APF ENERGY

November 19, 2004

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By Courier

SUPPL

Securities and Exchange Commission
Judiciary Plaza
450, 5th Street, N.W.
Washington, D.C. 20549

Re: APF Energy Trust (the "Company")
File No. 82-5166
<u>Exemption Pursuant to Rule 12g3-2(b)</u>

Dear Sir or Madam:

Please find enclosed documentation relating to Rule 12g3-2(b). Pursuant to Rule 12g3-2(b) under the Securities Exchange Act of 1934, as amended, we enclose the following documents.

Date of Filing	Document Filed	Date of Filing	Document Filed
Nov 8 2004	News Release - Third Quarter Financial & Operating Results	Nov 12, 2004	Form 52-109FT2 – CFO Certification
Nov 12, 2004	Interim Financial Statements	Nov 12, 2004	Form 52-109FT2 – CEO Certification
Nov 12, 2004	MD&A – English	Nov 17, 2004	News Release Dec 15 2004 Distribution Announcement

As required pursuant to Rule 12g3-2(b), the exemption number appears in the upper right-hand corner of each unbound page and on the first page of each bound document.

Please indicate your receipt of the enclosed by stamping the enclosed copy of this letter and returning it to the sender in the enclosed self-addressed, stamped* envelope.

Very truly yours,

SCloutier

Steve Cloutier
President

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Exemption Order
82-5166

APF ENERGY

RECEIVED NOV 23 2004 SEC MAIL PROCESSING SECTION WASH. D.C. 213

NEWS RELEASE
November 8, 2004

TSX: AY.UN; AY.DB

APF ENERGY ANNOUNCES THIRD QUARTER OPERATING AND FINANCIAL RESULTS

Drilling, recompletions and other optimization activities grew APF's production base, as the Trust continued to focus on internally generated opportunities to create value for unitholders.

On the heels of completing its largest acquisition ever, the $291 million corporate purchase of Great Northern Exploration Ltd. ("Great Northern") in early June, APF saw its daily production increase to an average of 18,262 boe. During the third quarter, the Trust brought on stream approximately 1,100 boe/d of new production through the drill bit and other production enhancement techniques, replacing production by approximately 108%, after taking into account natural production declines.

For the nine months ended September 30, 2004, APF drilled 99 (41.9 net) wells, of which 24 (11.2 net) were drilled during the third quarter, with a 100% success rate. Drilling activity was delayed across all business units due to surface restrictions relating to wet weather as unseasonable conditions continued to impact the entire sector beyond traditional spring break-up periods. With these restrictions removed, APF resumed its most active drilling program since inception, with a total of 100 (62 net) wells planned for the fourth quarter. During October, APF drilled 43 (37.8 net) of the 100 wells. Capital expenditures relating to drilling and completions have amounted to $24.8 million in the first nine months of 2004, with $11.2 million spent during the third quarter.

In addition to identifying opportunities on existing APF properties, the Trust has actively added to its undeveloped land position in the first nine months of the year, with the purchase of 32,260 net acres (10,870 net acres during the third quarter) for a total cost of $6.1 million. APF's objective is to add to its inventory of high quality prospects to ensure that production and reserves continue to grow independently from mergers and acquisitions activity.

The Canadian government recently announced draft regulations to restrict the level of non-resident ownership of a mutual fund trust at less than 50% based upon a fair market value assessment. Under the current regulations trusts, would have until January 1, 2007 to reduce non-resident ownership to below the 50% level in order to maintain their mutual fund trust status. APF's non-resident ownership level is currently less than 20%.

BUSINESS UNIT UPDATES

Southern Alberta
During the period, APF continued to focus on shallow gas-bearing zones in the Cretaceous formation. The Trust drilled 3 (1.1 net) wells at Carmangay, Retlaw and Iron Springs, targeting the Sunburst, Glauconitic and Barons zones respectively. Capital expenditures totalled $1.9 million during the period. Production was weighted 86% to natural gas and averaged 3,700 boe/d.

Since the completion of the quarter, APF has drilled 28 shallow gas wells on its 100% interest lands at Countess, in addition to two 100% interest deeper wells. All of these will be on stream by the end of November. APF will also be participating in a non-operated 46 (15.2 net) well shallow gas program at Countess, slated to commence by the end of the quarter, with a target on-stream date of March, 2005. At Robsart, in southwest Saskatchewan, APF expects to drill four shallow gas wells by year-end.

Central Alberta
The Central Alberta Business Unit largely comprises the assets that were acquired in the Great Northern transaction, principally at Innisfail and Wood River. As a result of the time required to integrate Great Northern's drilling prospects into APF's capital program, there was no conventional drilling activity in this area during the period. Activity was restricted to coalbed methane ("CBM") operations, where APF drilled three 100% working interest wells into the dry

Horseshoe Canyon coals. The Trust continues to experience encouraging results in the area and added to its CBM inventory at Crown land sales in August and October, strengthening APF's position in this exciting resource play.

Capital expenditures amounted to $6.2 million for the quarter, 59% of which was allocated to CBM and included $2.5 million for land acquisitions. Production averaged 7,000 boe/d during the period, weighted 53% to natural gas.

Plans for the fourth quarter include the drilling of five shallow Edmonton sand gas wells at Innisfail with an average working interest of 88%; two Ellerslie/Basal Quartz gas wells at Wood River (81% and 100% interest) with the potential for five more follow-up wells in early 2005; and two heavy oil wells at Lone Rock and Epping (80% and 100% interest), with the potential for eight more locations to be drilled, completed and producing in the first quarter of 2005.

Western Alberta

Activity in this Business Unit focused on completions, facilities upgrades and the acquisition of land and seismic, as APF continued to focus on long term geological prospects in an area where it controls several blocks of high working-interest lands. Capital expenditures amounted to $2.6 million and production averaged 3,700 boe/d during the period, weighted 62% to natural gas.

Development initiatives during the fourth quarter contemplate 5 (2.5 net) gas wells of varying depth at Redwater, with on-stream dates in early 2005.

Southeast Saskatchewan

APF drilled 4 (2.0 net) Mississippian oil wells during the period on capital expenditures of $2.8 million. Production averaged 3,600 boe/d during the period, weighted 96% to oil.

Seven locations have been identified for the fourth quarter of 2004 or early 2005, with additional capital to be invested in optimization and waterflood programs at Tatagwa, Macoun and Queensdale.

Wyoming

APF's assets in Wyoming consist exclusively of CBM, where 8 (2.8 net) shallow wells were drilled during the period. Three initial phases at Kane have been drilled and completed this year with 15 (3.75 net) wells currently on production and another 13 (3.25 net) wells awaiting tie-in. Average production from APF's Wyoming assets has increased from 730 mcf/d at the beginning of the year to an average of 1,100 mcf/d during the third quarter. Capital expenditures for the period amounted to $0.42 million.

The fourth phase of drilling at Kane has commenced and 24 additional wells (9.6 net) will be drilled and completed during the fourth quarter, bringing the total number of producing wells to 52 (16.6 net). At Big Bend, development plans are being submitted for an additional 20 (18 net) wells to be drilled in the first half of 2005. The preliminary results have been very encouraging with gas production commencing fairly rapidly.

	3 Months Ended September 30				9 Months Ended September 30			
	2004		2003		**2004**		2003	
Drilling Activity	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**6.0**	**2.1**	28.0	9.4	**22.0**	**6.0**	45.0	13.7
Gas	**4.0**	**1.1**	15.0	11.8	**23.0**	**10.7**	42.0	18.5
Coalbed methane	**11.0**	**5.8**	-	-	**49.0**	**21.9**	-	-
Other	**3.0**	**2.2**	1.0	0.5	**4.0**	**2.3**	5.0	0.8
Dry and abandoned	-	-	-	-	**1.0**	**1.0**	-	-
Total	**24.0**	**11.2**	44.0	21.7	**99.0**	**41.9**	92.0	33.0

FINANCIAL SUMMARY

Cash flow for the quarter amounted to $30.9 million with distributions totalling $26.5 million ($0.48 per unit). Cash flow for the quarter was reduced by $5.9 million ($0.11 per unit) as a result of derivative settlements arising from the sharp run up in the price of crude oil. APF's payout ratio, after accounting for accrued interest on the convertible debentures, was 89%. APF remains committed to retaining a greater portion of its cash flow and is targeting a payout ratio of 80% by the end of 2004.

Impacting cash flows were increased operating expenses resulting from workovers and other remedial activity on projects not originally budgeted for by APF. In aggregate, corporate operating costs for the quarter amount to $9.78 per boe, versus $8.21 per boe during the previous quarter. In the near term, APF expects operating costs to remain stable at third quarter rates, as the Trust formulates its operating and capital budgets for 2005. Further guidance regarding longer term operating costs will be provided when APF next releases financial and engineering results in the first quarter of 2005.

On September 8, 2004, the Trust completed a $35 million equity offering at $11.30 per unit. The proceeds were used initially to repay bank debt which, at the end of the third quarter, amounted to $150 million. Taking into account the monthly proceeds from APF's distribution reinvestment plan, the surplus generated by the cash holdback and the anticipated capital expenditures, the Trust estimates the net effect to be a year-end debt position of approximately $164 million at current commodity prices. Together with $48 million of principal outstanding on its convertible debenture, total debt will be approximately $212 million or 1.7 times annualized third quarter cash flow.

SUMMARY OF OPERATING & FINANCIAL RESULTS

FINANCIAL	3 Months Ended September 30		9 Months Ended September 30	
($000, except per unit/boe amounts)	**2004**	2003	**2004**	2003
		Restated[4]		Restated[4]
Cash flow from operations[1]	**30,874**	20,528	**79,431**	67,288
Per unit - basic	**$ 0.56**	$ 0.63	**$ 1.76**	$ 2.25
Per unit - diluted	**$ 0.52**	$ 0.56	**$ 1.60**	$ 2.14
Distributable income[2]	**$ 29,711**	$ 19,391	**$ 76,007**	$ 66,151
Per unit - basic	**$ 0.54**	$ 0.60	**$ 1.68**	$ 2.21
Per unit - diluted	**$ 0.50**	$ 0.53	**$ 1.53**	$ 2.10
Distributions declared	**26,517**	18,909	**68,862**	50,891
Per unit	**$ 0.48**	$ 0.57	**$ 1.52**	$ 1.67
Payout ratio	**89%**	98%	**91%**	77%
Bank debt	**150,000**	90,000	**150,000**	90,000
Operating costs per boe	**$ 9.78**	$ 7.17	**$ 8.69**	$ 6.81
Operating netbacks per boe	**$ 21.84**	$ 20.75	**$ 22.52**	$ 23.56
Market				
Units outstanding (000)				
End of period	**57,692**	33,868	**57,692**	33,868
Weighted average - basic	**54,720**	32,507	**45,181**	29,953
Weighted average - fully diluted	**59,141**	36,870	**49,602**	31,493
Trust unit trading				
High	**$ 12.14**	$ 12.63	**$ 12.63**	$ 12.63
Low	**$ 11.24**	$ 11.08	**$ 10.32**	$ 9.30
Close	**$ 11.74**	$ 11.66	**$ 11.74**	$ 11.66
Average daily volume	**336,912**	228,260	**295,409**	177,700

OPERATIONS	3 Months 2004	3 Months 2003	9 Months 2004	9 Months 2003
Daily production (average)				
Total crude oil (bbl)	**7,675**	6,731	**6,712**	6,462
NGLs (bbl)	**971**	400	**660**	319
Natural gas (mcf)	**57,695**	33,675	**46,926**	32,744
Total (boe)[3]	**18,262**	12,744	**15,193**	12,238
Realized commodity prices ($Cdn.)				
Total crude oil (bbl)	**$ 41.05**	$ 32.94	**$ 38.56**	$ 35.40
NGLs (bbl)	**$ 42.28**	$ 29.35	**$ 39.17**	$ 32.06
Natural gas (mcf)	**$ 6.52**	$ 6.15	**$ 6.80**	$ 7.00
Average (boe)[3]	**$ 40.09**	$ 34.56	**$ 39.74**	$ 38.27
Reference pricing				
WTI (U.S.$/bbl)	**$ 43.88**	$ 30.20	**$ 39.10**	$ 30.99
AECO gas ($Cdn./mcf)	**$ 6.66**	$ 6.29	**$ 6.69**	$ 7.07
Foreign Exchange ($U.S./$Cdn.)	**1.3072**	1.3801	**1.3282**	1.4294

(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) Distributable income has been calculated by reducing cash flow from operations by interest accrued on the convertible debentures.

(3) 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.

(4) 2003 comparative results have been restated for the three and nine month periods ended September 30 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

November 3, 2004

Management's Discussion and Analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements for the nine months ended September 30, 2004 and September 30, 2003 and with the audited consolidated financial statements and MD&A for the year ended December 31, 2003. The financial information has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") and is presented in Canadian dollars. Additional information relating to APF, including disclosures required under National Instrument 51-101 ("NI 51-101"), can be found in the APF's 2003 Annual Information Form ("AIF") on SEDAR at www.sedar.com or on APF's website at www.apfenergy.com. This MD&A was written on October 27, 2004.

PRODUCTION

Production volumes were 43% higher during the third quarter of 2004 compared to 2003, reflecting both the integration of corporate acquisitions and a successful drilling program. Light and medium crude oil production increased 17% while drilling activity offset heavy crude oil natural production declines. Natural gas production increased 71% and related natural gas liquids increased 143% over the prior quarter due mainly to the Great Northern Exploration Ltd ("Great Northern") acquisition completed during the second quarter of 2004. A full three months of operations are included in the third quarter results and four months of operations are included in the nine months ended September 30, 2004.

	3 Months Ended September 30			9 Months Ended September 30		
	2004	2003	% Change	**2004**	2003	% Change
Light/medium crude oil (bbl/d)	**6,485**	5,541	17	**5,587**	5,463	2
Heavy oil (bbl/d)	**1,190**	1,190	-	**1,125**	999	13
NGL (bbl/d)	**971**	400	143	**660**	319	107
Natural gas (mcf/d)	**57,695**	33,675	71	**46,926**	32,744	43
Total (boe/d)	**18,262**	12,744	43	**15,193**	12,238	24
Production split						
Oil & NGLs	**47%**	56%	(15)	**49%**	55%	(12)
Natural Gas	**53%**	44%	20	**51%**	45%	15

MARKETING

For the three months ended September 30, 2004, APF's production split was 47% crude oil and NGLs and 53% natural gas. Crude oil is sold under 30-day evergreen contracts while the majority of natural gas production is sold in the spot market. Approximately 15% of natural gas volumes are sold to aggregators pursuant to long-term contracts; this weighting had decreased from 20% due to the Great Northern acquisition. APF's current quarter and year-to-date production split reflects the impact of natural gas weighted acquisitions.

PRICES

Third quarter crude oil prices before realized derivatives increased 40% compared to the same quarter in 2003, which is consistent with a 45% increase in the benchmark West Texas Intermediate ("WTI") over the same period. The impact of favourable crude oil prices was partly offset by a 5% decline in the value of the US dollar relative to the Canadian dollar during the quarter. Third quarter natural gas prices before realized derivatives increased 9% over the prior quarter, while the benchmark AECO price increased 6% over the same period.

