Exemption Order
82-5166

05006769

APF ENERGY

NEWS RELEASE

TSX: AY.UN; AY.DB

APF ENERGY RELEASES 2004 FINANCIAL AND OPERATING RESULTS

March 3, 2005 - APF Energy Trust ("APF") is pleased to announce its 2004 year-end financial and operating results.

HIGHLIGHTS

- Completed the $291.08 million acquisition of Great Northern Exploration Ltd., adding 5,600 boe/d and growing the Trust by approximately 45%.
- APF had record cash flow of $107.13 million in 2004 and declared cash distributions of $96.93 million, resulting in a 2004 payout ratio of 90 percent. APF realized cash flow of $31.13 million for the three months ended December 31, 2004, an increase of 109 percent over the fourth quarter of 2003. The Trust declared cash distributions of $28.07 million ($0.48 per unit) for the three months ended December 31, 2004.
- Drilled 284 (131.1 net) wells with a 98 percent success rate, a 73 percent increase over 2003 activity levels.
- Capital expenditures of $68.78 million were devoted to the 2004 development program and resulted in incremental production that offset natural production declines on existing properties. Ongoing internal development and optimization activities are expected to result in average production of approximately 18,000 to 18,500 boe/d, with the potential to increase, pending rig and crew availability. Production averaged 16,012 boe/d in 2004, compared to 14,463 boe/d in 2003. Production for the three months ended December 31, 2004 averaged 18,450 boe/d.
- Provided investors with a 16 percent cash yield throughout the year.
- Strong participation levels in the Premium Distribution, Distribution Reinvestment and Optional Unit Purchase Plan provided $39.66 million of funding, which was utilized in partially funding the capital development program.

dlw 3/24

SUMMARY OF OPERATING & FINANCIAL RESULTS	Three Months Ended December 31 2004		Three Months Ended December 31 2003		Twelve Months Ended December 31 2004		Twelve Months Ended December 31 2003
FINANCIAL				Restated[3]			Restated[3]
($000, except per unit/boe amounts)							
Cash flow from operations[1]		**31,125**		14,873		**107,126**	81,019
Per unit - basic	**$**	**0.53**	$	0.44	**$**	**2.21**	$ 2.62
Per unit - diluted	**$**	**0.50**	$	0.39	**$**	**2.03**	$ 2.42
Distributions		**28,068**		17,822		**96,930**	68,713
Per unit	**$**	**0.48**	$	0.53	**$**	**2.00**	$ 2.20
Payout ratio		**90%**		120%		**90%**	85%
Bank debt		**169,000**		98,000		**169,000**	98,000
Operating costs per boe	**$**	**9.21**	$	7.96	**$**	**8.84**	$ 7.12
Operating netbacks per boe (before derivatives)	**$**	**26.33**	$	18.20	**$**	**25.34**	$ 22.89
Market							
Units outstanding (000s)							
End of period		**58,845**		34,074		**58,845**	34,074
Weighted average - basic		**58,292**		33,907		**48,486**	30,970
Weighted average - diluted		**62,675**		38,612		**52,869**	33,489
Trust unit trading							
High	**$**	**12.47**	$	12.67	**$**	**12.63**	$ 12.67
Low	**$**	**11.31**	$	11.45	**$**	**10.32**	$ 9.30
Close	**$**	**11.72**	$	12.54	**$**	**11.72**	$ 12.54
Average daily volume		**336,761**		123,000		**305,706**	163,000
OPERATIONS							
Daily production (average)							
Crude oil (bbl)		**7,734**		6,498		**6,969**	6,472
NGLs (bbl)		**1,048**		474		**758**	358
Natural gas (mcf)		**58,008**		36,929		**49,712**	33,799
Total (boe)[2]		**18,450**		13,127		**16,012**	12,463
Average commodity prices ($Cdn.)							
Total crude oil (bbl)	**$**	**46.43**	$	32.68	**$**	**44.63**	$ 36.07
NGLs (bbl)	**$**	**41.82**	$	31.37	**$**	**40.09**	$ 31.83
Natural gas (mcf)	**$**	**6.74**	$	5.59	**$**	**6.79**	$ 6.64
Average (boe)[2]	**$**	**43.01**	$	33.04	**$**	**42.40**	$ 37.66
Drilling (gross wells)							
Oil		**15**		31		**37**	60
Gas		**112**		15		**135**	80
Coalbed methane		**55**		19		**104**	19
Other		**3**		0		**8**	5
Total		**185**		65		**284**	164

1) 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.

2) 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.

3) 2003 comparative results have been restated for the three and twelve month periods ended December 31 to reflect the adoption of CICA Handbook Section 3110 "Asset Retirement Obligations", as well as section 3870, "Stock-based Compensation and Other Stock-based Payments"

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") for APF Energy Trust ("APF" or the "Trust") should be read in conjunction with the December 31, 2004 and 2003 audited annual consolidated financial statements ("consolidated financial statements") and related note disclosures. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("Canadian GAAP") and are presented in Canadian currency (except where indicated as being in another currency). APF is an oil and gas issuer and disclosures pertaining to oil and gas activities are presented in accordance with National Instrument 51-101 ("NI 51-101"). This MD&A is dated March 1, 2005.

RESULTS OF OPERATIONS

PRODUCTION AND MARKETING

The Trust increased average production volumes by 28 percent to 16,012 boe/d for the year ended December 31, 2004 due primarily to the acquisition of Great Northern Exploration Ltd ("Great Northern") which added 5,600 boe/d of production effective June 2004, combined with a successful drilling program. The Great Northern acquisition and the Trust's gas-focused drilling program, has shifted production from 45 percent natural gas-weighted in 2003, to 52 percent in 2004.

The Trust increased light/medium and heavy oil production by seven and nine percent respectively during 2004, despite unseasonable conditions that extended beyond the traditional spring break-up period. NGL and natural gas daily production volumes increased 112 and 47 percent respectively relative to the prior year, due primarily to the gas-levered Great Northern acquisition. The increase in production volumes is more pronounced in the fourth quarter and is more representative of the impact of Great Northern going forward.

	Three Months Ended December 31			Twelve Months Ended December 31		
	2004	2003	% Change	**2004**	2003	% Change
Light/medium crude oil (bbl/d)	**6,443**	5,205	24	**5,802**	5,399	7
Heavy oil (bbl/d)	**1,291**	1,293	(0)	**1,167**	1,073	9
NGL (bbl/d)	**1,048**	474	121	**758**	358	112
Natural gas (mcf/d)	**58,008**	36,929	57	**49,712**	33,799	47
Total (boe/d)	**18,450**	13,127	41	**16,012**	12,463	28
Production split						
Oil & NGLs	**48%**	53%	(10)	**48%**	55%	(12)
Natural Gas	**52%**	47%	12	**52%**	45%	14

Crude oil is sold under 30-day evergreen contracts while the majority of natural gas production is sold in the spot market. Approximately 15 percent of natural gas volumes are sold to aggregators pursuant to long-term contracts declining from 20 percent prior to acquiring Great Northern volumes.

REALIZED OIL AND GAS PRICES

The Trust's combined crude oil pricing before derivatives increased 24 percent for the year and 42 percent for the three months ended December 31, 2004, relative to the industry benchmark West Texas Intermediate ("WTI") measured in U.S. currency, which increased 33 and 55 percent over the same periods. The difference is consistent with observed differentials between WTI and the Canadian dollar-denominated Edmonton Par crude, which increased 22 and 46 percent for the year and three months ended December 31, 2004 respectively. U.S. and Canadian product differentials are primarily driven by U.S./Cdn. currency exchange rates; however, quality differentials and U.S. demand for Canadian imports also impact relative pricing. The remaining difference between the Trust's combined crude pricing before derivatives as compared to Edmonton Par is due to product quality differentials attributable to the Trust's heavy oil production. For the year ended December 31, 2004, heavy oil as a percentage of total crude oil production remained relatively unchanged whereas this percentage for the three months ended December 31, 2004 decreased from 20 percent to 17 percent. As a result, the Trust realized a higher average price relative to the comparative period.

Natural gas pricing before derivatives for the year ended December 31, 2004 increased two percent over the prior year. This is consistent with the one percent increase in the benchmark AECO price for the corresponding period as the relative balance between the supply of and demand for natural gas in North America remained constant. For the three months ended December 31, 2004, the 21 percent increase in the price of natural gas relative to the comparable quarter is due mainly to depressed North American natural gas prices during October and November 2003.

Price realizations include the impact of realized crude oil and natural gas financial derivative instruments. For the year ended December 31, 2004, crude oil price realizations increased 11 percent to $38.19 per boe and include the settlement of crude oil derivatives, which lowered pricing before derivatives by 14 percent or $6.44 per boe. Crude oil price realizations during the fourth quarter of 2004 were 18 percent higher than 2003 price realizations despite derivative losses that lowered per boe pricing 20 percent from $46.43 before derivatives to $37.23 after realized derivatives.

The impact of realized derivatives did not significantly impact natural gas price realizations. Consistent with pricing before derivatives, for the year ended December 31, 2004, price realizations were up slightly to $6.80 per mcf, which represents a two percent increase over the prior year. Price realizations during the fourth quarter of 2004 were up 18 percent as compared to 2003, due to depressed North American natural gas prices during the first two months of the fourth quarter of 2003.

Effective January 1, 2004, the Trust began segregating costs associated with the transportation and selling of crude oil, natural gas and NGLs. Previously, the Trust had followed industry practice, presenting revenue net of these costs. The comparative figures have been restated with these costs segregated, resulting in an increase to the gross price per mcf (boe).

	Three Months Ended December 31			Twelve Months Ended December 31		
Prices - Before Derivatives ($Cdn.)	**2004**	2003	% Change	**2004**	2003	% Change
Light/medium crude oil (bbl)	**$ 49.89**	$ 35.21	42	**$ 47.29**	$ 38.03	24
Heavy oil (bbl)	**29.15**	22.48	30	**31.43**	$ 26.19	20
Total crude oil (bbl)	**46.43**	32.68	42	**44.63**	36.07	24
NGLs (bbl)	**41.82**	31.37	33	**40.09**	$ 31.83	26
Natural gas (mcf)	**6.74**	5.59	21	**6.79**	$ 6.64	2
Total (boe)	**$ 43.01**	$ 33.04	30	**$ 42.40**	$ 37.66	13
Realized Oil and Gas Derivatives ($Cdn.)						
Crude oil (bbl)	**$ (9.20)**	$ (1.01)	811	**$ (6.44)**	$ (1.61)	300
Natural gas (mcf)	**0.05**	0.16	(69)	**0.01**	0.02	(50)
Total (boe)	**$ (3.69)**	$ (0.04)	9,125	**$ (2.78)**	$ (0.79)	252
Prices - After Realized Oil and Gas Derivatives ($Cdn.)						
Total crude oil (bbl)	**$ 37.23**	$ 31.67	18	**$ 38.19**	$ 34.46	11
NGLs (bbl)	**41.82**	31.37	33	**40.09**	31.83	26
Natural gas (mcf)	**6.79**	5.75	18	**6.80**	6.66	2
Total (boe)	**$ 39.32**	$ 33.00	19	**$ 39.62**	$ 36.87	7
Reference Pricing						
WTI ($U.S./bbl)	**$ 48.28**	$ 31.18	55	**$ 41.40**	$ 31.04	33
Edmonton Par ($Cdn./bbl)	**$ 57.71**	$ 39.56	46	**$ 52.55**	$ 43.14	22
AECO gas ($Cdn./mcf)	**$ 7.08**	$ 5.59	27	**$ 6.79**	$ 6.70	1
Foreign exchange ($U.S./$Cdn.)	**1.2207**	1.3157	(7)	**1.3282**	1.4010	(5)

The Trust uses derivative instruments to manage commodity price fluctuations and stabilize cash flows available for unitholder distributions and future development programs (see Risk Management section of this document). Derivative instruments are also used to help manage exposures to foreign currency exchange rates, interest rates, and electricity rates. APF does not enter into derivative contracts for speculative purposes. A detailed summary of the Trust's derivative position at December 31, 2004 is presented in the Risk Management section of this document.

APF's current approach to derivatives involves the use of swaps, collars, and sold WTI call options for light and medium crude oil, and swaps and collars for natural gas. The following table summarizes crude oil and natural gas derivative contracts settled during 2004 as a percentage of quarterly production volumes and contracts outstanding as at the date of this report relating to future production:

Percentage of	**2004**				2005				2006	
Production hedged	**Q1**	**Q2**	**Q3**	**Q4**	Q1	Q2	Q3	Q4	Q1	Q2
Crude oil	**49%**	**44%**	**44%**	**49%**	34%	50%	47%	27%	27%	7%
Natural gas	**33%**	**30%**	**35%**	**22%**	16%	41%	41%	25%	16%	0%

OIL AND GAS REVENUE

Gross oil and gas revenue for the year ended December 31, 2004 increased 45 percent over the prior year, due to the Trust's acquisition of Great Northern and sustained strength in commodity prices. Seven months of Great Northern production volumes are reflected in the 2004 fiscal year. The impact of Great Northern is more evident when comparing the three month periods ended December 31. Gross oil and gas revenue for the fourth quarter of 2004 increased 83 percent over the comparable period in 2003. The variance can be explained by a 30 percent increase in prices (before realized derivatives) on 41 percent higher production volumes.

Effective January 1, 2004, the Trust began segregating costs associated with the transportation and selling of crude oil, natural gas and NGLs. Previously, the Trust had followed industry practice, presenting revenue net of these costs. The comparative figures have been restated with these costs segregated, resulting in an increase to the gross price per mcf (boe).

	Three Months Ended December 31			Twelve Months Ended December 31		
Oil and Gas		Restated			Restated	
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Light/medium crude oil sales	**29,571**	16,862	75	**100,419**	74,934	34
Heavy oil sales	**3,463**	2,675	29	**13,423**	10,260	31
NGL sales	**4,031**	1,368	195	**11,115**	4,157	167
Natural gas sales	**35,944**	18,997	89	**123,527**	81,938	51
Gross oil and gas revenue	**73,009**	39,902	83	**248,484**	171,289	45
Realized oil and gas derivatives	**(6,260)**	(44)	14,127	**(16,305)**	(3,565)	357
Transportation	**(1,427)**	(1,150)	24	**(5,245)**	(4,174)	26
Other	**2,197**	421	422	**4,729**	1,925	146
Net oil and gas revenue	**67,519**	39,129	73	**231,663**	165,475	40
Per boe	**$ 39.79**	$ 32.39	23	**$ 39.53**	$ 36.38	9

ROYALTIES

Royalties paid are calculated in accordance with royalty reference rates directly related to gross oil and gas revenues generated by the Trust from mineral leases with the Crown, freeholders and other operators. Total royalties for the year ended December 31, 2004 as a percentage of gross oil and gas revenue were consistent with rates paid during the prior year. Total royalties recorded for the fourth quarter of 2004 are approximately 18 percent of gross oil and gas revenue due to an adjustment for royalties previously accrued for during 2004. Going forward, the Trust expects royalty rates to remain consistent with annual rates recorded in 2004 and 2003.

	Three Months Ended December 31			Twelve Months Ended December 31		
		Restated			Restated	
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Crown royalties	**8,711**	4,838	80	**30,429**	19,364	57
Freehold royalties	**3,231**	2,120	52	**12,679**	10,193	24
Overriding royalties	**1,309**	609	115	**4,602**	2,916	58
Total royalties	**13,251**	7,567	75	**47,710**	32,473	47
% of gross oil and gas revenue	**18.1%**	19.0%	(4)	**19.2%**	19.0%	1
Per boe	**$ 7.81**	$ 6.27	25	**$ 8.14**	$ 7.14	14

OPERATING EXPENSE

On a gross and per boe basis, operating costs were higher for the three months and year ended December 31, 2004 when compared to the same periods in 2003 due primarily to the acquisition and integration of Great Northern. The Trust completed a significant portion of optimization projects planned for Great Northern properties during the third and fourth quarters of 2004 and operating costs have trended lower following completion of these initiatives. The Trust has planned for additional initiatives to control future field costs and expects operating costs to continue to trend downwards to an average $9.00 per boe during fiscal 2005.

