



A D V A N T A G E

ENERGY INCOME FUND

Advantage Energy Income Fund – News Release

Advantage Announces Release of Fourth Quarter and Year Ended December 31, 2006 Financial Results and Reserves

March 22, 2007

(TSX : AVN.UN, NYSE: AAV)

CALGARY, ALBERTA, March 22, 2007 – Advantage Energy Income Fund (“Advantage” or the “Fund”) is pleased to announce the financial and operating results and reserves for the year ended December 31, 2006.

A conference call will be held on Friday, March 23, 2007 at 9:00 a.m. MST (11:00 a.m. EST). The conference call can be accessed toll-free at **1-866-585-6398**. A replay of the call will be available from approximately 2:00 p.m. EST on March 24, until approximately midnight, March 31, 2007 and can be accessed by dialing toll free **1-866-245-6755**. The passcode required for playback is **587317**. A live web cast of the conference call will be accessible via the Internet on Advantage's website at www.advantageincome.com.

Merger of Advantage Energy Income Fund and Ketch Resources Trust

- Advantage completed the largest transaction in its history by merging with Ketch Resources Trust on June 23, 2006 adding production and proven plus probable reserves of approximately 13,000 boe/d and 37.0 million boes respectively.
- Strong operational synergies were achieved by combining Advantage's longer-life reserve base with Ketch's large undeveloped land base and significant prospect inventory which has led to increased diversification, growth opportunities and complimentary winter/summer drilling programs.
- In addition, the merger strengthened Advantage's executive, technical and administrative groups through the addition of many of the key personnel from Ketch.

Drilling Program and Reserves

- The integration of the Ketch assets was seamless as evidenced by the strong operational execution throughout the year which resulted in the drilling of 147 gross (90.2 net) wells in 2006 at a 95% success rate. During the fourth quarter of 2006 a total of 44 gross (25.1 net) wells were drilled at a 94% success rate.
- The Fund replaced 104% of its production through the drill bit with favorable Finding & Development costs of \$17.26 per proven plus probable boe (excluding changes in future development capital).
- Our technical and operations group completed a review of the combined asset base and have identified over 500 high quality drilling locations (light oil and liquids rich natural gas focus) which represents a four year drilling inventory.
- Overall, the Fund replaced 529% of annual production at an all-in Finding, Development & Acquisition cost of \$23.88 per proven plus probable boe (excluding changes in future development capital).
- The Fund's proven plus probable reserve life index remains among the highest in the natural gas weighted sector at 11.4 years.

Commodity Prices and Hedging

- Crude oil prices strengthened in 2006 due to continued global demand growth while natural gas prices fell considerably due to the mild 2005 – 2006 winter experienced in North America.
- The decline in natural gas prices was one of the key factors leading to lower cash distribution levels in 2006 due to our 67% natural gas production weighting.

- The outlook for gas prices has since improved as a sustained cold period through February 2007 has significantly reduced natural gas inventories closer to historical levels. In addition, natural gas supply in both the U.S. and Canada has struggled to increase despite record levels of well completions in the last 3 years.
- The Fund has an active hedging program which has secured 48% of our net natural gas production at an average floor price of \$7.55/mcf and 14% of our oil production at an average floor price of US\$65.00/bbl for 2007.

Federal Government Tax Fairness Proposal

- On October 31, 2006 the Canadian Federal Government announced its intention to impose a tax on income trusts beginning in 2011. This announcement which represented a major turnaround in policy, caught the income trust investment community completely by surprise and resulted in severe reductions in Unit prices.
- The final outcome of this policy change remains unknown at this time, but Advantage remains in a strong position given our considerable tax pool base of \$1.2 billion which is available to shield future taxes.
- Based on the Fund's market capitalization at October 31, 2006 Advantage's safe harbour provides for the issuance of \$1.6 billion of new equity by 2011.
- We will continue to monitor the situation and will take the required course of action to ensure that taxes are minimized for our Unitholders.

Advantage is Well-positioned for 2007

- The October federal government announcement has caused a great deal of upheaval in the trust sector which has resulted in a significant contraction in Unit prices and the amount of capital available to the sector.
- Advantage has responded by raising \$110 million of new equity in February, 2007 and reducing our payout ratio in order to strengthen our balance sheet and enhance the sustainability of cash distributions.
- We believe that the sector is entering a new environment that will be characterized by the emergence of a "buyers market" for oil and gas properties as well as a consolidation phase for royalty trusts and junior E&Ps.
- Advantage is well positioned to capitalize on these opportunities as we enter this new environment due to our:
 - Long-life asset base and stable production platform,
 - High quality, multi-year drilling inventory,
 - Strong balance sheet,
 - Considerable tax pool base,
 - Moderate payout ratio supported by an active hedging program and
 - Superior technical and administrative team that is highly motivated to create Unitholder value.

2007 First Quarter Drilling Highlights

- Execution of the 2007 winter drilling program is on schedule and costs are on-track.
- The largest component of the winter program is at Martin Creek in Northeast British Columbia where results have exceeded expectations with well deliverability in excess of expanded facilities capacity. Drilling has also extended pool boundaries beyond last year's interpretations setting up a strong drilling program for 2008.
- At Nevis, Alberta horizontal drilling for light oil in the new western development area has been 100% successful with initial production rates at or above expectations. A multi-year drilling inventory and enhanced oil recovery potential exists on this property.
- At Chigwell, Alberta the Fund's first major Horseshoe Canyon coalbed methane project involving 28 gross wells was successfully completed and brought on-stream in early January at production rates which were higher than forecast. Advantage has not aggressively pursued coalbed methane development on its land base which has over 250 locations in the heart of the Horseshoe Canyon fairway.
- To date 30 gross (18.2 net) wells have been drilled in 2007 at a 97% success rate.
- The Fund has significant behind pipe volumes as a result of these activities which will be brought on-stream in the second quarter.

Financial and Operating Highlights

Year ended December 31,	2006	2005	2004	2003	2002
Financial (\$000)					
Revenue before royalties	419,727	376,572	241,481	166,075	97,837
per Unit ⁽¹⁾	5.18	6.65	5.89	5.44	3.64
per boe	47.80	51.27	38.92	36.81	24.85
Funds from operations	214,758	211,541	126,478	94,735	52,537
per Unit ⁽¹⁾	2.63	3.72	3.05	3.09	1.94
per boe	24.77	28.80	20.39	21.01	13.34
Net income	49,814	75,072	24,038	38,503	10,910
per Unit ⁽¹⁾	0.62	1.33	0.59	1.26	0.41
Cash distributions	217,246	177,366	117,655	83,382	46,883
per Unit ⁽²⁾	2.66	3.12	2.82	2.71	1.73
Payout ratio ⁽³⁾	101%	84%	93%	88%	89%
Working capital deficit	42,655	31,612	56,408	47,143	21,515
Bank indebtedness	410,574	252,476	267,054	102,968	114,222
Convertible debentures	180,730	135,111	148,450	99,984	55,000
Operating					
Daily Production					
Natural gas (mcf/d)	94,074	78,561	77,188	57,631	47,753
Crude oil and NGLs (bbls/d)	8,075	7,029	4,084	2,756	2,828
Total boe/d @ 6:1	23,754	20,123	16,949	12,361	10,787
Average pricing (including hedging)					
Natural gas (\$/mcf)	6.86	7.98	6.08	6.07	3.71
Crude oil & NGLs (\$/bbl)	62.44	57.58	46.58	38.14	32.07
Proved plus probable reserves ⁽⁴⁾					
Natural gas (bcf)	442.7	286.9	296.9	237.4	223.1
Crude oil & NGLs (mmbbls)	47,524	36,267	34,316	13,697	13,995
Total mboe	121,317	84,082	83,799	53,271	51,180
Reserve life index ⁽⁵⁾	11.4	12.0	9.9	9.1	10.9
Supplemental (000)					
Trust Units outstanding at end of year	105,390	57,846	49,675	36,717	27,099
Trust Units issuable					
Convertible Debentures	8,334	6,819	7,602	6,155	4,135
Exchangeable Shares	-	122	1,450	-	-
Trust Unit Rights Incentive Plan	188	310	310	140	175
Trust Units outstanding and issuable at end of year	113,912	65,097	59,037	43,012	31,409
Basic weighted average Trust Units	80,958	56,593	41,008	30,536	26,900

(1) based on basic weighted average Trust Units outstanding

(2) based on number of Trust Units outstanding at each cash distribution record date

(3) payout ratio represents the cash distributions declared for the period as a percentage of funds from operations

(4) 2006, 2005 and 2004 represents company interest reserves with prior years being gross working interest reserves. 2002 reserves represent proved plus 50% of probable reserves

(5) based on fourth quarter 2006 average production rates

RESERVES

Advantage's year end reserve evaluation is based on an independent engineering study conducted by Sproule Associates Limited ("Sproule") effective December 31, 2006 and prepared in accordance with National Instrument 51-101 ("NI 51-101").

Reserves included herein are stated on a Company Interest basis (before royalty burdens and including royalty interests receivable) unless noted otherwise. This report contains several cautionary statements that are specifically required by NI 51-101. In addition to the detailed information disclosed in this press release more detailed information on a net interest basis (after royalty burdens and including royalty interests) and on a gross interest basis (before royalty burdens and excluding royalty interests) will be included in Advantage's Annual Information Form ("AIF") and available at www.advantageincome.com or www.sedar.com.

Highlights - Company Interest Reserves (Working Interests plus Royalty Interests Receivable)

- The Fund's net asset value at December 31, 2006 is \$17.92 per Unit, (using a 5% discount factor).
- Proved plus probable ("P+P") reserve life index remains among the highest in the gas weighted sector at 11.4 years.
- Replaced 104% of annual production through the drill bit at an all-in Finding and Development ("F&D") cost of \$17.26 per P+P boe before consideration of future development capital. Including future development capital, the F&D cost was \$20.93 per P+P boe.
- Replaced 529% of annual production at an all-in Finding, Development & Acquisition ("FD&A") cost of \$23.88 per P+P boe before consideration of future development capital. Including future development capital, the FD&A cost was \$24.62 per P+P boe. This includes the acquisition of Ketch Resources Trust, which was effective June 23, 2006.

	December 31, 2006	December 31, 2005
Proved plus probable reserves (mboe)	121,317	84,082
Present Value of reserves discounted at 5%, proved plus probable (\$000)	\$2,445,236	\$1,814,159
Fund Net Asset Value per Unit discounted at 5%	\$17.92	\$24.46
Reserve Life Index (proved plus probable - years) ⁽¹⁾	11.4	12.0
Reserves per Unit (proved plus probable) ⁽²⁾	1.15	1.42
Bank debt per boe of reserves ⁽³⁾	\$3.38	\$3.00
Convertible debentures per boe of reserves ⁽³⁾	\$1.49	\$1.61

⁽¹⁾ Based on Q4 average production.

⁽²⁾ Based on 58.75 million Units and Trust Unit Rights outstanding at December 31, 2005, and 105.58 million Units and Trust Unit Rights outstanding as December 31, 2006.

⁽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.

Company Interest Reserves - Summary as at December 31, 2006

	Light & Medium Oil (mbbl)	Heavy Oil (mbbl)	Natural Gas Liquids (mbbl)	Natural Gas (mmcf)	Oil Equivalent (mboe)
Proved					
Developed Producing	16,021	1,926	6,289	255,344	66,794
Developed Non-producing	474	0	242	11,643	2,656
Undeveloped	3,513	0	881	27,970	9,056
Total Proved	20,008	1,926	7,412	294,957	78,506
Probable	13,631	693	3,854	147,802	42,811
Total Proved + Probable	33,639	2,619	11,266	442,759	121,317

Gross Working Interest Reserves - Summary as at December 31, 2006

	Light & Medium Oil (mbl)	Heavy Oil (mbl)	Natural Gas Liquids (mbl)	Natural Gas (mmcf)	Oil Equivalent (mboe)
Proved					
Developed Producing	15,949	1,908	6,252	253,286	66,324
Developed Non-producing	473	0	241	11,523	2,635
Undeveloped	3,513	0	882	27,970	9,056
Total Proved	19,935	1,908	7,375	292,779	78,015
Probable	13,586	688	3,833	146,566	42,534
Total Proved + Probable	33,521	2,596	11,208	439,345	120,549

**Present Value of Future Net Revenue using Sproule price and cost forecasts ⁽¹⁾
 (\$000)**

	Before Income Taxes Discounted at		
	0%	5%	10%
Proved			
Developed Producing	\$ 2,110,371	\$ 1,495,671	\$ 1,200,133
Developed Non-producing	70,588	57,401	48,211
Undeveloped	184,664	146,958	111,997
Total Proved	2,365,623	1,700,030	1,360,341
Probable	1,395,504	745,206	489,732
Total Proved + Probable	\$ 3,761,127	\$ 2,445,236	\$ 1,850,073

⁽¹⁾ Advantage's crude oil, natural gas and natural gas liquid reserves were evaluated using Sproule's product price forecast effective December 31, 2006 prior to the provision for income taxes, interests, debt services charges and general and administrative expenses. It should not be assumed that the discounted future revenue estimated by Sproule represents the fair market value of the reserves.

Sproule Price Forecasts

The present value of future net revenue at December 31, 2006 was based upon crude oil and natural gas pricing assumptions prepared by Sproule effective December 31, 2006. These forecasts are adjusted for reserve quality, transportation charges and the provision of any applicable sales contracts. The price assumptions used over the next seven years are summarized in the table below:

Year	WTI Crude Oil (\$US/bbl)	Edmonton Light Crude Oil (\$Cdn/bbl)	Alberta Plantgate Natural Gas (\$Cdn/mmbtu)	Henry Hub Natural Gas (\$US/mmbtu)	Exchange Rate (\$US/\$Cdn)
2007	65.73	74.10	7.47	7.85	0.87
2008	68.82	77.62	8.36	8.39	0.87
2009	62.42	70.25	7.53	7.65	0.87
2010	58.37	65.56	7.35	7.48	0.87
2011	55.20	61.90	7.52	7.63	0.87
2012	56.31	63.15	7.65	7.75	0.87
2013	57.43	64.42	7.80	7.86	0.87

Net Asset Value using Sproule price and cost forecasts

The following net asset value ("NAV") table shows what is normally referred to as a "produce-out" NAV calculation under which the current value of the Fund's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time.

(\$000, except per Unit amounts)	0%	5%	10%
Net asset value per Unit ⁽¹⁾ - December 31, 2005	\$ 38.29	\$ 24.46	\$ 17.79
Present value proved and probable reserves	\$ 3,761,127	\$ 2,445,236	\$ 1,850,073
Undeveloped acreage and seismic ⁽²⁾	50,520	50,520	50,520
Working capital (deficit) and other	(12,093)	(12,093)	(12,093)
Convertible debentures	(180,730)	(180,730)	(180,730)
Bank debt	(410,574)	(410,574)	(410,574)
Net asset value - December 31, 2006	\$ 3,208,250	\$ 1,892,359	\$ 1,297,196
Net asset value per Unit⁽¹⁾ - December 31, 2006	\$ 30.39	\$ 17.92	\$ 12.29

⁽¹⁾ Based on 58.75 million Units and Trust Unit Rights outstanding at December 31, 2005, and 105.58 million Units and Trust Unit Rights outstanding at December 31, 2006.