The net impact of realized crude oil derivatives during the third quarter reduced the price of crude oil before derivatives by 15% to $41.05 per boe. Crude oil prices after derivatives increased 25% over the prior quarter despite the negative impact of derivatives due to a strong commodity price environment. Realized natural gas derivatives reduced the price of natural gas during the quarter to $6.52 per mcf, which is 1% lower than the price before derivatives and represents a 6% increase over the price realized during the same period in 2003.

NYMEX futures contracts for the remainder of 2004 and into 2005 suggest crude oil prices will exceed the average 2004 level to date, as geopolitical events continue to inject a premium into the price of crude oil in the commodity markets. APF expects gas prices to increase during the fourth quarter 2004 and to exceed 2004 levels in 2005.

Effective January 1, 2004, APF had segregated costs associated with the transportation and selling of crude oil, natural gas and NGLs. Previously, APF had followed industry practice, which was to present revenue net of these costs. Accordingly, the September 30, 2003 comparative figures have been restated with these costs segregated, resulting in an increase to the gross price per unit.

	3 Months Ended September 30			9 Months Ended September 30		
Prices - Before Derivatives ($Cdn.)	**2004**	2003	% Change	**2004**	2003	% Change
Light/medium crude oil (bbl)	$ **50.38**	$ 36.09	40	$ **46.28**	$ 38.93	19
Heavy oil (bbl)	**37.79**	26.94	40	**32.31**	$ 27.82	16
Total crude oil (bbl)	**48.42**	34.47	40	**43.93**	37.21	18
NGLs (bbl)	**42.28**	29.35	44	**39.17**	$ 32.06	22
Natural gas (mcf)	**6.61**	6.09	9	**6.81**	$ 7.04	(3)
Total (boe)	$ **43.48**	$ 35.21	23	$ **42.15**	$ 39.32	7
Derivatives ($Cdn.)						
Crude oil (bbl)	$ **(7.37)**	$ (1.53)	382	$ **(5.37)**	$ (1.81)	197
Natural gas (mcf)	**(0.09)**	0.06	(250)	**(0.01)**	(0.04)	(75)
Total (boe)	$ **(3.39)**	$ (0.65)	422	$ **(2.41)**	$ (1.05)	130
Prices - After Derivatives ($Cdn.)						
Total crude oil (bbl)	**41.05**	32.94	25	**38.56**	35.40	9
NGLs (bbl)	**42.28**	29.35	44	**39.17**	32.06	22
Natural gas (mcf)	**6.52**	6.15	6	**6.80**	7.00	(3)
Total (boe)	$ **40.09**	$ 34.56	16	$ **39.74**	$ 38.27	4
Reference Pricing						
WTI ($U.S./bbl)	$ **43.88**	$ 30.20	45	$ **39.10**	$ 30.99	26
AECO gas ($Cdn./mcf)	$ **6.66**	$ 6.29	6	$ **6.69**	$ 7.07	(5)
Foreign exchange ($U.S./$Cdn.)	**1.3072**	1.3801	(5)	**1.3282**	1.4294	(7)

DERIVATIVES

APF enters into derivative contracts as part of its risk mitigation strategy in order to manage commodity price fluctuations and stabilize cash flows available for unitholder distributions and future development programs. Derivatives 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 fair value of all derivatives at September 30, 2004 is presented in Note 6 to the unaudited third quarter financial statements.

For the third quarter of 2004, APF had entered into crude oil and natural gas derivatives representing approximately 49% (3,761 bbl/d) of crude oil volumes and 35% (20,193 mcf/d) of natural gas production volumes. Realized crude oil and natural gas derivatives lowered third quarter revenues by $5.69 million, or $7.37 per barrel of crude oil and $0.09 per mcf of natural gas. Revenues for the nine months ended September 30, 2004 were reduced by $10.05 million, or $5.37 per barrel of crude oil and $0.01 per mcf of natural gas.

For the balance of 2004, APF has entered into derivatives that hedge approximately 47% of projected crude oil and 22% of projected natural gas volumes. 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, collars, and NYMEX futures for natural gas volumes. A summary of crude oil and natural gas derivative contracts outstanding at the end of the quarter and those in place at the effective date of this report are presented in the table below.

Effective January 1, 2004, APF implemented the Canadian Institute of Chartered Accountants ("CICA") Accounting Guideline 13 "Hedging Relationships". Under the new guideline, in order to apply hedge accounting, an entity must formally document the hedging arrangement and sufficiently demonstrate that the hedging item will be effective over the life of the hedged item. APF previously recognized hedging gains and losses as they were realized at the end of the contract. Based on our review of existing hedging relationships, the majority of APF's commodity, interest rate and foreign currency contracts do not qualify for hedge accounting. The effectiveness of APF's AECO natural gas hedges could potentially be demonstrated, however, the Trust has decided that applying hedge accounting on some transactions but not others would result in less transparent and potentially misleading financial information.

In accordance with the new guideline, on January 1, 2004, the fair value all outstanding derivative instruments deemed not to qualify for hedge accounting was recorded on the Consolidated Balance sheet with an offsetting net deferred loss amount. APF recorded a derivative liability of $1.30 million, which was comprised of a $0.40 million unrealized loss related to crude oil and natural gas contracts and a $0.90 million unrealized loss related to interest rate swaps, with a corresponding $1.30 million deferred derivative loss. At September 30, 2004, $1.06 million of the deferred derivative loss had been recognized into income; the remaining $0.24 million expected to settle during the fourth quarter of 2004.

At September 30, 2004, the estimated fair value of outstanding derivative instruments resulted in a derivative liability of $12.45 million. Included in the derivative liability balance was $0.63 million in call premiums received on sold call options. A loss on unrealized derivative contracts of $6.09 million had been recorded as an expense on the statement of operations to reflect the change in fair values since June 30, 2004.

At September 30, 2004, APF had the following derivative instruments in place:

Period	Commodity	Type of Contract	Average Daily Quantity	Average Daily Price
October 2004	Natural gas	Swap	14,000 GJ	Cdn.$5.79/GJ
October 2004	Natural gas	Swap	2,000 mmbtu	US$5.95/mmbtu
October 2004	Natural gas	Bought Put	5,000 GJ	Cdn.$6.50/GJ
November 2004 to March 2005	Natural gas	Sold Call	5,000 GJ	Cdn.$11.80/GJ
October to December 2004	Crude oil	Swap	3,600 bbls	US$32.61/bbl
November to December 2004	Crude oil	Sold Call	1,000 bbls	US$44.83/bbl
January to March 2005	Crude oil	Swap	1,500 bbls	US$35.78/bbl
January to March 2005	Crude oil	Collars	1,000 bbls	US$38.00 to US$44.95/bbl
January to March 2005	Crude oil	Sold Call	500 bbls	US$42.37/bbl
April to June 2005	Crude oil	Swap	667 bbls	US$36.66/bbl
April to June 2005	Crude oil	Collars	1,500 bbls	US$38.33 to US$42.85/bbl
April to June 2005	Crude oil	Sold Call	500 bbls	US$40.95/bbl

APF sold call options on crude oil volumes during the quarter and received the following call premiums relating to outstanding contracts at September 30, 2004:

Period	Commodity	Type of Contract	Average Daily Quantity	Average Premium
November to December 2004	Crude oil	Sold Call	1,000 bbls	US$3.11/bbl
January to March 2005	Crude oil	Sold Call	500 bbls	US$3.19/bbl
April to June 2005	Crude oil	Sold Call	500 bbls	US$3.45/bbl

The following derivative instruments were entered into subsequent to September 30, 2004 and are currently in place:

Period	Commodity	Type of Contract	Average Daily Quantity	Average Daily Price
November 2004 to March 2005	Natural gas	Collars	5,000 GJ	Cdn.$7.00 to Cdn.$11.35/GJ
April to June 2005	Crude oil	Collars	500 bbls	US$42.00 to US$51.20/bbl
July to September 2005	Crude oil	Collars	500 bbls	US$42.00 to US$52.10/bbl

In addition to commodity derivatives, APF has also entered into foreign currency derivative contracts. APF has hedged $U.S. 30 million of revenue at an average rate of $Cdn. 1.3416 or $U.S. 0.7454 for calendar 2004.

At September 30, 2004, APF had the following fixed interest rates on a portion of its outstanding debt:

Term	Amount (000)	Interest rate
July 2004 to May 2006	$20,000	3.60% plus stamping fee
July 2004 to March 2007	$20,000	3.58% plus stamping fee
July 2004 to November 2005	$20,000	3.58% plus stamping fee
September 2004 to September 2007	$20,000	3.65% plus stamping fee

REVENUES

Net oil and gas revenue for the third quarter of 2004 was 68% higher than the comparable period in 2003, reflecting increased natural gas production resulting from the Great Northern acquisition combined with higher crude oil price realizations. Net oil and gas revenue for the nine months ended September 30, was 30% higher in 2004 when compared to the prior period. Effective January 1, 2004, APF has segregated costs associated with transportation and selling crude oil, natural gas and NGLs. APF previously followed industry practice which was to present revenue net of these costs, however, the comparative figures presented have been restated with these costs segregated.

	3 Months Ended September 30			9 Months Ended September 30		
Oil and Gas		Restated			Restated	
(000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Light/medium crude oil sales	**$ 30,063**	$ 18,399	63	**$ 70,848**	$ 58,071	22
Heavy oil sales	**4,137**	2,949	40	**9,960**	7,585	31
NGL sales	**3,777**	1,080	250	**7,084**	2,790	154
Natural gas sales	**35,068**	18,867	86	**87,584**	62,941	39
Gross Oil and Gas Revenue	**73,045**	41,295	77	**175,476**	131,388	34
Commodity price derivative loss	**(5,690)**	(772)	637	**(10,045)**	(3,521)	185
Transportation	**(1,461)**	(1,047)	40	**(3,818)**	(3,024)	26
Other	**1,139**	495	130	**2,766**	1,504	84
Net Oil and Gas Revenue	**67,033**	39,971	68	**164,379**	126,347	30
Per boe	**$ 39.90**	$ 34.09	17	**$ 39.49**	$ 37.82	4

ROYALTIES

During the third quarter, total royalties as a percentage of gross oil and gas revenue was marginally higher at 19.0% compared to 17.5% during 2003 due to an increase in the crown royalty reference rates and higher realized crude oil prices than during the same three month period last year. As expected, year-to-date royalties as a percentage of gross oil and gas revenue is consistent with the prior year.

	3 Months Ended September 30			9 Months Ended September 30		
(000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Crown royalties	**$ 8,956**	$ 4,266	110	**$ 21,718**	$ 14,526	50
Freehold royalties	**3,613**	2,207	64	**9,448**	8,073	17
Overriding royalties	**1,343**	760	77	**3,293**	2,307	43
Total royalties	**$ 13,912**	$ 7,233	92	**$ 34,459**	$ 24,906	38
% of gross oil and gas revenue	**19.0%**	17.5%	9	**19.6%**	19.0%	4
Per boe	**$ 8.28**	$ 6.17	34	**$ 8.28**	$ 7.45	11

OPERATING EXPENSES

Operating expenses per boe for the three and nine months ended September 30, 2004 increased 36% and 28%, respectively, over the prior periods presented. The increase is due to ongoing field optimization costs on newly-acquired properties and higher energy costs compared to the prior quarter. APF plans to continue with field optimization initiatives on Great Northern properties and expects operating costs will remain stable for the remainder of 2004.

	3 Months Ended September 30			9 Months Ended September 30		
		Restated			Restated	
(000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Operating expenses	**$ 16,438**	$ 8,403	96	**$ 36,160**	$ 22,751	59
Per boe	**$ 9.78**	$ 7.17	36	**$ 8.69**	$ 6.81	28

OPERATING NETBACKS

Operating netbacks for the three month period ended September 30 increased 5% over the same period in 2003, with higher realized commodity prices partially offset by an increase in operating costs and royalty expense.

	3 Months Ended September 30			9 Months Ended September 30		
($ per boe)	**2004**	2003	% Change	**2004**	2003	% Change
Gross revenue						
(after commodity price derivatives)	**$40.09**	$34.56	16	**$39.74**	$38.27	4
Transportation	**(0.87)**	(0.89)	(3)	**(0.92)**	(0.91)	1
Other	**0.68**	0.42	61	**0.66**	0.45	48
	$39.90	$34.09	17	**$39.49**	$37.82	4
Royalties	**(8.28)**	(6.17)	34	**(8.28)**	(7.45)	11
Operating costs	**(9.78)**	(7.17)	36	**(8.69)**	(6.81)	28
Operating Netback	**$21.84**	$20.75	5	**$22.52**	$23.56	(4)

GENERAL AND ADMINISTRATIVE

On a per barrel of oil equivalent basis, third quarter general and administrative cost decreased 19% over the comparable quarter in 2003 and 1% over the nine months ended September 30, 2003. Staff and administrative costs have increased over the prior nine months ended September 30, however, the year-to-date increase is commensurate with the growth of APF operations.

	3 Months Ended September 30			9 Months Ended September 30		
(000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
General and administrative	**$ 2,722**	$ 2,334	17	**$ 7,438**	$ 6,042	23
Per boe	**$ 1.62**	$ 1.99	(19)	**$ 1.79**	$ 1.81	(1)

INTEREST

Interest expense for the three and nine months ended September 30, 2004 increased by 27% and 0% per boe, respectively. Additional debt of approximately $127 million was incurred to finance the Great Northern acquisition in June 2004 and net proceeds of approximately $33 million from the September 8, 2004 trust unit offering were used to repay long-term debt.

	3 Months Ended September 30			9 Months Ended September 30		
(000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Interest	**$ 1,594**	$ 877	82	**$ 3,849**	$ 3,084	25
Per boe	**$ 0.95**	$ 0.75	27	**$ 0.92**	$ 0.92	-

DEPLETION, DEPRECIATION AND ACCRETION

Depletion, depreciation and accretion ("DD&A") per boe increased 58% and 57%, respectively, for the three and nine months ended September 30 compared to the same periods in 2003. The increase is due primarily to acquisitions completed during 2003 and 2004 resulting in a larger property, plant, and equipment base. Asset retirement obligation accretion contributes to the remainder of the increase over the prior periods presented. September 30, 2003 comparative figures include the impact of adopting CICA Handbook Section 3110 "Asset Retirement Obligations".

	3 Months Ended September 30			9 Months Ended September 30		
		Restated			Restated	
(000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Depletion, depreciation and accretion	**$ 29,023**	$ 12,799	127	**$ 69,889**	$ 35,686	96
Per boe	**$ 17.27**	$ 10.92	58	**$ 16.79**	$ 10.68	57

COMPENSATION EXPENSE

APF prospectively adopted the CICA Handbook Section 3870 – "Stock Based Compensation" during the fourth quarter of 2003. As per the transitional provisions of the new standard, companies that adopted the standard prior to December 31, 2003 were required to recognize compensation expense for those options granted during 2003 and later, with proforma disclosure of options granted during 2002. Comparative figures for 2003 have been restated to reflect the impact of stock-based compensation.

For the three and nine months ended September 30, 2004, APF recorded compensation expense of $0.79 million and $0.99 million, respectively, compared to $0.43 million and $0.66 million in 2003. The increase is due mainly to a higher per unit market value and accumulated price reductions under the Trust Unit Rights Plan.