	Three Months Ended December 31			Twelve Months Ended December 31		
		Restated			Restated	
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Operating expense	**15,628**	9,619	62	**51,788**	32,370	60
Per boe	**$ 9.21**	$ 7.96	16	**$ 8.84**	$ 7.12	24

PRODUCT NETBACKS

Light/medium crude oil netbacks for the year ended December 31, 2004 decreased by two percent from $19.76 to $19.31, due primarily to lower price realizations after derivatives and higher operating costs related to Great Northern properties. The 2004 quarterly light/medium netback increased four percent over the prior period presented, resulting from higher prices received before derivatives and a smaller increase in operating costs relative to the prior period.

	Three Months Ended December 31			Twelve Months Ended December 31		
Light/medium		Restated			Restated	
crude oil ($Cdn. per bbl)	**2004**	2003	% Change	**2004**	2003	% Change
Price - After realized derivatives	**$ 38.85**	$ 33.95	14	**$ 39.55**	$ 36.10	10
Royalties	**(9.24)**	(7.55)	22	**(9.01)**	(7.56)	19
Operating expense	**(12.76)**	(10.26)	24	**(11.23)**	(8.78)	28
Operating netback	**$ 16.85**	$ 16.14	4	**$ 19.31**	$ 19.76	(2)

Heavy oil netbacks increased 22 percent and 95 percent for year and three months ended December 31, 2004, respectively, as compared to the prior periods in 2003. The increase is due primarily to higher price realizations offset by an increase in royalty expense. Operating costs for the year ended December 31, 2004 increased four percent over the prior year but were down 14 percent during the fourth quarter due to additional processing recoveries that reduce operating costs.

	Three Months Ended December 31			Twelve Months Ended December 31		
		Restated			Restated	
Heavy oil ($Cdn. per bbl)	**2004**	2003	% Change	**2004**	2003	% Change
Price - After realized derivatives	**$ 29.15**	$ 22.48	30	**$ 31.43**	$ 26.19	20
Royalties	**(4.68)**	(3.51)	33	**(4.42)**	(2.56)	73
Operating expense	**(9.93)**	(11.53)	(14)	**(11.09)**	(10.62)	4
Operating netback	**$ 14.54**	$ 7.44	95	**$ 15.92**	$ 13.01	22

NGL netbacks increased 33 percent and 59 percent for year and three months ended December 31, 2004, respectively, relative to the corresponding periods in 2003 due to higher price realizations in a strong commodity price environment.

	Three Months Ended December 31			Twelve Months Ended December 31		
		Restated			Restated	
NGLs ($Cdn. per bbl)	**2004**	2003	% Change	**2004**	2003	% Change
Price - After realized derivatives	**$ 41.82**	$ 31.37	33	**$ 40.09**	$ 31.83	26
Royalties	**(7.52)**	(9.84)	(24)	**(10.31)**	(9.41)	10
Operating expense	**-**	-	-	**-**	-	-
Operating netback	**$ 34.30**	$ 21.53	59	**$ 29.78**	$ 22.42	33

Natural gas netbacks declined six percent for the year ended December 31, 2004 and increased 15 percent for the three months ended December 31, 2004. Price realizations for the year ended December 31, 2004 were relatively flat as compared to 2003 and the 21 percent quarter-over-quarter increase in the price of natural gas after deducting transportation is due to unusually low North American natural gas prices experienced during October and November of 2003. The increase in operating costs per mcf was due to planned optimization initiatives related to Great Northern properties.

	Three Months Ended December 31			Twelve Months Ended December 31		
		Restated			Restated	
Natural gas ($Cdn. per mcf)	**2004**	2003	% Change	**2004**	2003	% Change
Price - After realized derivatives	**$ 6.79**	$ 5.75	18	**$ 6.80**	$ 6.66	2
Transportation	**(0.27)**	(0.34)	(21)	**(0.29)**	(0.34)	(15)
	6.52	5.41	21	**6.51**	6.32	3
Royalties	**(1.22)**	(0.92)	33	**(1.31)**	(1.24)	6
Operating expense	**(1.29)**	(0.99)	30	**(1.28)**	(0.89)	44
Operating netback	**$ 4.01**	$ 3.50	15	**$ 3.92**	$ 4.19	(6)

On a combined boe basis, the increase in price realizations less transportation and other income is consistent with higher commodity prices offset by realized derivative losses. Despite the negative impact of derivatives and higher operating costs during the year ended December 31, 2004, netbacks increased two percent over 2003. Netbacks for the fourth quarter performed better against the comparable quarter due to a weaker commodity price environment during the fourth quarter of 2003, combined with operating costs that have trended lower since the third quarter of 2004.

	Three Months Ended December 31			Twelve Months Ended December 31		
		Restated			Restated	
Combined ($Cdn. per boe)	**2004**	2003	% Change	**2004**	2003	% Change
Price - After realized derivatives	**$ 39.32**	$ 33.00	19	**$ 39.62**	$ 36.87	7
Transportation	**(0.84)**	(0.95)	(12)	**(0.90)**	(0.92)	(2)
Other	**1.18**	0.35	237	**0.82**	0.41	100
	39.66	32.40	22	**39.54**	36.36	9
Royalties	**(7.81)**	(6.27)	25	**(8.14)**	(7.14)	14
Operating expense	**(9.21)**	(7.97)	16	**(8.84)**	(7.12)	24
Operating netback	**$ 22.64**	$ 18.16	25	**$ 22.56**	$ 22.10	2

GENERAL AND ADMINISTRATIVE

General and administrative ("G&A") expense for the year ended December 31, 2004, increased commensurate with increased staffing levels required by growth in the Trust's operations from recent corporate and property acquisitions. On a per boe basis, G&A has declined 18 percent for the year and 43 percent for the three months ended December 31, 2004 due primarily to lower costs accrued for under the Trust's short-term incentive plan ("STIP").

		Restated			Restated	
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
General and administrative	**3,197**	3,980	(20)	**10,635**	10,023	6
Per boe	**$ 1.88**	$ 3.29	(43)	**$ 1.81**	$ 2.20	(18)

The STIP is designed to align employee and unitholder interests and to reward exceptional employee performance. The STIP enables all eligible employees to participate in a group bonus pool, provided the Trust generates a minimum total annual return of 10 percent. The total annual return on the Trust units as calculated by management for the year ended December 31, 2004 was 10.7 percent (2003 – 50 percent). Based on this total return figure, the 2004 STIP bonus pool was $1.17 million (2003 - $3.35 million). Senior employees, including officers, are also eligible to receive performance bonuses based on criteria applicable to their individual responsibilities. Excluding the STIP, G&A cost per boe for the year and three months ended December 31, 2004 was $1.62 (2003 - $1.47).

INTEREST ON LONG-TERM DEBT AND CONVERTIBLE DEBENTURES

Interest expense on long-term debt on a per boe basis remained consistent with 2003 for both the year and three months ended December 31, 2004. On a gross basis, interest expense has increased commensurate with higher average debt levels used to fund growth in the Trust's operations.

Interest and financing charges on convertible debentures for the year ended December 31, 2004 increased 97 percent in dollar terms and 53 percent on a per boe basis due to the fact that the debentures were issued on July 3, 2003, resulting in only six months of interest expense being included in the comparative figure. For the quarter ended December 31, 2004, interest expense on debentures decreased one percent in dollar terms as compared to the same period in 2003 due to $0.22 million in conversions during 2004.

Effective December 31, 2004, the Trust retroactively adopted the revised CICA Handbook Section 3860 ("HB 3860"), "Financial Instruments - Presentation and Disclosure" for financial instruments that may be settled at the issuer's option in cash or its own equity instruments. The revised standard requires the Trust to classify the convertible debenture proceeds as either debt or equity based on fair value measurement and the substance of the contractual arrangement. The Trust previously presented the convertible debenture proceeds (net of financing costs) and related interest obligations as equity on the consolidated balance sheet on the basis that the Trust could settle its obligations in exchange for trust units. The comparative figures presented have been restated to conform to the amended accounting standard.

	Three Months Ended December 31					Twelve Months Ended December 31				
				Restated					Restated	
($000 except per boe amounts)		**2004**		2003	% Change		**2004**		2003	% Change
Interest on long-term debt		**1,556**		1,088	43		**5,405**		4,171	30
Per boe	**$**	**0.92**	$	0.90	2	**$**	**0.92**	$	0.92	1
Interest and financing charges on convertible debentures		**1,327**		1,347	(1)		**5,263**		2,669	97
Per boe	**$**	**0.78**	$	1.12	(30)	**$**	**0.90**	$	0.59	53

DEPLETION, DEPRECIATION, AND ACCRETION

Depletion, depreciation and accretion ("DD&A") per boe increased 25 percent for the year and decreased 35 percent for the quarter ended December 31, 2004, respectively, as compared to the prior periods presented. The annual increase is due primarily to the acquisition of Great Northern resulting in a larger depletable base. The decrease quarter-over-quarter is attributable to an increase in proved reserves following the Trust's most active drilling quarter and revisions to the Trust's depletable base during the fourth quarter of 2004.

Effective January 1, 2004, the Trust retroactively adopted CICA Handbook Section 3110, "Asset Retirement Obligations" (ARO). The new standard requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred with a corresponding increase to property, plant and equipment. Prior periods presented include the impact of adopting this standard.

	Three Months Ended December 31					Twelve Months Ended December 31				
				Restated					Restated	
($000 except per boe amounts)		**2004**		2003	% Change		**2004**		2003	% Change
Depletion, depreciation and accretion		**16,108**		17,704	(9)		**85,997**		53,389	61
Per boe	**$**	**9.49**	$	14.66	(35)	**$**	**14.68**	$	11.74	25

UNIT-BASED COMPENSATION

For the year and three months ended December 31, 2004, the Trust recorded a recovery of unit-based compensation of $0.88 million and $1.87 million respectively, as compared to an expense of $1.24 million and $0.58 million for the corresponding periods in 2003. The decrease in unit-based compensation expense recorded in 2004 is due to a change in the Trust's approach to valuing equity instruments awarded to employees and directors. During the fourth quarter of 2004, the Trust began using the Black-Scholes option-pricing model to estimate the fair value of unit-based compensation. Previously, the Trust used the excess of the period-end market price over the exercise price as an estimate of fair value.

Effective December 31, 2003, the Trust prospectively adopted CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments." The standard requires that equity instruments awarded to employees after December 31, 2002 be measured at fair value and recognized over the vesting period. Companies that adopted the standard during 2003 were permitted to provide proforma disclosure of equity instruments granted before January 1, 2003. Comparative figures for 2003 have been restated to reflect the impact of unit-based compensation.

	Three Months Ended December 31			Twelve Months Ended December 31		
		Restated			Restated	
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Compensation expense (recovery)	**(1,866)**	582	(421)	**(877)**	1,241	(171)
Per boe	**$ (1.10)**	$ 0.48	(328)	**$ (0.15)**	$ 0.27	(155)

TAXES

Saskatchewan capital tax and federal large corporation tax increased 22 percent for the year and 54 percent for the quarter ended December 31, 2004 as compared to fiscal 2003 reflecting an increase in taxable capital after the acquisition of Great Northern.

Future income taxes are recorded on corporate acquisitions to the extent the book value of assets acquired, excluding goodwill, exceeds the tax basis. This future income tax liability increases the book cost of the assets acquired. It is anticipated that the future income tax liability will not be paid by APF Energy, but will instead be passed on to unitholders along with the income. Accordingly, this income tax liability will reduce each year and will be recognized as an income tax recovery at that time, to the extent that no income taxes were paid by APF Energy. For the year ended December 31, 2004, the Trust recovered $27.02 million in future income taxes compared to a future tax recovery of $14.21 million in 2003. At December 31, 2004 the Trust had a future income tax liability of $86.71 million as compared to $63.99 million at the end of 2003. The increase is due primarily to the future tax liability acquired with Great Northern, less recoveries recognized during the year. The December 31, 2003 comparative figures include the impact of adopting CICA Handbook Section 3110 "Asset Retirement Obligations".

	Three Months Ended December 31			Twelve Months Ended December 31		
		Restated			Restated	
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Capital and other taxes	**957**	623	54	**3,321**	2,720	22
Per boe	**$ 0.56**	$ 0.52	9	**$ 0.57**	$ 0.60	(5)
Recovery of future taxes	**(5,712)**	451	1,367	**(27,016)**	(14,207)	90

SUMMARY OF ANNUAL RESULTS

	Year Ended December 31		
		Restated	Restated
($000, except per unit amounts)	**2004**	2003	2002
Total revenue	**184,152**	132,984	75,314
Net income	**49,636**	40,608	11,582
Per unit - basic	**$ 1.02**	$ 1.31	$ 0.57
Per unit - diluted	**$ 1.02**	$ 1.29	$ 0.56
Cash flow from operations	**107,126**	81,019	43,789
Per unit	**$ 2.21**	$ 2.62	$ 2.14
Distributions	**96,930**	68,713	37,766
Per unit	**$ 2.00**	$ 2.20	$ 1.81
Total assets	**862,170**	498,750	306,322
Total long-term debt	**169,000**	98,000	88,000

Total revenue is primarily affected by commodity prices, production volumes, royalties and realized and unrealized (non-cash) derivative gains and losses. Total revenue has increased commensurate with strong commodity prices, corporate and property acquisitions and internal development activity. The Trust has been an active acquirer over the past three years, completing the acquisition of Great Northern during 2004; the acquisitions of CanScot Resources, Nycan Energy, Hawk Oil, and an additional interest at Swan Hills during 2003; and the acquisitions of Kinwest Resources and Paddle River assets in 2002.

The new accounting requirement to recognize gains/losses in the Trust's unrealized derivative position has introduced additional non-cash volatility in reported income. Prior to fiscal 2004, derivative gains/losses were reflected in income upon settlement of the related contracts; the 2003 and 2002 figures presented above have not been restated in accordance with the transitional provision of the new accounting pronouncement.

Net income has increased each year; however, the growth in income was lowered by realized oil and gas derivative losses, higher royalty expense in proportion with gross oil and gas revenues and higher operating costs and DD&A as a percentage of gross oil and gas revenues. The sustained strength in commodity prices, particularly light/medium crude oil has resulted in larger than expected derivative losses. Operating costs associated with newly-acquired Great Northern properties escalated through the third quarter of 2004, but have trended downward during the fourth quarter and should remain stable throughout fiscal 2005. As the Trust is able to take advantage of internal development opportunities, DD&A per boe is expected to remain consistent with 2004.

Given the sustained strength in commodity prices during 2004, despite realized oil and gas derivative losses and higher cash operating costs, the Trust has generated growth in cash flow from operations. Cash distributions have also increased, however, distributions declared per unit have decreased to provide the Trust with additional development capital to sustain future cash distributions. Non-cash items such as depletion, depreciation and accretion, future income taxes, and unrealized gains or losses on derivative instruments do not influence the Trust's current ability to distribute cash to unitholders.

The increase in total assets year-over-year is due primarily to oil and gas assets and goodwill purchased through corporate acquisitions. The increase in total long-term debt is commensurate with a larger asset base and increased development expenditures.