⁽²⁾ Internal estimate

Gross Working Interest Reserves Reconciliation

	Light & Medium Oil (mdbl)	Heavy Oil (mdbl)	Natural Gas Liquids (mdbl)	Natural Gas (mmcf)	Oil Equivalent (mboe)
Proved					
Opening balance Dec. 31, 2005	15,558	1,720	3,747	195,534	53,613
Extensions	40	0	174	6,420	1,284
Improved recovery	2,327	167	275	4,536	3,525
Discoveries	53	0	0	5	54
Economic factors	(249)	(27)	(60)	(3,129)	(859)
Technical revisions	1,747	342	156	4,930	3,068
Acquisitions	2,455	0	3,741	119,212	26,065
Dispositions	0	0	0	(392)	(65)
Production	(1,996)	(294)	(658)	(34,337)	(8,670)
Closing balance at Dec. 31, 2006	19,935	1,908	7,375	292,779	78,015

Proved + Probable	Light & Medium Oil (mdbl)	Heavy Oil (mdbl)	Natural Gas Liquids (mdbl)	Natural Gas (mmcf)	Oil Equivalent (mboe)
Opening balance Dec. 31, 2005	27,470	2,677	5,953	283,547	83,358
Extensions	118	0	258	10,760	2,169
Improved recovery	4,289	240	504	8,044	6,374
Discoveries	94	0	0	14	96
Economic factors	(440)	(43)	(95)	(4,537)	(1,334)
Technical revisions	1,121	16	54	2,939	1,680
Acquisitions	2,865	0	5,192	173,456	36,966
Dispositions	0	0	0	(541)	(90)
Production	(1,996)	(294)	(658)	(34,337)	(8,670)
Closing balance at Dec. 31, 2006	33,521	2,596	11,208	439,345	120,549

Finding, Development & Acquisitions Costs ("FD&A") ⁽¹⁾

FD&A Costs – Gross Working Interest Reserves excluding Future Development Capital

	Proved	Proved + Probable
Capital expenditures (\$000)	\$ 155,091	\$ 155,091
Acquisitions net of dispositions (\$000)	940,155	940,155
Total capital (\$000)	\$ 1,095,246	\$ 1,095,246
Total mboe, end of period	78,015	120,549
Total mboe, beginning of period	53,613	83,358
Production, mboe	8,670	8,670
Reserve additions, mboe	33,072	45,861
FD&A costs (\$/boe)	\$ 33.12	\$ 23.88
Three year average FD&A Costs (\$/boe)	\$ 27.01	\$ 18.56
F&D costs (\$/boe)	\$ 21.93	\$ 17.26
Three year average F&D costs (\$/boe)	\$ 25.46	\$ 17.24

NI 51-101

FD&A Costs – Gross Working Interest Reserves including Future Development Capital

	Proved	Proved + Probable
Capital expenditures (\$000)	\$ 155,091	\$ 155,091
Acquisitions net of dispositions (\$000)	940,155	940,155
Net change in Future Development Capital	324	34,045
Total capital (\$000)	\$ 1,095,570	\$ 1,129,291
Reserve additions, mboe	33,072	45,861
FD&A costs (\$/boe)	\$ 33.13	\$ 24.62
Three year average FD&A Costs (\$/boe)	\$ 27.74	\$ 19.74
F&D costs (\$/boe)	\$ 21.97	\$ 20.93
Three year average F&D costs (\$/boe)	\$ 28.12	\$ 21.54

⁽¹⁾ Under NI 51-101, the methodology to be used to calculate FD&A costs includes incorporating changes in future development capital ("FDC") required to bring the proved undeveloped and probable reserves to production. For continuity, Advantage has presented herein FD&A costs calculated both excluding and including FDC.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year. Changes in forecast FDC occur annually as a result of development activities, acquisition and disposition activities and capital cost estimates that reflect Sproule's best estimate of what it will cost to bring the proved undeveloped and probable reserves on production.

In all cases, the FD&A number is calculated by dividing the identified capital expenditures by the applicable reserve additions. Boes may be misleading, particularly if used in isolation. A boe conversion ratio of 6 MCF:1 BBL is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Land Inventory at December 31, 2006

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Alberta	907,997	438,611	541,547	260,910
British Columbia	169,584	72,330	122,835	68,854
Saskatchewan	32,978	23,969	94,194	78,413
Total Acreage	1,110,559	534,910	758,576	408,177

MANAGEMENT'S DISCUSSION & ANALYSIS

The following Management's Discussion and Analysis ("MD&A"), dated as of March 21, 2007, provides a detailed explanation of the financial and operating results of Advantage Energy Income Fund ("Advantage", the "Fund", "us", "we" or "our") for the quarter and year ended December 31, 2006 and should be read in conjunction with the audited consolidated financial statements. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and all references are to Canadian dollars unless otherwise indicated. All per barrel of oil equivalent ("boe") amounts are stated at a conversion rate of six thousand cubic feet of natural gas being equal to one barrel of oil or liquids.

Non-GAAP Measures

The Fund discloses several financial measures in the MD&A that do not have any standardized meaning prescribed under GAAP. These financial measures include funds from operations and per Trust Unit, cash netbacks, and payout ratio. Management believes that these financial measures are useful supplemental information to analyze operating performance, leverage and provide an indication of the results generated by the Fund's principal business activities prior to the consideration of how those activities are financed or how the results are taxed. Investors should be cautioned that these measures should not be construed as an alternative to net income, cash provided by operating activities or other measures of financial performance as determined in accordance with GAAP. Advantage's method of calculating these measures may differ from other companies, and accordingly, they may not be comparable to similar measures used by other companies.

Funds from operations, as presented, is based on cash provided by operating activities before expenditures on asset retirement and changes in non-cash working capital. Funds from operations per Trust Unit is based on the number of Trust Units outstanding at each cash distribution record date. Both cash netbacks and payout ratio are dependent on the determination of funds from operations. Cash netbacks include the primary cash revenues and expenses on a per boe basis that comprise funds from operations. Payout ratio represents the cash distributions declared for the period as a percentage of funds from operations. Funds from operations reconciled to cash provided by operating activities is as follows:

(\$000)	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Cash provided by operating activities	\$ 65,495	\$ 70,117	(7)%	\$ 229,087	\$ 186,606	23%
Expenditures on asset retirement	3,462	445	678%	5,974	2,025	195%
Changes in non-cash working capital	(6,220)	(9,656)	(36)%	(20,303)	22,910	(189)%
Funds from operations	\$ 62,737	\$ 60,906	3%	\$ 214,758	\$ 211,541	2%

Forward-Looking Information

The information in this report contains certain forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "would" and similar expressions. These statements involve substantial known and unknown risks and uncertainties, certain of which are beyond Advantage's control, including: the impact of general economic conditions; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; fluctuations in commodity prices and foreign exchange and interest rates; stock market volatility and market valuations; volatility in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; obtaining required approvals of regulatory authorities and other risk factors set forth in Advantage's Annual Information Form which will be available at www.advantageincome.com or www.sedar.com. Advantage's actual results, performance or achievement could differ materially from those expressed in, or implied by, such forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur or, if any of them do, what benefits that Advantage will derive from them. Except as required by law, Advantage undertakes no obligation to publicly update or revise any forward-looking statements.

Merger with Ketch Resources Trust

On June 22, 2006, the previously announced merger of Advantage and Ketch Resources Trust (“Ketch”) was approved by 96.6% of the votes cast at the Advantage Unitholder meeting and 88.4% of the votes cast at the Ketch Unitholder meeting. Court approval was received on June 22, 2006 with closing of the Arrangement and the successful merger of the two trusts occurring the following day. The financial and operational information for the year ended December 31, 2006 reflect operations from the Ketch properties effective the closing date, June 23, 2006. The combined trust is managed by an experienced senior management team which includes key management, technical personnel and administrative employees from both Advantage and Ketch. The merger was accomplished through the exchange of each Ketch Unit for 0.565 of an Advantage Unit and upon completion, Advantage Unitholders owned approximately 65% of the combined trust and Ketch Unitholders owned approximately 35%.

The merger was conditional on Advantage internalizing the external management contract structure and eliminating all related fees. The Fund reached an agreement with Advantage Investment Management Ltd. (“AIM” or the “Manager”) to purchase all of the outstanding shares of AIM pursuant to the terms of the Plan of Arrangement for total original consideration of 1,933,208 Advantage Trust Units initially valued at \$39.1 million using the weighted average trading value for June 22, 2006 of \$20.23 per Advantage Trust Unit. The Trust Unit consideration was placed in escrow for a 3-year period ensuring Advantage Unitholders will receive continued benefit and commitment of the existing management team and employees. The Fund paid final management fees and performance fees for the period January 1 to March 31, 2006 in the amount of \$3.3 million. The consideration to settle the fees consisted of \$0.9 million in cash and 117,662 Trust Units. AIM agreed to forego fees for the period April 1, 2006 to the closing of the Arrangement.

Overview

	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Funds from operations (\$000)	\$ 62,737	\$ 60,906	3%	\$ 214,758	\$ 211,541	2%
per Trust Unit ⁽¹⁾	\$ 0.59	\$ 1.06	(44)%	\$ 2.63	\$ 3.72	(29)%
Net income (\$000)	\$ 8,736	\$ 25,846	(66)%	\$ 49,814	\$ 75,072	(34)%
per Trust Unit - Basic	\$ 0.08	\$ 0.45	(82)%	\$ 0.62	\$ 1.33	(53)%
- Diluted	\$ 0.08	\$ 0.45	(82)%	\$ 0.61	\$ 1.32	(54)%

⁽¹⁾ Based on Trust Units outstanding at each cash distribution record date.

Funds from operations increased 3% for the three months and 2% for the year ended December 31, 2006, as compared to the same periods of 2005. Funds from operations per Trust Unit decreased 44% and 29% respectively. The slight increase in funds from operations has been primarily due to the Ketch merger. However, both funds from operations and funds from operations per Trust Unit have been negatively impacted by significantly lower natural gas prices throughout 2006. Weak natural gas prices have been partially offset by a successful hedging program that was implemented in November 2006. Net income decreased 66% for the three months ended December 31, 2006, as compared to 2005 and 34% for the year ended December 31, 2006. Net income per basic Trust Unit decreased 82% for the three months and 53% for the year ended December 31, 2006. The lower net income has been primarily due to the lower natural gas prices realized during the periods, amortization of the management internalization consideration, and increased depletion and depreciation expense. The primary factor that causes significant variability of Advantage’s funds from operations, cash flows and net income is commodity prices. Refer to the section “Commodity Prices and Marketing” for a more detailed discussion of commodity prices and our price risk management.

Cash Distributions

	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Cash distributions declared (\$000)	\$ 58,791	\$ 43,265	36%	\$ 217,246	\$ 177,366	22%
per Trust Unit ⁽¹⁾	\$ 0.56	\$ 0.75	(25)%	\$ 2.66	\$ 3.12	(15)%
Payout ratio (%)	94%	71%	23%	101%	84%	17%

⁽¹⁾ Based on Trust Units outstanding at each cash distribution record date.

Total distributions increased 36% for the three months and 22% for the year ended December 31, 2006. The higher total distributions reflect the increased Trust Units outstanding from the continued growth and development of the Fund, especially due to the Ketch

acquisition. Natural gas prices were very weak during the fourth quarter and year resulting in reduced funds from operations and a higher payout ratio of 94% and 101%, respectively. As a result, we reduced the distribution level during the last half of 2006 to more appropriately reflect the current commodity price environment. Cash distributions per Trust Unit were \$0.56 for the three months and \$2.66 for the year ended December 31, 2006 representing decreases of 25% and 15% respectively, as compared to the same periods of 2005. In January 2007, the monthly distribution was further decreased to \$0.15 as natural gas prices continued to show prolonged weakness throughout the winter. To mitigate the persisting risk associated with lower natural gas prices and the resulting negative impact on distributions, the Fund implemented a hedging program in 2006 with 58% of natural gas hedged for January to March 2007 and 54% hedged for April to October 2007. See "Commodity Price Risk" section for a more detailed discussion of our price risk management. It is also important to note that the timing of the Ketch merger negatively impacted the payout ratio for the year ended December 31, 2006 as the arrangement closed prior to the June record date resulting in the payment of a full month distribution to Ketch Unitholders; however funds from operations for June only included eight days of cash flows from the Ketch properties. We believe the Fund has taken the necessary action and is now well-positioned with the objective of providing long-term distribution sustainability to Unitholders.

Cash distributions are determined by Management and the Board of Directors. We closely monitor our distribution policy considering forecasted cash flows, optimal debt levels, capital spending activity, taxability to Unitholders, working capital requirements, and other potential cash expenditures. Cash distributions are announced monthly and are based on the cash available after retaining a portion to meet such spending requirements. The level of cash distributions are primarily determined by cash flows received from the production of oil and natural gas from existing Canadian resource properties and will be susceptible to the risks and uncertainties associated with the oil and natural gas industry generally. If the oil and natural gas reserves associated with the Canadian resource properties are not supplemented through additional development or the acquisition of additional oil and natural gas properties, our cash distributions will decline over time in a manner consistent with declining production from typical oil and natural gas reserves. Therefore, cash distributions are highly dependent upon our success in exploiting the current reserve base and acquiring additional reserves. Furthermore, monthly cash distributions we pay to Unitholders are highly dependent upon the prices received for oil and natural gas production. Oil and natural gas prices can fluctuate widely on a month-to-month basis in response to a variety of factors that are beyond our control. Declines in oil or natural gas prices will have an adverse effect upon our operations, financial condition, reserves and ultimately on our ability to pay distributions to Unitholders. The Fund attempts to mitigate the volatility in commodity prices through our hedging program. It is our long-term objective to provide stable and sustainable cash distributions to the Unitholders, while continuing to grow the Fund. However, given that funds from operations can vary significantly from month-to-month due to these factors, the Fund may utilize various financing alternatives as an interim measure to maintain stable distributions.

For Canadian holders of Advantage Trust Units, the distributions paid for 2006 were 50% non-taxable return of capital and 50% taxable. For U.S. unitholders, distributions paid during 2006 were 47% non-taxable return of capital and 53% taxable. All Unitholders of the Fund are encouraged to consult their tax advisors as to the proper treatment of Advantage distributions for income tax purposes.

Revenue

(\$000)	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Natural gas excluding hedging	\$ 74,309	\$ 78,001	(5)%	\$ 231,548	\$ 238,902	(3)%
Realized hedging gains (losses)	4,046	(6,749)	(160)%	4,164	(10,063)	(141)%
Natural gas including hedging	\$ 78,355	\$ 71,252	10%	\$ 235,712	\$ 228,839	3%
Crude oil and NGLs excluding hedging	\$ 48,051	\$ 39,318	22%	\$ 182,882	\$ 151,639	21%
Realized hedging gains (losses)	1,133	(398)	(385)%	1,133	(3,906)	(129)%
Crude oil and NGLs including hedging	\$ 49,184	\$ 38,920	26%	\$ 184,015	\$ 147,733	25%
Total revenue	\$ 127,539	\$ 110,172	16%	\$ 419,727	\$ 376,572	11%

Natural gas revenues, excluding hedging, have decreased 5% for the three months and 3% for the year ended December 31, 2006, compared to 2005. Natural gas revenues have increased due to additional production from the Ketch merger but have been more than offset by weak natural gas prices. However, due to the Fund's hedge positions that were in place for the latter part of 2006, natural gas revenues, including hedging, have increased 10% for the three months and 3% for the year ended December 31, 2006. Crude oil and NGL revenues, excluding hedging, have increased by 22% for the three months and 21% for the year ended December 31, 2006 compared to 2005 due to a combination of continued strong oil prices and increased production levels from Ketch. The Fund had several oil hedges that came into effect in October 2006, further increasing crude oil and NGL revenues 26% for the three months and 25% for the year ended December 31, 2006, as compared to 2005.