	3 Months Ended September 30			9 Months Ended September 30		
		Restated			Restated	
(000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Compensation expense	**$ 790**	$ 434	82	**$ 989**	$ 659	50
Per boe	**$ 0.47**	$ 0.37	27	**$ 0.24**	$ 0.20	20

TAXES

Saskatchewan capital tax and federal large corporation tax increased 66% and 13%, respectively, over the three and nine month period ended September 30, 2004, reflecting the 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.

During the third quarter of 2004, APF recovered $9.20 million in future income taxes compared to a future tax recovery of $3.80 million in 2003. A future income tax balance of $92.42 million is recorded as a liability as at September 30, 2004. The September 30, 2003 comparative figures include the impact of adopting CICA Handbook Section 3110 "Asset Retirement Obligations".

	3 Months Ended September 30			9 Months Ended September 30		
		Restated			Restated	
(000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Capital and other taxes	**$ 948**	$ 572	66	**$ 2,364**	$ 2,096	13
Per boe	**$ 0.56**	$ 0.49	15	**$ 0.57**	$ 0.63	(10)
Recovery of future income taxes	**$ (9,200)**	$ (3,800)	142	**$ (21,304)**	$ (14,659)	45

NET INCOME

Net income for the three and nine months ended September 30, 2004 has decreased 60% (81% per unit-basic and diluted) and 64% (75% per unit-basic and diluted), respectively, compared to the same periods in 2003. The decrease can be attributed to unrealized losses recognized under CICA Accounting Guideline 13 (AcG-13) "Hedging Relationships", higher operating expenses resulting from continued field optimization initiatives on Great Northern properties, and higher depletion, depreciation, and accretion on a larger property, plant, and equipment base.

The loss reported by APF during the fourth quarter of 2003 is a result of the Trust's Short Term Incentive Plan ("STIP") and lower commodity prices realized during the quarter. APF has provided for the STIP earned to the end of September 30, 2004.

SUMMARY OF QUARTERLY RESULTS

($000, except per	2004			Restated				Restated
unit amounts)	**Q3**	**Q2**	**Q1**	2003 Q4	2003 Q3	2003 Q2	2003 Q1	2002 Q4
Total revenue	**46,776**	**39,169**	**32,141**	31,543	32,737	33,294	35,410	23,944
Net income	**4,461**	**6,113**	**8,127**	(2,507)	11,118	20,977	13,688	(942)
Per unit - basic ($)	**0.06**	**0.12**	**0.19**	(0.11)	0.32	0.65	0.54	(0.04)
Per unit - diluted ($)	**0.06**	**0.12**	**0.19**	(0.11)	0.31	0.65	0.54	(0.04)

Total revenues have increased commensurate with production volumes and a strong commodity price environment. Total revenue in 2004 includes the impact of unrealized derivative losses on commodity contracts outstanding at the end of each quarter. Prior periods presented do not reflect similar unrealized derivative losses as CICA Accounting Guideline 13 "Hedging Relationships" did not become effective until January 1, 2004.

CAPITAL EXPENDITURES, ACQUISITIONS AND DISPOSITIONS

Capital expenditures for the nine months ended September 30, 2004 totalled $330.46 million, including the $291.08 million acquisition of Great Northern. The 2003 comparative period totals $182.59 and reflects the acquisitions of Hawk Oil Inc., Nycan Energy Corp., and CanScot Resources Ltd. Capital expenditures during the third quarter were down significantly from the prior quarter due to a 45% decline in drilling activity resulting from an unusually long spring break-up period. On August 19, 2004, APF expanded its 2004 drilling program from $40 million to between $55 million and $64 million for the 2004 calendar year as a result of the acquired Great Northern properties.

	3 Months Ended September 30		9 Months Ended September 30	
(000)	2004	2003	2004	2003
Corporate acquisitions	$ -	$ 32,981	$ 291,084	$ 137,622
Property acquisitions	14	16,333	6,587	23,821
Land acquisitions	3,332	1,443	6,096	1,823
Seismic	447	390	1,570	974
Drilling and completions	8,167	8,188	19,158	15,768
Production facilities	3,044	2,016	5,601	4,533
Other	241	146	559	378
Subtotal	$ 15,245	$ 61,497	$ 330,655	$ 184,919
Dispositions	-	(2,069)	(199)	(2,331)
Net capital expenditures	$ 15,245	$ 59,428	$ 330,456	$ 182,588

CASH DISTRIBUTIONS

Cash distributions during the third quarter of 2004 were $26.52 million, or $0.48 per trust unit, compared to $18.91 million or $0.57 per trust unit during the prior year comparable period. The payout ratio, after adjusting for accumulated interest on the outstanding convertible debentures, was 89% for the third quarter, during which period APF funded $2.39 million of operations from cash flow (2003 - ($0.18) million). For the nine month period ended September 30, 2004, cash distributions totalled $68.86 million (2003 - $50.89 million), resulting in a 91% payout ratio (2003 - 77%). For the remainder of 2004, APF intends to maintain its historical policy of retaining a portion of available cash flow to fund capital expenditures and development initiatives, with a target range of 10% to 20%, working ultimately towards an 80% payout ratio.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2004, APF had a revolving term credit facility in the amount of $200 million, of which $150 million was drawn (December 31, 2003 - $98 million). The facility may be drawn down or repaid at any time, and there are no scheduled repayment terms. The balance of convertible debentures, net of conversions, at the end of the quarter was $48.56 million (December 31, 2003 - $48.79 million).

At September 30, 2004, APF had a working capital deficit of approximately $21.18 million, compared to a working capital deficit of $10.25 million at December 31, 2003. The change in APF's working capital position is due to a derivative liability recorded in accordance with CICA Accounting Guideline 13 (AcG-13) "Hedging Relationships". Effective January 1, 2004, the guideline requires that all derivative instruments be measured at fair value and recorded on the balance sheet as an asset or liability. At September 30, 2004, a derivative liability of $12.45 million is recorded on the balance sheet (December 31, 2003 - $nil). The ultimate settlement of these derivative liabilities is dependent upon changes in commodity prices, foreign exchange rates, and interest rates during the remaining life of derivative contracts.

UNITHOLDERS' EQUITY

At September 30, 2004, APF had 57.69 million Trust units outstanding (2003 - 33.87 million) and a market capitalization of approximately $677 million (2003 - $395 million).

APF issued 0.99 million Trust units (2003 - nil) in the third quarter pursuant to the Premium Distribution Reinvestment Plan ("Premium DRIP"), generating $10.75 million in proceeds. During the first nine months of 2004, APF issued 2.50 million Trust units (2003 - nil) for total proceeds of $27.95 million in respect of the Premium DRIP.

During 2004, APF has completed three Trust unit issuances:

- February 4, 2004 - APF issued 4.78 million Trust units at $11.60 per unit for gross proceeds of $55.40 million. The proceeds of this offering were initially used to provide working capital flexibility and to reduce leverage, and later used to finance the cash portion of the Great Northern acquisition.
- On June 4, 2004, APF issued 12.89 million Trust units at $12.18 per unit as part of the Great Northern acquisition.
- On September 8, 2004, APF issued 3.10 million Trust units at $11.30 per unit for gross proceeds of $35.03 million. The net proceeds of the issue were used to repay outstanding indebtedness and ultimately to fund APF's expanded 2004 capital expenditure program.

BUSINESS RISKS

No changes have been made to the Business Risks as stated in APF's quarterly report for the three months ended March 31, 2004.

CRITICAL ACCOUNTING ESTIMATES

No changes have been made to the Critical Accounting Estimates as stated in APF's quarterly report for the three months ended March 31, 2004.

OUTLOOK

APF is an industry leader in adopting a full cycle development business model and is committed to complementing its effective acquisition strategy with a program of acquiring land and exploiting its land base through drilling, recompletions and field optimizations. APF will continue to accelerate the pace of its CBM program with particular focus on its inventory of Horseshoe Canyon prospects. With low production declines and the potential for higher rates of return than conventional gas production, CBM presents a very attractive opportunity that is ideally suited for the trust structure. APF's revised capital expenditure budget for the balance of 2004 will result in drilling activity during the final quarter of 2004 to be considerably higher than that experienced to date.

DISCLAIMER

Certain statements in this document are "forward-looking statements" including outlook on oil and gas prices, royalty rates, operating expenses, estimates of future production, estimated completion dates of construction and development projects, business plans for drilling and exploration, estimated amounts and timing of capital expenditures and anticipated future debt levels. Information concerning reserves contained in this material may also be deemed to be forward-looking statements as such estimates involving 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 Energy Trust and APF Energy Inc. These risks include, but are not limited to: the risks of the oil and gas industry (e.g., operational risks in exploration for; development and production of crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; and health, safety and environmental risks); risks in conducting foreign operations (e.g., political and fiscal instability in nations where APF Energy does business); the possibility that government policies may change or governmental approvals may be delayed or withheld; and price and exchange rate fluctuations. These and other risks are described in APF Energy's reports that are on file with Canadian securities regulatory authorities. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors and management's course of action would depend upon its assessment of the future considering all information then available. Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to APF or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. APF assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

CONSOLIDATED BALANCE SHEETS (unaudited)

	September 30, 2004 ($000)	December 31, 2003 Restated (note 2) ($000)
ASSETS		
Current assets		
Cash	$ 894	$ 1,381
Accounts receivable	40,053	27,542
Deferred derivative loss (note 6)	244	-
Other current assets	5,136	3,506
	46,327	32,429
Asset retirement fund	3,400	2,342
Goodwill	118,479	48,230
Property, plant and equipment	663,207	413,706
	$ 831,413	$ 496,707
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	$ 45,819	$ 36,711
Derivative liabilities (note 6)	12,452	-
Cash distribution payable (note 3)	9,231	5,963
	67,502	42,674
Future income taxes	92,423	63,991
Long-term debt (note 8)	150,000	98,000
Asset retirement obligation (note 5)	30,836	21,803
	340,761	226,468
UNITHOLDERS' EQUITY		
Unitholders' investment account (note 7)	598,070	324,317
Contributed surplus	1,706	1,241
Accumulated earnings	98,594	79,895
Accumulated cash distributions (note 3)	(248,225)	(179,363)
Convertible debentures	46,247	46,466
Accumulated interest on convertible debentures	(5,740)	(2,317)
	490,652	270,239
	$ 831,413	$ 496,707

CONSOLIDATED STATEMENTS OF OPERATIONS AND ACCUMULATED EARNINGS (unaudited)
(000's except for per unit amounts)

	3 months ended September 30		9 months ended September 30	
	2004	2003	**2004**	2003
		Restated (note 2)		Restated (note 2)
REVENUE				
Oil and gas	**$ 74,184**	$ 41,789	**$ 178,242**	$ 132,893
Realized derivative loss - net	**(5,949)**	(772)	**(10,304)**	(3,521)
Unrealized derivative loss - net (note 6)	**(6,086)**	-	**(11,575)**	-
Royalties expense, net of ARTC	**(13,912)**	(7,233)	**(34,459)**	(24,906)
Transportation	**(1,461)**	(1,047)	**(3,818)**	(3,024)
	46,776	32,737	**118,086**	101,442
EXPENSES				
Operating	**16,438**	8,403	**36,160**	22,751
General and administrative	**2,722**	2,334	**7,438**	6,042
Interest on long-term debt	**1,594**	877	**3,849**	3,084
Depletion, depreciation and accretion	**29,023**	12,799	**69,889**	35,686
Stock-based compensation expense (note 7)	**790**	434	**989**	659
Capital and other taxes	**948**	572	**2,364**	2,096
	51,515	25,419	**120,689**	70,318
Income (loss) before future income taxes	**(4,739)**	7,318	**(2,603)**	31,124
Recovery of future income taxes	**(9,200)**	(3,800)	**(21,304)**	(14,659)
Net income	**4,461**	11,118	**18,701**	45,783
Accumulated earnings - beginning of period, as restated	**94,135**	70,254	**78,637**	35,589
Retroactive application of change in accounting policy (note 2)	**-**	-	**1,258**	-
Accumulated earnings - end of period, as restated	**$ 98,596**	$ 81,372	**$ 98,596**	$ 81,372
Net income per unit - basic [1]	**$ 0.06**	$ 0.32	**$ 0.34**	$ 1.50
Net income per unit - diluted	**$ 0.06**	$ 0.31	**$ 0.34**	$ 1.46

(1) Net income has been reduced by interest accrued on the convertible debentures.

CONSOLIDATED STATEMENTS OF CASH FLOWS (unaudited)
(000's except for per unit amounts)

	3 months ended September 30		9 months ended September 30	
	2004	2003	**2004**	2003
		Restated (note 2)		Restated (note 2)
Cash provided by (used in)				
Operating activities				
Net income for the period	**$ 4,461**	$ 11,118	**$ 18,701**	$ 45,783
Items not affecting cash				
Depletion, depreciation and accretion	**29,023**	12,799	**69,889**	35,686
Future income taxes	**(9,200)**	(3,800)	**(21,304)**	(14,659)
Unrealized derivative loss - net (note 6)	**6,086**	-	**11,575**	-
Stock-based compensation expense	**790**	434	**989**	659
Asset retirement expenditures (note 5)	**(286)**	(23)	**(419)**	(181)
	30,874	20,528	**79,431**	67,288
Net change in non-cash working capital items				
Accounts receivable	**4,017**	2,491	**1,596**	5,735
Other current assets	**(205)**	9,393	**(933)**	(151)
Accounts payable and accrued liabilities	**(1,852)**	2,233	**(9,121)**	3,572
Derivative liabilities (note 6)	**633**	-	**633**	-
Due to APF Management	**-**	-	**-**	(3,923)
	2,593	14,117	**(7,825)**	5,233
Asset retirement fund contribution - net	**(249)**	(460)	**(1,058)**	(1,268)
	33,218	34,185	**70,548**	71,253
Investing activities				
Purchase of Great Northern (note 4)	**148**	-	**(65,405)**	-
Purchase of Hawk Oil	**-**	-	**-**	(3,457)
Purchase of Nycan Energy	**-**	-	**-**	(34,287)
Purchase of CanScot Resources	**-**	(20,516)	**-**	(20,516)
Additions to property, plant and equipment	**(15,231)**	(10,360)	**(32,984)**	(21,653)
Purchase of oil and natural gas properties	**(14)**	(18,156)	**(6,587)**	(25,644)
Proceeds on sale of properties	**-**	2,069	**199**	2,331
Changes in non-cash working capital - investing items	**1,085**	1,814	**(1,433)**	997
	(14,012)	(45,149)	**(106,210)**	(102,229)
Financing activities				
Issue of units for cash	**35,030**	-	**90,426**	55,670
Issue of units under DRIP	**10,748**	-	**27,945**	-
Issue of units for cash upon exercise of stock options	**1,156**	629	**2,937**	1,469
Convertible debentures - net of costs	**-**	47,684	**-**	47,684
Interest on convertible debentures	**(1,163)**	(1,137)	**(3,424)**	(1,137)
Unit issue costs	**(2,028)**	(41)	**(5,241)**	(3,335)
Net proceeds (repayment) of long-term debt	**(40,000)**	(18,150)	**(11,874)**	(20,920)
Cash distributions	**(26,517)**	(18,910)	**(68,862)**	(50,891)
Changes in non-cash working capital - financing items	**780**	(549)	**3,268**	2,362
	(21,994)	9,526	**35,175**	30,902
Change in cash during the period	**(2,788)**	(1,438)	**(487)**	(74)
Cash - Beginning of period	**3,682**	2,314	**1,381**	950
Cash - End of period	**$ 894**	$ 876	**$ 894**	$ 876

Supplemental information (note 9)

1. Significant Accounting Policies

The interim consolidated financial statements of APF Energy Trust ("APF") have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2003, except as described in Note 2 below. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto in APF's annual report for the year ended December 31, 2003.