SUMMARY OF QUARTERLY RESULTS

The following table highlights the Trust's performance for the two most recent fiscal years presented on a quarterly basis:

($000, except per	**2004 Restated**				2003 Restated			
unit amounts)	**Q4**	**Q3**	**Q2**	**Q1**	Q4	Q3	Q2	Q1
Total revenue	**66,066**	**46,776**	**39,169**	**32,141**	31,543	32,737	33,295	35,410
Net income	**34,870**	**3,176**	**4,788**	**6,802**	(3,852)	9,799	20,977	13,687
Per unit - basic	**$ 0.60**	**$ 0.06**	**$ 0.11**	**$ 0.18**	$ (0.11)	$ 0.30	$ 0.65	$ 0.54
Per unit - diluted	**$ 0.58**	**$ 0.06**	**$ 0.11**	**$ 0.18**	$ (0.11)	$ 0.30	$ 0.65	$ 0.54
Cash flow from operations	**31,125**	**29,729**	**24,415**	**21,857**	14,873	19,389	21,563	25,194
Per unit	**$ 0.53**	**$ 0.54**	**$ 0.56**	**$ 0.58**	$ 0.44	$ 0.60	$ 0.67	$ 1.00
Distributions	**28,068**	**26,517**	**22,516**	**19,829**	17,822	18,909	18,916	13,066
Per unit	**$ 0.48**	**$ 0.48**	**$ 0.51**	**$ 0.53**	$ 0.53	$ 0.57	$ 0.59	$ 0.51
Total assets	**862,170**	**833,093**	**853,234**	**496,871**	498,750	501,689	446,527	377,916
Total long-term debt	**169,000**	**150,000**	**190,000**	**55,000**	98,000	90,000	102,000	97,000

Total revenue has trended upward over the past eight quarters. The new accounting requirement to mark the Trust's unrealized derivative position to market at period end and record the change in income lowered 2004 quarterly revenues by $3.27 million in Q1, $2.22 million in Q2, and $6.09 million in Q3, and increased Q4 total revenue by $0.22 million. As previously mentioned, unrealized gains/losses were not recorded for periods prior to 2004.

The volatility in quarterly net income over the past two years is partially due to derivative gains/losses, higher operating costs and non-cash charges such as DD&A as well as the timing of certain other cash expenses. Net income for the fourth quarter of 2003 is significantly lower than any other quarter reported over the past two years due to the STIP bonus accrual recorded at December 31.

Cash flow from operations and cash distributions to unitholders have increased steadily since the fourth quarter of 2003. Growth in cash flows has been less than the observed increase in gross oil and gas revenues due to realized derivative losses and higher cash operating costs. Non-cash items such as DD&A, future income taxes, and unrealized gains or losses on derivative instruments do not influence the Trust's ability to distribute cash to unitholders.

Significant corporate and property acquisitions explain the movement in total assets and total long-term debt. Great Northern was acquired in June 2004; CanScot was acquired in September 2003; Nycan Energy in April 2003; and Hawk Oil was acquired in February 2003. The increase in long-term debt at the end of 2004 is the result of the most active capital development program in the Trust's history.

LIQUIDITY AND CAPITAL RESOURCES

WORKING CAPITAL

At December 31, 2004, the Trust had a working capital deficit of approximately $11.99 million as compared to $8.19 million at December 31, 2003. The 46 percent increase is the result of the fourth quarter of 2004 being the Trust's most active drilling quarter since inception. The Trust anticipates cash flow from operations will be sufficient to meet this current deficit.

Included in the calculation of working capital are unrealized derivative instruments measured at fair value and recorded on the balance sheet as a current asset or liability in accordance with EIC 128. At December 31, 2004, a current derivative asset of $3.31 million was recorded on the balance sheet (2003 - $nil) offset by a current derivative liability of $3.14 million (2003 - $nil). The ultimate settlement of these derivative positions is dependent upon changes in commodity prices, foreign currency exchange rates, and interest rates during the remaining life of derivative contracts.

LONG-TERM DEBT

Credit facility

At December 31, 2004, the Trust had a revolving credit and term facility for $200 million (2003 - $150 million) with a syndicate of Canadian financial institutions. The facility may be drawn down or repaid at any time but there are no scheduled repayment terms.

The debt is collateralized by a $300 million demand debenture containing a first fixed charge on all crude oil and natural gas assets of APF as required by the lenders and a floating charge on all other property together with a general assignment of book debts. At December 31, 2004, the interest rate was Bank Prime of 4.25 percent plus 0.125 percent (2003 – 4.50 percent plus 0.125 percent).

Convertible debentures

On July 3, 2003, the Trust issued $50 million of 9.40 percent unsecured subordinated convertible debentures ("convertible debentures") for proceeds of $50 million ($47.68 million net of issue costs). Interest is paid semi-annually on January 31 and July 31 and the instruments mature on July 31, 2008.

The debentures are convertible at the holder's option into fully paid and non-assessable trust units at any time prior to July 31, 2008, at a conversion price of $11.25 per trust unit. The holder will receive accrued and unpaid interest up to and including the conversion date. The Trust can redeem the debentures after July 31, 2006, or earlier under certain circumstances. The convertible debentures become redeemable at $1,050 per convertible debenture, in whole or in part, after July 31, 2006 and redeemable at $1,025 after July 31, 2007 and before maturity.

The following table highlights accretion, conversions and the carrying value of Trust's convertible debentures:

($000s)	Liability Component	Equity Component	Total
Issued on July 3, 2003	48,817	1,183	50,000
Accretion of liability during 2003	89	-	89
Conversions into Trust units during 2003	(1,187)	(29)	(1,216)
Carrying value at December 31, 2003	47,719	1,154	48,873
Accretion of liability during 2004	193	-	193
Conversions into Trust units during 2004	(215)	(5)	(220)
Carrying value at December 31, 2004	**47,697**	**1,149**	**48,846**

UNITHOLDERS' EQUITY

Trust unit offerings

At December 31, 2004, the Trust had 58.85 million Trust units outstanding (2003 – 34.07 million) and a market capitalization of approximately $690 million (2003 - $427 million). During 2004, the Trust completed three trust unit issuances:

Date of Issue	Units Issued	Price per Unit	Gross Proceeds	Use of Proceeds
1. February 4, 2004	4.77 million	$11.60	$55.27	Reduced financial leverage; a portion of proceeds were used to finance Great Northern acquisition.
2. June 4, 2004	12.89 million	$12.18	$156.94	Issued as part of the Great Northern acquisition.
3.September 8, 2004	3.10 million	$11.30	$35.03	Reduced financial leverage and partially fund the Trust's expanded 2004 capital expenditure program.

Distribution reinvestment plan

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

The premium distribution component permits eligible unitholders to elect to receive 102 percent 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. 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 the Trust 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 percent of the outstanding Trust units.

The Trust issued 3.03 million trust units during the year ended December 31, 2004 (2003 – 0.12 million) pursuant to the Premium DRIP, generating $33.89 million in proceeds (2003 – $1.33 million). During the fourth quarter of 2004, the Trust issued 0.89 million Trust units (2003 – 0.12 million) for total proceeds of $9.91 million (2003 – $1.33 million) in respect of the Premium DRIP. Under the Regular DRIP, the Trust issued 0.52 million Trust units during 2004 (2003 – 0.02 million) for proceeds of $5.76 million (2003 - $0.27 million). During the quarter ended December 31, 2004, the Trust issued 0.16 million units (2003 – 0.02 million) for proceeds of $1.81 million (2003 – $0.27 million)

Unitholder distributions

Distributions to unitholders are paid monthly and can fluctuate depending on the cash flow generated from operations. Distributable cash is dependent upon many factors including commodity prices, production levels, debt levels, capital spending requirements, and other market factors. The Trust declared unitholder distributions of $96.93 million, or $2.00 per trust unit during the year ended December 31, 2004 (2003 – $68.71 million or $2.20 per unit). For the quarter ended December 31, 2004, the Trust declared distributions of $28.07 million, or $0.48 per Trust unit (2003 – $17.82 million or $0.53 per unit).

The Trust distributed 90 percent of cash flow from operations for both the three months and year ended December 31, 2004 as compared to 120 percent and 85 percent for the three months and the year ended December 31, 2003.

Taxation of unitholder distributions

Distributions to unitholders have two components for taxation purposes: the taxable return on capital portion and the tax deferred return of capital. The return on capital is considered taxable to unitholders whereas the return of capital reduces the adjusted cost base of the unit each time a distribution is received. The following table summarizes the components of annual distributions paid by the Trust since inception:

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
2004	**$1.374**	**$0.636**	**$2.010**	**68.345%**	**31.655%**
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%
	$8.733	$7.107	$15.840		

Distribution payments to U.S. resident unitholders are subject to 15 percent Canadian withholding tax, which is deducted from the distribution amount prior to deposit into accounts.

CAPITAL EXPENDITURES

Net capital expenditures for the year ended December 31, 2004 totalled $369.71 million (2003 - $191.18 million). The current year includes the $291.08 million gross acquisition cost of Great Northern and the comparative year reflects the gross acquisition cost of Hawk Oil Inc. ($49.70 million), Nycan Energy Corp. ($42.44 million), and CanScot Resources Ltd. ($42.08 million). Overall, the aggregate value of corporate acquisitions during 2004 exceeded 2003 levels by $156.86 million. The $24.13 million increase in seismic, drilling and completions, and production facilities over 2003 is attributable to a larger asset base and development opportunities resulting from the aforementioned acquisitions completed in 2003 and 2004.

Given the magnitude of corporate acquisitions during 2004, fewer property acquisitions were completed as compared to 2003, during which the Trust had acquired incremental production at Countess for $7.03 million and an interest in Swan Hills Unit No. 1 for $15.90 million. Conversely, the Trust was more active at crown land sales during 2004 in order to continue to build high-quality drilling prospects so that production and reserves can be added independent of acquisition activity.

Net capital expenditures for the quarter increased to $39.25 million from $8.59 million during the same period in 2003 and is explained by the fact that the three months ended December 31, 2004 was the Trust's most active quarter for drilling and development since inception, as the Trust capitalized on the drilling opportunities associated with the Great Northern acquisition.

	Three Months Ended December 31		Twelve Months Ended December 31	
($000)	**2004**	2003	**2004**	2003
Corporate acquisitions	**-**	-	**291,084**	137,622
Property acquisitions	**3,764**	3,107	**10,351**	26,928
Land acquisitions	**4,248**	487	**10,344**	2,310
Seismic	**2,991**	96	**4,561**	1,070
Drilling and completions	**22,291**	8,519	**41,449**	24,287
Production facilities	**5,621**	3,216	**11,222**	7,749
Head office	**643**	116	**1,203**	494
Subtotal	**39,559**	15,541	**370,214**	200,460
Dispositions	**(306)**	(6,953)	**(505)**	(9,284)
Net capital expenditures	**39,253**	8,588	**369,709**	191,176

CONTRACTUAL OBLIGATIONS AND CONTINGENCIES

The Trust is involved in certain legal actions that occurred in the normal course of business. The Trust is required to determine whether a contingent loss is probable and whether that loss can be reasonably estimated. When the loss has satisfied both criteria, it is charged to net income. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

The Trust leases its office premises through an arrangement deemed to be an operating lease for accounting purposes. As such, the Trust is not required to record its lease obligation as a liability nor does it record its leased premises as an asset. The estimated operating lease commitments for the Trust's leased office premises for the next five years are as follows:

($000)	
2005	1,398
2006	1,213
2007	1,252
2008	1,083
2009	934
Thereafter	934

RISK MANAGEMENT

The Trust's objective is to provide unitholders with stable cash distributions and strong overall returns. APF is committed to full-cycle internal development opportunities and selectively pursuing acquisitions identified to be accretive on a per unit basis to cash flow, production, reserves, and net asset value as a means to achieving its objectives. The Trust has established a risk management framework in order to mitigate risks inherent in the oil and gas sector.

Commodity price risk
Commodity price risk is defined as fluctuations in crude oil, natural gas, and natural gas liquid prices. The Trust uses derivative instruments as part of its risk management approach to manage commodity price fluctuations and stabilize cash flows available for unitholder distributions and future development programs. At December 31, 2004, the Trust had recorded a $2.30 million unrealized loss on outstanding crude oil derivative instruments and a $2.06 million unrealized gain on outstanding natural gas derivative instruments.

Crude oil and natural gas derivative instruments outstanding at the end of 2004 are as follows:

Period	Commodity	Type of Contract	Average Daily Quantity	Average Daily Price per bbl/GJ,mmbtu
January to March 2005	Crude oil	Swap	1,500 bbls	U.S.$35.78
January to March 2005	Crude oil	Collar	1,000 bbls	U.S.$38.00 to U.S.$44.95
January to March 2005	Crude oil	Sold Call	500 bbls	U.S.$42.37 (U.S.$3.19 premium)
April to June 2005	Crude oil	Swap	667 bbls	U.S.$36.66
April to June 2005	Crude oil	Collar	2,000 bbls	U.S.$39.25 to U.S.$44.94
April to June 2005	Crude oil	Sold Call	500 bbls	U.S.$40.95 (U.S.$3.45 premium)
July to September 2005	Crude oil	Collar	1,000 bbls	U.S.$41.00 to U.S.$51.30
January to March 2005	Natural gas	Sold Call	5,000 GJ	Cdn.$11.80
January to March 2005	Natural gas	Collar	5,000 GJ	Cdn.$7.00 to Cdn.$11.35
April to October 2005	Natural gas	Collar	5,000 mmbtu	U.S.$6.50 to U.S.$6.90
April to October 2005	Natural gas	Collar	10,000 GJ	Cdn.$6.25 to Cdn.$7.20

The following contracts were entered into subsequent to December 31, 2004:

Period	Commodity	Type of Contract	Average Daily Quantity	Average Daily Price per Unit
April to June 2005	Crude oil	Collar	1,000 bbls	U.S.$43.00 to U.S.$51.65
July to September 2005	Crude oil	Collar	2,500 bbls	U.S.$44.00 to U.S.$50.99
October to December 2005	Crude oil	Collar	1,500 bbls	U.S.$44.00 to U.S.$51.82
January to March 2006	Crude oil	Collar	2,000 bbls	U.S.$44.00 to U.S.$51.28
April to June 2006	Crude oil	Collar	500 bbls	U.S.$44.00 to U.S.$50.60
April to October 2005	Natural gas	Collar	10,000 GJ	Cdn.$6.00 to Cdn.$7.30
November 2005 to March 2006	Natural gas	Collar	10,000 GJ	Cdn.$6.50 to Cdn.$9.90

Electricity price risk

Electricity price risk is defined as fluctuations in input power prices charged to operating costs. The Trust's electricity cost management activities had an unrealized gain of $0.03 million at year-end. APF had assumed a fixed price electricity contract through the acquisition of Great Northern. At December 31, 2004, the Trust had a 2MW (7x24) contract with a fixed price of $46.40/MWh for calendar 2005; the forward price in the market for calendar 2005 was $49.00/MWh.

Foreign currency risk

Foreign currency risk is the risk that a variation in the U.S.$/Cdn.$ exchange rate will negatively impact the Trust's operating and financial results. The Trust's currency risk management activities had an unrealized gain of $1.10 million at December 31, 2004. The derivative instruments currently outstanding are as follows:

Term	Type of Contract	Amount (U.S.$000)	Exchange Rate (U.S.$/Cdn.$)
January to April 2005	Forward	5,000	1.3550
January to April 2005	Forward	5,000	1.3680
January to December 2005	Collar	5,000	1.2300 to 1.2700
January to December 2005	Collar	10,000	1.2000 to 1.2600
February to December 2005	Collar	10,000	1.2300 to 1.2700

The costless collar arrangements have counterparty call options on December 30, 2005 whereby the Trust's counterparty can extend the contract term for calendar 2006 at an average rate of 1.2740.

Interest rate risk
Interest rate risk is the risk that variations in interest rates will negatively impact the Trust's financial results. The Trust had entered into various derivative instruments to manage its interest rate exposure on debt instruments. At December 31, 2004 the Trust's interest rate risk management activities had an unrealized loss of $0.67 million related to the following fixed rate contracts:

Term	Amount ($000)	Interest rate
January 2005 to November 2005	20,000	3.58% plus stamping fee
January 2005 to May 2006	20,000	3.60% plus stamping fee
January 2005 to March 2007	20,000	3.58% plus stamping fee
January 2005 to September 2007	20,000	3.65% plus stamping fee

Production risk
Production risk relates to the Trust's ability to produce, process and transport crude oil and natural gas. To manage this risk to an acceptable level, the Trust performs regular and proactive maintenance on its wells, facilities and pipelines. The Trust operates approximately 85 percent of its production, which affords greater control over operations.