Production

	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Natural gas (mcf/d)	117,134	72,587	61%	94,074	78,561	20%
Crude oil (bbls/d)	7,148	5,900	21%	6,273	5,854	7%
NGLs (bbls/d)	2,422	1,206	101%	1,802	1,175	53%
Total (boe/d)	29,092	19,204	51%	23,754	20,123	18%
Natural gas (%)	67%	63%		66%	65%	
Crude oil (%)	25%	31%		26%	29%	
NGLs (%)	8%	6%		8%	6%	

The Fund's total daily production averaged 29,092 boe/d for the fourth quarter of 2006, an increase of 51% compared with the same period of 2005. Natural gas production increased 61%, crude oil production increased 21%, and NGLs production increased 101%. Average daily production for the year ended December 31, 2006 was 23,754 boe/d, an increase of 18% compared with December 31, 2005. During this same period natural gas production increased 20%, crude oil production increased 7% and NGLs production increased 53%.

The increase in production during the quarter and year has been primarily attributed to the Ketch acquisition, which closed June 23, 2006. Other key production additions included light oil production from our Nevis and Sunset properties located in Central Alberta of 500 boe/d and gas additions of 3.5 mmcf/d realized from our Sweetgrass and Chigwell properties. An additional 5.0 mmcf/d was placed onstream in July from the Westerose-Battle Lake area. The additions have been offset somewhat by further capacity constraints at third party facilities, a one-time adjustment recognizing the impact of several wells that had paid out whereby partners had elected to convert to working interest positions and pipeline curtailments. The curtailment on the main northern leg of the Trans Canada Pipeline system impacted most of our Northern Alberta areas and resulted in a loss of 150 boe/d for the year. In addition, significant adverse production impacts occurred in November and December due to the extreme cold weather conditions at Fontas and Martin Creek, a compressor failure at Worsley, battery outages at Nevis and Westerose and high declines at our Hamelin Creek property. Production has also been impacted by maximum rate limitations ("MRL") initiated on our Chip Lake and Nevis properties beginning January 1, 2006. At the close of 2006 our Chigwell North coal bed methane joint venture and our new gas pool at Sweetgrass were placed onstream. The Chigwell North and Sweetgrass wells were delayed primarily due to regulatory delays in each respective area, but the regulations have since been satisfied and production began in late December.

Commodity Prices and Marketing

Natural Gas

(\$/mcf)	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Realized natural gas prices						
Excluding hedging	\$ 6.90	\$ 11.68	(41)%	\$ 6.74	\$ 8.33	(19)%
Including hedging	\$ 7.27	\$ 10.67	(32)%	\$ 6.86	\$ 7.98	(14)%
AECO monthly index	\$ 6.36	\$ 11.68	(46)%	\$ 6.98	\$ 8.49	(18)%

Realized natural gas prices, excluding hedging, decreased 41% for the three months and 19% for the year ended December 31, 2006, as compared to the same periods of 2005. The price of natural gas is primarily based on supply and demand fundamentals in the North American marketplace. Natural gas prices began to weaken near the end of 2005 as North America recorded one of the mildest winters on record, thereby reducing demand. This weakness has continued through 2006 with relatively uneventful weather resulting in natural gas inventories that swelled to historic levels. The 2006/2007 winter has also been mild, with inventory levels remaining high, causing significant downward pressure on commodity prices. However, February 2007 brought sustained colder weather and inventory levels decreased below 2006 levels but are still ample compared to demand. The withdrawals from inventories resulted in a modest rebound in natural gas prices but overall the prices still remain low due to weather uncertainty. We continue to believe that the long-term pricing fundamentals for natural gas remain strong. These fundamentals include (i) the continued strength of crude oil prices, which has

eliminated the economic advantage of fuel switching away from natural gas, (ii) long-term tightness in supply that has resulted from persistent demand and the decline in North American natural gas production levels and (iii) ongoing weather related factors such as hot summers, cold winters and annual hurricane season in the Gulf of Mexico, all of which have an impact on the delicate supply/demand balance that exists.

Crude Oil and NGLs

(\$/bbl)	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Realized crude oil prices						
Excluding hedging	\$ 56.10	\$ 61.11	(8)%	\$ 63.85	\$ 61.02	5%
Including hedging	\$ 57.82	\$ 60.37	(4)%	\$ 64.34	\$ 59.20	9%
Realized NGLs prices						
Excluding hedging	\$ 50.09	\$ 55.42	(10)%	\$ 55.81	\$ 49.54	13%
Realized crude oil and NGLs prices						
Excluding hedging	\$ 54.58	\$ 60.14	(9)%	\$ 62.05	\$ 59.10	5%
Including hedging	\$ 55.86	\$ 59.53	(6)%	\$ 62.44	\$ 57.58	8%
WTI (\$US/bbl)	\$ 60.21	\$ 60.04	0%	\$ 66.35	\$ 56.61	17%
\$US/\$Canadian exchange rate	\$ 0.88	\$ 0.85	4%	\$ 0.88	\$ 0.83	6%

Realized crude oil and NGLs prices, excluding hedging, decreased 9% for the three months and increased 5% for the year ended December 31, 2006, as compared to the same periods of 2005. Advantage's crude oil prices are based on the benchmark pricing of West Texas Intermediate Crude ("WTI") adjusted for quality, transportation costs and \$US/\$Canadian exchange rates. Advantage's realized crude oil price has not changed to the same extent as WTI due to strengthening of the Canadian dollar and the widening of Canadian crude oil differentials relative to WTI. The price of WTI fluctuates based on worldwide supply and demand fundamentals. There has been significant price volatility experienced over the last several years whereby WTI has reached historic high levels. For the three months ended December 31, 2006 WTI has remained relatively stable and increased 17% for the year ended December 31, 2006, compared to 2005. Many developments have resulted in the current price levels, including significant geopolitical and weather related issues. Early in 2006, prices remained strong due to concerns regarding the lack of North American refining capacity, and the continued strength of global demand. However, the mild 2005/2006 winter and the surge in crude imports to North America have resulted in significantly higher inventories, which prompted the relative price decrease towards the end of 2006. These key issues persist and will continue to impact overall commodity prices. With the current softening of crude price levels, it is notable that production restrictions are frequently being considered by the OPEC cartel and that inventory levels can quickly decline. We believe that the pricing fundamentals for crude oil remain strong with many factors affecting the continued strength including (i) supply management and supply restrictions by the OPEC cartel, (ii) ongoing civil unrest in Venezuela, Nigeria, and the Middle East, (iii) strong world wide demand, particularly in China, India and the United States and (iv) North American refinery capacity constraints.

Commodity Price Risk

The Fund's operational results and financial condition will be dependent on the prices received for oil and natural gas production. Oil and natural gas prices have fluctuated widely during recent years and are determined by economic and, in the case of oil prices, political factors. Supply and demand factors, including weather and general economic conditions as well as conditions in other oil and natural gas regions impact prices. Any movement in oil and natural gas prices could have an effect on the Fund's financial condition and therefore on the cash distributions to holders of Advantage Trust Units. As current and future practice, Advantage has established a financial hedging strategy and may manage the risk associated with changes in commodity prices by entering into financial derivatives. These commodity risk management activities could expose Advantage to losses or gains. To the extent that Advantage engages in risk management activities related to commodity prices, it will be subject to credit risk associated with counterparties with which it contracts. Credit risk is mitigated by entering into contracts with only stable, creditworthy parties and through frequent reviews of exposures to individual entities.

Currently, the Fund has the following financial derivatives in place:

Description of Financial Derivative	Term	Volume	Average Price	
Natural gas - AECO				
Fixed price	November 2006 to March 2007	5,687 mcf/d		Cdn\$8.70/mcf
Fixed price	November 2006 to March 2007	3,791 mcf/d		Cdn\$10.02/mcf
Fixed price	April 2007 to October 2007	9,478 mcf/d		Cdn\$7.16/mcf
Fixed price	April 2007 to October 2007	9,478 mcf/d		Cdn\$7.55/mcf
Collar	November 2006 to March 2007	9,478 mcf/d	Floor	Cdn\$8.18/mcf
			Ceiling	Cdn\$11.24/mcf
Collar	November 2006 to March 2007	4,739 mcf/d	Floor	Cdn\$8.44/mcf
			Ceiling	Cdn\$12.40/mcf
Collar	November 2006 to March 2007	4,739 mcf/d	Floor	Cdn\$8.18/mcf
			Ceiling	Cdn\$11.66/mcf
Collar	November 2006 to March 2007	4,739 mcf/d	Floor	Cdn\$8.44/mcf
			Ceiling	Cdn\$12.29/mcf
Collar	November 2006 to March 2007	5,687 mcf/d	Floor	Cdn\$7.91/mcf
			Ceiling	Cdn\$9.81/mcf
Collar	November 2006 to March 2007	9,478 mcf/d	Floor	Cdn\$8.44/mcf
			Ceiling	Cdn\$13.82/mcf
Collar	November 2007 to March 2008	9,478 mcf/d	Floor	Cdn\$8.44/mcf
			Ceiling	Cdn\$10.29/mcf
Crude oil - WTI				
Collar	October 2006 to March 2007	1,250 bbls/d	Floor	US\$65.00/bbl
			Ceiling	US\$87.40/bbl
Collar	October 2006 to September 2007	1,000 bbls/d	Floor	US\$65.00/bbl
			Ceiling	US\$90.00/bbl

In addition, the Fund has the following physical natural gas contracts in place:

Description of Physical Contract	Term	Volume	Average Price	
Natural gas - AECO				
Collar	November 2006 to March 2007	4,739 mcf/d	Floor	Cdn\$8.07/mcf
			Ceiling	Cdn\$11.61/mcf
Collar	April 2007 to October 2007	4,739 mcf/d	Floor	Cdn\$7.12/mcf
			Ceiling	Cdn\$8.67/mcf
Collar	April 2007 to October 2007	4,739 mcf/d	Floor	Cdn\$6.86/mcf
			Ceiling	Cdn\$9.13/mcf
Collar	April 2007 to October 2007	9,478 mcf/d	Floor	Cdn\$7.39/mcf
			Ceiling	Cdn\$9.63/mcf
Collar	April 2007 to October 2007	9,478 mcf/d	Floor	Cdn\$6.33/mcf
			Ceiling	Cdn\$7.20/mcf

As at December 31, 2006 the settlement amount of the financial derivatives outstanding was an asset of approximately \$10,433,000. For the year ended December 31, 2006, \$10,242,000 was recognized in income as an unrealized derivative gain. As a result of the Ketch merger, we assumed several of these contracts which had an estimated fair value of \$191,000 on closing. Recorded in revenue are realized hedging gains of \$5.2 million for the three months and \$5.3 million for the year ended December 31, 2006, which partially alleviated lower revenue from reduced commodity prices. The Fund does not apply hedge accounting and current accounting standards require changes in the fair value to be included in the income statement as an unrealized derivative gain or loss with a corresponding derivative asset or liability recorded on the balance sheet. The valuation is the estimated fair value to settle the financial contracts as at December 31, 2006 and is based on pricing models, estimates, assumptions and market data available at that time. The actual gain or loss realized on cash settlement can vary materially due to subsequent fluctuations in commodity prices as compared to the valuation assumptions.

The Fund has fixed the commodity price on anticipated production as follows:

Commodity	Approximate Production Hedged, Net of Royalties	Minimum Price	Maximum Price
Natural gas - AECO			
Winter 2006/2007	58%	Cdn\$8.42/mcf	Cdn\$11.46/mcf
Summer 2007	54%	Cdn\$7.08/mcf	Cdn\$8.09/mcf
Winter 2007/2008	11%	Cdn\$8.44/mcf	Cdn\$10.29/mcf
Crude Oil - WTI			
Winter 2006/2007	30%	US\$65.00/bbl	US\$88.56/bbl
Summer 2007	14%	US\$65.00/bbl	US\$90.00/bbl

Royalties

	Three months ended			Year ended		
	December 31			December 31		
	2006	2005	% change	2006	2005	% change
Royalties, net of Alberta Royalty Credit (\$000)	\$ 23,349	\$ 23,281	0%	\$ 76,456	\$ 74,290	3%
per boe	\$ 8.72	\$ 13.18	(34)%	\$ 8.82	\$ 10.11	(13)%
As a percentage of revenue, excluding hedging	19.1%	19.8%	(0.7)%	18.4%	19.0%	(0.6)%

Advantage pays royalties to the owners of mineral rights from which we have leases. The Fund currently has mineral leases with provincial governments, individuals and other companies. Royalties are shown net of Alberta Royalty Credit which is a royalty rebate provided by the Alberta government to certain producers and was eliminated effective January 1, 2007. Royalties have increased in total due to the increase in revenue from higher production but have decreased on a per boe basis due to the significantly reduced natural gas prices. Royalties as a percentage of revenue, excluding hedging, have remained relatively consistent with comparable periods and we expect the royalty rate to continue as such.

On February 13, 2007, the Alberta provincial government announced it will begin an oil and gas royalty and tax system review expected to conclude by August 31, 2007. The review will concentrate on the oil sands royalty structure initially, followed by an analysis of the conventional oil and gas and coal bed methane levies. The panel in charge will perform a comparison to other oil and gas-producing jurisdictions, ensure the system is sufficiently sensitive to market conditions, examine the tax treatment compared to other sectors, assess the impacts of potential changes to the structure and determine the treatment of existing resource development if changes are made to the system. The review may result in imposed modifications that affect the Fund's royalties in the future.

Operating Costs

	Three months ended			Year ended		
	December 31			December 31		
	2006	2005	% change	2006	2005	% change
Operating costs (\$000)	\$ 27,803	\$ 17,381	60%	\$ 82,911	\$ 57,941	43%
per boe	\$ 10.39	\$ 9.84	6%	\$ 9.56	\$ 7.89	21%

Total operating costs increased 60% for the three months ended and 43% for the year ended December 31, 2006 as compared to 2005 mainly due to the Ketch acquisition and service costs that have escalated in 2006. Operating costs per boe increased 6% for the three months and 21% for the year ended December 31, 2006. In the fourth quarter of 2006, crude oil pipeline restrictions in Southeast Saskatchewan resulted in additional trucking, increasing operating costs per boe for the quarter. In addition, operating costs per boe for the quarter and year ended December 31, 2006 have increased due to significantly higher costs associated with the shortage of supplies and services in the field. However, there has been recent evidence of reduced demand on the current available support and service resources as drilling rig utilization rates have decreased. The impact on operating costs is uncertain but we will be opportunistic and proactive in pursuing alternatives that will improve our operating cost structure. A significant operating cost that Advantage has been successful in stabilizing is electricity costs associated with field operations. The Fund has been active in preserving the price of power by hedging 3.5 MW at \$56.68/MWh for 2007 and 3.0 MW at \$54.00/MWh for 2008. Management of operating costs will be a persistent challenge in the current environment and we expect operating costs per boe to average between \$9.50 to \$10.50 for 2007.