2. Change in Accounting Policy

Asset Retirement Obligations

During the first quarter of 2004, APF adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3110 "Asset Retirement Obligations" (ARO). This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

The new standard requires the recognition of the liability associated with the future site reclamation costs of tangible long-lived assets. This liability would be comprised of APF's net ownership interest in producing wells and processing plant facilities. The liability for future retirement obligations is to be recorded in the financial statements at the time the liability is incurred.

The asset retirement obligation is initially recorded at the estimated fair value as a long-term liability with a corresponding increase to property, plant and equipment. The depreciation of property, plant and equipment is allocated to expense on the unit-of-production basis. The liability is increased each reporting period for the fair value of any new future site reclamation costs and the corresponding accretion on the original provision. The accretion is charged to earnings in the period incurred. The provision will also be revised for any changes to timing related to cash flows or undiscounted reclamation costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligation to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized to earnings in the period incurred.

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

As a result of adopting the new standard, at December 31, 2003, the ARO increased to $21.80 million, PP&E net of accumulated depletion increased by $12.42 million and the future income tax liability decreased by $0.23 million. Opening accumulated earnings as at January 1, 2004 increased by $1.26 million to reflect the cumulative impact of accretion and depletion expense, net of the cumulative site restoration provision and future income taxes, on the asset retirement obligation recorded retroactively to 1996, the inception of the Trust.

Comparative statements of operations and accumulated earnings were also restated at September 30, 2003. Depletion, accretion and amortization increased by $0.75 million and future tax recovery decreased by $0.07 million for the three month period ended September 30, 2003. Depletion, accretion and amortization increased by $2.06 million and future tax recovery decreased by $0.16 million for the nine month period ended September 30, 2003.

Derivatives Accounting

Effective January 1, 2004 APF implemented CICA Accounting Guideline 13 (AcG-13) "Hedging Relationships", which deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003.

The new guideline addresses hedging transactions for the purposes of applying hedge accounting and establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue hedge accounting for positions hedged with derivatives. APF is not applying hedge accounting to its hedging relationships.

At January 1, 2004, APF recorded $1.30 million for the mark-to-market value of the outstanding hedges as a derivative liability and a $1.30 million deferred derivative loss, to be realized upon settlement of the corresponding derivative instruments. The deferred loss at January 1, 2004 was comprised of a $0.40 million loss for crude oil and natural gas, and a $0.90 million loss for interest rate swaps.

The guideline requires that all derivative instruments be measured at fair value and recorded on the balance sheet as an asset or liability. AcG-13 also requires that all changes to fair value be recognized in earnings in the period, regardless of whether or not the contract has been settled. All derivative contracts entered into by APF subsequent to January 1, 2004 have been recorded as either a deferred derivative asset or liability on the balance sheet with a corresponding unrealized derivative gain or loss on the income statement. Refer to Note 6 for additional disclosures on derivatives.

3. Cash Distributions

(000's except for per unit amounts)

	3 months ended September 30		9 months ended September 30	
	2004	2003	**2004**	2003
		Restated (note 2)		Restated (note 2)
Oil and gas sales	**$ 74,184**	$ 41,789	**$ 178,242**	$ 132,893
Realized derivative loss - net	**(5,949)**	(772)	**(10,304)**	(3,521)
Transportation	**(1,461)**	(1,047)	**(3,818)**	(3,024)
Gross overriding royalties and lessor's royalties	**(4,957)**	(2,967)	**(12,742)**	(10,380)
	61,817	37,003	**151,378**	115,968
Operating costs	**16,438**	8,403	**36,160**	22,751
General and administrative	**2,697**	2,279	**7,074**	5,417
Interest on long-term debt	**1,594**	877	**3,849**	3,084
Abandonment fund contribution	**535**	483	**1,477**	1,449
Capital and other taxes	**948**	572	**2,364**	2,096
Operations funded from cash flow	**2,389**	(182)	**5,075**	13,459
	24,601	12,432	**55,999**	48,256
Income subject to the Royalty	**37,216**	24,571	**95,379**	67,712
99% of income subject to the Royalty	**36,846**	24,324	**94,425**	67,034
Crown charges, net of the Alberta Royalty Tax Credit	**(9,141)**	(4,223)	**(21,775)**	(14,380)
Interest on convertible debentures	**(1,163)**	(1,137)	**(3,424)**	(1,137)
General and administrative costs of the Trust	**(25)**	*(55)*	**(364)**	*(626)*
Cash distributed and available to be distributed	**26,517**	18,909	**68,862**	50,891
Cash distributed to date	**17,286**	12,983	**59,631**	44,965
Cash distribution payable	**$ 9,231**	$ 5,926	**$ 9,231**	$ 5,926
Actual cash distribution declared per unit	**$ 0.48**	$ 0.57	**$ 1.52**	$ 1.67
Opening accumulated cash distributions	**$ 221,708**	$ 142,632	**$ 179,363**	$ 110,650
Distribution declared and paid	**17,286**	12,983	**59,631**	44,965
Distribution declared and payable	**9,231**	5,926	**9,231**	5,926
Closing accumulated cash distributions	**$ 248,225**	$ 161,541	**$ 248,225**	$ 161,541

4. Acquisition of Great Northern Exploration Ltd.

Effective June 4, 2004, APF acquired all of the issued and outstanding shares of Great Northern Exploration Ltd. ("Great Northern"). The transaction was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired at assigned values:	
Working capital deficiency	(4,857)
Property, plant and equipment	255,941
Undeveloped land and seismic	22,943
Goodwill	70,248
Debt assumed	(63,874)
Financial derivatives	(1,103)
Asset retirement obligation	(7,866)
Future income taxes	(49,084)
Net assets acquired	**222,348**
Financed by:	
Trust units	156,943
Cash	63,250
Acquisition costs	2,155
Purchase price	**222,348**

5. Asset Retirement Obligations

Management has estimated the total future asset retirement obligation based on APF's net ownership interest in all wells and facilities. Included in this estimate are costs to abandon and reclaim wells and facilities, and the estimated timing for when these reclamation activities will occur in the future.

($000)	
Asset retirement obligation at December 31, 2003	**$ 21,803**
Liabilities acquired	7,866
Liabilities incurred	417
Liabilities settled	(419)
Accretion expense	1,169
Asset retirement obligation at September 30, 2004	**$ 30,836**

The undiscounted amount of estimated cash flows required to settle the obligation is $105.26 million (September 30, 2003 - $69.54 million). The estimated cash flows have been discounted using a credit-adjusted risk free rate of 8% and an inflation rate of 1.5%. The expected years until settlement range from a minimum of 5 years to a maximum of 50 years, costs will be provided through the fund reserved for site reclamation and abandonment. The abandonment fund is currently funded at $0.54 million per quarter through cash flow from operations.

6. Financial Derivatives

On January 1, 2004, APF recorded $1.3 million as an estimate of the fair value of outstanding hedges on transition. In the nine months ending September 30, 2003, APF has recognized $1.06 million upon settlement of the corresponding derivative instruments. The remaining $0.24 million deferred derivative loss will be realized in the fourth quarter of 2004.

The estimated fair value of outstanding derivative contracts is reported as a derivative liability on the consolidated balance sheet with any change in the unrealized positions deducted from net revenue. The following is a summary of the change in unrealized amounts from January 1, 2004 to September 30, 2004:

	Deferred derivative loss recognized on transition	Fair value	Total unrealized gain/(loss)
Fair value of contracts, January 1, 2004 (note 2)	$ 1,300	$ (1,300)	$ -
Change in fair value of dervative contracts still outstanding at September 30	-	(539)	(539)
Fair value of derivative contracts entered into during the period	-	(11,036)	(11,036)
Fair value of derivative contracts realized during the period	(1,056)	1,056	-
Fair value of contracts, September 30, 2004	$ 244	$ (11,819)	$ (11,575)
Premiums received on sold call options	-	(633)	-
FV of contracts and premiums received, September 30, 2004	$ 244	$ (12,452)	$ (11,575)

The following is a summary of unrealized fair value financial positions by derivative category at September 30, 2004:

September 30, 2004	Deferred derivative loss recognized on transition	Fair value	Total unrealized gain/(loss)
Commodity price risk			
Crude oil	$ -	$ (12,625)	$ (12,625)
Natural gas	-	18	18
Utilities	-	147	147
Foreign currency risk	-	1,048	1,048
Interest rate risk	244	(407)	(163)
	$ 244	$ (11,819)	$ (11,575)

7. Unitholders' Equity

	September 30, 2004		December 31, 2003	
Trust Units	**Units (000)**	**($000)**	Units (000)	($000)
Balance - Beginning of period	**34,074**	**324,317**	22,942	214,405
Issued to acquire Great Northern (note 4)	**12,885**	**156,943**	-	-
Issued to acquire Hawk Oil	-	-	3,990	37,710
Issued to acquire CanScot	-	-	1,342	15,433
Issued for cash	**7,875**	**90,426**	5,352	55,670
Cost of units issued	-	**(5,241)**	-	(3,467)
Distribution reinvestment program	**2,500**	**27,945**	141	1,602
Issued on conversion of debentures	**19**	**219**	108	1,215
Issued on exercise of options/rights	**339**	**2,937**	199	1,749
Allocated from contributed surplus	-	**524**	-	-
Balance - End of period	**57,692**	**598,070**	34,074	324,317

The per unit calculations for the three and nine month periods ended September 30, 2004 were based on weighted average trust units outstanding of 54.72 million (September 30, 2003 - 32.51 million) and 45.18 million (September 30, 2003 - 29.95 million), respectively. In computing net income per unit - basic for the three and nine months ended September 30, 2004, $1.16 million (September 30, 2003 - $1.14 million) and $3.42 million (September 30, 2003 - $1.14 million), respectively, was deducted from net income relating to interest accrued on convertible debentures assumed to be debt for per share calculations.

In computing net income per unit - diluted, 4.42 million units were added to the weighted average number of units outstanding for the three and nine months ended September 30, 2004 (three months ended September 30, 2003 - 4.36 million; nine months ended September 30, 2003 - 1.54 million), reflecting the dilutive effect of employee options and rights and the convertible debentures.

During the nine month period ended September 30, 2004, no options were granted to employees to purchase trust units. A summary of the Options Plan at September 30, 2004 and December 31, 2003 is as follows:

		September 30, 2004		December 31, 2003
Trust Unit Options	**Options (000)**	**Weighted Average Price ($)**	Options (000)	Weighted Average Price ($)
Balance- Beginning of period	**127**	**9.59**	244	9.13
Granted	**-**	**-**	-	-
Exercised	**(42)**	**9.42**	(107)	8.55
Cancelled	**-**	**-**	(11)	9.42
Balance - End of period	**85**	**9.68**	126	9.59
Exercisable - End of period	**85**	**9.68**	60	9.48

During the nine month period ended September 30, 2004, 0.77 million trust unit rights were granted to employees and directors. A summary of the Rights Plan at September 30, 2004 and December 31, 2003 is as follows:

		September 30, 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	**771**	**12.03**	1,538	9.78
Exercised	**(296)**	**8.56**	(92)	9.05
Cancelled	**(291)**	**9.50**	(51)	9.67
Balance - Before price reduction	**2,008**	**10.24**	1,824	9.72
Reduction of exercise price		**(0.59)**	-	(0.63)
Balance - End of period	**2,008**	**9.65**	1,824	9.09
Exercisable - End of period	**334**	**8.58**	47	8.58

For the nine months ended September 30, 2004, APF recorded compensation expense of $0.99 million relating to rights granted during 2003. For rights granted in 2002, APF has elected to disclose pro forma results as if CICA Handbook Section 3870, "Stock-based Compensation and other Stock-based Payments" had been applied retroactively. At September 30, 2004, proforma net income and earnings per share would not be materially different from those disclosed in the consolidated statements of operations and accumulated earnings at September 30, 2004 and 2003.

8. Long Term Debt

In conjunction with the closing of the Great Northern acquisition, APF's lenders increased the borrowing base under the revolving term credit facility to $200 million (2003 – $150 million).

9. Supplemental Information for the Statements of Cash Flows

($000)	3 Months Ended September 30 2004	3 Months Ended September 30 2003	9 Months Ended September 30 2004	9 Months Ended September 30 2003
Cash payments related to certain items				
Interest	**1,514**	808	**3,380**	2,801
Interest on debentures	**2,283**	-	**4,947**	-
Interest rate swap settlement	**301**	-	**569**	-
Distributions to unitholders	**25,680**	19,458	**65,536**	48,530
Capital and other taxes	**735**	717	**2,119**	2,762

This news release shall not constitute an offer to sell or the solicitation of an offer to buy any securities in any jurisdiction. The trust units of APF offered will not be and will not have been registered under the United States Securities Act of 1933.

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

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FORM 52-109FT2 - Certification of Interim Filings
During Transition Period

I, Alan MacDonald, Chief Financial Officer of APF Energy Inc., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of APF Energy Trust, (the issuer) for the interim period ending September 30, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

Date: November _____, 2004

Alan MacDonald
Chief Financial Officer
APF Energy Inc. on its own behalf and on behalf of APF Energy Trust

FORM 52-109FT2 - Certification of Interim Filings
During Transition Period

I, Martin Hislop, Chief Executive Officer of APF Energy Inc., certify that:

1. I have reviewed the interim filings (as this term is defined in Multilateral Instrument 52-109 *Certification of Disclosure in Issuers' Annual and Interim Filings*) of APF Energy Trust, (the issuer) for the interim period ending September 30, 2004;

2. Based on my knowledge, the interim filings do not contain any untrue statement of a material fact or omit to state a material fact required to be stated or that is necessary to make a statement not misleading in light of the circumstances under which it was made, with respect to the period covered by the interim filings; and

3. Based on my knowledge, the interim financial statements together with the other financial information included in the interim filings fairly present in all material respects the financial condition, results of operations and cash flows of the issuer, as of the date and for the periods presented in the interim filings.

Date: November 8, 2004

Martin Hislop
Chief Executive Officer
APF Energy Inc. on its own behalf and on behalf of APF Energy Trust

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APF ENERGY

NEWS RELEASE

TSX: AY.UN
AY.DB

APF Energy Trust announces distribution of $0.16 per unit

November 17, 2004 - APF Energy Trust announces it is maintaining its monthly distribution of $0.16 per unit. Payment will be made on December 15, 2004 to unitholders of record on November 30, 2004. The ex-distribution date is November 26, 2004.