Natural decline and reserve replacement risk
Natural decline risk relates to the Trust's ability to replace reserves in excess of annual production declines through development activities such as drilling, well completions, well workovers and other capital activities. The Trust manages its business using a portfolio approach whereby capital is allocated across a number of areas so that significant capital is not risked on any one activity. Capital is spent only after strict economic criteria for production and reserve additions are assessed.

The Trust's reserves are evaluated on an annual basis by independent third-party consultants reporting to the Trust's Audit and Reserves Committee of the Board of Directors. The Trust's approach is to invest in mature, long-life properties with a high proved producing component combined with low-risk development opportunities where the reserve risk is generally lower and cash flows are more stable and predictable.

Acquisition risk
Acquisition risk arises when the Trust acquires producing properties as a means to growing its asset base. The Trust is proactive in seeking out corporate or property transactions that will be accretive on a per unit basis to cash flow, production, reserves, and net asset value. The cross-functional acquisition teams identify opportunities for value enhancement through operational efficiencies or strategic fit, and evaluate estimates against established acquisition and economic hurdle rates.

Environmental health and safety risk
Environment, health and safety risks relate primarily to field operations associated with oil and gas assets. To mitigate this risk, a preventative environmental, health and safety program is in place as well as operational loss insurance coverage. APF employees and contractors adhere to APF's environment, health and safety program, which is routinely reviewed and updated to ensure the Trust operates in a manner consistent with best practices in the industry. The Board of Directors is actively involved in the risk assessment and risk mitigation process.

Regulation, tax and royalty risk
Regulation, tax and royalty risk relates to changing government royalty regulations, income tax laws and incentive programs impacting the Trust's financial and operating results. The tax efficiency of the royalty trust model is contingent upon its status as a mutual fund trust under Canadian tax laws and, therefore, may be subject to unanticipated legislative and/or regulatory modification. Management and oversight committees, with the assistance of legal counsel, stay informed of proposed changes in laws and regulations and proactively respond to and plan for the effects that these changes.

Capital market risk
APF's ability to maintain its financial strength and liquidity is dependent upon its ability to access Canadian capital markets. If Canadian debt or equity markets were to become less accessible to the Trust, it may affect the ability of APF to continue to replace production and maintain distributions.

SIGNIFICANT ACCOUNTING POLICIES AND ESTIMATES

CONSOLIDATION

These consolidated financial statements include the accounts of the Trust, Energy, LP and Tika and are referred to collectively as "APF" or "the Trust". Investments in jointly controlled companies and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Trust's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

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.

PROPERTY, PLANT, AND EQUIPMENT

APF uses the full cost method for oil and gas exploration, development and production activities as set out in CICA Accounting Guideline 16 ("AcG-16"), "Oil and Gas Accounting – Full Cost". The cost of acquiring oil and natural gas properties as well as subsequent development costs are capitalized and accumulated in a cost center. Maintenance and repairs are charged against income, 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 at least 20 percent.

AcG-16 requires that a ceiling test be performed at least annually to assess the carrying value of oil and gas assets. A cost center is tested for recoverability using undiscounted future cash flows from proved reserves and forward indexed commodity prices, adjusted for contractual obligations and product quality differentials. A cost center is written down to its fair value when its carrying value, less the cost of unproved properties, is in excess of the related undiscounted cash flows. Fair value is estimated using accepted present value techniques that incorporate risk and uncertainty when determining expected future cash flows. Unproved properties are excluded from the ceiling test calculation and subject to a separate impairment test.

DEPRECIATION, DEPLETION, AND ACCRETION

In accordance with the full cost accounting method, all crude oil and natural gas acquisition, exploration, and development costs, including asset retirement costs, are accumulated in a cost center. The aggregate of net capitalized costs and estimated future development costs, less the cost of unproved properties and estimated salvage value, is amortized using the unit-of-production method based on current period production and estimated proved oil and gas reserves calculated using constant prices.

All other equipment is depreciated over the estimated useful life of the respective assets.

OIL AND GAS RESERVES

The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity prices, and consider the timing of future expenditures. The Trust expects reserve estimates to be revised based on the results of future drilling activity, testing, production levels, and economics of recovery based on cash flow forecasts.

GOODWILL

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Net identifiable liabilities acquired include an estimate of future income taxes. In accordance with CICA Handbook Section 3062 ("HB 3062"), "Goodwill and Other Intangibles", goodwill for the reporting unit, the consolidated Trust, is tested at least annually for impairment. Impairment is charged to income during the period in which it is deemed to have occurred.

The test for impairment is the comparison of the book value of net assets to the fair value of the Trust. If the fair value of the Trust is less than its book value, the impairment loss is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. The excess of the Trust's fair value over the identifiable net assets is the implied fair value of goodwill. If this amount is less than the book value of goodwill, the difference is the impairment amount and would be charged to income during the period.

INCOME TAXES

The Trust is an inter vivos trust for income tax purposes. As such, the Trust is taxable on income that is not distributed or distributable to unitholders. As the Trust distributes all of its taxable income to the unitholders no current provision for income taxes has been recorded. Should the Trust incur any income taxes, the funds available for distribution would be reduced accordingly.

The provision for income taxes is recorded in Energy using the liability method of accounting for income taxes. Future income taxes are recorded to the extent the accounting bases of assets and liabilities differ from their corresponding tax values using substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted during the period with the adjustment recognized in net income.

The determination of the Trust's income and other tax liabilities are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, actual income tax liabilities or recoveries may differ significantly from estimates.

COMMITMENTS AND CONTINGENCIES

APF is involved in various legal claims associated with the normal course of operations. APF is required to determine whether a contingent loss is probable and whether that loss can be reasonably estimated. When the loss has satisfied both criteria it is charged to net income. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

CHANGES IN ACCOUNTING POLICIES AND ESTIMATES

ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2004, APF retroactively adopted CICA Handbook Section 3110, "Asset Retirement Obligations" (ARO). The new standard requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made.

The present value of the asset retirement obligation is recognized as a liability with the corresponding asset retirement cost capitalized as part of property, plant and equipment. The asset retirement obligation will increase over time due to accretion and the asset retirement cost will be depreciated on a basis consistent with depreciation and depletion. APF previously used the unit-of-production method to match estimated future retirement costs with the revenues generated over the life of the petroleum and natural gas properties based on total estimated proved reserves and an estimated future liability.

The impact of this change has been disclosed in Note 3 to the consolidated financial statements.

COMPENSATION EXPENSE

Effective December 31, 2003, APF prospectively adopted CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments." The standard requires that equity instruments awarded to employees after December 31, 2002 be measured at fair value and recognized over the related period of service ("vesting period") with a corresponding increase to contributed surplus. When rights are exercised by employees and directors of the Trust, the consideration paid is recorded to the unitholders' investment account along with related non-cash compensation expense previously recognized in contributed surplus.

APF has established a Trust Units Options Plan (the "Plan") and a Trust Unit Incentive Rights Plan (the "Rights Plan") for employees and independent directors that are described in Note 13 to the financial statements. The exercise price of the rights granted under the Rights Plan may be reduced in future periods based on future operating performance in accordance with the terms of the Rights Plan. The Trust uses a Black-Scholes option-pricing model to estimate the fair value of rights awarded under the Rights Plan as at the grant date. The fair value ascribed to awarded rights is not subsequently revised for any change in underlying assumptions. Compensation expense is adjusted prospectively for rights cancelled under the Rights Plan during the period.

Details of both the Options Plan and Rights Plan are disclosed in Note 13 and the impact of this change has been disclosed in Note 3 to the consolidated financial statements.

DERIVATIVE INSTRUMENTS AND HEDGING RELATIONSHIPS

Effective January 1, 2004, APF prospectively adopted CICA Accounting Guideline 13 ("AcG-13"), "Hedging Relationships" and the amended Emerging Issues Committee 126 ("EIC-126"), "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments". In accordance with the new guideline, all unrealized derivative instruments that either do not qualify as a hedge under AcG-13, or are not designated as a hedge, are recorded as a derivative asset or a derivative liability on the consolidated balance sheet with any changes in fair value during the period recognized in income. Prior to January 1, 2004, the Trust recognized gains and losses on derivative contracts at the time of settlement.

In order to apply hedge accounting, an entity must formally document the hedging arrangement and sufficiently demonstrate the effectiveness of the hedging relationship. Based on a review of the Trust's derivative position at January 1, 2004, the majority of derivative contracts did not qualify for hedge accounting.

APF's mark-to-market position on derivative contracts is disclosed in Note 7 and the transitional impact of this change has been disclosed in Note 3 to the consolidated financial statements.

FINANCIAL INSTRUMENTS WITH A CONVERSION FEATURE

Effective December 31, 2004, APF retroactively adopted the revised CICA Handbook Section 3860 ("HB 3860"), "Financial Instruments - Presentation and Disclosure" for financial instruments that may be settled at the issuer's option in cash or its own equity instruments. The revised standard requires APF to classify the convertible debenture proceeds as either debt or equity based on fair value measurement and the substance of the contractual arrangement. The Trust previously presented the convertible debenture proceeds (net of financing costs) and related interest obligations as equity on the consolidated balance sheet on the basis that the Trust could settle its obligations in exchange for trust units.

The Trust's obligation to make scheduled payments of principal and interest constitutes a financial liability under the revised standard and exists until the instrument is either converted or redeemed. The holders' option to convert the financial liability into trust units is an embedded conversion option. The conversion option is presented as equity because it is the initial value ascribed to the holders' right to convert a financial liability into trust units at the date of issuance. The sum of the liability and equity components is equal to the $50.0 million proceeds received from the convertible debenture issuance. Details of the convertible debentures are disclosed in Note 10 and the impact of this change on prior periods presented has been disclosed in Note 3 to the consolidated financial statements.

OUTLOOK

STRATEGY

APF emphasizes a full-cycle approach to its business and plans to continue with internal development opportunities as a means to enhancing its production base and ultimately creating value for unitholders. Consistent with its full-cycle approach, APF actively added to its undeveloped land position through crown land sales during 2004 in order to establish high-quality drilling prospects. The objective is to position APF so that production and reserves can be added independent of acquisition activity. In that regard, the Trust's ability to add production through the drill bit creates a competitive advantage over those competitors that have depleted their development inventories and are reliant upon acquisitions to build or maintain their production base.

APF will continue to pursue acquisitions that will be accretive on a per unit basis to cash flow, production, reserves and net asset value. APF is committed to maintaining stable cash distributions over the long-term. In order to mitigate the commodity price risk that is inherent to the oil and gas sector, APF will continue to actively hedge commodity prices. APF believes that over the long term, outlook for both crude oil and natural gas pricing remains strong.

2005 CAPITAL INVESTMENT AND DEVELOPMENT ACTIVITIES

Based on current estimates and assumptions, APF plans to focus its 2005 capital program in the following manner:

Business Unit ($000)	Drilling & Development	Land & Seismic	Total
Southeast Saskatchewan	8,554	1,300	9,854
Southern	7,952	2,000	9,952
Central	11,394	1,035	12,429
Western	5,781	3,300	9,081
CBM - Alberta	15,289	375	15,664
CBM - Wyoming	4,483	-	4,483
Total	**53,453**	**8,010**	**61,463**

In addition, the Trust anticipates spending $2.80 million on environmental health and safety initiatives throughout the year.

The Trust expects its 2005 core capital investment program to be funded from its DRIP, cash flow and proceeds from the divestiture of non-core assets.

Recent land acquisitions within the Western Business Unit ("Western") complement ongoing and planned internal development activities at APF's Paddle River properties. Coalbed methane opportunities exist in the Upper Mannville formation and APF is currently in the de-watering process at Corbett Creek.

The Central Business Unit ("Central") contains a large inventory of conventional and unconventional drilling opportunities. APF will continue to exploit new opportunities and undeveloped acres while continuing to focus internal development capital on the core Innisfail asset. CBM activity in the Horseshoe Canyon coals is expected to increase as APF continues to build its unconventional asset base.

A significant percentage of the upcoming year's capital budget will be targeted at Queensdale and Handsworth located within the Southeast Saskatchewan Business Unit ("Southeast Saskatchewan"). This area has historically generated excellent operating results and full cycle investment returns and is capable of generating excellent economics despite high natural decline rates.

APF is most active in its Southern Business Unit ("Southern"). The historical focus has been low productivity, long life shallow gas in the Milk River and Medicine Hat formations. Future development will move beyond shallow gas drilling to include deeper prospects at Countess, Turin and Carmangay.

2005 PRODUCTION VOLUMES

The production outlook for 2005 will be principally impacted by weather, timing of new production and drilling activity. APF expects to average 18,000 to 18,500 boe/d of production based on its capital budget of $61.46 million for fiscal 2005. Assumptions include drilling costs, well performance, operating costs, projected sales volumes, interest rates, foreign currency exchange rates and other factors that impact operations. These inputs can change significantly as a result of actual events and may result in material variances from the Trust's estimates.

The following tables provide projected estimates for 2005 of the sensitivity of the Trust's 2005 cash flow to changes in a number of variables:

Variable	Assumption	Change	Impact on annual cash flow ($000)	Impact on cash flow per unit
Crude oil price ($U.S./bbl)	$ 42.00	$ 1.00	$ 3,010	$ 0.05
Natural gas price ($Cdn./mcf)	$ 6.60	$ 0.10	$ 1,730	$ 0.03
U.S.$/Cdn.$ exchange rate	$ 0.82	$ 0.01	$ 1,540	$ 0.02
Interest rate	5.0%	1.0%	$ 2,010	$ 0.03
Crude oil production (bbl/d)	8,500	100 bbl/d	$ 890	$ 0.01
Natural gas production (mcf/d)	58,000	1,000 mcf/d	$ 1,360	$ 0.02

CONSOLIDATED BALANCE SHEET

($000s except for per unit amounts)

As at December 31 (unaudited)	2004	2003 Restated (note 3)
ASSETS		
Current assets		
Cash	**567**	1,381
Accounts receivable	**42,200**	27,542
Derivative asset (note 7)	**3,313**	-
Other current assets	**7,162**	5,549
	53,242	34,472
Asset retirement fund	**3,271**	2,342
Goodwill (note 5)	**118,478**	48,230
Property, plant and equipment (note 6)	**687,179**	413,706
	862,170	498,750
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**52,677**	36,698
Derivative liability (note 7)	**3,141**	-
Distribution payable (note 4)	**9,415**	5,963
	65,233	42,661
Future income taxes (note 9)	**86,711**	63,991
Long-term debt (note 8)	**169,000**	98,000
Convertible debentures (note 10)	**47,697**	47,719
Asset retirement obligations (note 11)	**30,993**	21,803
Derivative liability (note 7)	**335**	-
	399,969	274,174
UNITHOLDERS' EQUITY		
Unitholders' investment account (note 12)	**610,194**	324,318
Contributed surplus (note 13)	**289**	1,241
Accumulated earnings	**126,862**	77,226
Accumulated distributions (note 4)	**(276,293)**	(179,363)
Convertible debenture conversion feature (note 10)	**1,149**	1,154
	462,201	224,576
	862,170	498,750

Contractual obligations and commitments (note 16)
See accompanying notes to consolidated financial statements

Approved by the Board of Directors

Martin Hislop
Director

Donald Engle
Director

CONSOLIDATED STATEMENT OF OPERATIONS AND ACCUMULATED EARNINGS

($000s except for per unit amounts)

For the year ended December 31 (unaudited)		2004		2003
				Restated (note 3)
REVENUE				
Oil and gas		**253,213**		173,196
Realized derivative loss - net (note 7)		**(16,329)**		(3,565)
Unrealized derivative gain - net (note 7)		**223**		-
Royalties expense, net of ARTC		**(47,710)**		(32,473)
Transportation		**(5,245)**		(4,174)
		184,152		132,984
EXPENSES				
Operating		**51,788**		32,370
General and administrative		**10,635**		10,023
Interest on long-term debt (note 8)		**5,405**		4,171
Convertible debenture interest and financing charges (note 10)		**5,263**		2,669
Depletion, depreciation and accretion		**85,997**		53,389
Unit-based compensation expense (recovery) (note 13)		**(877)**		1,241
Capital and other taxes		**3,321**		2,720
		161,532		106,583
Income before future income taxes		**22,620**		26,401
Recovery of future income taxes (note 9)		**(27,016)**		(14,207)
Net income		**49,636**		40,608
Accumulated earnings - beginning of period, as previously reported		**77,226**		35,589
Change in accounting policy (note 3)		**-**		1,029
Accumulated earnings - end of period, as restated		**126,862**		77,226
Net income per unit - basic	**$**	**1.02**	$	1.31
Net income per unit - diluted [1]	**$**	**1.02**	$	1.29

[1] Convertible debenture interest has been added back to net income to calculate net income per unit – diluted.