General and Administrative

	Three months ended			Year ended		
	December 31			December 31		
	2006	2005	% change	2006	2005	% change
General and administrative expense (\$000)	\$ 4,586	\$ 1,521	202%	\$ 13,738	\$ 5,452	152%
per boe	\$ 1.71	\$ 0.86	99%	\$ 1.58	\$ 0.74	114%
Employees at December 31				135	80	69%

General and administrative (“G&A”) expense has increased 202% for the three months and 152% for the year ended December 31, 2006, as compared to 2005. G&A per boe increased 99% for the three months and 114% for the year when compared to the same periods of 2005. G&A expense has increased overall and per boe primarily due to an increase in staff levels that have resulted from the Ketch acquisition and growth of the Fund. Additionally, the Ketch acquisition was conditional on Advantage internalizing the external management contract structure and eliminating all related fees for a more typical employee compensation arrangement. The new employee compensation plan has resulted in higher G&A expense that is offset by the elimination of future management fees and performance incentive. Prior to elimination of the management contract, the quarterly management fee and annual performance incentive were not included within G&A.

Current employee compensation includes salary, benefits, a short-term incentive plan and a long-term incentive plan. The long-term incentive plan consists of Restricted Trust Unit (“RTU”) grants based on the Fund’s individual Trust Unit performance from June 23 to December 31, 2006, adjusted for each monthly distribution, and compared to a peer group approved by the Board of Directors. The RTU grants vest over two years and are not available to previous AIM management for a period of three years following the Ketch acquisition. As the Fund did not meet the 2006 grant thresholds, there was no RTU grant made for the 2006 year.

Management Fee, Performance Incentive, and Management Internalization

	Three months ended			Year ended		
	December 31			December 31		
	2006	2005	% change	2006	2005	% change
Management fee (\$000)	\$ -	\$ 1,043	(100)%	\$ 887	\$ 3,665	(76)%
per boe	\$ -	\$ 0.59	(100)%	\$ 0.10	\$ 0.50	(80)%
Performance incentive (\$000)	\$ -	\$ 10,544	(100)%	\$ 2,380	\$ 10,544	(77)%
Management internalization (\$000)	\$ 5,497	\$ -	-	\$ 13,449	\$ -	-

Prior to the Ketch merger, the Manager received both a management fee and a performance incentive fee as compensation pursuant to the Management Agreement approved by the Board of Directors. Management fees were calculated based on 1.5% of operating cash flow defined as revenues less royalties and operating costs.

The Manager was entitled to earn an annual performance incentive fee when the Fund’s total annual return exceeded 8%. The total annual return was calculated at the end of the year by dividing the year-over-year change in Unit price plus cash distributions by the opening Unit price, as defined in the Management Agreement. Ten percent of the amount of the total annual return in excess of 8% was multiplied by the market capitalization (defined as the opening Unit price multiplied by the weighted average number of Trust Units outstanding during the year) to determine the performance incentive fee. The Management Agreement provided an option to the Manager to receive the performance incentive fee in equivalent Trust Units. The Manager did not receive any form of compensation in respect of acquisition or divestiture activities nor were there any form of stock option or bonus plan for the Manager or the employees of Advantage outside of the management and performance fees. The management fees and performance fees were shared amongst all management and employees.

As a condition of the merger with Ketch, the Fund and the Manager reached an agreement to internalize the management contract arrangement. As part of the agreement, Advantage agreed to purchase all of the outstanding shares of the Manager pursuant to the terms of the Arrangement for total original consideration of 1,933,208 Advantage Trust Units initially valued at \$39.1 million using the weighted average trading value for June 22, 2006 of \$20.23 per Advantage Trust Unit. The Trust Unit consideration was placed in escrow for a 3-year period and is being deferred and amortized into income as management internalization expense over the specific vesting periods during which employee services are provided. The Fund paid final management fees and performance fees for the period January 1 to March 31, 2006 in the amount of \$3.3 million, representing \$0.9 million in management fees and \$2.4 million in performance fees. The performance fees were settled through the issuance of 117,662 Trust Units of the Fund. The Manager agreed to forego fees for the period April 1, 2006 to the closing of the Arrangement.

Interest

	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Interest expense (\$000)	\$ 5,414	\$ 2,865	89%	\$ 18,258	\$ 10,275	78%
per boe	\$ 2.02	\$ 1.62	25%	\$ 2.11	\$ 1.40	51%
Average effective interest rate	5.5%	4.4%	1.1%	5.1%	4.3%	0.8%
Bank indebtedness at December 31 (\$000)				\$ 410,574	\$ 252,476	63%

Interest expense has increased 89% for the three months and 78% for the year ended December 31, 2006, as compared to 2005. The increase in interest expense is primarily attributable to a higher average debt level associated with the growth of the Fund, an increase in the average effective interest rates, and the merger with Ketch which included the assumption of Ketch's additional bank indebtedness. The increased debt has been used in financing continued development activities and pursuit of expansion opportunities. We monitor the debt level to ensure an optimal mix of financing and cost of capital that will provide a maximum return to Unitholders. Our current credit facilities have been a favorable financing alternative with an effective interest rate of approximately 5.5% for the three months and 5.1% for the year ended December 31, 2006. The Fund's interest rates are primarily based on short term Bankers Acceptance rates plus a stamping fee.

Interest and Accretion on Convertible Debentures

	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
Interest on convertible debentures (\$000)	\$ 3,289	\$ 2,727	21%	\$ 11,210	\$ 11,210	0%
per boe	\$ 1.23	\$ 1.54	(20)%	\$ 1.29	\$ 1.53	(16)%
Accretion on convertible debentures (\$000)	\$ 604	\$ 532	14%	\$ 2,106	\$ 2,182	(3)%
per boe	\$ 0.23	\$ 0.30	(23)%	\$ 0.24	\$ 0.30	(20)%
Convertible debentures maturity value at December 31 (\$000)				\$ 180,730	\$ 135,111	34%

Interest on convertible debentures has increased 21% for the three months and was unchanged for the year ended December 31, 2006 compared to the same periods of 2005. Accretion on convertible debentures has increased 14% for the three months and decreased 3% for the year ended December 31, 2006 as compared to 2005. The increases in total interest and accretion for the quarter as well as the increased convertible debentures maturity value are due to Advantage assuming Ketch's 6.50% convertible debentures in the merger. The increased interest and accretion from the additional debentures has been offset for the year due to the continual exchange of convertible debentures to Trust Units that will pay distributions rather than interest. During the year ended December 31, 2006, \$24.3 million of convertible debentures were converted resulting in the issuance of 1,286,901 Trust Units.

Cash Netbacks

	Three months ended December 31				Year ended December 31			
	2006		2005		2006		2005	
	\$000	per boe	\$000	per boe	\$000	per boe	\$000	per boe
Revenue	\$ 122,360	\$ 45.72	\$ 117,319	\$ 66.40	\$ 414,430	\$ 47.80	\$ 390,541	\$ 53.17
Realized hedging gains (losses)	5,179	1.93	(7,147)	(4.05)	5,297	0.61	(13,969)	(1.90)
Royalties	(23,349)	(8.72)	(23,281)	(13.18)	(76,456)	(8.82)	(74,290)	(10.11)
Operating costs	(27,803)	(10.39)	(17,381)	(9.84)	(82,911)	(9.56)	(57,941)	(7.89)
Operating	\$ 76,387	\$ 28.54	\$ 69,510	\$ 39.33	\$ 260,360	\$ 30.03	\$ 244,341	\$ 33.27
General and administrative	(4,586)	(1.71)	(1,521)	(0.86)	(13,738)	(1.58)	(5,452)	(0.74)
Management fee	-	-	(1,043)	(0.59)	(887)	(0.10)	(3,665)	(0.50)
Interest	(5,414)	(2.02)	(2,865)	(1.62)	(18,258)	(2.11)	(10,275)	(1.40)
Interest on convertible debentures	(3,289)	(1.23)	(2,727)	(1.54)	(11,210)	(1.29)	(11,210)	(1.53)
Taxes	(361)	(0.13)	(448)	(0.25)	(1,509)	(0.17)	(2,198)	(0.30)
Funds from operations	\$ 62,737	\$ 23.45	\$ 60,906	\$ 34.47	\$ 214,758	\$ 24.78	\$ 211,541	\$ 28.80

Funds from operations per boe have decreased from \$28.80 per boe in the prior year to \$24.78 per boe for the year ended December 31, 2006. The lower cash netback per boe is primarily due to lower revenues resulting from soft natural gas prices as well as higher operating costs, general and administrative expenses and interest. Operating costs per boe for the year ended December 31, 2006 were \$9.56, an increase of 21% from the \$7.89 experienced in 2005. Operating costs have steadily increased over the past year due to significantly higher field costs associated with the shortage of supplies and services that has resulted from the high level of industry activity. General and administrative expenses per boe for the 2006 year have increased 114% over the prior year period due to the additional employees from the growth of the Fund and the Ketch merger, which also resulted in internalization of the management arrangement and a new employee compensation plan. Interest expense per boe on bank indebtedness for the year ended December 31, 2006 has increased 51% over the prior year due to the assumption of debt in the Ketch merger, higher average effective interest rates and the general growth of the Fund.

Depletion, Depreciation and Accretion

	Three months ended December 31			Year ended December 31		
	2006	2005	% change	2006	2005	% change
	Depletion, depreciation & accretion (\$000)	\$ 63,521	\$ 32,581	95%	\$ 194,309	\$ 135,096
per boe	\$ 23.73	\$ 18.44	29%	\$ 22.41	\$ 18.39	22%

Depletion and depreciation of property and equipment is provided on the "unit-of-production" method based on total proved reserves. The depletion, depreciation and accretion ("DD&A") provision has increased by 95% for the three months and 44% for the year ended December 31, 2006. The DD&A per boe has increased by 29% for the three months and 22% for the year ended December 31, 2006 compared to prior years. The higher DD&A is primarily due to increased production from the Ketch acquisition while the DD&A per boe increase was caused by a higher valuation for the Ketch reserves than accumulated from prior acquisitions and development activities.

Taxes

Current taxes paid or payable for the quarter ended December 31, 2006 amounted to \$0.4 million, compared to \$0.4 million expensed for the same period of 2005. For the year ended December 31, 2006, current taxes paid or payable were \$1.5 million, compared to \$2.2 million for the comparative period. Current taxes primarily represent Federal large corporations tax and Saskatchewan resource surcharge. Federal large corporations tax was based on debt and equity levels of the Fund and has been eliminated effective January 1, 2006 due to government legislation. Saskatchewan resource surcharge is based on the petroleum and natural gas revenues within the province of Saskatchewan.

Future income taxes arise from differences between the accounting and tax bases of the operating company's assets and liabilities. For the year ended December 31, 2006, the Fund recognized an income tax reduction of \$37.1 million compared to a reduction of \$11.4 million for 2005.

Under the Fund's current structure, payments are made between the operating company and the Fund transferring income tax obligations to the Unitholders. Therefore, based on the current structure and existing legislation, no cash income taxes are to be paid by the operating company or the Fund, and as such, the future income tax liability recorded on the balance sheet will be recovered through earnings over time. As at December 31, 2006, the operating company had a future income tax liability balance of \$61.9 million. Canadian generally accepted accounting principles require that a future income tax liability be recorded when the book value of assets exceeds the balance of tax pools.

On October 31, 2006, the Federal Government proposed changes to Canada's tax system that include altering the tax treatment of income trusts. The government proposed a two-tier tax structure, similar to that of corporations, whereby distributions paid by trusts that represent a return on capital will be subject to tax at the trust level in addition to personal tax as if they were dividends from a taxable Canadian corporation. The changes are proposed to take effect in 2011 for existing publicly-traded trusts. If enacted, the proposal could affect the Fund in several ways, and Advantage is currently assessing several options for the future. The Fund may allocate a portion of cash flows to additional tax on distributions, resulting in less cash flow available for distribution or the Fund may determine strategic alternatives such as increasing cash flow allocated to capital spending, conversion to a corporation, or paying a higher percentage of distributions on a return of capital basis, all of which could result in a decrease or elimination of distributions. The following is a table provided by the Federal Government showing a simplified comparison of the effects of the proposed changes to investor tax rates in 2011:

	Current System		Enacted System (2011)	
	Income Portion of Trust Distributions	Large Corporation (Dividend)	Income Portion of Trust Distributions	Large Corporation (Dividend)
Taxable Canadian individuals ⁽¹⁾	46%	46%	45.5%	45.5%
Canadian tax-exempt investors	0%	32%	31.5%	31.5%
Taxable U.S. investors ⁽²⁾	15%	42%	41.5%	41.5%

⁽¹⁾All rates in the table are as of 2011, and include both entity- and investor-level tax (as applicable). Rates for "Taxable Canadian individuals" assume that top personal income tax rates apply and that provincial governments increase their dividend tax credit for dividends of large corporations.

⁽²⁾Canadian taxes only. U.S. tax will also apply in most cases, net of any foreign tax credits.

The Fund has approximately \$1.2 billion in tax pools and deductions at December 31, 2006, which can be used to declare a higher percentage of distributions as a return of capital and thus reduce the amount of taxes paid by Unitholders. The Fund and AOG had the following estimated tax pools in place at December 31, 2006:

December 31, 2006	
Estimated Tax Pools	
(\$ millions)	
Undepreciated Capital Cost	\$ 453
Canadian Oil and Gas Property Expenses	333
Canadian Development Expenses	303
Canadian Exploration Expenses	44
Non-capital losses	29
Other	<u>22</u>
	<u>\$ 1,184</u>

Non-Controlling Interest

Non-controlling interest expense for the year ended December 31, 2006 was \$29,000, a decrease of 88% from the \$232,000 recognized during the same period of 2005. Non-controlling interest expense represents the net income attributable to Exchangeable Share ownership interests. The non-controlling interest was created when Advantage Oil & Gas Ltd. ("AOG"), a subsidiary of the Fund, issued Exchangeable Shares as partial consideration for the acquisition of Defiant Energy Corporation ("Defiant") that occurred at the end of 2004. The decrease in non-controlling interest expense is directly attributable to the continued conversion of Exchangeable Shares to Trust Units since the original issuance. On March 8, 2006, AOG elected to exercise its redemption right to redeem all of the Exchangeable Shares outstanding. The redemption price per Exchangeable Share was satisfied by delivering that number of Advantage Trust Units equal to the Exchange Ratio of 1.22138 in effect on May 9, 2006. As such, there is no non-controlling interest expense recorded in the quarter and no exchangeable shares remain outstanding.

Contractual Obligations and Commitments

The Fund has contractual obligations in the normal course of operations including purchases of assets and services, operating agreements, transportation commitments, sales contracts and convertible debentures. These obligations are of a recurring and consistent nature and impact cash flow in an ongoing manner. The following table is a summary of the Fund's remaining contractual obligations and commitments. Advantage has no guarantees or off-balance sheet arrangements other than as disclosed.