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

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Exemption Order
82-5166

APF ENERGY

For the Period Ended September 30, 2004

Third Quarter

Drilling, recompletions and other optimization activities grew APF's production base, as the Trust continued to focus on internally generated opportunities to create value for unitholders.

On the heels of completing its largest acquisition ever, the $291 million corporate purchase of Great Northern Exploration Ltd. ("Great Northern") in early June, APF saw its daily production increase to an average of 18,262 boe. During the third quarter, the Trust brought on stream approximately 1,100 boe/d of new production through the drill bit and other production enhancement techniques, replacing production by approximately 108%, after taking into account natural production declines.

For the nine months ended September 30, 2004, APF drilled 99 (41.9 net) wells, of which 24 (11.2 net) were drilled during the third quarter, with a 100% success rate. Drilling activity was delayed across all business units due to surface restrictions relating to wet weather as unseasonable conditions continued to impact the entire sector beyond traditional spring break-up periods. With these restrictions removed, APF resumed its most active drilling program since inception, with a total of 100 (62 net) wells planned for the fourth quarter. During October, APF drilled 43 (37.8 net) of the 100 wells. Capital expenditures relating to drilling and completions have amounted to $24.8 million in the first nine months of 2004, with $11.2 million spent during the third quarter.

In addition to identifying opportunities on existing APF properties, the Trust has actively added to its undeveloped land position in the first nine months of the year, with the purchase of 32,260 net acres (10,870 net acres during the third quarter) for a total cost of $6.1 million. APF's objective is to add to its inventory of high quality prospects to ensure that production and reserves continue to grow independently from mergers and acquisitions activity.

The Canadian government recently announced draft regulations to restrict the level of non-resident ownership of a mutual fund trust at less than 50% based upon a fair market value assessment. Under the current regulations trusts, would have until January 1, 2007 to reduce non-resident ownership to below the 50% level in order to maintain their mutual fund trust status. APF's non-resident ownership level is currently less than 20%.

FINANCIAL SUMMARY

Cash flow for the quarter amounted to $30.9 million with distributions totalling $26.5 million ($0.48 per unit). Cash flow for the quarter was reduced by $5.9 million ($0.11 per unit) as a result of derivative settlements arising from the sharp run up in the price of crude oil. APF's payout ratio, after accounting for accrued interest on the convertible debentures, was 89%. APF remains committed to retaining a greater portion of its cash flow and is targeting a payout ratio of 80% by the end of 2004.

Impacting cash flows were increased operating expenses resulting from workovers and other remedial activity on projects not originally budgeted for by APF. In aggregate, corporate operating costs for the quarter amount to $9.78 per boe, versus $8.21 per boe during the previous quarter. In the near term, APF expects operating costs to remain stable at third quarter rates, as the Trust formulates its operating and capital budgets for 2005. Further guidance regarding longer term operating costs will be provided when APF next releases financial and engineering results in the first quarter of 2005.

On September 8, 2004, the Trust completed a $35 million equity offering at $11.30 per unit. The proceeds were used initially to repay bank debt which, at the end of the third quarter, amounted to $150 million. Taking into account the monthly proceeds from APF's distribution reinvestment plan, the surplus generated by the cash holdback and the anticipated capital expenditures, the Trust estimates the net effect to be a year-end debt position of approximately $164 million at current commodity prices. Together with $48 million of principal outstanding on its convertible debenture, total debt will be approximately $212 million or 1.7 times annualized third quarter cash flow.

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Summary of Operating & Financial Results

FINANCIAL ($000, except per unit/boe amounts)	Three Months Ended September 30 **2004**	2003 Restated (4)	Nine Months Ended September 30 **2004**	2003 Restated (4)
Cash flow from operations (1)	**30,874**	20,528	**79,431**	67,288
Per unit - basic	**$0.56**	$0.63	**$1.76**	$2.25
Per unit - diluted	**$0.52**	$0.56	**$1.60**	$2.14
Distributable income (2)	**29,711**	19,391	**76,007**	66,151
Per unit - basic	**$0.54**	$0.60	**$1.68**	$2.21
Per unit - diluted	**$0.50**	$0.53	**$1.53**	$2.10
Distributions declared	**26,517**	18,909	**68,862**	50,891
Per unit	**$0.48**	$0.57	**$1.52**	$1.67
Payout ratio	**89%**	98%	**91%**	77%
Bank debt	**150,000**	90,000	**150,000**	90,000
Operating costs per boe	**$9.78**	$7.17	**$8.69**	$6.81
Operating netbacks per boe	**$21.84**	$20.75	**$22.52**	$23.56
MARKET				
Units outstanding (000)				
End of period	**57,692**	33,868	**57,692**	33,868
Weighted average - basic	**54,720**	32,507	**45,181**	29,953
Weighted average - fully diluted	**59,141**	36,870	**49,602**	31,493
Trust unit trading				
High	**$12.14**	$12.63	**$12.63**	$12.63
Low	**$11.24**	$11.08	**$10.32**	$9.30
Close	**$11.74**	$11.66	**$11.74**	$11.66
Average daily volume	**336,912**	228,260	**295,409**	177,700
OPERATIONS				
Daily production (average)				
Total crude oil (bbl)	**7,675**	6,731	**6,712**	6,462
NGLs (bbl)	**971**	400	**660**	319
Natural gas (mcf)	**57,695**	33,675	**46,926**	32,744
Total (boe) (3)	**18,262**	12,744	**15,193**	12,238
Realized commodity prices ($Cdn.)				
Total crude oil (bbl)	**$41.05**	$32.94	**$38.56**	$35.40
NGLs (bbl)	**$42.28**	$29.35	**$39.17**	$32.06
Natural gas (mcf)	**$6.52**	$6.15	**$6.80**	$7.00
Average (boe) (3)	**$40.09**	$34.56	**$39.74**	$38.27
Reference pricing				
WTI (U.S.$/bbl)	**$43.88**	$30.20	**$39.10**	$30.99
AECO gas ($Cdn./mcf)	**$6.66**	$6.29	**$6.69**	$7.07
Foreign Exchange ($U.S./$Cdn.)	**1.307**	1.380	**1.328**	1.429

(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) Distributable income has been calculated by reducing cash flow from operations by interest accrued on the convertible debentures.

(3) 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.

(4) 2003 comparative results have been restated for the three and nine month periods ended September 30 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"

Operations & Development

BUSINESS UNIT UPDATES

Southern Alberta

During the period, APF continued to focus on shallow gas-bearing zones in the Cretaceous formation. The Trust drilled 3 (1.1 net) wells at Carmangay, Retlaw and Iron Springs, targeting the Sunburst, Glauconitic and Barons zones respectively. Capital expenditures totalled $1.9 million during the period. Production was weighted 86% to natural gas and averaged 3,700 boe/d.

Since the completion of the quarter, APF has drilled 28 shallow gas wells on its 100% interest lands at Countess, in addition to two 100% interest deeper wells. All of these will be on stream by the end of November. APF will also be participating in a non-operated 46 (15.2 net) well shallow gas program at Countess, slated to commence by the end of the quarter, with a target on-stream date of March, 2005. At Robsart, in southwest Saskatchewan, APF expects to drill four shallow gas wells by year-end.

Central Alberta

The Central Alberta Business Unit largely comprises the assets that were acquired in the Great Northern transaction, principally at Innisfail and Wood River. As a result of the time required to integrate Great Northern's drilling prospects into APF's capital program, there was no conventional drilling activity in this area during the period. Activity was restricted to coalbed methane ("CBM") operations, where APF drilled three 100% working interest wells into the dry Horseshoe Canyon coals. The Trust continues to experience encouraging results in the area and added to its CBM inventory at Crown land sales in August and October, strengthening APF's position in this exciting resource play.

Capital expenditures amounted to $6.2 million for the quarter, 59% of which was allocated to CBM and included $2.5 million for land acquisitions. Production averaged 7,000 boe/d during the period, weighted 53% to natural gas.

Plans for the fourth quarter include the drilling of five shallow Edmonton sand gas wells at Innisfail with an average working interest of 88%; two Ellerslie/Basal Quartz gas wells at Wood River (81% and 100% interest) with the potential for five more follow-up wells in early 2005; and two heavy oil wells at Lone Rock and Epping (80% and 100% interest), with the potential for eight more locations to be drilled, completed and producing in the first quarter of 2005.

Western Alberta

Activity in this Business Unit focused on completions, facilities upgrades and the acquisition of land and seismic, as APF continued to focus on long term geological prospects in an area where it controls several blocks of high working-interest lands. Capital expenditures amounted to $2.6 million and production averaged 3,700 boe/d during the period, weighted 62% to natural gas.

Development initiatives during the fourth quarter contemplate 5 (2.5 net) gas wells of varying depth at Redwater, with on-stream dates in early 2005.

Southeast Saskatchewan

APF drilled 4 (2.0 net) Mississippian oil wells during the period on capital expenditures of $2.8 million. Production averaged 3,600 boe/d during the period, weighted 96% to oil.

Seven locations have been identified for the fourth quarter of 2004 or early 2005, with additional capital to be invested in optimization and waterflood programs at Tatagwa, Macoun and Queensdale.

	Three Months Ended September 30				Nine Months Ended September 30			
	2004		2003		**2004**		2003	
Drilling Activity	**Gross**	**Net**	Gross	Net	**Gross**	**Net**	Gross	Net
Oil	**6.0**	**2.1**	28.0	9.4	**22.0**	**6.0**	45.0	13.7
Gas	**4.0**	**1.1**	15.0	11.8	**23.0**	**10.7**	42.0	18.5
Coalbed methane	**11.0**	**5.8**	–	–	**49.0**	**21.9**	–	–
Other	**3.0**	**2.2**	1.0	0.5	**4.0**	**2.3**	5.0	0.8
Dry and abandoned	**–**	**–**	–	–	**1.0**	**1.0**	–	–
Total	**24.0**	**11.2**	44.0	21.7	**99.0**	**41.9**	92.0	33.0

Wyoming

APF's assets in Wyoming consist exclusively of CBM, where 8 (2.8 net) shallow wells were drilled during the period. Three initial phases at Kane have been drilled and completed this year with 15 (3.75 net) wells currently on production and another 13 (3.25 net) wells awaiting tie-in. Average production from APF's Wyoming assets has increased from 730 mcf/d at the beginning of the year to an average of 1,100 mcf/d during the third quarter. Capital expenditures for the period amounted to $0.42 million.

The fourth phase of drilling at Kane has commenced and 24 additional wells (9.6 net) will be drilled and completed during the fourth quarter, bringing the total number of producing wells to 52 (16.6 net). At Big Bend, development plans are being submitted for an additional 20 (18 net) wells to be drilled in the first half of 2005. The preliminary results have been very encouraging with gas production commencing fairly rapidly.

Management's Discussion and Analysis

Management's Discussion and Analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements for the nine months ended September 30, 2004 and September 30, 2003 and with the audited consolidated financial statements and MD&A for the year ended December 31, 2003. The financial information has been prepared in accordance with Canadian Generally Accepted Accounting Principles ("GAAP") and is presented in Canadian dollars. Additional information relating to APF, including disclosures required under National Instrument 51-101 ("NI 51-101"), can be found in the APF's 2003 Annual Information Form ("AIF") on SEDAR at www.sedar.com or on APF's website at www.apfenergy.com. This MD&A was written on October 27, 2004.

PRODUCTION

Production volumes were 43% higher during the third quarter of 2004 compared to 2003, reflecting both the integration of corporate acquisitions and a successful drilling program. Light and medium crude oil production increased 17% while drilling activity offset heavy crude oil natural production declines. Natural gas production increased 71% and related natural gas liquids increased 143% over the prior quarter due mainly to the Great Northern Exploration Ltd ("Great Northern") acquisition completed during the second quarter of 2004. A full three months of operations are included in the third quarter results and four months of operations are included in the nine months ended September 30, 2004.

	Three Months Ended September 30			Nine Months Ended September 30		
	2004	2003	% Change	**2004**	2003	% Change
Light/medium crude oil (bbl/d)	**6,485**	5,541	17	**5,587**	5,463	2
Heavy oil (bbl/d)	**1,190**	1,190	–	**1,125**	999	13
NGL (bbl/d)	**971**	400	143	**660**	319	107
Natural gas (mcf/d)	**57,695**	33,675	71	**46,926**	32,744	43
Total (boe/d)	**18,262**	12,744	43	**15,193**	12,238	24
Production split						
Oil & NGLs	**47%**	56%	(15)	**49%**	55%	(12)
Natural gas	**53%**	44%	20	**51%**	45%	15

MARKETING

For the three months ended September 30, 2004, APF's production split was 47% crude oil and NGLs and 53% natural gas. Crude oil is sold under 30-day evergreen contracts while the majority of natural gas production is sold in the spot market. Approximately 15% of natural gas volumes are sold to aggregators pursuant to long-term contracts; this weighting had decreased from 20% due to the Great Northern acquisition. APF's current quarter and year-to-date production split reflects the impact of natural gas weighted acquisitions.

PRICES

Third quarter crude oil prices before realized derivatives increased 40% compared to the same quarter in 2003, which is consistent with a 45% increase in the benchmark West Texas Intermediate ("WTI") over the same period. The impact of favourable crude oil prices was partly offset by a 5% decline in the value of the US dollar relative to the Canadian dollar during the quarter. Third quarter natural gas prices before realized derivatives increased 9% over the prior quarter, while the benchmark AECO price increased 6% over the same period.

The net impact of realized crude oil derivatives during the third quarter reduced the price of crude oil before derivatives by 15% to $41.05 per boe. Crude oil prices after derivatives increased 25% over the prior quarter despite the negative impact of derivatives due to a strong commodity price environment. Realized natural gas derivatives reduced the price of natural gas during the quarter to $6.52 per mcf, which is 1% lower than the price before derivatives and represents a 6% increase over the price realized during the same period in 2003.

NYMEX futures contracts for the remainder of 2004 and into 2005 suggest crude oil prices will exceed the average 2004 level to date, as geopolitical events continue to inject a premium into the price of crude oil in the commodity markets. APF expects gas prices to increase during the fourth quarter 2004 and to exceed 2004 levels in 2005.

Effective January 1, 2004, APF had segregated costs associated with the transportation and selling of crude oil, natural gas and NGLs. Previously, APF had followed industry practice, which was to present revenue net of these costs. Accordingly, the September 30, 2003 comparative figures have been restated with these costs segregated, resulting in an increase to the gross price per unit.