See accompanying notes to consolidated financial statements

CONSOLIDATED STATEMENT OF CASH FLOWS

(S000s except for per unit amounts)

For the year ended December 31 (unaudited)	2004	2003
		Restated (note 3)
Cash flows from operating activities		
Net income	**49,636**	40,608
Items not affecting cash		
Depletion, depreciation and accretion	**85,997**	53,389
Debenture accretion and amortization of deferred financing charges	**692**	362
Future income taxes	**(27,016)**	(14,207)
Unrealized derivative gain - net (note 7)	**(223)**	-
Unit-based compensation expense (recovery) (note 13)	**(877)**	1,241
Asset retirement expenditures (note 11)	**(1,083)**	(374)
Cash flow from operations	**107,126**	81,019
Net change in non-cash working capital items (note 15)	**(10,473)**	5,823
Asset retirement fund contribution - net	**(929)**	(1,558)
Net cash provided by operating activities	**95,724**	85,284
Cash flows from investing activities		
Corporate acquisitions (note 5)	**(65,405)**	(58,259)
Additions to property, plant and equipment	**(68,779)**	(33,601)
Purchase of oil and natural gas properties	**(10,351)**	(29,238)
Proceeds on sale of properties	**505**	9,284
Changes in non-cash working capital - investing items	**5,205**	2,961
Net cash used in investing activities	**(138,825)**	(108,853)
Cash flows from financing activities		
Issue of units for cash	**90,451**	55,670
Issue of units for cash under DRIP	**33,895**	1,329
Issue of units for cash upon exercise of stock options/rights	**3,799**	1,749
Net proceeds (repayment) of convertible debentures	**-**	47,681
Unit issue costs	**(5,270)**	(3,467)
Net proceeds (repayment) of long-term debt	**7,126**	(12,920)
Cash distributions, net of distribution reinvestment	**(91,166)**	(68,440)
Changes in non-cash working capital - financing items	**3,452**	2,398
Net cash provided by financing activities	**42,287**	24,000
Change in cash during the period	**(814)**	431
Cash - Beginning of period	**1,381**	950
Cash - End of period	**567**	1,381

Supplemental information (note 14)

See accompanying notes to consolidated financial statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2004 and 2003 (unaudited)

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" or "the Trust". Investments in jointly controlled companies and unincorporated joint ventures are accounted for using the proportionate consolidation method, whereby the Trust's proportionate share of revenues, expenses, assets and liabilities are included in the accounts.

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.

Property, plant and equipment
APF uses the full cost accounting method for oil and gas exploration, development and production activities as set out in CICA Accounting Guideline 16 ("AcG-16"), "Oil and Gas Accounting – Full Cost". The cost of acquiring oil and natural gas properties as well as subsequent development costs are capitalized and accumulated in a cost center. Maintenance and repairs are charged against income, 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 at least 20 percent.

All other equipment is carried at the lesser of depreciated cost and fair value.

Ceiling test
AcG-16 requires that a ceiling test be performed at least annually to assess the carrying value of oil and gas assets. A cost centre is tested for recoverability using undiscounted future cash flows from proved reserves and forward indexed commodity prices, adjusted for contractual obligations and product quality differentials. A cost centre is written down to its fair value when its carrying value, less the cost of unproved properties, is in excess of the related undiscounted cash flows. Fair value is estimated using accepted present value techniques that incorporate risk and uncertainty when determining expected future cash flows. Unproved properties are excluded from the ceiling test calculation and subject to a separate impairment test.

Depletion, depreciation and accretion
In accordance with the full cost accounting method, all crude oil and natural gas acquisition, exploration, and development costs, including asset retirement costs, are accumulated in a cost center. The aggregate of net capitalized costs and estimated future development costs, less the cost of unproved properties and estimated salvage value, is amortized using the unit-of-production method based on current period production and estimated proved oil and gas reserves calculated using constant prices.

All other equipment is depreciated over the estimated useful life of the respective assets.

Oil and gas reserves
The estimation of reserves is a subjective process. Forecasts are based on engineering data, projected future rates of production, estimated commodity prices, and consider the timing of future expenditures. The Trust expects reserve estimates to be revised based on the results of future drilling activity, testing, production levels, and economics of recovery based on cash flow forecasts.

Goodwill
Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the fair value of the net identifiable assets and liabilities of the acquired business. Net identifiable liabilities acquired include an estimate of future income taxes. In accordance with CICA Handbook Section 3062 ("HB 3062"), "Goodwill and Other Intangibles", goodwill for the reporting unit, the consolidated Trust, is tested at least annually for impairment. Impairment is charged to income during the period in which it is deemed to have occurred.

The test for impairment is the comparison of the book value of net assets to the fair value of the Trust. If the fair value of the Trust is less than its book value, the impairment loss is measured by allocating the fair value of the Trust to the identifiable assets and liabilities at their fair values. The excess of the Trust's fair value over the identifiable net assets is the implied fair value of goodwill. If this amount is less than the book value of goodwill, the difference is the impairment amount and would be charged to income during the period.

Unit-based compensation expense
Effective December 31, 2003, the Trust prospectively adopted CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments." The standard requires that equity instruments awarded to employees after December 31, 2002 be measured at fair value and recognized over the related vesting period with a corresponding increase to contributed surplus. When rights are exercised by employees and directors of the Trust, the consideration paid is recorded to the unitholders' investment account along with related non-cash compensation expense previously recognized in contributed surplus.

APF has established a Trust Units Options Plan (the "Plan") and a Trust Unit Incentive Rights Plan (the "Rights Plan") for employees and independent directors that are described in Note 13. The exercise price of the rights granted under the Rights Plan may be reduced in future periods based on future operating performance in accordance with the terms of the Rights Plan. The Trust uses a Black-Scholes option-pricing model to estimate the fair value of rights awarded under the Rights Plan at the grant date. The fair value ascribed to awarded rights is not subsequently revised for any change in underlying assumptions. Unit-based compensation expense is adjusted prospectively for rights cancelled under the Rights Plan during the period.

The new accounting standard resulted in the Trust recognizing an expense of $1.24 million for the year ended December 31, 2003 with a corresponding increase to contributed surplus. In conformity with the amended accounting standard, the Trust has elected to disclose pro forma results for equity instruments awarded to employees prior to January 1, 2003 as if CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" had been adopted retroactively.

There was no impact on the Trust's cash flow as a result of adopting the new standard. See Note 13 for additional information on compensation plans.

Income taxes
The Trust is an inter vivos trust for income tax purposes. As such, the Trust is taxable on income that is not distributed or distributable to unitholders. As the Trust distributes all of its taxable income to the unitholders no current provision for income taxes has been recorded. Should the Trust incur any income taxes, the funds available for distribution would be reduced accordingly.

The provision for income taxes is recorded in Energy using the liability method of accounting for income taxes. Future income taxes are recorded to the extent the accounting bases of assets and liabilities differ from their corresponding tax values using substantively enacted income tax rates. Accumulated future income tax balances are adjusted to reflect changes in income tax rates that are substantively enacted during the period with the adjustment recognized in net income.

The determination of the Trust's income and other tax liabilities are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, actual income tax liabilities or recoveries may differ significantly from estimates.

Trust unit calculations

The Trust applies the treasury stock method to determine the dilutive effect of trust unit rights and trust unit options. Under the treasury stock method, outstanding and exercisable instruments that will have a dilutive effect are included in per unit – diluted calculations, ordered from most dilutive to least dilutive.

The dilutive effect of convertible debentures is determined using the "if-converted" method whereby if the current market price per unit is in excess of the stated conversion price per unit the weighted-average number of potential units assumed issued are included in the per unit – diluted calculations. The units issued upon conversion are included in the denominator of per unit – basic calculations from the date of conversion. Consequently, units assumed issued are weighted for the period the convertible debentures were outstanding, and units actually issued are weighted for the period the units were outstanding.

Measurement uncertainty

The timely preparation of financial statements in conformity with Canadian generally accepted accounting principles ("GAAP") requires that management make estimates and assumptions and use judgment regarding assets, liabilities, revenues, and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, actual results may differ from estimated amounts as future confirming events occur.

Amounts recorded for depreciation, depletion, and amortization, asset retirement costs and obligations, and amounts used for ceiling test and impairment calculations are based on estimates of oil and natural gas reserves and future costs required to develop those reserves. By their nature, these estimates are subject to measurement uncertainty, and the impact on the financial statements of future periods could be material.

3. CHANGES IN ACCOUNTING POLICIES

Asset retirement obligations

Effective January 1, 2004, the Trust retroactively adopted CICA Handbook Section 3110, "Asset Retirement Obligations" (ARO). The standard requires that the fair value of an asset retirement obligation be recognized in the period in which it is incurred. The present value of the asset retirement obligation is recognized as a liability with the corresponding asset retirement cost capitalized as part of property, plant and equipment. The asset retirement obligation will increase over time due to accretion and the asset retirement cost will be depreciated on a basis consistent with depreciation and depletion. APF previously used the unit-of-production method to match estimated future retirement costs with the revenues generated over the life of the petroleum and natural gas properties based on total estimated proved reserves and an estimated future liability.

The following table summarizes the impact of the new standard on the 2003 comparative period:

	As at and for the year ended December 31, 2003		
($000s except for per unit amounts)	As reported	Change	As restated
Consolidated Balance Sheet			
Assets			
Property, plant, and equipment	401,286	12,420	413,706
Liabilities			
Future income taxes	64,222	(231)	63,991
Asset retirement obligation	-	21,803	21,803
Site restoration liability	10,410	(10,410)	-
Unitholders' Equity			
Opening accumulated earnings	35,589	1,029	36,618
Consolidated Statement of Operations			
Depletion, depreciation, and accretion	50,417	2,972	53,389
Site restoration	3,327	(3,327)	-
Recovery of future income taxes	(14,333)	126	(14,207)

See Note 11 for additional information on asset retirement obligations.

Derivative instruments and hedging relationships

Effective January 1, 2004, the Trust prospectively adopted CICA Accounting Guideline 13 ("AcG-13"), "Hedging Relationships" and the amended Emerging Issues Committee Abstract 128, "Accounting for Trading, Speculative or Non Trading Derivative Financial Instruments". In accordance with these standards, all unrealized derivative instruments that either do not qualify as a hedge under AcG-13, or are not designated as a hedge, are recorded as a derivative asset or a derivative liability on the consolidated balance sheet with any changes in fair value during the period recognized in income. Prior to January 1, 2004, the Trust recognized gains and losses on derivative contracts at the time of settlement.

In order to apply hedge accounting, an entity must formally document the hedging arrangement and sufficiently demonstrate the effectiveness of the hedging relationship. Based on a review of the Trust's derivative position at January 1, 2004, the majority of derivative contracts did not qualify for hedge accounting. Consequently, the Trust recorded $1.30 million liability as an estimate for the fair value of its derivative position on January 1, 2004, which was comprised of a $0.40 million unrealized loss on crude oil and natural gas derivative instruments and a $0.90 million unrealized loss on interest rate swaps. In accordance with the transitional provisions of the new guideline, the Trust recorded a corresponding deferred derivative loss, which was amortized into income during 2004 upon settlement of the underlying derivative instruments. There was no impact on the Trust's cash flow as a result of adopting this new guideline. See Note 7 for additional disclosure on derivative instruments.

Financial instruments with a conversion feature

Effective December 31, 2004, the Trust retroactively adopted the revised CICA Handbook Section 3860 ("HB 3860"), "Financial Instruments - Presentation and Disclosure" for financial instruments that may be settled at the issuer's option in cash or its own equity. The revised standard requires the Trust to classify proceeds from convertible debentures issued on July 3, 2003 as either debt or equity based on fair value measurement and the substance of the contractual arrangement. The Trust previously presented the convertible debenture proceeds (net of financing costs) and related interest obligations as equity on the consolidated balance sheet on the basis that the Trust could settle its obligations in exchange for trust units.

The Trust's obligation to make scheduled payments of principal and interest constitutes a financial liability under the revised standard and exists until the instrument is either converted or redeemed. The holders' option to convert the financial liability into trust units is an embedded conversion option. Gross proceeds of $50 million received at issuance were allocated $48.82 million to debt and $1.18 million to the equity conversion feature. At December 31, 2003, after conversions and accretion, the debt component was $47.72 million and the equity component was $1.15 million. Underwriter costs and professional fees associated with the issuance totalled $2.32 million and will be amortized into income on a straight-line basis over the term of the instrument. At December 31, 2003, $2.04 million was included in other current assets.

The following table summarizes the impact of the revised standard on the 2003 comparative period:

	As at and for the year ended December 31, 2003		
($000s except for per unit amounts)	As reported	Change	As restated
Consolidated Balance Sheet			
Assets			
Other current assets (includes deferred financing)	3,506	2,043	5,549
	3,506	2,043	5,549
Liabilities			
Accounts payable and accrued liabilities	36,711	(13)	36,698
Convertible debentures	-	47,719	47,719
	36,711	47,706	84,417
Unitholders' Equity			
Unitholders investment account	324,317	1	324,318
Convertible debentures	46,466	(46,466)	-
Accumulated interest on convertible debentures	(2,317)	2,317	-
Convertible debenture conversion feature	-	1,154	1,154
	368,466	(42,994)	325,472
Consolidated Statement of Operations			
Convertible debenture interest and financing charges	-	2,669	2,669

There was no impact on the Trust's cash flow as a result of adopting the revised standard. See Note 10 for additional information on convertible debentures.

4. DISTRIBUTIONS

	For the year ended December 31	
($000s except for per unit amounts)	**2004**	2003
		Restated (note 3)
Cash flow from operations	**107,126**	81,019
Add (deduct):		
Abandonment fund contributions	**(2,012)**	(1,932)
Cash retained to fund operations	**(6,368)**	(21,556)
Working capital change	**(1,816)**	11,182
Distributions	**96,930**	68,713
Distributed to date	**87,515**	62,750
Distribution payable	**9,415**	5,963
	96,930	68,713
Opening accumulated distributions	**179,363**	110,650
Closing accumulated distributions	**276,293**	179,363
Actual distribution declared per unit	**$ 2.00**	$ 2.20

5. ACQUISITIONS

On June 4, 2004, the Trust acquired the issued and outstanding shares of Great Northern Exploration Ltd. ("Great Northern"). During 2003, APF acquired the issued and outstanding shares of Hawk Oil Inc. ("Hawk Oil") on February 5, Nycan Energy Corp. ("Nycan") on April 28, and CanScot Resources Ltd. ("CanScot") on September 26.