(\$ millions)	Payments due by period					
	Total	2007	2008	2009	2010	2011
Building leases	\$ 5.4	\$ 2.2	\$ 1.4	\$ 0.8	\$ 0.8	\$ 0.2
Capital leases	2.9	2.6	0.3	-	-	-
Pipeline/transportation	5.9	4.2	1.4	0.3	-	-
Convertible debentures ⁽¹⁾	180.7	1.4	5.4	57.1	70.0	46.8
Total contractual obligations	\$ 194.9	\$ 10.4	\$ 8.5	\$ 58.2	\$ 70.8	\$ 47.0

(1) As at December 31, 2006, Advantage had \$180.7 million convertible debentures outstanding. Each series of convertible debentures are convertible to Trust Units based on an established conversion price. The Fund expects that the obligations related to convertible debentures will be settled through the issuance of Trust Units.

(2) Bank indebtedness of \$410.6 million has been excluded from the contractual obligations table as the credit facilities constitute a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period at the option of the syndicate. If not extended, the revolving credit facility is converted to a two year term facility with the first payment due one year and one day after commencement of the term.

Liquidity and Capital Resources

The following table is a summary of the Fund's capitalization structure:

(\$000, except as otherwise indicated)	December 31, 2006
Bank indebtedness (long-term)	\$ 410,574
Working capital deficit ⁽¹⁾	42,655
Net debt	\$ 453,229
Trust Units outstanding (000)	105,390
Trust Unit closing market price (\$/Trust Unit)	\$ 12.43
Market value	\$ 1,309,998
Capital lease obligation (long-term)	\$ 305
Convertible debentures maturity value (long-term)	179,245
Total capitalization	\$ 1,942,777

(1) Working capital deficit includes accounts receivable, prepaid expenses and deposits, accounts payable and accrued liabilities, cash distributions payable, and the current portion of capital lease obligations and convertible debentures.

Unitholders' Equity, Exchangeable Shares and Convertible Debentures

Advantage has utilized a combination of Trust Units, Exchangeable Shares, convertible debentures and bank debt to finance acquisitions and development activities.

As at December 31, 2006, the Fund had 105.4 million Trust Units outstanding. On January 20, 2006, Advantage issued 475,263 Trust Units to satisfy \$10.5 million of the performance incentive fee obligation related to the 2005 year. On June 23, 2006, Advantage issued 32,870,465 Trust Units as consideration for the acquisition of Ketch, 1,933,208 Trust Units as consideration for all of the outstanding shares of AIM to internalize the external management contract, and 117,662 Trust Units to satisfy the final obligation related to the 2006 first quarter performance fee. The Trust Units issued as consideration for the external management contract are subject to escrow provisions and 19,366 Trust Units were forfeited during the year ended December 31, 2006. On August 1, 2006 Advantage issued 7,500,000 Trust Units, plus an additional 1,125,000 Trust Units upon full exercise of the Underwriters' over-allotment option on August 4, 2006, at \$17.30 per Trust Unit for net proceeds of \$141.4 million (net of Underwriters' fees and other issue costs of \$7.8 million). The net proceeds of the offering were used to pay down bank indebtedness and to subsequently fund capital and general corporate expenditures. As at March 21, 2007, Advantage had 115.0 million Trust Units issued and outstanding.

Exchangeable Shares issued and outstanding were exchangeable for Advantage Trust Units at any time on the basis of the applicable exchange ratio in effect at that time. On March 8, 2006, AOG elected to exercise its redemption right to redeem all of the Exchangeable Shares outstanding. The redemption price per Exchangeable Share was satisfied by delivering that number of Advantage Trust Units equal to the Exchange Ratio of 1.22138 in effect on May 9, 2006. During 2006, the Fund issued 127,014 Trust Units for the remaining Exchangeable Shares.

Effective June 25, 2002, a Trust Units Rights Incentive Plan for external directors of the Fund was established and approved by the Unitholders of Advantage. A total of 500,000 Trust Units have been reserved for issuance under the plan with an aggregate of 400,000 rights granted since inception. The initial exercise price of rights granted under the plan may not be less than the current market price of the Trust Units as of the date of the grant and the maximum term of each right is not to exceed ten years with all rights vesting immediately upon grant. At the option of the rights holder, the exercise price of the rights can be adjusted downwards over time based upon distributions paid by the Fund to Unitholders. In exchange for an equivalent number of Trust Units, all of the remaining 85,000 Series A Trust Units Rights were exercised in the third quarter and 37,500 Series B Trust Unit Rights were exercised in the second quarter of 2006. As at March 21, 2007, 187,500 Series B Trust Unit Rights remain outstanding.

As at December 31, 2006, the Fund had \$180.7 million convertible debentures outstanding that were convertible to 8.3 million Trust Units based on the applicable conversion prices. During the year ended December 31, 2006, \$24.3 million convertible debentures were exchanged for the issuance of 1.3 million Trust Units. As at March 21, 2007, the convertible debentures outstanding have not changed from December 31, 2006.

On July 24, 2006, Advantage announced that it adopted a Premium Distribution^(TM), Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "Plan"). The Plan commenced with the monthly cash distribution payable on August 15, 2006 to Unitholders of record on July 31, 2006. For Unitholders that elect to participate in the Plan, Advantage will settle the monthly distribution obligation through the issuance of additional Trust Units at 95% of the Average Market Price (as defined in the Plan). Unitholder enrollment in the Premium Distribution^(TM) component of the Plan effectively authorizes the subsequent disposal of the issued Trust Units in exchange for a cash payment equal to 102% of the cash distributions that the Unitholder would otherwise have received if they did not participate in the Plan. During the year ended December 31, 2006, 2,005,499 Trust Units were issued as a result of the Plan, generating \$27.7 million reinvested in the Fund and representing an approximate 26% participation rate.

On February 14, 2007 Advantage issued 7,800,000 Trust Units, plus an additional 800,000 Trust Units upon exercise of the Underwriters' over-allotment option on March 7, 2007, at \$12.80 per Trust Unit for approximate net proceeds of \$104.2 million (net of Underwriters' fees and other issue costs of \$5.9 million). The net proceeds of the offering will be used to pay down bank indebtedness and to subsequently fund capital and general corporate expenditures.

In the October 31, 2006 proposal to tax distributions at the income trust level as well as the existing Unitholder level, the Federal Government warned against income trusts incurring "undue expansion" during the period between the proposal announcement and 2011 when the tax rules will effectively change. On December 15, 2006 the Federal Government clarified "undue expansion" by providing a set of guidelines for "normal growth". An income trust is permitted to double its market capitalization as it stands on October 31, 2006 by growing a maximum of 40% in 2007 and 20% for the years 2008 to 2010. Any unused expansion from the prior year can be brought forward into the following year until the new tax rules take effect. In addition, an income trust may replace debt that was outstanding as of October 31, 2006 with new equity or issue new, non-convertible debt without affecting the normal growth percentage. An income trust may also merge with another income trust without a change to their normal growth percentage, provided there is no net addition to equity as a result of the merger. As of October 31, 2006, the Fund had an approximate market capitalization of \$1.6 billion and bank indebtedness of \$0.4 billion. Therefore, as a result of the "normal growth" guidelines, the Fund is permitted to issue \$2.0 billion of new equity over the next four years, which we believe is adequate for any growth we expect to incur.

Bank Indebtedness, Credit Facility and Other Obligations

At December 31, 2006, Advantage had bank indebtedness outstanding of \$410.6 million. Advantage assumed net bank indebtedness of approximately \$188 million in the Ketch merger. The Fund has a \$600 million credit facility agreement consisting of a \$580 million extendible revolving loan facility and a \$20 million operating loan facility. The current credit facilities are secured by a \$1 billion floating charge demand debenture, a general security agreement and a subordination agreement from the Fund covering all assets and cash flows.

At December 31, 2006, Advantage had a working capital deficiency of \$42.7 million that has remained relatively consistent with the previous year end. Our working capital includes items expected for normal operations such as trade receivables, prepaids, deposits, trade payables and accruals. Working capital varies primarily due to the timing of such items, the current level of business activity including our capital program, commodity price volatility, and seasonal fluctuations. Advantage has no unusual working capital requirements. We do not anticipate any problems in meeting future obligations as they become due given the strength of our funds from operations. It is also important to note that working capital is effectively integrated with Advantage's operating credit facility, which assists with the timing of cash flows as required.

Advantage generally does not make use of capital leases to finance development expenditures. However, Advantage currently has two capital leases outstanding at December 31, 2006 for \$2.8 million that were both assumed from corporate acquisitions.

Capital Expenditures

(\$000)	Three months ended December 31		Year ended December 31	
	2006	2005	2006	2005
Land and seismic	\$ 522	\$ 609	\$ 5,261	\$ 3,860
Drilling, completions and workovers	42,612	24,293	113,146	77,794
Well equipping and facilities	17,690	2,758	39,437	20,322
Other	285	300	1,643	1,253
	\$ 61,109	\$ 27,960	\$ 159,487	\$ 103,229
Purchase adjustment of Defiant acquisition	-	98	-	98
Property acquisitions	46	(3)	244	210
Property dispositions	-	76	(8,727)	(3,379)
Total capital expenditures	\$ 61,155	\$ 28,131	\$ 151,004	\$ 100,158

Advantage's growth strategy has been to acquire properties in or near areas where we have large land positions, shallow to medium depth drilling opportunities, and preserve a balance of year round access. We focus on areas where past activity has yielded long-life reserves with high cash netbacks. With the integration of the Ketch assets, Advantage is very well positioned to selectively exploit the highest value-generating drilling opportunities given the size, strength and diversity of our asset base. As a result, the Fund has shifted its remaining capital program to further oil development due to superior project economics. Our preference is to operate a high percentage of our properties such that we can maintain control of capital expenditures, operations and cash flows.

For the three month period ended December 31, 2006, the Fund spent a net \$61.2 million on capital expenditures. Approximately \$42.6 million was expended on drilling and completion operations where the Fund drilled a total of 25.1 net (44 gross) wells. During the quarter we drilled 4.4 net (13 gross) gas wells at Chigwell, two 100% working interest gas wells at Black, five 70% working interest oil wells at Sunset, three oil wells and one gas well with 100% working interests at Nevis and several wells at other minor properties. Total capital spending in the quarter included \$13.8 million at Nevis, \$7.5 million at Sunset, \$5.4 million at Chigwell, \$2.7 million at Hardy, \$2.6 million at Worsley, \$2.6 million at Westeros, \$2.5 million at Martin Creek, \$2.4 million at Conroy Creek, and \$2.4 million at Willesden Green.

For the year ended December 31, 2006, the Fund spent a net \$151.0 million on capital expenditures. The Fund drilled a total of 90.2 net (147 gross) wells as a result of spending approximately \$113.1 million on drilling and completion operations. During the year, Advantage drilled 10.4 net (25 gross) gas wells at Chigwell, 15 gas wells with 100% working interest at Medicine Hat, 2.3 net (4 gross) gas wells at Worsley, 9.8 net (14 gross) oil wells at Sunset, 4.2 net (6 gross) gas wells and 11 oil wells with 100% working interest at Nevis, and 3 100% working interest gas wells at Shouldice, along with numerous wells at other minor properties. The Fund experienced a 95% success rate on wells drilled in 2006. Total capital spending for the year included \$36.5 million at Nevis, \$17.4 million at Sunset, \$8.0 million at Chigwell, \$7.8 million at Willesden Green, and \$6.5 million at Worsley. The majority of capital spending was used for drilling and facilities throughout the year as well as some residual development activity remaining from the end of 2005. Activity occurring late in the year included three new oil wells at the Westeros Banff "C" unit adding a net 200 boe/d, two new oil wells at Little Bow in Southern Alberta adding a net 150 boe/d, the Chigwell North coal bed methane joint venture and new gas pool at Sweetgrass.

The following table summarizes the various funding requirements during the year ended December 31, 2006 and the sources of funding to meet those requirements.

Sources and Uses of Funds

(\$000)	Year ended December 31, 2006
Sources of funds	
Funds from operations	\$ 214,758
Units issued, net of costs	169,631
Property dispositions	8,727
Decrease in working capital	27,222
	\$ 420,338
Uses of funds	
Cash distributions to Unitholders	\$ 212,738
Expenditures on property and equipment	159,487
Decrease in bank indebtedness	30,767
Acquisition costs of Ketch Resources Trust	10,109
Expenditures on asset retirement	5,974
Reduction of capital lease obligations	1,019
Property acquisitions	244
	\$ 420,338

Annual Financial Information

The following is a summary of selected financial information of the Fund for the periods indicated.

	Year ended Dec. 31, 2006	Year ended Dec. 31, 2005	Year ended Dec. 31, 2004
Total revenue (before royalties) (\$000)	\$ 419,727	\$ 376,572	\$ 241,481
Net income (\$000)	\$ 49,814	\$ 75,072	\$ 24,038
per Trust Unit - Basic	\$ 0.62	\$ 1.33	\$ 0.59
- Diluted	\$ 0.61	\$ 1.32	\$ 0.58
Total assets (\$000)	\$ 1,981,587	\$ 1,012,847	\$ 1,033,251
Long term financial liabilities (\$000) ⁽¹⁾	\$ 581,698	\$ 379,903	\$ 144,039
Cash distributions declared per Trust Unit	\$ 2.66	\$ 3.12	\$ 2.82

⁽¹⁾ Given amendments made in 2005 to the credit facility repayment terms, the bank indebtedness is classified as a long-term liability while in 2004 bank indebtedness was shown as a current liability. Long term financial liabilities also exclude asset retirement obligations and future income taxes.