	Three Months Ended September 30			Nine Months Ended September 30		
Prices - Before Derivatives ($Cdn.)	**2004**	2003	% Change	**2004**	2003	% Change
Light/medium crude oil (bbl)	**$ 50.38**	$ 36.09	40	**$ 46.28**	$ 38.93	19
Heavy oil (bbl)	**37.79**	26.94	40	**32.31**	27.82	16
Total crude oil (bbl)	**48.42**	34.47	40	**43.93**	37.21	18
NGLs (bbl)	**42.28**	29.35	44	**39.17**	32.06	22
Natural gas (mcf)	**6.61**	6.09	9	**6.81**	7.04	(3)
Total (boe)	**$ 43.48**	$ 35.21	23	**$ 42.15**	$ 39.32	7
Derivatives ($Cdn.)						
Crude oil (bbl)	**$ (7.37)**	$ (1.53)	382	**$ (5.37)**	$ (1.81)	197
Natural gas (mcf)	**(0.09)**	0.06	(250)	**(0.01)**	(0.04)	(75)
Total (boe)	**$ (3.39)**	$ (0.65)	422	**$ (2.41)**	$ (1.05)	130
Prices - After Derivatives ($Cdn.)						
Total crude oil (bbl)	**$ 41.05**	$ 32.94	25	**$ 38.56**	$ 35.40	9
NGLs (bbl)	**42.28**	29.35	44	**39.17**	32.06	22
Natural gas (mcf)	**6.52**	6.15	6	**6.80**	7.00	(3)
Total (boe)	**$ 40.09**	$ 34.56	16	**$ 39.74**	$ 38.27	4
Reference Pricing						
WTI ($U.S./bbl)	**$ 43.88**	$ 30.20	45	**$ 39.10**	$ 30.99	26
AECO gas ($Cdn./mcf)	**$ 6.66**	$ 6.29	6	**$ 6.69**	$ 7.07	(5)
Foreign exchange ($U.S./$Cdn.)	**$ 1.307**	$ 1.380	(5)	**$ 1.328**	$ 1.429	(7)

DERIVATIVES

APF enters into derivative contracts as part of its risk mitigation strategy in order to manage commodity price fluctuations and stabilize cash flows available for unitholder distributions and future development programs. Derivatives 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 fair value of all derivatives at September 30, 2004 is presented in Note 6 to the unaudited third quarter financial statements.

For the third quarter of 2004, APF had entered into crude oil and natural gas derivatives representing approximately 49% (3,761 bbl/d) of crude oil volumes and 35% (20,193 mcf/d) of natural gas production volumes. Realized crude oil and natural gas derivatives lowered third quarter revenues by $5.69 million, or $7.37 per barrel of crude oil and $0.09 per mcf of natural gas. Revenues for the nine months ended September 30, 2004 were reduced by $10.05 million, or $5.37 per barrel of crude oil and $0.01 per mcf of natural gas.

For the balance of 2004, APF has entered into derivatives that hedge approximately 47% of projected crude oil and 22% of projected natural gas volumes. 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, collars, and NYMEX futures for natural gas volumes. A summary of crude oil and natural gas derivative contracts outstanding at the end of the quarter and those in place at the effective date of this report are presented in the table below.

Effective January 1, 2004, APF implemented the Canadian Institute of Chartered Accountants ("CICA") Accounting Guideline 13 "Hedging Relationships". Under the new guideline, in order to apply hedge accounting, an entity must formally document the hedging arrangement and sufficiently demonstrate that the hedging item will be effective over the life of the hedged item. APF previously recognized hedging gains and losses as they were realized at the end of the contract. Based on our review of existing hedging relationships, the majority of APF's commodity, interest rate and foreign currency contracts do not qualify for hedge accounting. The effectiveness of APF's AECO natural gas hedges could potentially be demonstrated, however, the Trust has decided that applying hedge accounting on some transactions but not others would result in less transparent and potentially misleading financial information.

In accordance with the new guideline, on January 1, 2004, the fair value all outstanding derivative instruments deemed not to qualify for hedge accounting was recorded on the Consolidated Balance sheet with an offsetting net deferred loss amount. APF recorded a derivative liability of $1.30 million, which was comprised of a $0.40 million unrealized loss related to crude oil and natural gas contracts and a $0.90 million unrealized loss related to interest rate swaps, with a corresponding $1.30 million deferred derivative loss. At September 30, 2004, $1.06 million of the deferred derivative loss had been recognized into income; the remaining $0.24 million expected to settle during the fourth quarter of 2004.

At September 30, 2004, the estimated fair value of outstanding derivative instruments resulted in a derivative liability of $12.45 million. Included in the derivative liability balance was $0.63 million in call premiums received on sold call options. A loss on unrealized derivative contracts of $6.09 million had been recorded as an expense on the statement of operations to reflect the change in fair values since June 30, 2004.

At September 30, 2004, APF had the following derivative instruments in place:

Period	Commodity	Type of Contract	Average Daily Quantity	Average Daily Price
October 2004	Natural gas	Swap	14,000 GJ	$Cdn. 5.79/GJ
October 2004	Natural gas	Swap	2,000 mmbtu	$U.S. 5.95/mmbtu
October 2004	Natural gas	Bought Put	5,000 GJ	$Cdn. 6.50/GJ
November 2004 to March 2005	Natural gas	Sold Call	5,000 GJ	$Cdn. 11.80/GJ
October to December 2004	Crude oil	Swap	3,600 bbls	$U.S. 32.61/bbl
November to December 2004	Crude oil	Sold Call	1,000 bbls	$U.S. 44.83/bbl
January to March 2005	Crude oil	Swap	1,500 bbls	$U.S. 35.78/bbl
January to March 2005	Crude oil	Collars	1,000 bbls	$U.S. 38.00 to $U.S. 44.95/bbl
January to March 2005	Crude oil	Sold Call	500 bbls	$U.S. 42.37/bbl
April to June 2005	Crude oil	Swap	667 bbls	$U.S. 36.66/bbl
April to June 2005	Crude oil	Collars	1,500 bbls	$U.S. 38.33 to $U.S. 42.85/bbl
April to June 2005	Crude oil	Sold Call	500 bbls	$U.S. 40.95/bbl

APF sold call options on crude oil volumes during the quarter and received the following call premiums relating to outstanding contracts at September 30, 2004:

Period	Commodity	Type of Contract	Average Daily Quantity	Average Premium
November to December 2004	Crude oil	Sold Call	1,000 bbls	$U.S. 3.11
January to March 2005	Crude oil	Sold Call	500 bbls	$U.S. 3.19
April to June 2005	Crude oil	Sold Call	500 bbls	$U.S. 3.45

The following derivative instruments were entered into subsequent to September 30, 2004 and are currently in place:

Period	Commodity	Type of Contract	Average Daily Quantity	Average Daily Price
November 2004 to March 2005	Natural gas	Collars	5,000 GJ	$Cdn. 7.00 to $Cdn. 11.35/GJ
April to June 2005	Crude oil	Collars	500 bbls	$U.S. 42.00 to $U.S. 51.20/bbl
July to September 2005	Crude oil	Collars	500 bbls	$U.S. 42.00 to $U.S. 52.10/bbl

In addition to commodity derivatives, APF has also entered into foreign currency derivative contracts. APF has hedged $U.S. 30 million of revenue at an average rate of $Cdn. 1.3416 or $U.S. 0.7454 for calendar 2004.

At September 30, 2004, APF had the following fixed interest rates on a portion of its outstanding debt:

Term	Amount ($000)	Interest rate
October 2004 to May 2006	$20,000	3.60% plus stamping fee
October 2004 to March 2007	$20,000	3.58% plus stamping fee
October 2004 to November 2005	$20,000	3.58% plus stamping fee
October 2004 to September 2007	$20,000	3.65% plus stamping fee

REVENUES

Net oil and gas revenue for the third quarter of 2004 was 68% higher than the comparable period in 2003, reflecting increased natural gas production resulting from the Great Northern acquisition combined with higher crude oil price realizations. Net oil and gas revenue for the nine months ended September 30, was 30% higher in 2004 when compared to the prior period. Effective January 1, 2004, APF has segregated costs associated with transportation and selling crude oil, natural gas and NGLs. APF previously followed industry practice which was to present revenue net of these costs, however, the comparative figures presented have been restated with these costs segregated.

Oil and Gas	Three Months Ended September 30			Nine Months Ended September 30		
($000 except per boe amounts)	**2004**	Restated 2003	% Change	**2004**	Restated 2003	% Change
Light/medium crude oil sales	**$ 30,063**	$ 18,399	63	**$ 70,848**	$ 58,071	22
Heavy oil sales	**4,137**	2,949	40	**9,960**	7,585	31
NGL sales	**3,777**	1,080	250	**7,084**	2,790	154
Natural gas sales	**35,068**	18,867	86	**87,584**	62,941	39
Gross oil and gas revenue	**73,045**	41,295	77	**175,476**	131,388	34
Commodity price derivative loss	**(5,690)**	(772)	637	**(10,045)**	(3,521)	185
Transportation	**(1,461)**	(1,047)	40	**(3,818)**	(3,024)	26
Other	**1,139**	495	130	**2,766**	1,504	84
Net oil and gas revenue	**67,033**	39,971	68	**164,379**	126,347	30
Per boe	**$ 39.90**	$ 34.09	17	**$ 39.49**	$ 37.82	4

ROYALTIES

During the third quarter, total royalties as a percentage of gross oil and gas revenue was marginally higher at 19.0% compared to 17.5% during 2003 due to an increase in the crown royalty reference rates and higher realized crude oil prices than during the same three month period last year. As expected, year-to-date royalties as a percentage of gross oil and gas revenue is consistent with the prior year.

	Three Months Ended September 30			Nine Months Ended September 30		
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Crown royalties	**$ 8,956**	$ 4,266	110	**$ 21,718**	$ 14,526	50
Freehold royalties	**3,613**	2,207	64	**9,448**	8,073	17
Overriding royalties	**1,343**	760	77	**3,293**	2,307	43
Total royalties	**$ 13,912**	$ 7,233	92	**$ 34,459**	$ 24,906	38
% of gross oil and gas revenue	**19.0%**	17.5%	9	**19.6%**	19.0%	4
Per boe	**$ 8.28**	$ 6.17	34	**$ 8.28**	$ 7.45	11

OPERATING EXPENSES

Operating expenses per boe for the three and nine months ended September 30, 2004 increased 36% and 28%, respectively, over the prior periods presented. The increase is due to ongoing field optimization costs on newly-acquired properties and higher energy costs compared to the prior quarter. APF plans to continue with field optimization initiatives on Great Northern properties and expects operating costs will remain stable for the remainder of 2004.

	Three Months Ended September 30			Nine Months Ended September 30		
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Operating expenses	**$ 16,438**	$ 8,403	96	**$ 36,160**	$ 22,751	59
Per boe	**$ 9.78**	$ 7.17	36	**$ 8.69**	$ 6.81	28

OPERATING NETBACKS

Operating netbacks for the three month period ended September 30 increased 5% over the same period in 2003, with higher realized commodity prices partially offset by an increase in operating costs and royalty expense.

	Three Months Ended September 30			Nine Months Ended September 30		
		Restated			Restated	
($ per boe)	**2004**	2003	% Change	**2004**	2003	% Change
Gross revenue						
(after commodity price derivatives)	**$ 40.09**	$ 34.56	16	**$ 39.74**	$ 38.27	4
Transportation	**(0.87)**	(0.89)	(3)	**(0.92)**	(0.91)	1
Other	**0.68**	0.42	61	**0.66**	0.45	48
	$ 39.90	$ 34.09	17	**$ 39.49**	$ 37.82	4
Royalties	**(8.28)**	(6.17)	34	**(8.28)**	(7.45)	11
Operating costs	**(9.78)**	(7.17)	36	**(8.69)**	(6.81)	28
Operating netback	**$ 21.84**	$ 20.75	5	**$ 22.52**	$ 23.56	(4)

GENERAL AND ADMINISTRATIVE

On a per barrel of oil equivalent basis, third quarter general and administrative cost decreased 19% over the comparable quarter in 2003 and 1% over the nine months ended September 30, 2003. Staff and administrative costs have increased over the prior nine months ended September 30, however, the year-to-date increase is commensurate with the growth of APF operations.

	Three Months Ended September 30			Nine Months Ended September 30		
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
General and administrative	**$ 2,722**	$ 2,334	17	**$ 7,438**	$ 6,042	23
Per boe	**$ 1.62**	$ 1.99	(19)	**$ 1.79**	$ 1.81	(1)

INTEREST

Interest expense for the three and nine months ended September 30, 2004 increased by 27% and 0% per boe, respectively. Additional debt of approximately $127 million was incurred to finance the Great Northern acquisition in June 2004 and net proceeds of approximately $33 million from the September 8, 2004 trust unit offering were used to repay long-term debt.

	Three Months Ended September 30			Nine Months Ended September 30		
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Interest	**$ 1,594**	$ 877	82	**$ 3,849**	$ 3,084	25
Per boe	**$ 0.95**	$ 0.75	27	**$ 0.92**	$ 0.92	–

DEPLETION, DEPRECIATION AND ACCRETION

Depletion, depreciation and accretion ("DD&A") per boe increased 58% and 57%, respectively, for the three and nine months ended September 30 compared to the same periods in 2003. The increase is due primarily to acquisitions completed during 2003 and 2004 resulting in a larger property, plant, and equipment base. Asset retirement obligation accretion contributes to the remainder of the increase over the prior periods presented. September 30, 2003 comparative figures include the impact of adopting CICA Handbook Section 3110 "Asset Retirement Obligations".

	Three Months Ended September 30			Nine Months Ended September 30		
		Restated			Restated	
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Depletion, depreciation and accretion	**$ 29,023**	$ 12,799	127	**$ 69,889**	$ 35,686	96
Per boe	**$ 17.27**	$ 10.92	58	**$ 16.79**	$ 10.68	57

COMPENSATION EXPENSE

APF prospectively adopted the CICA Handbook Section 3870 – "Stock Based Compensation" during the fourth quarter of 2003. As per the transitional provisions of the new standard, companies that adopted the standard prior to December 31, 2003 were required to recognize compensation expense for those options granted during 2003 and later, with proforma disclosure of options granted during 2002. Comparative figures for 2003 have been restated to reflect the impact of stock-based compensation.

For the three and nine months ended September 30, 2004, APF recorded compensation expense of $0.79 million and $0.99 million, respectively, compared to $0.43 million and $0.66 million in 2003. The increase is due mainly to a higher per unit market value and accumulated price reductions under the Trust Unit Rights Plan.

	Three Months Ended September 30			Nine Months Ended September 30		
		Restated			Restated	
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Compensation expense	**$ 790**	$ 434	82	**$ 989**	$ 659	50
Per boe	**$ 0.47**	$ 0.37	27	**$ 0.24**	$ 0.20	20

TAXES

Saskatchewan capital tax and federal large corporation tax increased 66% and 13%, respectively, over the three and nine month period ended September 30, 2004, reflecting the 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.

During the third quarter of 2004, APF recovered $9.20 million in future income taxes compared to a future tax recovery of $3.80 million in 2003. A future income tax balance of $92.42 million is recorded as a liability as at September 30, 2004. The September 30, 2003 comparative figures include the impact of adopting CICA Handbook Section 3110 "Asset Retirement Obligations".

	Three Months Ended September 30			Nine Months Ended September 30		
		Restated			Restated	
($000 except per boe amounts)	**2004**	2003	% Change	**2004**	2003	% Change
Capital and other taxes	**$ 948**	$ 572	66	**$ 2,364**	$ 2,096	13
Per boe	**$ 0.56**	$ 0.49	15	**$ 0.57**	$ 0.63	(10)
Recovery of future income taxes	**$ (9,200)**	$ (3,800)	142	**$ (21,304)**	$ (14,659)	45

NET INCOME

Net income for the three and nine months ended September 30, 2004 has decreased 60% (81% per unit-basic and diluted) and 64% (75% per unit-basic and diluted), respectively, compared to the same periods in 2003. The decrease can be attributed to unrealized losses recognized under CICA Accounting Guideline 13 (AcG-13) "Hedging Relationships", higher operating expenses resulting from continued field optimization initiatives on Great Northern properties, and higher depletion, depreciation, and accretion on a larger property, plant, and equipment base.