The purchase price allocation for each acquisition and components of consideration paid is as follows:

($000)	**Great Northern 2004**	CanScot 2003	Nycan 2003	Hawk Oil 2003
Net assets acquired at assigned values:				
Working capital deficiency	**(4,857)**	178	928	(634)
Property, plant and equipment	**255,941**	32,980	47,495	57,146
Undeveloped land and seismic	**22,943**	-	-	-
Goodwill	**70,248**	16,884	8,792	11,078
Debt assumed	**(63,874)**	(6,150)	(8,870)	(7,900)
Financial derivatives	**(1,103)**	-	-	-
Asset retirement obligation	**(7,866)**	(388)	(580)	(263)
Future income taxes	**(49,084)**	(7,399)	(13,266)	(18,266)
Net assets acquired	**222,348**	36,105	34,499	41,161
Purchase price comprised of:				
Trust units	**156,943**	15,433	-	37,710
Cash	**63,250**	-	-	2,856
Bank debt	**-**	19,689	34,374	-
Acquisition costs	**2,155**	983	125	595
Purchase price	**222,348**	36,105	34,499	41,161

The following table highlights investing cash flows associated with corporate acquisitions completed in 2004 and 2003:

($000)	**Great Northern 2004**	CanScot 2003	Nycan 2003	Hawk Oil 2003
Net assets acquired	**222,348**	36,105	34,499	41,161
Deduct:				
Debt assumed (cash acquired)	**-**	(156)	(212)	5
Trust units issued	**(156,943)**	(15,433)	-	(37,710)
Net cash flows from corporate acquisitions	**65,405**	20,516	34,287	3,456

6. PROPERTY, PLANT AND EQUIPMENT

($000)	**2004**	2003
Property, plant, and equipment	907,819	548,229
Accumulated depletion, depreciation, and accretion	(220,640)	(134,523)
	687,179	413,706

Future development costs of $48.22 million (2003 – $25.00 million) related to total proved reserves were included as depletable costs in the calculation of depletion, depreciation and accretion. Costs related to unproved properties totalled $28.45 million (2003 – $10.80 million) and were excluded from depletable costs. All costs of unproved properties, net of any associated revenues, have been capitalized. Ultimate recoverability of these costs will be dependent upon the finding of proved oil and natural gas reserves. The Trust performed a separate impairment review of assets excluded from the ceiling test and determined that $nil (2003 - $nil) should be charged to income during the year.

Included in property, plant, and equipment are asset retirement costs of $26.54 million (2003 - $18.86 million). The Trust capitalized $0.50 million (2003 - $0.46 million) of administrative costs during the year associated with coalbed methane projects considered to be in the pre-production stage.

The prices used in the ceiling test evaluation of the Trust's natural gas, crude oil, and natural gas liquids reserves at December 31, 2004 were as follows:

Year	WTI Oil ($U.S./bbl)	Foreign Exchange ($U.S./$Cdn.)	WTI Oil ($Cdn./bbl)	AECO Gas ($Cdn./mmbtu)
2005	42.76	1.1667	48.95	6.43
2006	40.56	1.1931	47.37	6.56
2007	39.44	1.2202	47.26	6.28
2008	37.77	1.2561	46.74	6.04
2009	37.14	1.2961	47.31	5.83
2010 - 2016 [1]	37.41	1.2961	47.56	5.87
Remainder [2]	2.00%	1.2961	2.00%	2.00%

[1] Represents the average for the period noted

[2] Percentage change represents the annual change each year from 2014 to the end of the reserve life

7. RISK MANAGEMENT AND FINANCIAL INSTRUMENTS

The Trust has entered into various derivative instruments and physical contracts to manage fluctuations in commodity prices, foreign currency exchange rates, utility prices, and interest rates in the normal course of operations. A derivative instrument meets the definition of a financial instrument because it involves the exchange of financial assets, usually cash, and not the delivery or acceptance of oil and gas inventory. Conversely, a physical contract is not a financial instrument because it involves the delivery or acceptance of physical product. In conformity with AcG-13 and EIC 128 (see note 3), the following information only presents positions related to financial instruments.

The estimated fair value of unrealized derivative instruments is reported on the consolidated balance sheet with any change in the unrealized positions recorded to income.

The following is a summary of the change in unrealized amounts from January 1, 2004 to December 31, 2004:

($000)	Deferred derivative loss recognized on transition	Total realized gain/(loss)	Total gain/(loss)
Fair value of contracts, January 1, 2004	1,300		(1,300)
Fair value of derivative contracts entered into during the period			(14,806)
Fair value of derivative contracts realized during the period		(16,329)	16,329
Fair value of contracts, December 31, 2004			223
Premiums received on sold call options			(386)
FV of contracts and premiums received, December 31, 2004			(163)

The following is a summary of unrealized fair value financial positions by risk management activity at December 31, 2004:

($000)	Total unrealized gain/(loss)
Commodity price	
Crude oil	(2,298)
Natural gas	2,059
Utilities	32
Foreign currency	1,103
Interest rate	(673)
	223
Premiums received on sold call options	(386)
	(163)

The following highlights the balance sheet classification of unrealized fair value financial positions at December 31, 2004:

($000)	Unrealized asset (liability)
Current asset	3,313
Long-term asset	-
Current liability	(3,141)
Long-term liability	(335)
	(163)

Commodity price risk

Commodity price risk is defined as fluctuations in crude oil, natural gas, and natural gas liquid prices. The Trust uses derivative instruments as part of its risk management approach to manage commodity price fluctuations and stabilize cash flows available for unitholder distributions and future development programs. At December 31, 2004, the Trust had recorded a $2.30 million unrealized loss on outstanding crude oil derivative instruments and a $2.06 million unrealized gain on outstanding natural gas derivative instruments.

Crude oil and natural gas derivative instruments outstanding at the end of 2004 are as follows:

Period	**Commodity**	**Type of Contract**	**Average Daily Quantity**	**Average Daily Price per bbl/GJ,mmbtu**
January to March 2005	Crude oil	Swap	1,500 bbls	U.S.$35.78
January to March 2005	Crude oil	Collar	1,000 bbls	U.S.$38.00 to U.S.$44.95
January to March 2005	Crude oil	Sold Call	500 bbls	U.S.$42.37 (U.S.$3.19 premium)
April to June 2005	Crude oil	Swap	667 bbls	U.S.$36.66
April to June 2005	Crude oil	Collar	2,000 bbls	U.S.$39.25 to U.S.$44.94
April to June 2005	Crude oil	Sold Call	500 bbls	U.S.$40.95 (U.S.$3.45 premium)
July to September 2005	Crude oil	Collar	1,000 bbls	U.S.$41.00 to U.S.$51.30
January to March 2005	Natural gas	Sold Call	5,000 GJ	Cdn.$11.80
January to March 2005	Natural gas	Collar	5,000 GJ	Cdn.$7.00 to Cdn.$11.35
April to October 2005	Natural gas	Collar	5,000 mmbtu	U.S.$6.50 to U.S.$6.90
April to October 2005	Natural gas	Collar	10,000 GJ	Cdn.$6.25 to Cdn.$7.20

Electricity price risk

The Trust's electricity cost management activities had an unrealized gain of $0.03 million at year end. APF had assumed a fixed price electricity contract through the acquisition of Great Northern. At December 31, 2004, the Trust had a 2MW (7x24) contract with a fixed price of $46.40/MWh for calendar 2005.

Foreign currency risk

The Trust's foreign currency risk management activities had an unrealized gain of $1.10 million at year end. Foreign currency risk is the risk that a variation in the U.S./Cdn. exchange rate will negatively impact the Trust's operating and financial results. At December 31, 2004, the Trust had entered into contracts to sell U.S. dollars at a fixed rate in exchange for Canadian dollars as follows:

Term	Type of Contract	Amount (U.S.$000)	Exchange Rate (U.S.$/Cdn.$)
January to April 2005	Forward	5,000	1.3550
January to April 2005	Forward	5,000	1.3680
January to December 2005	Collar	5,000	1.2300 to 1.2700
January to December 2005	Collar	10,000	1.2000 to 1.2600

The costless collar arrangements have counterparty call options on December 30, 2005 whereby the Trust's counterparty can extend the $5.00 million contract term for calendar 2006 at 1.3100 and the $10.00 million contract term for calendar 2006 at 1.2700.

Interest rate risk

The Trust's interest rate risk management activities had an unrealized loss of $0.67 million at year end. The Trust had entered into various derivative instruments to manage its interest rate exposure on debt instruments. At December 31, 2004 the Trust had fixed the interest rate on a portion of its debt as follows:

Term	Amount ($000)	Interest rate
January 2005 to November 2005	20,000	3.58% plus stamping fee
January 2005 to May 2006	20,000	3.60% plus stamping fee
January 2005 to March 2007	20,000	3.58% plus stamping fee
January 2005 to September 2007	20,000	3.65% plus stamping fee

Fair value of financial assets and liabilities

The fair values of financial instruments presented on the consolidated balance sheet, other than long-term borrowings, approximate their carrying amount due to the short-term nature of those instruments. The estimated fair values of long-term borrowings approximated its fair value due to the floating rate of interest charged under the facilities.

8. LONG-TERM DEBT

At December 31, 2004, APF had a revolving credit and term facility for $200 million (2003 - $150 million) with a syndicate of Canadian financial institutions. The facility may be drawn down or repaid at any time but there are no scheduled repayment terms. The credit facility 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 to a maximum of the bank's prime rate plus 1.625 percent (2003 – 0.125 to 1.625 percent) or where available, at Banker's Acceptances rates plus a stamping fee of 1.00 to 2.25 percent (2003 – 1.125 to 2.00 percent). The facility contains an option to extend the revolving period for an additional 364 days at the option of the lenders upon notice from the Trust no earlier than 180 days and no less than 90 days prior to the end of the initial revolving period, being October 31, 2005. If not extended, the outstanding principal converts to a one-year non-revolving reducing loan for a term of one year. From the date of conversion to a one-year term facility, APF will pay one-sixth of the outstanding principal after 180 days and one-twelfth of the outstanding principal every 90 days thereafter.

The debt is collateralized by a $300 million demand debenture containing a first fixed charge on all crude oil and natural gas assets of APF as required by the lenders and a floating charge on all other property together with a general assignment of book debts. At December 31, 2004, the interest rate was bank prime of 4.25 percent plus 0.125 percent (2003 – 4.5 percent plus 0.125 percent).

9. INCOME TAXES

The Trust applies substantively enacted income tax rates to derive its future income tax liability and the related provision (recovery) during the year. The Trust recorded a future income tax recovery of $27.02 million during the year (2003 - $14.21 million). The acquisition of Great Northern increased the future tax liability by $49.08 million resulting from temporary differences between tax bases and the fair value assigned to assets and liabilities acquired.

Federal corporate income tax rate reductions received Royal Accent during 2003. The applicable tax rate on resource income will ultimately be reduced from 28 per cent to 21 per cent over a five-year period, provide for the deduction of crown royalties and eliminate the deduction for resource allowance. The tax provision differs from the amount computed by applying the combined Canadian federal and provincial income tax statutory rates to income before future income tax recovery as follows:

($000)	2004	2003
		Restated (note 3)
Income before income taxes	**22,620**	26,401
Statutory tax rate	**40.32%**	42.75%
Expected tax provision (recovery)	**9,120**	11,286
Adjustments:		
Net income of the Trust	**(26,191)**	(19,886)
Resource allowance	**(1,625)**	(2,250)
Non-deductible crown charges	**2,056**	669
Capital tax	**972**	1,163
Rate reduction	**(2,088)**	(3,717)
Revision to tax pool estimates	**(8,972)**	-
Other	**(288)**	(1,472)
Recovery of future income taxes	**(27,016)**	(14,207)
Future tax liability comprised of:		
Accounting basis for capital assets in excess of tax basis	**102,663**	80,269
Asset retirement obligations	**(11,197)**	(7,775)
Derivative contracts	**(59)**	-
Future tax losses likely to be utilized	**(4,696)**	(8,503)
	86,711	63,991

The petroleum and natural gas properties and facilities owned by Energy and LP have an approximate tax bases of $185.00 million (2003 - $70.00 million) available for future use as deductions from taxable income. Included in the tax bases are non-capital loss carry forwards of $6.60 million (2003- $22.30) which expire during years 2005 through 2010. No current income taxes were paid or payable in 2004 or 2003.

Taxable income of the Trust is comprised of income from royalties, 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 percent on a declining balance basis and issue costs which are claimed at 20 percent 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 tax bases held within the Trust at December 31, 2004 was $214.00 million (2003 - $122.30 million).

10. CONVERTIBLE DEBENTURES

On July 3, 2003, APF issued $50.0 million of 9.40 percent unsecured subordinated convertible debentures ("convertible debentures") for proceeds of $50.0 million ($47.7 million net of issue costs). Interest is paid semi-annually on January 31 and July 31 and the instruments mature on July 31, 2008.

The debentures are convertible at the holder's option into fully paid and non-assessable Trust units at any time prior to July 31, 2008, at a conversion price of $11.25 per Trust unit. The holder will receive accrued and unpaid interest up to and including the conversion date. The debentures are not redeemable by the Trust before July 31, 2006, except under certain circumstances. The convertible debentures become redeemable at $1,050 per convertible debenture, in whole or in part, after July 31, 2006 and redeemable at $1,025 after July 31, 2007 and before maturity.

The convertible debentures are a debt security with an embedded conversion option and the following summarizes the accounting for the principal amount of the convertible debentures since their issuance:

($000s)	Liability Component	Equity Component	Total
Issued on July 3, 2003	48,817	1,183	50,000
Accretion of liability during 2003	89	-	89
Conversions into Trust Units during 2003	(1,187)	(29)	(1,216)
Carrying value at December 31, 2003	47,719	1,154	48,873
Accretion of liability during 2004	193	-	193
Conversions into Trust Units during 2004	(215)	(5)	(220)
Carrying value at December 31, 2004	**47,697**	**1,149**	**48,846**

11. ASSET RETIREMENT OBLIGATIONS

The following table presents the reconciliation of the beginning and ending aggregate asset retirement obligation associated with the retirement of oil and gas properties:

($000)	2004	2003
Asset retirement obligation, beginning of year	**21,803**	12,961
Liabilities acquired	**7,866**	4,673
Liabilities incurred	**834**	3,249
Liabilities settled	**(1,083)**	(374)
Accretion expense	**1,573**	1,294
Asset retirement obligation, end of year	**30,993**	21,803

The total undiscounted amount of estimated cash flows required to settle the obligation is $108.29 million (2003 - $70.72 million), which has been discounted using a credit-adjusted risk free rate of eight percent and an inflation factor of one and one-half percent. Most of these obligations are not expected to be paid for several years, or decades, in the future and will be funded from general company resources and the fund reserved for site reclamation and abandonment. The abandonment fund is currently funded at $0.53 million per quarter through cash flow from operations.

12. UNITHOLDERS' INVESTMENT ACCOUNT

The per unit calculations for the year ended December 31, 2004 was based on weighted average Trust units outstanding of 48.49 million (2003 – 30.97 million). In computing net income per unit – diluted, 0.33 million units (2003 – 0.33 million) were added to the weighted average number of units outstanding for the year, reflecting the dilutive effect of employee options and rights. An additional 4.32 million Trust units (2003 – 2.18 million) were added to the weighted average number of units outstanding for the year relating to the assumed conversion of debentures. Interest on debentures assumed to be converted into Trust units totalled $5.26 million (2003 - $2.67 million) and was added back to net income for per unit – diluted calculations.

	December 31, 2004		December 31, 2003	
Trust Units	**Units (000)**	**($000)**	Units (000)	($000)
Balance - Beginning of period	**34,074**	**324,318**	22,942	214,405
Corporate acquisitions (note 5)	**12,885**	**156,943**	5,332	53,143
Issued for cash	**7,877**	**90,451**	5,352	55,670
Cost of units issued	**-**	**(5,270)**	-	(3,467)
Regular DRIP	**516**	**5,764**	24	273
Premium DRIP	**3,031**	**33,895**	117	1,329
Issued on conversion of debentures	**19**	**220**	108	1,216
Issued on exercise of options/rights	**442**	**3,799**	199	1,749
Allocated from contributed surplus	**-**	**74**	-	-
Balance - End of period	**58,845**	**610,194**	34,074	324,318

Unitholders' rights plan

In 1999, the Trust created a Unitholders' Rights Plan and authorized the issuance of one right in respect of each Trust unit outstanding. Each right would entitle a unitholder under certain circumstances to acquire upon payment of an exercise price of $50.00, the number of Trust units having an aggregate market price equal to twice the exercise price of the rights.