Quarterly Performance

(\$000, except as otherwise indicated)	2006				2005			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Daily production								
Natural gas (mcf/d)	117,134	122,227	70,293	65,768	72,587	75,994	79,492	86,350
Crude oil and NGLs (bbls/d)	9,570	9,330	6,593	6,760	7,106	7,340	6,772	6,892
Total (boe/d)	29,092	29,701	18,309	17,721	19,204	20,006	20,021	21,284
Average prices								
Natural gas (\$/mcf)								
Excluding hedging	\$ 6.90	\$ 5.89	\$ 6.18	\$ 8.69	\$ 11.68	\$ 8.25	\$ 7.27	\$ 6.52
Including hedging	\$ 7.27	\$ 5.90	\$ 6.18	\$ 8.69	\$ 10.67	\$ 7.79	\$ 7.30	\$ 6.47
AECO monthly index	\$ 6.36	\$ 6.03	\$ 6.28	\$ 9.31	\$ 11.68	\$ 8.15	\$ 7.38	\$ 6.70
Crude oil and NGLs (\$/bbl)								
Excluding hedging	\$ 54.58	\$ 67.77	\$ 68.69	\$ 58.26	\$ 60.14	\$ 66.00	\$ 56.57	\$ 53.02
Including hedging	\$ 55.86	\$ 67.77	\$ 68.69	\$ 58.26	\$ 59.53	\$ 61.10	\$ 56.24	\$ 53.02
WTI (US\$/bbl)	\$ 60.21	\$ 70.55	\$ 70.75	\$ 63.88	\$ 60.04	\$ 63.17	\$ 53.13	\$ 49.90
Total revenues (before royalties)	\$ 127,539	\$ 124,521	\$ 80,766	\$ 86,901	\$ 110,172	\$ 95,715	\$ 87,476	\$ 83,209
Net income	\$ 8,736	\$ 1,209	\$ 23,905	\$ 15,964	\$ 25,846	\$ 18,674	\$ 26,537	\$ 4,015
per Trust Unit - basic	\$ 0.08	\$ 0.01	\$ 0.38	\$ 0.27	\$ 0.45	\$ 0.33	\$ 0.46	\$ 0.07
- diluted	\$ 0.08	\$ 0.01	\$ 0.38	\$ 0.27	\$ 0.45	\$ 0.32	\$ 0.46	\$ 0.07
Funds from operations	\$ 62,737	\$ 63,110	\$ 42,281	\$ 46,630	\$ 60,906	\$ 55,575	\$ 49,705	\$ 45,355
Cash distributions declared	\$ 58,791	\$ 60,498	\$ 53,498	\$ 44,459	\$ 43,265	\$ 43,069	\$ 44,693	\$ 46,339
Payout ratio (%)	94%	96%	127%	95%	71%	77%	90%	102%

The table above highlights the Fund's performance for the fourth quarter of 2006 and also for the preceding seven quarters. During 2005, production continued to experience normal declines until a more significant decrease occurred in the first quarter of 2006 due to a one-time adjustment for several payout wells, restricted production on wells in Chip Lake and Nevis, and some minor non-core property dispositions that occurred in 2005. Production increased in the second quarter of 2006 with the addition of eight days of production from the Ketch properties and further increased in the third quarter of 2006 as the acquisition was fully integrated with Advantage. Production in the fourth quarter of 2006 was significantly impacted by freezing problems at several properties due to extreme cold in Alberta during the latter part of November. Advantage's revenues and funds from operations for the third and fourth quarters of 2006 are higher primarily due to the production from the merger with Ketch, offset by significantly lower natural gas prices. Net income has been lower during the last two quarters due to reduced natural gas prices realized during the periods, amortization of the management internalization consideration, and increased depletion and depreciation expense due to the Ketch merger. During 2006, the payout ratio has been higher relative to prior quarters as a result of considerably weak natural gas prices. Additionally, the timing of the Ketch merger has also increased the payout ratio for the second quarter of 2006 as the arrangement closed prior to the June record date resulting in the payment of a full month distribution to Ketch Unitholders whereas funds from operations for June only included eight days of cash flows from the Ketch properties.

Critical Accounting Estimates

The preparation of financial statements in accordance with GAAP requires Management to make certain judgments and estimates. Changes in these judgments and estimates could have a material impact on the Fund's financial results and financial condition. Management relies on the estimate of reserves as prepared by the Fund's independent qualified reserves evaluator. The process of estimating reserves is critical to several accounting estimates. The process of estimating reserves is complex and requires significant judgments and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development and production activities becomes available and as economic conditions impact crude oil and natural gas prices, operating costs, royalty burden changes, and future development costs. Reserve estimates impact net income through depletion and depreciation of property and equipment, the provision for asset retirement costs and related accretion expense, and impairment calculations for property and equipment and goodwill. The reserve estimates are also used to assess the

borrowing base for the Fund's credit facilities. Revision or changes in the reserve estimates can have either a positive or a negative impact on net income and the borrowing base of the Fund.

Financial Reporting Update

Convergence of Canadian GAAP with International Financial Reporting Standards

In 2006, Canada's Accounting Standards Board ("AcSB") issued a strategic plan that will result in Canadian GAAP, as it applies to publicly accountable entities, being converged with International Financial Reporting Standards over a transitional period, initially indicated to be five years. The AcSB is expected to develop and release a detailed implementation plan and the Fund will consider the effect that this implementation plan might have on the consolidated financial statements during the transition period.

Financial Instruments Recognition and Measurement

In April 2005, a series of new accounting standards were released which established guidance for the recognition and measurement of financial instruments. These new standards include Section 1530 "Comprehensive Income", Section 3855 "Financial Instruments — Recognition and Measurement", and Section 3865 "Hedges". The new standards also resulted in a number of significant consequential amendments to other accounting standards to accommodate the new sections. The standards require all applicable financial instruments to be classified into one of several categories including: financial assets and financial liabilities held for trading, held-to-maturity investments, loans and receivables, available-for-sale financial assets, or other financial liabilities. The financial instruments are then included on a company's balance sheet and measured at fair value, cost or amortized value, depending on the classification. Subsequent measurement and recognition of changes in value of the financial instruments also depends on the initial classification. These standards are effective for interim and annual financial statements for fiscal years beginning on or after October 1, 2006 and must be implemented simultaneously. Advantage has adopted the new standards as of January 1, 2007 and there are no significant changes in the recognition and measurement of the Fund's financial instruments.

In December 2006, new accounting standards were released which provided further guidance on the presentation and disclosure of financial instruments and were intended to better align the Canadian standards with international accounting standards. The new standards are effective for interim and annual financial statements related to fiscal years beginning on or after October 1, 2007. Advantage has chosen to early adopt the new standards Section 3862 "Financial Instruments – Presentation" and Section 3863 "Financial Instruments – Disclosure" as issued by the CICA effective January 1, 2007. As a result, there will be several additional disclosures relating to financial instruments in 2007, but no significant changes to presentation.

Controls and Procedures

The Fund has established procedures and internal control systems to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP. Management of the Fund is committed to providing timely, accurate and balanced disclosure of all material information about the Fund. Disclosure controls and procedures are in place to ensure all ongoing reporting requirements are met and material information is disclosed on a timely basis. The Chief Executive Officer and Vice-President Finance and Chief Financial Officer, individually, sign certifications that the financial statements, together with the other financial information included in the regular filings, fairly present in all material respects the financial condition, results of operation, and cash flows as of the dates and for the periods presented in the filings. The certifications further acknowledge that the 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 filings. During 2006, there were no significant changes that would materially affect, or are reasonably likely to materially affect, the internal controls over financial reporting.

Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements and even those systems determined to be effective can provide only reasonable assurance with respect to the financial statement preparation and presentation. Further, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

Evaluation of Disclosure Controls and Procedures

The Fund has established a Disclosure Committee consisting of seven executive members with the responsibility of overseeing the Fund's disclosure practices and designing disclosure controls and procedures to ensure that all material information is communicated to the Disclosure Committee. All written public disclosures are reviewed and approved by at least one member of the Disclosure Committee prior to issuance. Additionally, the Disclosure Committee assists the Chief Executive Officer and Chief Financial Officer of the Fund in making certifications with respect to the disclosure controls of the Fund required under applicable regulations and ensures that the Board of Directors is promptly and fully informed regarding potential disclosure issues facing the Fund.

Management of Advantage, including our Chief Executive Officer and Vice-President, Finance and Chief Financial Officer, has evaluated the effectiveness of the design and operation of the disclosure controls and procedures as of December 31, 2006. Based on that evaluation, Management has concluded that the disclosure controls and procedures are effective as of the end of the period, in all material respects. It should be noted that while the Chief Executive Officer and Chief Financial Officer believe that the Fund's design of disclosure controls and procedures provide a reasonable level of assurance that they are effective, they do not expect that the disclosure controls and procedures or internal control over financial reporting will prevent all errors and fraud. A control system does not provide absolute, but rather is designed to provide reasonable, assurance that the objective of the control system is met.

Corporate Governance

The Board of Directors' mandate is to supervise the management of the business and affairs of the Fund including the business and affairs of the Fund delegated to AOG. In particular, all decisions relating to: (i) the acquisition and disposition of properties for a purchase price or proceeds in excess of \$5 million; (ii) the approval of annual operating and capital expenditure budgets; and (iii) the establishment of credit facilities and the issuance of additional Trust Units, will be made by the Board.

Computershare Trust Company of Canada, the Trustee of the Fund, has delegated certain matters to the Board of Directors. These include all decisions relating to issuance of additional Trust Units and the determination of the amount of distributions. Any amendment to any material contract to which the Fund is a party will require the approval of the Board of Directors and, in some cases, Unitholder approval.

The Board of Directors meets regularly to review the business and affairs of the Fund and AOG and to make any required decisions. The Board of Directors consists of ten members, seven of whom are unrelated to the Fund. The Independent Reserve Evaluation Committee has three members, all of whom are independent. The Human Resources, Compensation and Corporate Governance Committee and Audit Committee each have four members, all of whom are independent. One member of the Audit Committee has been designated a "Financial Expert" as defined in applicable regulatory guidance. In addition, the Chairman of the Board is not related and is not an executive officer of the Fund.

The Board of Directors approved and Management implemented a Code of Business Conduct and Ethics. The purpose of the code is to lay out the expectation for the highest standards of professional and ethical conduct from our directors, officers and employees. The code reflects our commitment to a culture of honesty, integrity and accountability and outlines the basic principles and policies with which all employees are expected to comply. Our Code of Business Conduct and Ethics is available on our website at www.advantageincome.com.

As a Canadian issuer listed on the New York Stock Exchange (the "NYSE"), Advantage is not required to comply with most of the NYSE rules and listing standards and instead may comply with domestic requirements. As a foreign private issuer, Advantage is only required to comply with three of the NYSE Rules: (i) have an audit committee that satisfies the requirements of the United States Securities Exchange Act of 1934; (ii) the Chief Executive Officer must promptly notify the NYSE in writing after an executive officer becomes aware of any material non-compliance with the applicable NYSE Rules; and (iii) provide a brief description of any significant differences between its corporate governance practices and those followed by U.S. companies listed under the NYSE. Advantage has reviewed the NYSE listing standards and confirms that its corporate governance practices do not differ significantly from such standards.

A further discussion of the Fund's corporate governance practices can be found in the Management Proxy Circular.

Outlook

The Fund has established a 2007 Budget, as approved by the Board of Directors, that retains a high degree of activity and will focus on drilling in many of our key properties where a high level of success was realized through 2006. Capital will also be directed to accommodate facility expansions and further develop enhanced recovery schemes as necessary. New drill bit additions are expected to be more effective in replacing production as corporate declines have continued to subside through 2006. Advantage's production now contains very little flush production from high impact wells and concentrated drilling programs (from 2004 and 2005 activities) creating a balanced and predictable platform. During the second and third quarters of 2007, we expect two major third party plant turnarounds to occur which will significantly affect our Lookout Butte and Westerosé properties. These two turnarounds combined with well payouts are

expected to result in an impact of approximately 400 boe/d to the 2007 annual average production. Overall, we expect production in 2007 to average between 27,500 to 29,500 boe/d.

Advantage's 2007 capital expenditures budget of \$120 to \$145 million includes the drilling, completion and tie-in of 107 gross wells (64 net) weighted approximately 50% toward light oil and 50% to natural gas. In Northeast B.C., a 17 well (14 net) natural gas drilling program is being substantially completed in the first quarter of 2007 at Martin Creek. This program exploits the northern portions of the Field where a successful drilling program was conducted in 2006 which extended pool boundaries. At this time, the 17 well drilling program has been completed and final facilities work and tie-ins are in progress. Results to date indicate a very successful program with tested well deliverability in excess of facilities capacity and budget assumptions. Combined with Advantage's already commanding position of facilities infrastructure and operatorship, we estimate three years of drilling inventory in this property. At Sunset, in Northern Alberta, four wells are planned to follow-up the successful 2006 development drilling program and capital will also be required to expand water flood facilities in this light oil pool. In Central Alberta, a 12 well (12 net) program is planned at Nevis for 40 degree light oil where horizontal drilling in 2006 showed excellent results. A net 15 sections of land were added through deals with industry third parties in 2006 bringing the total land under control to 37.5 net sections in this property. A second development drilling program in the western portion of the Nevis property is underway and facilities will be constructed to accommodate production additions. Additional gas opportunities will be pursued in the Central Alberta areas targeting down spacing and follow-up to successes. In Southern Alberta and S.E. Saskatchewan, 13 wells (10 net) will be drilled for oil targets in 2007.

Operating costs are forecasted to be closer to the \$9.50 to \$10.50/boe range as higher gas prices indicated by the current strip price through the summer of 2007 suggest higher power costs than what was realized in 2006. In addition, higher property taxes, surface rentals and additional trucking costs due to continued pipeline restrictions in Southeast Saskatchewan are expected to occur in 2007. Advantage is undertaking several operating cost reduction initiatives through 2007 to help offset these increases.

Advantage's funds from operations in 2007 will continue to be impacted by the volatility of crude oil and natural gas prices and the \$US/\$Canadian exchange rate. Advantage will continue to follow its strategy of acquiring properties that provide low risk development opportunities and enhance long term cash flow. Advantage will also continue to focus on low cost production and reserve additions through low to medium risk development drilling opportunities that have arisen as a result of the acquisitions completed in prior years and from the significant inventory of drilling opportunities that has resulted from the Ketch merger. The synergy of larger size and the complementary winter/summer drilling programs with the Ketch merger is providing benefits in terms of securing services, flexibility and quality of our capital program.

Looking forward, Advantage's high quality assets, three year drilling inventory, hedging program and excellent tax pools provides many options for the Fund and we are committed to maximizing value generation for our Unitholders.

The following table indicates our funds from operations sensitivity to changes in prices and production of natural gas, crude oil and NGLs, exchange rates and interest rates for 2007 based on production of 28,000 boe/d comprised of 110.4 mmcf/d of natural gas and 9,600 bbls/d of crude oil and NGLs. Advantage is considerably more sensitive to changes in natural gas prices as compared to oil due to the Fund's higher natural gas weighting.

Sensitivities

	Annual Funds from Operations (\$000)	Annual Funds from Operations per Trust Unit (\$/Trust Unit)
Natural gas		
AECO monthly price change of \$0.25/mcf	\$ 5,500	\$ 0.05
Production change of 1,000 mcf/d	\$ 1,800	\$ 0.02
Crude oil and NGLs		
WTI price change of US\$1.00/bbl	\$ 2,900	\$ 0.03
Production change of 200 bbls/d	\$ 2,800	\$ 0.03
\$US/\$Canadian exchange rate change of \$0.01	\$ 5,800	\$ 0.04
Interest rate change of 1%	\$ 3,800	\$ 0.03

Additional Information

Additional information relating to Advantage can be found on SEDAR at www.sedar.com and the Fund's website at www.advantageincome.com. Such other information includes the annual information form, the annual information circular – proxy statement, press releases, material contracts and agreements, and other financial reports. The annual information form will be of particular interest for current and potential Unitholders as it discusses a variety of subject matter including the nature of the business, structure of the Fund, description of our operations, general and recent business developments, risk factors, reserves data and other oil and gas information.

