of Mr. Martin Hislop, Chief Executive Officer, 100% of the 150,526 Trust Units issued are subject to escrow for 3 years, released as to one third on each anniversary date of the transaction. In the case of Mr. Cloutier, President and Chief Operating Officer, 80% of the 125,590 Trust Units issued are subject to escrow for 4 years, released as to one quarter on each anniversary date of the transaction. The remaining Trust Units issued to non-management shareholders of the Manager were not subject to escrow restrictions. Retention bonuses paid by the Manager to three other officers were used to subscribe for 53,665 Trust Units at a price of $10.482 per Trust Unit at closing. These Trust Units are subject to the same escrow restrictions as those Trust Units issued to the President.

Prior to the acquisition, APF paid fees to the Manager equal to 3.5% of net production revenue, structuring fees of 1.5% on the purchase price of acquisitions and dispositions, as well as the right to the residual 1% royalty. The internalization resulted in the elimination of all such fees under the management agreement.

Management contract

Prior to the internalization of the management contract, the Manager handled the business of APF pursuant to a management agreement. Fees payable to Management for management, advisory and administrative services included a fee equal to 3.5% of Net Production Revenue and structuring fees of 1.5% on both the purchase price of acquisitions and on the net proceeds of dispositions. In 2003, fees paid or payable to Management on Net Production Revenues were $nil (2002 – $1,976,000) and structuring fees were $nil (2002 – $1,022,000). During 2002 structuring fees were accounted for as either part of the purchase price or as a reduction of the proceeds of disposition of oil and natural gas properties.

During the year, Energy reimbursed Management $nil (2002 – $2,294,000) for general and administrative expenses. During 2002, Energy also acquired certain non-oil and gas business assets from Management for $850,000.

During 2002, Management, through its ownership of 100% of the shares of APF, was entitled to receive 1% of the royalty income derived from the Properties. The 1% minority interest is included as an expense in the consolidated statement of operations totalling $403,000 for 2002.

15 Financial instruments

APF is exposed to market risks resulting from fluctuations in commodity prices, foreign exchange rates and interest rates in the normal course of operations. Derivative instruments are used by APF to reduce its exposure to fluctuations in commodity prices and foreign exchange rates. The fair values of these derivative instruments are based on an estimate of the amounts that would have been received or paid to settle these instruments prior to maturity.

The fair values of financial instruments that are included in the balance sheet, including long-term borrowings, approximate their carrying amount due to the short-term maturity of those instruments and the floating prime rate applied to long-term borrowings.

A substantial portion of APF's accounts receivable are with customers in the oil and natural gas industry and are subject to normal industry credit risks.

APF has a price risk management program whereby the commodity price associated with a portion of its future production is fixed. APF sells forward a portion of its future production through commodity swap agreements with counterparties. The following contracts were outstanding as at December 31, 2003. The estimated market value at December 31, 2003, had the contracts been settled at that time, would have resulted in a reduction of revenues otherwise to be received of $400,000.

Term	Commodity	Type of contract	Average daily quantity	Average contract price	Price index
Jan. to Mar. 2004	Crude oil	Fixed price	3,167 bbls	US $29.63	WTI
Jan. to Mar. 2004	Natural gas	Fixed price	10,000 GJ	Cdn. $7.19	AECO
Jan. to Mar. 2004	Natural gas	Fixed price	2,000 mmbtu	US $7.00	NYMEX
Apr. to Jun. 2004	Crude oil	Fixed price	1,833 bbls	US $30.05	WTI
Jul. to Sept. 2004	Crude oil	Fixed price	1,167 bbls	US $28.86	WTI

At December 31, 2003, APF had fixed the interest rate on a portion of its debt as follows:

Term	Amount $000	Interest rate
January 2004 to February 2005	$20,000	3.67% plus stamping fee
January 2004 to May 2005	$20,000	3.75% plus stamping fee
January 2004 to November 2005	$20,000	3.58% plus stamping fee

The estimated market value of these interest rate contracts at December 31, 2003, had they been settled at that time, would be a cost of $900,000.

At December 31, 2003, APF had entered into the following foreign currency forward contract:

Term	Amount $000	Exchange rate (Cdn.$/US$)
January 2004 to December 2004	US $10,000	1.333

The estimated market value of these foreign currency forward contracts at December 31, 2003, had they been settled at that time, would be $nil.

16 Supplemental information for the Statements of Cash Flows

	2003 $000	2002 $000
Cash payments related to certain items		
Interest	4,070	2,843
Interest on debentures	30	-
Distributions to minority interests	-	415
Distributions to Unitholders	66,315	36,539
Capital taxes	3,389	2,165

17 Contingencies and commitments

APF is involved in certain legal actions that occurred in the ordinary course of business. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

APF has lease commitments relating to office buildings. The estimated annual operating lease rental payments for the building for the next five years are as follows:

	$000
2004	773
2005	756
2006	710
2007	706
2008	359

18 Subsequent events

Underwriting Agreement and prospectus filing

APF and the Underwriters entered into an Underwriting Agreement pursuant to which the Underwriters agreed to offer and the Trust agreed to issue and sell up to 4,765,000 Trust Units at a price of $11.60 per Trust Unit. Closing of the offering and the issue of 4,765,000 Trust Units took place on February 4, 2004. The estimated net proceeds from the offering, after deducting expenses of the issue and after Underwriters' commissions will be in the amount of $52.5 million and will be initially used to repay debt.

Certain statements in this material may be "forward-looking statements" including outlook on oil and gas prices, estimates of future production, estimated completion dates of acquisitions and construction and development projects, business plans for drilling and exploration, estimated amounts and timing of capital expenditures and anticipated future debt levels and royalty rates. Information concerning reserves contained in this material may also be deemed to be forward-looking statements as such estimates involve the implied assessment that the resources described can be profitably produced in the future. These statements are based on current expectations, estimates and projections that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated by APF. The Toronto Stock Exchange has neither approved nor disapproved of the contents of this news release.

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