Units issued for cash

The Trust issued Trust units on two separate occasions: 4.77 million Trust units at $11.60 per unit for gross proceeds of $55.27 million on February 4, 2004; and 3.10 million Trust units at $11.30 per unit for gross proceeds of $35.03 million on September 8, 2004.

Distribution reinvestment program

Commencing December 2003, the Trust initiated a distribution reinvestment plan ("DRIP"). The DRIP permits eligible unitholders to direct their distributions to the purchase of additional units at 95 percent of the average market price as defined in the plan ("Regular DRIP"). The premium distribution component permits eligible unitholders to elect to receive 102 percent 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.

13. UNIT-BASED COMPENSATION PLANS

APF has established a Trust Units Options Plan (the "Plan") and a Trust Unit Incentive Rights Plan (the "Rights Plan") for employees and independent directors. Pursuant to the Plan arrangement, employees, directors and long-term consultants may be granted options to purchase Trust units. The exercise price for each option granted was not less than the market price of the Trust's units on the grant date and the contractual term of each option is not to exceed five years. Options granted before February 1, 1998 vested immediately; options granted after January 28, 1998 vested in one-third increments on the first, second and third anniversaries of their grant date. The Plan was terminated in 2001 and replaced with the Rights Plan. No additional options have been granted under the Plan since 2001. A summary of the change in the Plan during 2004 and 2003 is as follows:

	December 31, 2004		December 31, 2003	
Trust Unit Options	**Options (000)**	**Weighted Average Price ($)**	Options (000)	Weighted Average Price ($)
Balance- Beginning of period	**126**	**9.59**	244	9.13
Granted	-	-	-	-
Exercised	**(46)**	**9.45**	(107)	8.55
Cancelled	-	-	(11)	9.42
Balance - End of period	**80**	**9.68**	126	9.59
Exercisable - End of period	**80**	**9.68**	60	9.48

The following table summarizes Plan related information at December 31, 2004:

	December 31, 2004				
	Weighted average remaining contractual life (years)	Options outstanding (000)	Weighted average exercise price ($)	Options exercisable (000)	Weighted average exercise price ($)
Range					
7.00 to 7.99	0.18	1	7.15	1	7.15
8.00 to 8.99	0.68	0	8.85	0	8.85
9.00 to 9.99	1.16	79	9.70	79	9.70
	1.16	80	9.68	80	9.68

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

A summary of the change in the Rights Plan during 2004 and 2003 is as follows:

	December 31, 2004		December 31, 2003	
Trust Unit Rights	**Rights (000)**	**Weighted Average Price ($)**	Rights (000)	Weighted Average Price ($)
Balance - Beginning of period	**1,824**	**9.09**	429	9.37
Granted	**952**	**11.91**	1,538	9.78
Exercised	**(395)**	**8.49**	(92)	9.05
Cancelled	**(510)**	**9.43**	(51)	9.67
Balance - Before price reduction	**1,871**	**10.56**	1,824	9.72
Reduction of exercise price	**-**	**(0.72)**	-	(0.63)
Balance - End of period	**1,871**	**9.84**	1,824	9.09
Exercisable - End of period	**241**	**8.50**	47	8.58

The following table summarizes Rights Plan related information at December 31, 2004:

	December 31, 2004				
	Weighted average remaining contractual life (years)	Rights outstanding (000)	Weighted average exercise price ($)	Rights exercisable (000)	Weighted average exercise price ($)
Range					
7.00 to 7.99	7.17	140	7.68	52	7.68
8.00 to 8.99	8.26	808	8.38	156	8.38
9.00 to 9.99	8.45	17	9.43	5	9.49
10.00 to 10.99	8.75	83	10.59	28	10.59
11.00 to 11.99	9.39	823	11.56	-	-
	8.70	1,871	9.84	241	8.50

In conformity with CICA Handbook Section 3870, "Stock-based Compensation and Other Stock-based Payments" discussed in note 3, no compensation cost has been recognized for unit-based compensation granted prior to January 1, 2003. In accordance with the transitional provisions, the Trust has disclosed pro forma results as if the new standard had been adopted retroactively. At December 31, 2004, proforma net income and earnings per share would not have been materially different from those disclosed in the consolidated statement of operations and accumulated earnings.

The fair value of rights granted after December 31, 2002 was estimated using a Black-Scholes option-pricing model incorporating the following assumptions: risk-free interest rates ranging from 3.01 to 4.62 percent; volatility ranging from 16.14 and 22.63 percent; expected rights term of five years; and dividend yield rates ranging from 11.10 to 13.87 percent, representing the difference between the anticipated distribution and price reduction yields. The initial fair value ascribed to rights granted under the Rights Plan is not subsequently revised for changes in any of the underlying assumptions and is recorded as compensation expense evenly over the contractual vesting period. Compensation expense is adjusted prospectively for rights cancelled under the Rights Plan during the period.

The Trust recorded a recovery of compensation expense of $0.88 million during 2004 (2003 – expense of $1.24 million) related to vested rights issued under the Rights Plan with a corresponding increase to contributed surplus. When rights are exercised by employees and directors of the Trust, the consideration paid is recorded to the unitholders' investment account along with related non-cash compensation expense previously recognized in contributed surplus.

14. SUPPLEMENTAL CASH FLOW INFORMATION

	Twelve Months Ended December 31	
($000)	**2004**	2003
Cash payments related to certain items		
Interest	**957**	4,070
Interest on debentures	**4,947**	30
Interest rate swap settlement	**901**	-
Capital and other taxes	**3,507**	3,389

15. NET CHANGE IN NON-CASH WORKING CAPITAL ITEMS

	Twelve Months Ended December 31	
($000)	**2004**	2003
Change in working capital items		
Accounts receivable	**(551)**	1,016
Other current assets	**(1,415)**	(397)
Accounts payable and accrued liabilities	**(8,893)**	5,204
Derviatives liabilities	**386**	-
	(10,473)	5,823

16. CONTRACTUAL OBLIGATIONS AND COMMITMENTS

APF is involved in certain legal actions that occurred in the normal course of business. APF is required to determine whether a contingent loss is probable and whether that loss can be reasonably estimated. When the loss has satisfied both criteria, it is charged to income. Management is of the opinion that losses, if any, arising from such legal actions would not have a material effect on these financial statements.

The Trust leases its office premises through an arrangement deemed to be an operating lease for accounting purposes. As such, the Trust is not required to record its lease obligation as a liability nor does it record its leased premises as an asset. The estimated operating lease commitments for the Trust's leased office premises for the next five years are as follows:

($000)	
2005	1,398
2006	1,213
2007	1,252
2008	1,083
2009	934
Thereafter	934

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.

For further information please contact:
Steve Cloutier, President
Alan MacDonald, V.P. Finance
Christine Ezinga, Corporate Planning Analyst
Telephone (403) 294-1000 ▲ Toll Free (800) 838-9206 ▲Fax (403) 294-1074
E-mail: invest@apfenergy.com ▲ Internet: www.apfenergy.com

Exemption Order
82-5166

APF ENERGY

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

APF ENERGY RELEASES 2004 RESERVES INFORMATION AND DETAILS OF 2005 CAPITAL PROGRAM

March 3, 2005 - APF Energy Trust ("APF" or the "Trust") is pleased to release selected 2004 year-end reserves information and details of its 2005 budgeted capital program.

Highlights

- Proved plus probable reserves increased 46% to 58.7 million barrels of oil equivalent.
- Drilling and optimization replaced 93% of 2004 production. Together with acquisitions executed during the year, APF replaced 314% of its annual production.
- Coalbed methane ("CBM") reserves increased 190% to 25.54 bcf. Daily production from all of APF's CBM assets now amounts to 1,800 mcf/d.
- Net asset value per unit (proved plus probable at NPV 10%) increased 53% to $8.08 per unit.
- Finding, development and acquisition ("FD&A") costs, inclusive of future capital obligations, were $16.86 per barrel of oil equivalent (rolling three-year average of $14.74 per boe).

Summary	December 31, 2004	December 31, 2003	% Change
Reserves (mboe)[1]			
Proved producing	35,019	24,652	42%
Total proved	43,017	29,894	44%
Total proved plus probable	58,733	40,322	46%
Proved plus probable RLI (years)	8.9	8.5	5%
Net present value @ 10% ($millions)	619.1	316.5	96%
Net asset value @ 10% ($millions)	475.3	179.6	165%
Net asset value per unit	$8.08	$5.27	53%

1) 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

Reserves

General Comments

All of APF's reserves were evaluated effective December 31, 2004. The Trust's Canadian conventional reserves were evaluated by Gilbert Laustsen Jung Associates Ltd. ("GLJ"), while APF's coalbed methane ("CBM") interests in Canada and the United States were evaluated by Sproule Associates Ltd. ("Sproule"). Both evaluations were prepared in accordance with National Instrument 51-101.

Company Interest Reserves at December 31, 2004 (based on forecast pricing and costs)	**Natural Gas (Mmcf)**	**Light & Medium Oil (Mbbl)**	**Heavy Oil (Mbbl)**	**NGL's (Mbbl)**	**Total (Mboe)**	**Reserve Life Index (years)[2]**
Proved						
Developed producing	98,935	15,483	1,106	1,941	35,019	5.3
Developed non-producing	11,574	486	479	116	3,009	
Undeveloped	15,224	2,169	154	130	4,989	
Total proved	125,733	18,137	1,738	2,186	43,017	6.5
Probable	43,679	6,718	1,085	634	15,716	
Proved plus probable	169,412	24,855	2,823	2,820	58,733	8.9

Columns may not add due to rounding

1) Company Interest Reserves are defined as working interest (before the deduction of royalties) plus royalty interest reserves.

2) As calculated by APF, using 18,000 boe/d

On a proved plus probable basis, APF added 5,423 mboe of reserves through exploration discoveries, drilling extensions, infill drilling and improved recoveries, replacing 93% of 2004 production. Together with acquisitions, APF replaced 314% of annual production.

APF registered positive technical revisions on a proved producing and total proved basis, but the elimination of previously-booked drilling locations resulted in nominal downward technical revisions of 574 mboe on a proved plus probable basis.

Acquisitions

Almost all of APF's 2004 acquisition activity can be accounted for in the $291.08 million purchase of Great Northern Exploration Ltd. ("GNL"). GNL's reserves were estimated to be 20,003 mboe (proved plus probable) at December 31, 2003 by GLJ. At December 31, 2004, and accounting for production, drilling, optimization and technical revisions, GNL's closing reserves balance was 18,038.

Coalbed Methane ("CBM")

Since acquiring its initial CBM position with the purchase of CanScot Resources in October of 2003, APF's daily CBM production has increased from 500 mcf to 1,800 mcf currently. At the end of 2003, APF's booked CBM reserves amounted to 1,475 mboe (proved plus probable), with a NPV 10% of $3.45 million. The December 31, 2004 evaluation has now assigned proved plus Probable reserves of 4,268 mboe and a value of $31.20 million. In addition to lands assigned reserves, APF has assembled an undeveloped CBM land position of 76,670 net undeveloped acres.

	Corporate Reconciliation (including CBM)		
Reconciliation (mboe)	**Proved Producing**	**Total Proved**	**Total Proved Plus Probable**
Opening balance	24,652	29,894	40,322
Exploration discoveries	111	111	189
Drilling extensions	336	485	699
Infill drilling	1,680	3,877	4,785
Improved recoveries	709	279	324
Technical revisions	1,301	789	(574)
Acquisitions	12,095	13,447	18,856
Dispositions	(5)	(5)	(8)
Production	(5,860)	(5,860)	(5,860)
Closing balance	35,019	43,017	58,733

	CBM Reconciliation		
Reconciliation (mboe)	**Proved Producing**	**Total Proved**	**Total Proved Plus Probable**
Opening balance	127	142	1,475
Infill drilling	163	1,804	1,913
Technical revisions	28	486	394
Acquisitions	36	404	552
Production	(66)	(66)	(66)
Closing balance	288	2,770	4,268

Net Asset Value

APF invested significant capital in 2004 to create an asset base capable of supporting a multi-year drilling program. Such activities included increased land and seismic acquisitions. In addition to the evaluation of its oil and gas reserves by GLJ and Sproule, the Trust's seismic database was independently valued by Boyd Exploration Consultants Ltd. at $20.21 million, while APF's 517,880 acres of net undeveloped land was evaluated by GLJ at $64.74 million.

Net present value of future net revenue before income taxes

As of December 31, 2004 (based on forecast pricing and costs, $000)	**8%**	**10%**	**12%**
Proved			
Developed producing	459,323	432,829	410,030
Developed non-producing	34,399	31,839	29,655
Undeveloped	31,987	27,684	24,060
Total proved	525,709	492,352	463,745
Probable	142,832	126,716	113,524
Proved plus probable	668,541	619,067	577,269

NPV values include allocations for asset abandonment

Net asset value of Proved Plus Probable reserves

As of December 31, 2004 (based on forecast pricing and costs, $000)	**8%**	**10%**	**12%**
Net present value	668,541	619,067	577,269
Land	64,735	64,735	64,735
Seismic	20,208	20,208	20,208
Bank debt	(169,000)	(169,000)	(169,000)
Convertible debentures	(47,697)	(47,697)	(47,697)
Working capital	(11,991)	(11,991)	(11,991)
Total net asset value	524,796	475,322	433,524
Units outstanding	58,845	58,845	58,845
Net asset value per unit ($)	8.92	8.08	7.37

GLJ Commodity Price Assumptions - January 1, 2005 Year	WTI Oil ($U.S./bbl)	Foreign Exchange ($U.S./$Cdn.)	Heavy Oil ($Cdn./bbl)	Light Oil ($Cdn./bbl)	AECO Gas ($Cdn./mmbtu)
2005	42.00	1.2195	27.50	50.25	6.60
2006	40.00	1.2195	28.50	47.75	6.35
2007	38.00	1.2195	28.75	45.50	6.15
2008	36.00	1.2195	27.25	43.25	6.00
2009	34.00	1.2195	25.50	40.75	6.00
2010	33.00	1.2195	24.75	39.50	6.00
2011	33.00	1.2195	24.75	39.50	6.00
2012	33.00	1.2195	24.75	39.50	6.00
2013	33.50	1.2195	24.75	40.00	6.10
2014	34.00	1.2195	25.50	40.75	6.20
2015	34.50	1.2195	25.75	41.25	6.30
Escalate thereafter	2%/yr	-	2%/yr	2%/yr	2%/yr

Finding and Development

Finding, Development and Acquisition costs included expenditures of approximately $15 million on land and seismic, with virtually no corresponding reserves assigned in the GLJ and Sproule reports. APF anticipates that a return on these investments will be generated within the next two to three years as the Trust's drilling program continues to expand.