The loss reported by APF during the fourth quarter of 2003 is a result of the Trust's Short Term Incentive Plan ("STIP") and lower commodity prices realized during the quarter. APF has provided for the STIP earned to the end of September 30, 2004.

SUMMARY OF QUARTERLY RESULTS

	2004			2003 Restated				2002 Restated
($000 except per unit amounts)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Total revenue	**46,776**	39,169	32,141	31,543	32,737	33,294	35,410	23,944
Net income	**4,461**	6,113	8,127	(2,507)	11,118	20,977	13,688	(942)
Per unit - basic ($)	**0.06**	0.12	0.19	(0.11)	0.32	0.65	0.54	(0.04)
Per unit - diluted ($)	**0.06**	0.12	0.19	(0.11)	0.31	0.65	0.54	(0.04)

Total revenues have increased commensurate with production volumes and a strong commodity price environment. Total revenue in 2004 includes the impact of unrealized derivative losses on commodity contracts outstanding at the end of each quarter. Prior periods presented do not reflect similar unrealized derivative losses as CICA Accounting Guideline 13 "Hedging Relationships" did not become effective until January 1, 2004.

CAPITAL EXPENDITURES, ACQUISITIONS AND DISPOSITIONS

Capital expenditures for the nine months ended September 30, 2004 totalled $330.46 million, including the $291.08 million acquisition of Great Northern. The 2003 comparative period totals $182.59 and reflects the acquisitions of Hawk Oil Inc., Nycan Energy Corp., and CanScot Resources Ltd. Capital expenditures during the third quarter, excluding corporate and property acquisitions, increased by 25% due to increased land acquisitions and facilities expenditures, while drilling and optimization activity levels remained stable compared with the same period last year. On August 19, 2004, APF expanded its 2004 drilling program from $40 million to between $55 million and $64 million for the 2004 calendar year as a result of the acquired Great Northern properties.

	Three Months Ended September 30		Nine Months Ended September 30	
($000)	**2004**	2003	**2004**	2003
Corporate acquisitions	**$ -**	$ 32,981	**$ 291,084**	$ 137,622
Property acquisitions	**14**	16,333	**6,587**	23,821
Land acquisitions	**3,332**	1,443	**6,096**	1,823
Seismic	**447**	390	**1,570**	974
Drilling and completions	**8,167**	8,188	**19,158**	15,768
Production facilities	**3,044**	2,016	**5,601**	4,533
Other	**241**	146	**559**	378
Subtotal	**$ 15,245**	$ 61,497	**$ 330,655**	$ 184,919
Dispositions	**-**	(2,069)	**(199)**	(2,331)
Net capital expenditures	**$ 15,245**	$ 59,428	**$ 330,456**	$ 182,588

CASH DISTRIBUTIONS

Cash distributions during the third quarter of 2004 were $26.52 million, or $0.48 per trust unit, compared to $18.91 million or $0.57 per trust unit during the prior year comparable period. The payout ratio, after adjusting for accumulated interest on the outstanding convertible debentures, was 89% for the third quarter, during which period APF funded $2.39 million of operations from cash flow (2003 - ($0.18) million). For the nine month period ended September 30, 2004, cash distributions totalled $68.86 million (2003 - $50.89 million), resulting in a 91% payout ratio (2003 - 77%). For the remainder of 2004, APF intends to maintain its historical policy of retaining a portion of available cash flow to fund capital expenditures and development initiatives, with a target range of 10% to 20%, working ultimately towards an 80% payout ratio.

LIQUIDITY AND CAPITAL RESOURCES

At September 30, 2004, APF had a revolving term credit facility in the amount of $200 million, of which $150 million was drawn (December 31, 2003 - $98 million). The facility may be drawn down or repaid at any time, and there are no scheduled repayment terms. The balance of convertible debentures, net of conversions, at the end of the quarter was $48.56 million (December 31, 2003 - $48.79 million).

At September 30, 2004, APF had a working capital deficit of approximately $21.18 million, compared to a working capital deficit of $10.25 million at December 31, 2003. The change in APF's working capital position is due to a derivative liability recorded in accordance with CICA Accounting Guideline 13 (AcG-13) "Hedging Relationships". Effective January 1, 2004, the guideline requires that all derivative instruments be measured at fair value and recorded on the balance sheet as an asset or liability. At September 30, 2004, a derivative liability of $12.45 million is recorded on the balance sheet (December 31, 2003 - $nil). The ultimate settlement of these derivative liabilities is dependent upon changes in commodity prices, foreign exchange rates, and interest rates during the remaining life of derivative contracts.

UNITHOLDERS' EQUITY

At September 30, 2004, APF had 57.69 million Trust units outstanding (2003 - 33.87 million) and a market capitalization of approximately $677 million (2003 - $395 million).

APF issued 0.99 million Trust units (2003 - nil) in the third quarter pursuant to the Premium Distribution Reinvestment Plan ("Premium DRIP"), generating $10.75 million in proceeds. During the first nine months of 2004, APF issued 2.50 million Trust units (2003 - nil) for total proceeds of $27.95 million in respect of the Premium DRIP.

During 2004, APF has completed three Trust unit issuances:

- February 4, 2004 - APF issued 4.78 million Trust units at $11.60 per unit for gross proceeds of $55.40 million. The proceeds of this offering were initially used to provide working capital flexibility and to reduce leverage, and later used to finance the cash portion of the Great Northern acquisition.
- On June 4, 2004, APF issued 12.89 million Trust units at $12.18 per unit as part of the Great Northern acquisition.
- On September 8, 2004, APF issued 3.10 million Trust units at $11.30 per unit for gross proceeds of $35.03 million. The net proceeds of the issue were used to repay outstanding indebtedness and ultimately to fund APF's expanded 2004 capital expenditure program.

BUSINESS RISKS

No changes have been made to the Business Risks as stated in APF's quarterly report for the three months ended March 31, 2004.

CRITICAL ACCOUNTING ESTIMATES

No changes have been made to the Critical Accounting Estimates as stated in APF's quarterly report for the three months ended March 31, 2004.

OUTLOOK

APF is an industry leader in adopting a full cycle development business model and is committed to complementing its effective acquisition strategy with a program of acquiring land and exploiting its land base through drilling, recompletions and field optimizations. APF will continue to accelerate the pace of its CBM program with particular focus on its inventory of Horseshoe Canyon prospects. With low production declines and the potential for higher rates of return than conventional gas production, CBM presents a very attractive opportunity that is ideally suited for the trust structure. APF's revised capital expenditure budget for the balance of 2004 will result in drilling activity during the final quarter of 2004 to be considerably higher than that experienced to date.

DISCLAIMER

Certain statements in this document are "forward-looking statements" including outlook on oil and gas prices, royalty rates, operating expenses, estimates of future production, estimated completion dates of construction and development projects, business plans for drilling and exploration, estimated amounts and timing of capital expenditures and anticipated future debt levels. Information concerning reserves contained in this material may also be deemed to be forward-looking statements as such estimates involving 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 Energy Trust and APF Energy Inc. These risks include, but are not limited to: the risks of the oil and gas industry (e.g., operational risks in exploration for; development and production of crude oil and natural gas; risks and uncertainties involving geology of oil and gas deposits; the uncertainty of reserve estimates; the uncertainty of estimates and projections relating to production, costs and expenses; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; and health, safety and environmental risks); risks in conducting foreign operations (e.g., political and fiscal instability in nations where APF Energy does business); the possibility that government policies may change or governmental approvals may be delayed or withheld; and price and exchange rate fluctuations. These and other risks are described in APF Energy's reports that are on file with Canadian securities regulatory authorities. The impact of any one factor on a particular forward-looking statement is not determinable with certainty as such factors are interdependent upon other factors and management's course of action would depend upon its assessment of the future considering all information then available. Readers are cautioned that the foregoing list of important factors is not exhaustive. Although the company believes that the expectations conveyed by the forward-looking statements are reasonable based on information available to it on the date such forward-looking statements are made, no assurances can be given as to future results, levels of activity and achievements. All subsequent forward-looking statements, whether written or oral, attributable to APF or persons acting on its behalf are expressly qualified in their entirety by these cautionary statements. APF assumes no obligation to update forward-looking statements should circumstances or management's estimates or opinions change.

Consolidated Balance Sheets (unaudited)

	September 30, 2004	December 31, 2003
		Restated (note 2)
	($000)	($000)
ASSETS		
Current assets		
Cash	**894**	1,381
Accounts receivable	**40,053**	27,542
Deferred derivative loss (note 6)	**244**	-
Other current assets	**5,136**	3,506
	46,327	32,429
Asset retirement fund	**3,400**	2,342
Goodwill	**118,479**	48,230
Property, plant and equipment	**663,207**	413,706
	831,413	496,707
LIABILITIES		
Current liabilities		
Accounts payable and accrued liabilities	**45,819**	36,711
Derivative liabilities (note 6)	**12,452**	-
Cash distribution payable (note 3)	**9,231**	5,963
	67,502	42,674
Future income taxes	**92,423**	63,991
Long-term debt (note 8)	**150,000**	98,000
Asset retirement obligation (note 5)	**30,836**	21,803
	340,761	226,468
UNITHOLDERS' EQUITY		
Unitholders' investment account (note 7)	**598,070**	324,317
Contributed surplus	**1,706**	1,241
Accumulated earnings	**98,594**	79,895
Accumulated cash distributions (note 3)	**(248,225)**	(179,363)
Convertible debentures	**46,247**	46,466
Accumulated interest on convertible debentures	**(5,740)**	(2,317)
	490,652	270,239
	831,413	496,707

Consolidated Statements of Operations and Accumulated Earnings (unaudited)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2004	2003	**2004**	2003
		Restated (note 2)		Restated (note 2)
	($000)	($000)	**($000)**	($000)
Revenue				
Oil and gas	**74,184**	41,789	**178,242**	132,893
Realized derivative loss - net	**(5,949)**	(772)	**(10,304)**	(3,521)
Unrealized derivative loss - net (note 6)	**(6,086)**	–	**(11,575)**	–
Royalties expense, net of ARTC	**(13,912)**	(7,233)	**(34,459)**	(24,906)
Transportation	**(1,461)**	(1,047)	**(3,818)**	(3,024)
	46,776	32,737	**118,086**	101,442
Expenses				
Operating	**16,438**	8,403	**36,160**	22,751
General and administrative	**2,722**	2,334	**7,438**	6,042
Interest on long-term debt	**1,594**	877	**3,849**	3,084
Depletion, depreciation and accretion	**29,023**	12,799	**69,889**	35,686
Stock-based compensation expense (note 7)	**790**	434	**989**	659
Capital and other taxes	**948**	572	**2,364**	2,096
	51,515	25,419	**120,689**	70,318
Income (loss) before future income taxes	**(4,739)**	7,318	**(2,603)**	31,124
Recovery of future income taxes	**(9,200)**	(3,800)	**(21,304)**	(14,659)
Net income	**4,461**	11,118	**18,701**	45,783
Accumulated earnings - beginning of period, as restated	**94,135**	70,254	**78,637**	35,589
Retroactive application of change in accounting policy (note 2)	**–**	–	**1,258**	–
Accumulated earnings - end of period, as restated	**98,596**	81,372	**98,596**	81,372
Net income per unit - basic (1)	**$ 0.06**	$ 0.32	**$ 0.34**	$ 1.50
Net income per unit - diluted	**$ 0.06**	$ 0.31	**$ 0.34**	$ 1.46

(1) Net income has been reduced by interest accrued on the convertible debentures.

Consolidated Statements of Cash Flows (unaudited)

	Three months ended Sept. 30		Nine months ended Sept. 30	
	2004	2003	**2004**	2003
		Restated (note 2)		Restated (note 2)
	($000)	($000)	**($000)**	($000)
CASH PROVIDED BY (USED IN)				
Operating activities				
Net income for the period	**4,461**	11,118	**18,701**	45,783
Items not affecting cash				
Depletion, depreciation and accretion	**29,023**	12,799	**69,889**	35,686
Future income taxes	**(9,200)**	(3,800)	**(21,304)**	(14,659)
Unrealized derivative loss - net (note 6)	**6,086**	-	**11,575**	-
Stock-based compensation expense	**790**	434	**989**	659
Asset retirement expenditures (note 5)	**(286)**	(23)	**(419)**	(181)
	30,874	20,528	**79,431**	67,288
Net change in non-cash working capital items				
Accounts receivable	**4,017**	2,491	**1,596**	5,735
Other current assets	**(205)**	9,393	**(933)**	(151)
Accounts payable and accrued liabilities	**(1,852)**	2,233	**(9,121)**	3,572
Derivative liabilities (note 6)	**633**	-	**633**	-
Due to APF Management	**-**	-	**-**	(3,923)
	2,593	14,117	**(7,825)**	5,233
Asset retirement fund contribution - net	**(249)**	(460)	**(1,058)**	(1,268)
	33,218	34,185	**70,548**	71,253
Investing activities				
Purchase of Great Northern (note 4)	**148**	-	**(65,405)**	-
Purchase of Hawk Oil	**-**	-	**-**	(3,457)
Purchase of Nycan Energy	**-**	-	**-**	(34,287)
Purchase of CanScot Resources	**-**	(20,516)	**-**	(20,516)
Additions to property, plant and equipment	**(15,231)**	(10,360)	**(32,984)**	(21,653)
Purchase of oil and natural gas properties	**(14)**	(18,156)	**(6,587)**	(25,644)
Proceeds on sale of properties	**-**	2,069	**199**	2,331
Changes in non-cash working capital - investing items	**1,085**	1,814	**(1,433)**	997
	(14,012)	(45,149)	**(106,210)**	(102,229)
Financing activities				
Issue of units for cash	**35,030**	-	**90,426**	55,670
Issue of units under DRIP	**10,748**	-	**27,945**	-
Issue of units for cash upon exercise of stock options	**1,156**	629	**2,937**	1,469
Convertible debentures - net of costs	**-**	47,684	**-**	47,684
Interest on convertible debentures	**(1,163)**	(1,137)	**(3,424)**	(1,137)
Unit issue costs	**(2,028)**	(41)	**(5,241)**	(3,335)
Net proceeds (repayment) of long-term debt	**(40,000)**	(18,150)	**(11,874)**	(20,920)
Cash distributions	**(26,517)**	(18,910)	**(68,862)**	(50,891)
Changes in non-cash working capital - financing items	**780**	(549)	**3,268**	2,362
	(21,994)	9,526	**35,175**	30,902
Change in cash during the period	**(2,788)**	(1,438)	**(487)**	(74)
Cash - Beginning of period	**3,682**	2,314	**1,381**	950
Cash - End of period	**894**	876	**894**	876

Supplemental information (note 9)

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

September 30, 2004 and 2003 (unaudited)

NOTE 1. SIGNIFICANT ACCOUNTING POLICIES

The interim consolidated financial statements of APF Energy Trust ("APF") have been prepared by management in accordance with accounting principles generally accepted in Canada. The interim consolidated financial statements have been prepared following the same accounting policies and methods of computation as the consolidated financial statements for the fiscal year ended December 31, 2003, except as described in Note 2 below. The interim consolidated financial statements should be read in conjunction with the consolidated financial statements and notes thereto in APF's annual report for the year ended December 31, 2003.