Consolidated Balance Sheets

(thousands of dollars)	December 31, 2006	December 31, 2005
Assets		
Current assets		
Accounts receivable	\$ 79,537	\$ 51,788
Prepaid expenses and deposits	16,878	7,791
Derivative asset (note 13)	9,840	-
	106,255	59,579
Deposit on property acquisition	1,410	-
Derivative asset (note 13)	593	-
Fixed assets (note 4)	1,753,058	907,795
Goodwill (note 3)	120,271	45,473
	\$ 1,981,587	\$ 1,012,847
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	\$ 116,109	\$ 76,371
Distributions payable to Unitholders	18,970	14,462
Current portion of capital lease obligations (note 5)	2,527	358
Current portion of convertible debentures (note 7)	1,464	-
	139,070	91,191
Capital lease obligations (note 5)	305	1,346
Bank indebtedness (note 6)	410,574	252,476
Convertible debentures (note 7)	170,819	126,081
Asset retirement obligations (note 8)	34,324	21,263
Future income taxes (note 11)	61,939	99,026
	817,031	591,383
Non-controlling Interest		
Exchangeable shares (note 9)	-	2,369
Unitholders' Equity		
Unitholders' capital (note 10)	1,592,758	681,574
Convertible debentures equity component (note 7)	8,041	6,159
Contributed surplus (note 10)	863	1,036
Accumulated deficit (note 12)	(437,106)	(269,674)
	1,164,556	419,095
	\$ 1,981,587	\$ 1,012,847

Commitments (note 15)

Subsequent Event (note 16)

see accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Income and Accumulated Deficit

(thousands of dollars, except for per Trust Unit amounts)	Year ended December 31, 2006	Year ended December 31, 2005
Revenue		
Petroleum and natural gas	\$ 419,727	\$ 376,572
Unrealized gain on derivatives (note 13)	10,242	214
Royalties, net of Alberta Royalty Credit	(76,456)	(74,290)
	353,513	302,496
Expenses		
Operating	82,911	57,941
General and administrative	13,738	5,452
Management fee (note 14)	887	3,665
Performance incentive (note 14)	2,380	10,544
Management internalization (note 14)	13,449	-
Interest	18,258	10,275
Interest and accretion on convertible debentures	13,316	13,392
Depletion, depreciation and accretion	194,309	135,096
	339,248	236,365
Income before taxes and non-controlling interest	14,265	66,131
Future income tax reduction (note 11)	(37,087)	(11,371)
Income and capital taxes (note 11)	1,509	2,198
	(35,578)	(9,173)
Net income before non-controlling interest	49,843	75,304
Non-controlling interest (note 9)	29	232
Net income	49,814	75,072
Accumulated deficit, beginning of year	(269,674)	(167,380)
Distributions declared	(217,246)	(177,366)
Accumulated deficit, end of year	\$ (437,106)	\$ (269,674)
Net income per Trust Unit (note 10)		
Basic	\$ 0.62	\$ 1.33
Diluted	\$ 0.61	\$ 1.32

see accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

(thousands of dollars)	Year ended December 31, 2006	Year ended December 31, 2005
Operating Activities		
Net income	\$ 49,814	\$ 75,072
Add (deduct) items not requiring cash:		
Unrealized gain on derivatives	(10,242)	(214)
Performance incentive	2,380	10,544
Management internalization	13,449	-
Accretion on convertible debentures	2,106	2,182
Depletion, depreciation and accretion	194,309	135,096
Future income taxes	(37,087)	(11,371)
Non-controlling interest	29	232
Expenditures on asset retirement	(5,974)	(2,025)
Changes in non-cash working capital	20,303	(22,910)
Cash provided by operating activities	229,087	186,606
Financing Activities		
Units issued, net of costs (note 10)	169,631	107,616
Decrease in bank indebtedness	(30,767)	(14,578)
Reduction of capital lease obligations	(1,019)	(7,687)
Cash distributions to Unitholders	(212,738)	(175,323)
Cash used in financing activities	(74,893)	(89,972)
Investing Activities		
Expenditures on property and equipment	(159,487)	(103,229)
Property acquisitions	(244)	(210)
Property dispositions	8,727	3,379
Acquisition costs of Ketch Resources Trust (note 3)	(10,109)	-
Purchase adjustment of Defiant acquisition	-	(98)
Changes in non-cash working capital	6,919	3,524
Cash used in investing activities	(154,194)	(96,634)
Net change in cash	-	-
Cash, beginning of year	-	-
Cash, end of year	\$ -	\$ -
Supplementary Cash Flow Information		
Interest paid	\$ 34,680	\$ 23,358
Taxes paid	\$ 1,783	\$ 2,605

see accompanying Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2006

All tabular amounts in thousands except for Units and per Unit amounts

1. Business and Structure of the Fund

Advantage Energy Income Fund (“Advantage” or the “Fund”) was formed on May 23, 2001 as a result of a plan of arrangement. For Canadian tax purposes, Advantage is an open-ended unincorporated mutual fund trust created under the laws of the Province of Alberta pursuant to a Trust Indenture originally dated April 17, 2001, and as occasionally amended, between Advantage Oil & Gas Ltd. (“AOG”) and Computershare Trust Company of Canada, as trustee. The Fund commenced operations on May 24, 2001. The beneficiaries of the Fund are the holders of the Trust Units (the “Unitholders”).

The principal undertaking of the Fund is to indirectly acquire and hold interests in petroleum and natural gas properties and assets related thereto. The business of the Fund is carried on by its wholly-owned subsidiary, AOG. The Fund’s primary assets are currently the common shares of AOG, a royalty in the producing properties of AOG (the “AOG Royalty”) and notes of AOG (the “AOG Notes”). The Fund’s strategy, through AOG, is to minimize exposure to exploration risk while focusing on growth through acquisition and development of producing crude oil and natural gas properties.

The purpose of the Fund is to distribute available cash flow to Unitholders on a monthly basis in accordance with the terms of the Trust Indenture. The Fund’s available cash flow includes principal repayments and interest income earned from the AOG Notes, royalty income earned from the AOG Royalty, and any dividends declared on the common shares of AOG less any expenses of the Fund including interest on convertible debentures. Cash received on the AOG Notes, AOG Royalty and common shares of AOG result in the effective transfer of the economic interest in the properties of AOG to the Fund. However, while the royalty is a contractual interest in the properties owned by AOG, it does not confer ownership in the underlying resource properties. Cash distributions are determined by Management and the Board of Directors. We closely monitor our distribution policy considering forecasted cash flows, optimal debt levels, capital spending activity, taxability to Unitholders, working capital requirements, and other potential cash expenditures. Cash distributions are announced monthly and are based on the cash available after retaining a portion to meet such spending requirements. The level of cash distributions are primarily determined by cash flows received from the production of oil and natural gas from existing Canadian resource properties and are highly dependent upon our success in exploiting the current reserve base and acquiring additional reserves. Furthermore, monthly cash distributions we pay to Unitholders are highly dependent upon the prices received for such oil and natural gas production. It is our long-term objective to provide stable and sustainable cash distributions to the Unitholders, while continuing to grow the Fund.

2. Summary of Significant Accounting Policies

The Management of the Fund prepares its consolidated financial statements in accordance with Canadian generally accepted accounting principles (“Canadian GAAP”) and all amounts are stated in Canadian dollars. The preparation of consolidated financial statements requires Management to make estimates and assumptions that effect the reported amount of assets, liabilities and equity and disclosures of contingencies at the date of the consolidated financial statements and the reported amounts of revenues and expenses during the period. The following significant accounting policies are presented to assist the reader in evaluating these consolidated financial statements and, together with the notes, should be considered an integral part of the consolidated financial statements.

(a) Consolidation and Joint Operations

These consolidated financial statements include the accounts of the Fund and all subsidiaries, including AOG. All intercompany balances and transactions have been eliminated.

The Fund conducts exploration and production activities jointly with other participants. The accounts of the Fund reflect its proportionate interest in such joint operations.

(b) Property and equipment

(i) Petroleum and natural gas properties and related equipment

The Fund follows the “full cost” method of accounting in accordance with the guideline issued by the Canadian Institute of Chartered Accountants (“CICA”) whereby all costs associated with the acquisition of and the exploration for and development of petroleum and natural gas reserves, whether productive or unproductive, are capitalized in a Canadian cost centre and charged to income as set out below. Such costs include lease acquisition, drilling and completion, production facilities, asset retirement costs, geological and geophysical costs and overhead expenses related to exploration and development activities.

Gains or losses are not recognized upon disposition of petroleum and natural gas properties unless crediting the proceeds against accumulated costs would result in a change in the rate of depletion and depreciation of 20% or more.

Depletion of petroleum and natural gas properties and depreciation of lease, well equipment and production facilities is provided on accumulated costs using the “unit-of-production” method based on estimated net proved petroleum and natural gas reserves, before royalties, as determined by independent engineers. For purposes of the depletion and depreciation calculation, proved petroleum and natural gas reserves are converted to a common unit-of-measure on the basis of one barrel of oil or liquids being equal to six thousand cubic feet of natural gas.

The depletion and depreciation cost base includes total capitalized costs, less costs of unproved properties, plus a provision for future development costs of proved undeveloped reserves. Costs of acquiring and evaluating unproved properties are excluded from depletion calculations until it is determined whether or not proved reserves are attributable to the properties or impairment occurs.

Petroleum and natural gas assets are evaluated in each reporting period to determine that the carrying amount in a cost centre is recoverable and does not exceed the fair value of the properties in the cost centre (the “ceiling test”). The carrying amounts are assessed to be recoverable when the sum of the undiscounted net cash flows expected from the production of proved reserves, the lower of cost and market of unproved properties and the cost of major development projects exceeds the carrying amount of the cost centre. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized to the extent that the carrying amount of the cost centre exceeds the sum of the discounted net cash flows expected from the production of proved and probable reserves, the lower of cost and market of unproved properties and the cost of major development projects of the cost centre. The net cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate.

(ii) Furniture and equipment

The Fund records furniture and equipment at cost and provides depreciation on the declining balance method at a rate of 20% per annum which is designed to amortize the cost of the assets over their estimated useful lives.

(c) Goodwill

Goodwill is the excess purchase price of a business over the fair value of identifiable assets and liabilities acquired. Goodwill is stated at cost less impairment and is not amortized. Goodwill impairment is assessed at year-end, or as economic events dictate, by comparing the fair value of the reporting unit (the Fund) to its carrying value, including goodwill. If the fair value of the Fund is less than its carrying value, a goodwill impairment loss is recognized by allocating the fair value of the Fund to the identifiable assets and liabilities as if the Fund had been acquired in a business acquisition for a purchase price equal to the fair value. The excess of the fair value of the Fund over the values assigned to the identifiable assets and liabilities is the implied fair value of the goodwill. Any excess of the carrying value of the goodwill over the implied fair value is the impairment amount and is charged to income in the period incurred. There has been no impairment of the Fund’s goodwill.

(d) Cash distributions

Cash distributions are calculated on an accrual basis and are paid to Unitholders monthly.

(e) Financial instruments

The Fund occasionally uses various types of derivative financial instruments to manage risk associated with commodity price fluctuations. These instruments are not used for trading or speculative purposes. Proceeds and costs realized from holding the related contracts are recognized in the appropriate revenue and expense categories of the income statement at the time that each transaction under a contract is settled. For the unrealized portion of such contracts, Advantage has chosen not to apply “hedge accounting” and

alternatively utilizes the “fair value” method of accounting. The fair value is based on an estimate of the amounts that would have been paid to or received from counterparties to settle these instruments given future market prices and other relevant factors. The Fund records changes in the fair value in the income statement as an unrealized derivative gain or loss with a corresponding derivative asset or liability recorded on the balance sheet.

(f) Convertible debentures

The Fund’s convertible debentures are financial liabilities consisting of a liability with an embedded conversion feature. As such, the debentures are segregated between liabilities and equity based on the relative fair market value of the liability and equity portions. Therefore, the debenture liabilities are presented at less than their eventual maturity values. The liability and equity components are further reduced for issuance costs initially incurred. The discount of the liability component as compared to maturity value is accreted by the “effective interest” method over the debenture term and expensed accordingly. As debentures are converted to Trust Units, an appropriate portion of the liability and equity components are transferred to Unitholders’ capital.

(g) Asset retirement obligations

The Fund follows the “asset retirement obligation” method of recording the future cost associated with removal, site restoration and asset retirement costs. The fair value of the liability for the Fund’s asset retirement obligations is recorded in the period in which it is incurred, discounted to its present value using the Fund’s credit adjusted risk-free interest rate and the corresponding amount recognized by increasing the carrying amount of property and equipment. The asset recorded is depleted on a “unit-of-production” basis over the life of the reserves consistent with the Fund’s depletion and depreciation policy for petroleum and natural gas properties and related equipment. The liability amount is increased each reporting period due to the passage of time and the amount of accretion is charged to income in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost could also result in an increase or decrease to the obligation. Actual costs incurred upon settlement of the retirement obligations are charged against the obligation to the extent of the liability recorded.

(h) Income taxes

The Fund is considered an open-ended unincorporated mutual fund trust under the Income Tax Act (Canada). Any taxable income is allocated to the Unitholders and therefore no provision for current income taxes relating to the Fund is included in these financial statements.

The Fund and its subsidiaries follow the “liability” method of accounting for income taxes. Under this method future tax assets and liabilities are determined based on differences between financial reporting and income tax bases of assets and liabilities, and are measured using substantively enacted tax rates and laws expected to apply when the differences reverse. The effect on future tax assets and liabilities of a change in tax rates is recognized in net income in the period in which the change is substantially enacted.

(i) Exchangeable shares

The Fund’s Exchangeable Shares are classified as non-controlling interest, outside of Unitholders’ equity, as they are transferable, although not publicly traded. The Exchangeable Shares and Trust Units are considered economically equivalent since the exchange ratio is increased on each date that a distribution is paid on the Trust Units and all shares must be exchanged for either Trust Units or cash, based on the current market price of the Trust Units. Since the Exchangeable Shares are required to be exchanged, there is no permanent non-controlling interest. Non-controlling interest expense is recorded that reflects the earnings attributable to the non-controlling interest. When Exchangeable Shares are converted to Trust Units, the carrying value of non-controlling interest on the balance sheet is reclassified to Unitholders’ capital.

(j) Unit-based compensation

The Fund has a unit-based compensation plan for external directors of the Fund (note 10) as well as Trust Units held in escrow relating to the management internalization (note 14). Advantage elected to prospectively adopt amendments to CICA Handbook Section 3870 “Stock-based Compensation and Other Stock-based Payments” pursuant to the transitional provisions contained therein. Under this amended standard, the Fund must account for compensation expense based on the “fair value” of rights granted under its unit-based compensation plans.

Since awards under the external directors’ unit-based compensation plan are vested immediately, associated compensation expense is recognized in the current period earnings and estimated forfeiture rates for such rights are not incorporated within the determination of fair value. The compensation expense results in the creation of contributed surplus until the rights are exercised. Consideration

paid upon the exercise of the rights together with the amount previously recognized in contributed surplus is recorded as an increase in Unitholders' capital.

The escrowed Trust Units relating to the management internalization vest equally over three years, the period during which employees are required to provide service to receive the Trust Units. Therefore, the associated compensation expense is recognized equally over the appropriate service period and incorporates estimated forfeitures.

(k) Revenue recognition

Revenue associated with the sale of crude oil, natural gas and natural gas liquids is recognized when the title and risks pass to the purchaser, normally at the pipeline delivery point for natural gas and at the wellhead for crude oil.