Finding and Development Costs ("F&D")

Proved + Probable	**2004**	2003	2002
($000)			
Total F&D	**67,576**	33,601	21,595
Change in future development	**40,752**	27,048	11,525
Total	**108,328**	60,649	33,120
Net reserve additions (mboe)	**5,423**	3,002	4,054
($/boe except recycle ratio values)			
F&D Cost[1]	**$ 19.98**	$ 20.20	$ 8.17
Operating Netback	**$ 22.56**	$ 22.10	$ 17.83
Recycle Ratio	**1.13**	1.09	2.18
Rolling three year average F&D costs	**$ 16.19**	$ 11.86	$ 7.88

1) Excluding land & seismic: 2004 - $17.23; 2003 - $19.85

Finding, Development and Acquisitions Costs ("F,D&A")

Proved + Probable		2004	2003	2002
($000)				
Total FD&A		**67,576**	33,601	21,595
Change in future development		**40,752**	27,048	11,525
Net acquisitions		**300,930**	157,576	79,532
Total		**409,258**	218,225	112,652
Net reserve additions (mboe)		**24,271**	12,881	13,064
($/boe except recycle ratio values)				
FD&A costs[2]	**$**	**16.86**	$ 16.94	$ 8.62
Operating netback	**$**	**22.56**	$ 22.10	$ 17.83
Recycle ratio		**1.34**	1.30	2.07
Rolling three year average F,D&A costs	**$**	**14.74**	$ 12.31	$ 9.59

2) Excluding land & seismic: 2004 - $16.25; 2003 - $16.85

Drilling Summary

	Three Months Ended December 31				Twelve Months Ended December 31			
	2004		2003		**2004**		2003	
	Gross	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**15**	**6.4**	15	5.7	**37**	**12.4**	60	19.4
Gas	**112**	**60.4**	38	21.7	**135**	**71.1**	80	40.2
Coalbed methane	**55**	**20.3**	19	4.4	**104**	**42.2**	19	4.4
Other	**-**	**-**	-	-	**4**	**2.3**	5	0.8
Dry and abandoned	**3**	**2.0**	-	-	**4**	**3.0**	-	-
Total	**185**	**89.1**	72	31.8	**284**	**131.0**	164	64.8

2005 Capital Program

APF's 2005 capital budget contemplates the expenditure of $61.46 million. Based on this budget APF expects production to average 18,000 to 18,500 boe/d, pending rig and crew availability these numbers could increase throughout the year. Funding for the program will be derived from cash flow, the Distribution Reinvestment Plan ("DRIP") and debt. Both conventional and CBM opportunities are expected to result in the drilling of 221 (138.87 net) risked wells. In addition, capital expenditures with respect to abandonment and reclamation initiatives are expected to amount to $2.80 million.

Business Unit ($000)	**Drilling & Development**	**Land & Seismic**	**Total**
Southeast Saskatchewan	8,554	1,300	9,854
Southern	7,952	2,000	9,952
Central	11,394	1,035	12,429
Western	5,781	3,300	9,081
CBM - Alberta	15,289	375	15,664
CBM - Wyoming	4,483	-	4,483
Total	**53,453**	**8,010**	**61,463**

Southeast Saskatchewan Business Unit

Activity in this light oil area will be focussed at Queensdale, Handsworth, Star Valley and Tableland, where APF's continued use of 3-dimensional seismic will assist in improved delineation of structures in the Mississippian formation.

Southern Business Unit

APF's largest gas producing area will continue to be the focus of downspacing in the shallow Cretaceous Milk River and Medicine Hat sands of the Countess area. Elsewhere, the Trust will continue its development of deeper horizons in the Barons, Bow Island and Sunburst zones, using 3-D seismic to assist in the identification of opportunities.

Central Business Unit

Activity in this area will increase in 2005 as a result of the Trust's mid-2004 purchase of GNL and the acquisition of additional lands at Crown sales. At Innisfail and Wood River, the shallow Edmonton and Belly River sands are being targeted, while deeper horizons in the Pekisko and Leduc zones will also be exploited.

Western Business Unit

APF's plans for 2005 will focus on finding new opportunities in this multi-zone region, while continuing to develop its existing asset base in the Paddle River, Leaman and Sakwatamau areas. Approximately 41% of APF's total land and seismic budget has been allocated to the Western Business Unit.

CBM

APF plans to aggressively pursue its South-Central Alberta Horseshoe Canyon ("HSC") drilling program in 2005, allocating approximately 28% of its total drilling and completions budget to this shallow gas play. Unlike CBM operations in the Upper Mannville zone of Central Alberta, the HSC produces no water. In total, 56 (41.37 net) risked HSC wells are expected to be drilled in 2005.

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.

For further information please contact:
Steve Cloutier, President
Alan MacDonald, V.P. Finance
Christine Ezinga, Corporate Planning Analyst
Telephone (403) 294-1000 ▲ Toll Free (800) 838-9206 ▲Fax (403) 294-1074
E-mail: invest@apfenergy.com ▲ Internet: www.apfenergy.com

Exemption Order
82-5166

APF ENERGY

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

APF ANNOUNCES TAX TREATMENT FOR NON-RESIDENT INVESTORS

March 3, 2005 - APF Energy Trust ("APF") announces that for U.S. tax reporting purposes, cash distributions paid to Unitholders in the 2004 taxation year were 72.600% taxable and 27.400% return of capital.

APF has been advised that "Qualified Dividends" should be reported on Line 9b of the U.S. Federal individual income tax return unless the situation of the U.S. individual Unitholder determines otherwise. Commentary on page 20 of the IRS 2004 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.

FOR NON-RESIDENT UNITHOLDERS

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 and guidance with respect to the appropriate tax treatment of their distributions.

U.S. Residents Invested in APF
After consulting with its tax advisors, APF is of the opinion that distributions paid by APF to non-corporate Unitholders who are U.S. residents or citizens during 2004 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 has calculated its current and accumulated earnings and profits in accordance with U.S. tax principles, which enables U.S. Unitholders to determine the taxable percentage of the distributions paid to them. For the 2004 taxation year APF distributions paid to U.S. residents were 72.600% taxable and 27.400% return of capital. Detailed information regarding historical distribution payments is available on the Trust's website, www.apfenergy.com

2004 U.S. INVESTOR TAX SUMMARY		**Taxable Amount**	**Return of**	**Total Cash Distribution**
Record Date	**Payment Date**	**(Other Income)**	**Capital**	**Paid**
December 31, 2003	January 15, 2004	$0.1270	$0.0480	$0.1750
January 31, 2004	February 16, 2004	$0.1270	$0.0480	$0.1750
February 28, 2004	March 15, 2004	$0.1270	$0.0480	$0.1750
March 31, 2004	April 15, 2004	$0.1270	$0.0480	$0.1750
April 30, 2004	May 17, 2004	$0.1270	$0.0480	$0.1750
May 31, 2004	June 15, 2004	$0.1270	$0.0480	$0.1750
June 30, 2004	July 15, 2004	$0.1162	$0.0438	$0.1600
July 31, 2004	August 16, 2004	$0.1162	$0.0438	$0.1600
August 29, 2004	September 15, 2004	$0.1162	$0.0438	$0.1600
September 30, 2004	October 15, 2004	$0.1162	$0.0438	$0.1600
October 31, 2004	November 15, 2004	$0.1162	$0.0438	$0.1600
November 30, 2004	December 15, 2004	$0.1162	$0.0438	$0.1600
Total Paid During 2004 Taxation Year		**$1.4592**	**$0.5508**	**$2.0100**

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.

Effective January 1, 2005 a 15% withholding tax was applied to all distributions paid to non-resident investors.

Subject to advice from your legal and tax advisors, you may reference this news release as support for your treatment of the 2004 distributions from APF Energy Trust.

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.

For further information please contact:
Steve Cloutier, President
Alan MacDonald, V.P. Finance
Christine Ezinga, Corporate Planning Analyst
Telephone (403) 294-1000 ▲ Toll Free (800) 838-9206 ▲ Fax (403) 294-1074
E-mail: invest@apfenergy.com ▲ Internet: www.apfenergy.com

Exemption Order
82-5166

Computershare

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

March 3, 2005

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
L'Autorite des marches financiers
Saskatchewan Financial Services 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 Special
2.	Security Description of Voting Issue	:	Trust Units
3.	CUSIP Number	:	001 85T 202
4.	Record Date	:	March 30, 2005
5.	Meeting Date	:	May 4, 2005
6.	Meeting Location	:	Calgary, Alberta

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

Exemption Order
82-5166

APF ENERGY

NEWS RELEASE

TSX: AY.UN
AY.DB

APF Energy Trust Announces Distribution of $0.16 per Unit

March 17, 2005 - APF Energy Trust announces that it is maintaining its monthly distribution of $0.16 per unit. Payment will be made on April 15, 2005 to unitholders of record on March 31, 2005. The ex-distribution date is March 29, 2005.

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

Steve Cloutier, President
Alan MacDonald, V.P. Finance
Christine Ezinga, Corporate Planning Analyst
Telephone: (403) 294-1000 ▲ Toll Free (800) 838 9206 ▲ Fax (403) 294-1010
Email: invest@apfenergy.com ▲ Internet: www.apfenergy.com

Exemption Order
82-5166

APF ENERGY

RECEIVED 2005 MAR 23 P 3:22 OFFICE OF INTERNATIONAL CORPORATE FINANCE

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

APF ANNOUNCES TAX TREATMENT OF DISTRIBUTIONS

February 28, 2005 - APF Energy Trust ("APF") announces that for Canadian tax reporting purposes, cash distributions paid to Unitholders in the 2004 taxation year were 68.345% taxable and 31.655% 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.

Units held within an RRSP, RRIF, or DPSP

In respect to units of APF Energy Trust held in a Registered Retirement Savings Plan (RRSP), Registered Retirement Income Fund (RRIF), or Deferred Profit Sharing Plan (DPSP) during 2004, no amount should be reported on the 2004 individual Income Tax Return ("T1").

Units held outside an RRSP, RRIF, or DPSP

Registered APF Energy Trust unitholders who held trust units outside an RRSP, RRIF, or DPSP will receive a T3 Supplementary Slip for 2004 ("T3") directly from APF's transfer agent, Computershare Trust Company of Canada, and must report the taxable portion of such distributions as "other income" in Box 26 of their T3. Beneficial unitholders who held units through intermediaries such as investment advisers will be receiving T3 receipts from their adviser or other intermediary.

FOR CANADIAN TAXPAYERS

The following table summarizes, on a monthly basis, cash distributions received in 2004 by unitholders indicating what portion of each distribution is taxable as income and what is considered return of capital. The distribution declared by APF in December 2004 was received by unitholders in January 2005, it is not to be included in the calculation of a unitholder's 2004 taxable income.

2004 CANADIAN TAX SUMMARY

Record Date	Payment Date	Taxable Amount (Other Income)	Return of Capital	Total Cash Distribution Paid
December 31, 2003	January 15, 2004	$0.1196	$0.0554	$0.1750
January 31, 2004	February 16, 2004	$0.1196	$0.0554	$0.1750
February 28, 2004	March 15, 2004	$0.1196	$0.0554	$0.1750
March 31, 2004	April 15, 2004	$0.1196	$0.0554	$0.1750
April 30, 2004	May 17, 2004	$0.1196	$0.0554	$0.1750
May 31, 2004	June 15, 2004	$0.1196	$0.0554	$0.1750
June 30, 2004	July 15, 2004	$0.1094	$0.0506	$0.1600
July 31, 2004	August 16, 2004	$0.1094	$0.0506	$0.1600
August 29, 2004	September 15, 2004	$0.1094	$0.0506	$0.1600
September 30, 2004	October 15, 2004	$0.1094	$0.0506	$0.1600
October 31, 2004	November 15, 2004	$0.1094	$0.0506	$0.1600
November 30, 2004	December 15, 2004	$0.1094	$0.0506	$0.1600
Total Paid During 2004 Taxation Year		**$1.3740**	**$0.6360**	**$2.0100**

Adjusted Cost Base Reduction

The Adjusted Cost Base ("ACB") of units is used in calculating capital gains or losses upon 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. Any capital gain realized 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, 2004 have an ACB of $2.893 per Trust Unit. This value adjusts for the cumulative return of capital of $7.107 as provided in the table below.

HISTORICAL CANADIAN 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
2004	**$1.374**	**$0.636**	**$2.010**	**0.000%**	**100.000%**
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%
	$8.733	$7.107	$15.840		

FOR NON-RESIDENT UNITHOLDERS

APF expects to have detailed taxation information relating to distributions paid to U.S. residents during 2004, by March 7, 2005.

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.

For further information please contact:
Steve Cloutier, President
Alan MacDonald, V.P. Finance
Christine Ezinga, Corporate Planning Analyst
Telephone (403) 294-1000 ▲ Toll Free (800) 838-9206 ▲ Fax (403) 294-1074
E-mail: invest@apfenergy.com ▲ Internet: www.apfenergy.com

Exemption Order
82-5166

CCNMatthews

Phone: (403) 266-2443 (Calgary) (403) 263-7210 (Calgary)
Email: ops@ccnmatthews.com Website: www.ccnmatthews.com

February 28, 2005

To whom it may concern:

On Feb 28, 2005 CCNMatthews filed a News Release for APF Energy Trustthat contained an incorrect document. Please note that we have filed the correct document as Submission Number 2 under the same Project Number (743078).

Please call me if you have any questions or inquiries.

Erin Pratt
CCN Matthews
(403)-266-2443

APF ENERGY

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

APF ANNOUNCES TAX TREATMENT OF DISTRIBUTIONS

February 28, 2005 - APF Energy Trust ("APF") announces that for Canadian tax reporting purposes, cash distributions paid to Unitholders in the 2004 taxation year were 68.345% taxable and 31.655% 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.

Units held within an RRSP, RRIF, or DPSP
In respect to units of APF Energy Trust held in a Registered Retirement Savings Plan (RRSP), Registered Retirement Income Fund (RRIF), or Deferred Profit Sharing Plan (DPSP) during 2004, no amount should be reported on the 2004 individual Income Tax Return ("T1").

Units held outside an RRSP, RRIF, or DPSP
Registered APF Energy Trust unitholders who held trust units outside an RRSP, RRIF, or DPSP will receive a T3 Supplementary Slip for 2004 ("T3") directly from APF's transfer agent, Computershare Trust Company of Canada, and must report the taxable portion of such distributions as "other income" in Box 26 of their T3. Beneficial unitholders who held units through intermediaries such as investment advisers will be receiving T3 receipts from their adviser or other intermediary.

FOR CANADIAN TAXPAYERS
The following table summarizes, on a monthly basis, cash distributions received in 2004 by unitholders indicating what portion of each distribution is taxable as income and what is considered return of capital. The distribution declared by APF in December 2004 was received by unitholders in January 2005, it is not to be included in the calculation of a unitholder's 2004 taxable income.

2004 CANADIAN TAX SUMMARY				
Record Date	**Payment Date**	**Taxable Amount (Other Income)**	**Return of Capital**	**Total Cash Distribution Paid**
December 31, 2003	January 15, 2004	$0.1196	$0.0554	$0.1750
January 31, 2004	February 16, 2004	$0.1196	$0.0554	$0.1750
February 28, 2004	March 15, 2004	$0.1196	$0.0554	$0.1750
March 31, 2004	April 15, 2004	$0.1196	$0.0554	$0.1750
April 30, 2004	May 17, 2004	$0.1196	$0.0554	$0.1750
May 31, 2004	June 15, 2004	$0.1196	$0.0554	$0.1750
June 30, 2004	July 15, 2004	$0.1094	$0.0506	$0.1600
July 31, 2004	August 16, 2004	$0.1094	$0.0506	$0.1600
August 29, 2004	September 15, 2004	$0.1094	$0.0506	$0.1600
September 30, 2004	October 15, 2004	$0.1094	$0.0506	$0.1600
October 31, 2004	November 15, 2004	$0.1094	$0.0506	$0.1600
November 30, 2004	December 15, 2004	$0.1094	$0.0506	$0.1600
Total Paid During 2004 Taxation Year		**$1.3740**	**$0.6360**	**$2.0100**

Adjusted Cost Base Reduction
The Adjusted Cost Base ("ACB") of units is used in calculating capital gains or losses upon 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. Any capital gain realized 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, 2004 have an ACB of $2.893 per Trust Unit. This value adjusts for the cumulative return of capital of $7.107 as provided in the table below.

HISTORICAL CANADIAN 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
2004	**$1.374**	**$0.636**	**$2.010**	**68.345%**	**31.655%**
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%
	$8.733	$7.107	$15.840		

FOR NON-RESIDENT UNITHOLDERS

APF expects to have detailed taxation information relating to distributions paid to U.S. residents during 2004, by March 7, 2005.

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.

For further information please contact:
Steve Cloutier, President
Alan MacDonald, V.P. Finance
Christine Ezinga, Corporate Planning Analyst
Telephone (403) 294-1000 ▲ Toll Free (800) 838-9206 ▲ Fax (403) 294-1074
E-mail: invest@apfenergy.com ▲ Internet: www.apfenergy.com