NOTE 2. CHANGE IN ACCOUNTING POLICY

Asset Retirement Obligations

During the first quarter of 2004, APF adopted the Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3110 "Asset Retirement Obligations" (ARO). This change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

The new standard requires the recognition of the liability associated with the future site reclamation costs of tangible long-lived assets. This liability would be comprised of APF's net ownership interest in producing wells and processing plant facilities. The liability for future retirement obligations is to be recorded in the financial statements at the time the liability is incurred.

The asset retirement obligation is initially recorded at the estimated fair value as a long-term liability with a corresponding increase to property, plant and equipment. The depreciation of property, plant and equipment is allocated to expense on the unit-of-production basis. The liability is increased each reporting period for the fair value of any new future site reclamation costs and the corresponding accretion on the original provision. The accretion is charged to earnings in the period incurred. The provision will also be revised for any changes to timing related to cash flows or undiscounted reclamation costs. Actual expenditures incurred for the purpose of site reclamation are charged to the asset retirement obligation to the extent that the liability exists on the balance sheet. Differences between the actual costs incurred and the fair value of the liability recorded are recognized to earnings in the period incurred.

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

As a result of adopting the new standard, at December 31, 2003, the ARO increased to \$21.80 million, PP&E net of accumulated depletion increased by \$12.42 million and the future income tax liability decreased by \$0.23 million. Opening accumulated earnings as at January 1, 2004 increased by \$1.26 million to reflect the cumulative impact of accretion and depletion expense, net of the cumulative site restoration provision and future income taxes, on the asset retirement obligation recorded retroactively to 1996, the inception of the Trust.

Comparative statements of operations and accumulated earnings were also restated at September 30, 2003. Depletion, accretion and amortization increased by \$0.75 million and future tax recovery decreased by \$0.07 million for the three month period ended September 30, 2003. Depletion, accretion and amortization increased by \$2.06 million and future tax recovery decreased by \$0.16 million for the nine month period ended September 30, 2003.

Derivatives Accounting

Effective January 1, 2004 APF implemented CICA Accounting Guideline 13 (AcG-13) "Hedging Relationships", which deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. The guideline is effective for fiscal years beginning on or after July 1, 2003.

The new guideline addresses hedging transactions for the purposes of applying hedge accounting and establishes conditions for applying or discontinuing hedge accounting. Under the new guideline, hedging transactions must be documented and it must be demonstrated that the hedges are sufficiently effective in order to continue hedge accounting for positions hedged with derivatives. APF is not applying hedge accounting to its hedging relationships.

At January 1, 2004, APF recorded \$1.30 million for the mark-to-market value of the outstanding hedges as a derivative liability and a \$1.30 million deferred derivative loss, to be realized upon settlement of the corresponding derivative instruments. The deferred loss at January 1, 2004 was comprised of a \$0.40 million loss for crude oil and natural gas, and a \$0.90 million loss for interest rate swaps.

The guideline requires that all derivative instruments be measured at fair value and recorded on the balance sheet as an asset or liability. AcG-13 also requires that all changes to fair value be recognized in earnings in the period, regardless of whether or not the contract has been settled. All derivative contracts entered into by APF subsequent to January 1, 2004 have been recorded as either a deferred derivative asset or liability on the balance sheet with a corresponding unrealized derivative gain or loss on the income statement. Refer to Note 6 for additional disclosures on derivatives.

NOTE 3. CASH DISTRIBUTIONS

	Three months ended Sept. 30		Nine months ended Sept. 30	
($000 except for per unit amounts)	**2004**	2003 Restated (note 2)	**2004**	2003 Restated (note 2)
Oil and gas sales	**$ 74,184**	$ 41,789	**$ 178,242**	$ 132,893
Realized derivative loss - net	**(5,949)**	(772)	**(10,304)**	(3,521)
Transportation	**(1,461)**	(1,047)	**(3,818)**	(3,024)
Gross overriding royalties and lessor's royalties	**(4,957)**	(2,967)	**(12,742)**	(10,380)
	61,817	37,003	**151,378**	115,968
Operating costs	**16,438**	8,403	**36,160**	22,751
General and administrative	**2,697**	2,279	**7,074**	5,417
Interest on long-term debt	**1,594**	877	**3,849**	3,084
Abandonment fund contribution	**535**	483	**1,477**	1,449
Capital and other taxes	**948**	572	**2,364**	2,096
Operations funded from cash flow	**2,389**	(182)	**5,075**	13,459
	24,601	12,432	**55,999**	48,256
Income subject to the Royalty	**37,216**	24,571	**95,379**	67,712
99% of income subject to the Royalty	**36,846**	24,324	**94,425**	67,034
Crown charges, net of the Alberta Royalty Tax Credit	**(9,141)**	(4,223)	**(21,775)**	(14,380)
Interest on convertible debentures	**(1,163)**	(1,137)	**(3,424)**	(1,137)
General and administrative costs of the Trust	**(25)**	(55)	**(364)**	(626)
Cash distributed and available to be distributed	**26,517**	18,909	**68,862**	50,891
Cash distributed to date	**17,286**	12,983	**59,631**	44,965
Cash distribution payable	**$ 9,231**	$ 5,926	**$ 9,231**	$ 5,926
Actual cash distribution declared per unit	**$ 0.48**	$ 0.57	**$ 1.52**	$ 1.67
Opening accumulated cash distributions	**221,708**	142,632	**179,363**	110,650
Distribution declared and paid	**17,286**	12,983	**59,631**	44,965
Distribution declared and payable	**9,231**	5,926	**9,231**	5,926
Closing accumulated cash distributions	**$ 248,225**	$ 161,541	**$ 248,225**	$ 161,541

NOTE 4. ACQUISITION OF GREAT NORTHERN EXPLORATION LTD.

Effective June 4, 2004, APF acquired all of the issued and outstanding shares of Great Northern Exploration Ltd. ("Great Northern"). The transaction was accounted for using the purchase method of accounting with the allocation of the purchase price and consideration paid as follows:

($000)	
Net assets acquired at assigned values:	
Working capital deficiency	$ (4,857)
Property, plant and equipment	255,941
Undeveloped land and seismic	22,943
Goodwill	70,248
Debt assumed	(63,874)
Financial derivatives	(1,103)
Asset retirement obligation	(7,866)
Future income taxes	(49,084)
Net assets acquired	**$ 222,348**

Financed by:	
Trust units	$ 156,943
Cash	63,250
Acquisition costs	2,155
Purchase price	**$ 222,348**

NOTE 5. ASSET RETIREMENT OBLIGATIONS

Management has estimated the total future asset retirement obligation based on APF's net ownership interest in all wells and facilities. Included in this estimate are costs to abandon and reclaim wells and facilities, and the estimated timing for when these reclamation activities will occur in the future.

($000)	
Asset retirement obligation at December 31, 2003	**$ 21,803**
Liabilities acquired	7,866
Liabilities incurred	417
Liabilities settled	(419)
Accretion expense	1,169
Asset retirement obligation at September 30, 2004	**$ 30,836**

The undiscounted amount of estimated cash flows required to settle the obligation is $105.26 million (September 30, 2003 - $69.54 million). The estimated cash flows have been discounted using a credit-adjusted risk free rate of 8% and an inflation rate of 1.5%. The expected years until settlement range from a minimum of 5 years to a maximum of 50 years, costs will be provided through the fund reserved for site reclamation and abandonment. The abandonment fund is currently funded at $0.54 million per quarter through cash flow from operations.

NOTE 6. FINANCIAL DERIVATIVES

On January 1, 2004, APF recorded $1.3 million as an estimate of the fair value of outstanding hedges on transition. In the nine months ending September 30, 2004, APF has recognized $1.06 million upon settlement of the corresponding derivative instruments. The remaining $0.24 million deferred derivative loss will be realized in the fourth quarter of 2004.

The estimated fair value of outstanding derivative contracts is reported as a derivative liability on the consolidated balance sheet with any change in the unrealized positions deducted from net revenue. The following is a summary of the change in unrealized amounts from January 1, 2004 to September 30, 2004:

($000)	Deferred derivative loss recognized on transition	Fair value	Total unrealized gain/(loss)
Fair value of contracts, January 1, 2004 (note 2)	$ 1,300	$ (1,300)	$ –
Change in fair value of derivative contracts still outstanding at September 30	–	(539)	(539)
Fair value of derivative contracts entered into during the period	–	(11,036)	(11,036)
Fair value of derivative contracts realized during the period	(1,056)	1,056	–
Fair value of contracts, September 30, 2004	$ 244	$ (11,819)	$ (11,575)
Premiums received on sold call options	–	(633)	–
FV of contracts and premiums received, September 30, 2004	$ 244	$ (12,452)	$ (11,575)

The following is a summary of unrealized fair value financial positions by derivative category at September 30, 2004:

($000)	Deferred derivative loss recognized on transition	Fair value	Total unrealized gain/(loss)
Commodity price risk			
Crude oil	$ –	$ (12,625)	$ (12,625)
Natural gas	–	18	18
Utilities	–	147	147
Foreign currency risk	–	1,048	1,048
Interest rate risk	244	(407)	(163)
	$ 244	$ (11,819)	$ (11,575)

NOTE 7. UNITHOLDERS' EQUITY

	September 30, 2004		December 31, 2003	
Trust Units	**Units (000)**	**($000)**	Units (000)	($000)
Balance - Beginning of period	**34,074**	**324,317**	22,942	214,405
Issued to acquire Great Northern (note 4)	**12,885**	**156,943**	–	–
Issued to acquire Hawk Oil	**-**	**-**	3,990	37,710
Issued to acquire CanScot	**-**	**-**	1,342	15,433
Issued for cash	**7,875**	**90,426**	5,352	55,670
Cost of units issued	**-**	**(5,241)**	–	(3,467)
Distribution reinvestment program	**2,500**	**27,945**	141	1,602
Issued on conversion of debentures	**19**	**219**	108	1,215
Issued on exercise of options/rights	**339**	**2,937**	199	1,749
Allocated from contributed surplus	**-**	**524**	–	–
Balance - End of period	**57,692**	**598,070**	34,074	324,317

The per unit calculations for the three and nine month periods ended September 30, 2004 were based on weighted average trust units outstanding of 54.72 million (September 30, 2003 - 32.51 million) and 45.18 million (September 30, 2003 - 29.95 million), respectively. In computing net income per unit - basic for the three and nine months ended September 30, 2004, $1.16 million (September 30, 2003 - $1.14 million) and $3.42 million (September 30, 2003 - $1.14 million), respectively, was deducted from net income relating to interest accrued on convertible debentures assumed to be debt for per share calculations.

In computing net income per unit - diluted, 4.42 million units were added to the weighted average number of units outstanding for the three and nine months ended September 30, 2004 (three months ended September 30, 2003 - 4.36 million; nine months ended September 30, 2003 - 1.54 million), reflecting the dilutive effect of employee options and rights and the convertible debentures.

During the nine month period ended September 30, 2004, no options were granted to employees to purchase trust units. A summary of the Options Plan at September 30, 2004 and December 31, 2003 is as follows:

	September 30, 2004		December 31, 2003	
Trust Unit Options	**Weighted Average Options (000)**	**Weighted Average Price ($)**	Options (000)	Price ($)
Balance- Beginning of period	**127**	**9.59**	244	9.13
Granted	**-**	**-**	–	–
Exercised	**(42)**	**9.42**	(107)	8.55
Cancelled	**-**	**-**	(11)	9.42
Balance - End of period	**85**	**9.68**	126	9.59
Exercisable - End of period	**85**	**9.68**	60	9.48

During the nine month period ended September 30, 2004, 0.77 million trust unit rights were granted to employees and directors. A summary of the Rights Plan at September 30, 2004 and December 31, 2003 is as follows:

	September 30, 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	**771**	**12.03**	1,538	9.78
Exercised	**(296)**	**8.56**	(92)	9.05
Cancelled	**(291)**	**9.50**	(51)	9.67
Balance - Before price reduction	**2,008**	**10.24**	1,824	9.72
Reduction of exercise price		**(0.59)**	–	(0.63)
Balance - End of period	**2,008**	**9.65**	1,824	9.09
Exercisable - End of period	**334**	**8.58**	47	8.58

For the nine months ended September 30, 2004, APF recorded compensation expense of $0.99 million relating to rights granted during 2003. For rights granted in 2002, APF has elected to disclose pro forma results as if CICA Handbook Section 3870, "Stock-based Compensation and other Stock-based Payments" had been applied retroactively. At September 30, 2004, proforma net income and earnings per share would not be materially different from those disclosed in the consolidated statements of operations and accumulated earnings at September 30, 2004 and 2003.

NOTE 8. LONG TERM DEBT

In conjunction with the closing of the Great Northern acquisition, APF's lenders increased the borrowing base under the revolving term credit facility to $200 million (2003 – $150 million).

NOTE 9. SUPPLEMENTAL INFORMATION FOR THE STATEMENTS OF CASH FLOWS

	Three Months Ended Sept. 30		Nine Months Ended Sept. 30	
($000)	**2004**	2003	**2004**	2003
Cash payments related to certain items				
Interest	**1,514**	808	**3,380**	2,801
Interest on debentures	**2,283**	–	**4,947**	–
Interest rate swap settlement	**301**	–	**569**	–
Distributions to unitholders	**25,680**	19,458	**65,536**	48,530
Capital and other taxes	**735**	717	**2,119**	2,762

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Computershare Trust Company of Canada

AUDITORS
PricewaterhouseCoopers LLP

STOCK EXCHANGE LISTING
Toronto Stock Exchange
Symbols: AY.UN and AY.DB

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Don Engle (1) (2) (3)
Independent Director and
Chairman of the Board

William Dickson (1) (3)
Independent Director

Daniel Mercier (1) (2) (3)
Independent Director

Robert MacDonald (1) (3)
Independent Director

John Howard (1) (3)
Independent Director

Martin Hislop
Director
Chief Executive Officer

Steven Cloutier
Director
President & Chief Operating Officer

Alan MacDonald
Vice President, Finance and
Chief Financial Officer

Dan Allan
Vice President, Exploration & Development

Wayne Geddes
Vice President, Land

(1) Member of Audit Committee
(2) Member of Compensation Committee
(3) Member of Reserves Committee

ABBREVIATIONS

ARTC	Alberta Royalty Tax Credit
bbl	barrel
boe	barrels of oil equivalent*
boe/d	barrels of oil equivalent per day*
CBM	coalbed methane
GJ	gigajoule
mbbls	thousand barrels
mmbbls	million barrels
mboe	thousand barrels of oil equivalent*
mcf	thousand cubic feet
mmcf	million cubic feet
mcf/d	thousand cubic feet per day
mmcf/d	million cubic feet per day
NGL	natural gas liquid
WTI	West Texas Intermediate

*6 mcf of gas = 1 barrel of oil

APF ENERGY