(l) Per Trust Unit amounts

Net income per Trust Unit is calculated using the weighted average number of Trust Units outstanding during the year. Diluted net income per Trust Unit is calculated using the "if-converted" method to determine the dilutive effect of convertible debentures and exchangeable shares and the "treasury stock" method for trust unit rights granted to directors and the management internalization escrowed Trust Units.

(m) Measurement uncertainty

The amounts recorded for depletion and depreciation of property and equipment, the provision for asset retirement obligation costs and related accretion expense, and impairment calculations for property and equipment and goodwill are based on estimates. These estimates are significant and include proved and probable reserves, future production rates, future crude oil and natural gas prices, future costs, future interest rates, relevant fair value assessments, and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future years could be material.

(n) Comparative figures

Certain comparative figures have been reclassified to conform to the current year's presentation.

3. Acquisition of Ketch Resources Trust

On June 23, 2006, Advantage acquired all of the issued and outstanding Trust Units of Ketch Resources Trust ("Ketch") in return for 32,870,465 Advantage Trust Units, utilizing an exchange ratio of 0.565 Advantage Trust Units for each Ketch Trust Unit outstanding. Ketch was an energy trust engaged in the development, acquisition and production of natural gas and crude oil in western Canada. The acquisition is being accounted for using the "purchase method" with the results of operations included in the consolidated financial statements as of the closing date of the acquisition. The purchase price has been allocated as follows:

Net assets acquired and liabilities assumed:		Consideration:	
Property and equipment	\$ 877,463	32,870,465 Trust Units issued	\$ 688,636
Goodwill	74,798	Acquisition costs incurred	<u>10,109</u>
Net working capital *	5,368		\$ 698,745
Bank indebtedness	(180,000)		
Convertible debentures	(66,981)		
Convertible debentures equity component	(2,971)		
Asset retirement obligations	(7,930)		
Capital lease obligation	<u>(1,002)</u>		
	\$ 698,745		

* Includes cash of \$2,713, accounts receivable of \$55,806, prepaid expenses of \$6,406, accounts payable of \$46,834, current bank indebtedness of \$11,578 and current portion of capital lease obligation \$1,145.

The value of \$20.95 per Trust Unit issued as consideration was determined based on the weighted average trading value of Advantage Trust Units during the two-day period before and after the terms of the acquisition were agreed to and announced.

4. Fixed Assets

December 31, 2006	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	\$ 2,324,948	\$ 576,707	\$1,748,241
Furniture and equipment	8,175	3,358	4,817
	\$ 2,333,123	\$ 580,065	\$1,753,058

December 31, 2005	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	\$ 1,290,588	\$ 385,140	\$ 905,448
Furniture and equipment	4,647	2,300	2,347
	\$ 1,295,235	\$ 387,440	\$ 907,795

During the year ended December 31, 2006, Advantage capitalized general and administrative expenditures directly related to exploration and development activities of \$6,444,000 (2005 - \$3,293,000).

Costs of \$43,467,000 (2005 - \$17,805,000) for unproved properties have been excluded from the calculation of depletion expense, and future development costs of \$123,464,000 (2005 - \$87,843,000) have been included in costs subject to depletion.

The Fund performed a ceiling test calculation at December 31, 2006 to assess the recoverable value of property and equipment. Based on the calculation, the carrying amounts are recoverable as compared to the sum of the undiscounted net cash flows expected from the production of proved reserves based on the following benchmark prices:

Year	WTI Crude Oil (\$US/bbl)	Exchange Rate (\$US/\$Cdn)	AECO Gas (\$Cdn/mmbtu)
2007	\$ 65.73	\$ 0.87	\$ 7.72
2008	\$ 68.82	\$ 0.87	\$ 8.59
2009	\$ 62.42	\$ 0.87	\$ 7.74
2010	\$ 58.37	\$ 0.87	\$ 7.55
2011	\$ 55.20	\$ 0.87	\$ 7.72
Percentage increase each year after 2011	2.0%	-	2.0%

Benchmark prices are adjusted for a variety of factors such as quality differentials to determine the expected price to be realized by the Fund when performing the ceiling test calculation.

5. Capital Lease Obligations

The Fund has capital leases on a variety of property and equipment. Future minimum lease payments at December 31, 2006 consist of the following:

2007	\$ 2,577
2008	308
	2,885
Less amounts representing interest	(53)
	2,832
Current portion	(2,527)
	\$ 305

On June 23, 2006, Advantage assumed a total capital lease obligation of \$2.1 million in the acquisition of Ketch (note 3). The lease ends in March 2008 and interest expense is recognized at 5.3%.

6. Bank Indebtedness

Advantage has a credit facility agreement with a syndicate of financial institutions which provides for a \$580 million extendible revolving loan facility and a \$20 million operating loan facility. The loan's interest rate is based on either prime, US base rate, LIBOR or bankers' acceptance rates, at the Fund's option, subject to certain basis point or stamping fee adjustments ranging from 0.00% to 1.25% depending on the Fund's debt to cash flow ratio. The credit facilities are secured by a \$1 billion floating charge demand debenture, a general security agreement and a subordination agreement from the Fund covering all assets and cash flows. The credit facilities are subject to review on an annual basis. Various borrowing options are available under the credit facilities, including prime rate-based advances, US base rate advances, US dollar LIBOR advances and bankers' acceptances loans. The credit facilities constitute a revolving facility for a 364 day term which is extendible annually for a further 364 day revolving period at the option of the syndicate. If not extended, the revolving credit facility is converted to a two year term facility with the first payment due one year and one day after commencement of the term. The credit facilities contain standard commercial covenants for facilities of this nature. The only financial covenant is a requirement for AOG to maintain a minimum cash flow to interest expense ratio of 3 ½:1, determined on a rolling four quarter basis. Breach of any covenant will result in an event of default in which case AOG has 20 days to remedy such default. If the default is not remedied or waived, and if required by the majority of lenders, the administrative agent of the lenders has the option to declare all obligations of AOG under the credit facilities to be immediately due and payable without further demand, presentation, protest, or notice of any kind. Distributions by AOG to the Fund (and effectively by the Fund to Unitholders) are subordinated to the repayment of any amounts owing under the credit facilities. Distributions to Unitholders are not permitted if the Fund is in default of such credit facilities or if the amount of the Fund's outstanding indebtedness under such facilities exceeds the then existing current borrowing base. Interest payments under the debentures are also subordinated to indebtedness under the credit facilities and payments under the debentures are similarly restricted. For the year ended December 31, 2006, the effective interest rate on the outstanding amounts under the facility was approximately 5.1%.

7. Convertible Debentures

The convertible unsecured subordinated debentures pay interest semi-annually and are convertible at the option of the holder into Trust Units of Advantage at the applicable conversion price per Trust Unit plus accrued and unpaid interest. The details of the convertible debentures including fair market values initially assigned and issuance costs are as follows:

	10.00%	9.00%	8.25%	7.75%	7.50%	6.50%	Total
Issue date	Oct. 18, 2002	July 8, 2003	Dec. 2, 2003	Sep. 15, 2004	Sep. 15, 2004	May 18, 2005	
Maturity date	Nov. 1, 2007	Aug. 1, 2008	Feb. 1, 2009	Dec. 1, 2011	Oct. 1, 2009	June 30, 2010	
Conversion price	\$ 13.30	\$ 17.00	\$ 16.50	\$ 21.00	\$ 20.25	\$ 24.96	
Liability component	\$ 52,722	\$ 28,662	\$ 56,802	\$ 47,444	\$ 71,631	\$ 66,981	\$ 324,242
Equity component	2,278	1,338	3,198	2,556	3,369	2,971	15,710
Gross proceeds	55,000	30,000	60,000	50,000	75,000	69,952	339,952
Issuance costs	(2,495)	(1,444)	(2,588)	(2,190)	(3,190)	-	(11,907)
Net proceeds	\$ 52,505	\$ 28,556	\$ 57,412	\$ 47,810	\$ 71,810	\$ 69,952	\$ 328,045

The convertible debentures are redeemable prior to their maturity dates, at the option of the Fund, upon providing 30 to 60 days advance notification. The redemption prices for the various debentures, plus accrued and unpaid interest, is dependent on the redemption periods and are as follows:

Convertible Debenture	Redemption Periods	Redemption Price
10.00%	After November 1, 2005 and on or before November 1, 2006 After November 1, 2006 and before November 1, 2007	\$1,050 \$1,025
9.00%	After August 1, 2006 and on or before August 1, 2007 After August 1, 2007 and before August 1, 2008	\$1,050 \$1,025
8.25%	After February 1, 2007 and on or before February 1, 2008 After February 1, 2008 and before February 1, 2009	\$1,050 \$1,025
7.75%	After December 1, 2007 and on or before December 1, 2008 After December 1, 2008 and on or before December 1, 2009 After December 1, 2009 and before December 1, 2011	\$1,050 \$1,025 \$1,000
7.50%	After October 1, 2007 and on or before October 1, 2008 After October 1, 2008 and before October 1, 2009	\$1,050 \$1,025
6.50%	After June 30, 2008 and on or before June 30, 2009 After June 30, 2009 and before June 30, 2010	\$1,050 \$1,025

The balance of debentures outstanding at December 31, 2006 and changes in the liability and equity components during the years ended December 31, 2006 and 2005 are as follows:

	10.00%	9.00%	8.25%	7.75%	7.50%	6.50%	Total
Debentures outstanding	\$ 1,485	\$ 5,392	\$ 4,867	\$ 46,766	\$ 52,268	\$ 69,952	\$ 180,730
Liability component:							
Balance at Dec. 31, 2004	\$ 3,923	\$ 10,388	\$ 12,237	\$ 45,548	\$ 64,337	\$ -	\$ 136,433
Accretion of discount	55	168	198	616	1,145	-	2,182
Converted to Trust Units	(1,525)	(3,297)	(4,285)	(266)	(3,161)	-	(12,534)
Balance at Dec. 31, 2005	2,453	7,259	8,150	45,898	62,321	-	126,081
Assumed on Ketch acquisition	-	-	-	-	-	66,981	66,981
Accretion of discount	30	107	103	589	897	380	2,106
Converted to Trust Units	(1,019)	(2,131)	(3,577)	(2,722)	(13,436)	-	(22,885)
Balance at Dec. 31, 2006	\$ 1,464	\$ 5,235	\$ 4,676	\$ 43,765	\$ 49,782	\$ 67,361	\$ 172,283
Equity component:							
Balance at Dec. 31, 2004	\$ 163	\$ 472	\$ 675	\$ 2,444	\$ 3,010	\$ -	\$ 6,764
Converted to Trust Units	(63)	(149)	(234)	(14)	(145)	-	(605)
Balance at Dec. 31, 2005	100	323	441	2,430	2,865	-	6,159
Assumed on Ketch acquisition	-	-	-	-	-	2,971	2,971
Converted to Trust Units	(41)	(94)	(193)	(144)	(617)	-	(1,089)
Balance at Dec. 31, 2006	\$ 59	\$ 229	\$ 248	\$ 2,286	\$ 2,248	\$ 2,971	\$ 8,041

As part of the acquisition of Ketch, the 6.50% convertible debentures, originally issued May 18, 2005, were assumed by Advantage on June 23, 2006.

During the year ended December 31, 2006, \$24,333,000 (2005 - \$13,339,000) debentures were converted resulting in the issuance of 1,286,901 Trust Units (2005 - 783,870 Trust Units).

8. Asset Retirement Obligations

The Fund's asset retirement obligations result from net ownership interests in petroleum and natural gas assets including well sites, gathering systems and processing facilities. The Fund estimates the total undiscounted and inflated amount of cash flows required to

settle its asset retirement obligations is approximately \$157.2 million which will be incurred between 2007 to 2057. A credit-adjusted risk-free rate of 7% was used to calculate the fair value of the asset retirement obligations.

A reconciliation of the asset retirement obligations is provided below:

	Year ended December 31, 2006	Year ended December 31, 2005
Balance, beginning of year	\$ 21,263	\$ 17,503
Accretion expense	1,684	1,162
Assumed in Ketch acquisition (note 3)	7,930	-
Liabilities incurred	9,421	4,623
Liabilities settled	(5,974)	(2,025)
Balance, end of year	\$ 34,324	\$ 21,263

9. Exchangeable Shares

	Number of Shares	Amount
Balance at December 31, 2004	1,450,030	\$ 30,842
Converted to Trust Units	(1,345,358)	(28,705)
Non-controlling interest in net income	-	232
Balance at December 31, 2005	104,672	2,369
Converted to Trust Units	(104,672)	(2,398)
Non-controlling interest in net income	-	29
Balance at December 31, 2006	-	\$ -
Trust Units issuable	-	-

AOG is authorized to issue an unlimited number of non-voting Exchangeable Shares. As partial consideration for the acquisition of Defiant which closed on December 21, 2004, AOG issued 1,450,030 Exchangeable Shares. The value of the Exchangeable Shares issued was determined based on the weighted average trading value of Advantage Trust Units during the two-day period before and after the terms of the acquisition were agreed to and announced. Each Exchangeable Share previously issued by AOG was exchangeable for Advantage Trust Units at any time (subject to the provisions of the Voting and Exchange Trust Agreement), on the basis of the applicable exchange ratio in effect at that time. Dividends were not declared or paid on the Exchangeable Shares and the Exchangeable Shares were not publicly traded.

On March 8, 2006 AOG elected to exercise its redemption right to redeem all of the Exchangeable Shares outstanding. The redemption price per Exchangeable Share was satisfied by delivering that number of Advantage Trust Units equal to the Exchange Ratio of 1.22138 in effect on May 9, 2006.

10. Unitholders' Equity

(a) Unitholders' capital

(i) Authorized

Unlimited number of voting Trust Units

(ii) Issued

	Number of Units	Amount
Balance at December 31, 2004	49,674,783	\$ 515,544
2004 non-cash performance incentive	763,371	16,570
Issued for cash, net of costs	5,250,000	107,616
Issued on conversion of debentures	783,870	13,139
Issued on conversion of exchangeable shares	1,374,300	28,705
Balance at December 31, 2005	57,846,324	681,574
2005 non-cash performance incentive	475,263	10,544
Issued on conversion of debentures	1,286,901	23,974
Issued on conversion of exchangeable shares	127,014	2,398
Issued on exercise of Trust Unit rights	122,500	682
Ketch acquisition (note 3)	32,870,465	688,636
Management internalization	1,913,842	38,716
2006 non-cash performance incentive	117,662	2,380
Distribution reinvestment plan	2,005,499	27,722
Issued for cash, net of costs	8,625,000	141,399
	105,390,470	\$ 1,618,025
Management internalization escrowed Trust Units		(25,267)
Balance at December 31, 2006		\$ 1,592,758

On January 19, 2005, Advantage issued 763,371 Trust Units to partially satisfy the obligation related to the 2004 year end performance incentive fee.

On February 9, 2005, Advantage issued 5,250,000 Trust Units at \$21.65 per Trust Unit for net proceeds of \$107.6 million (net of Underwriters' fees and other issue costs of \$6.1 million). The net proceeds of the offering were used to pay down debt incurred in the acquisition of Defiant, for 2005 capital expenditures and for general corporate purposes.

On January 20, 2006, Advantage issued 475,263 Trust Units to satisfy the obligation related to the 2005 year end performance incentive fee.

On June 23, 2006, Advantage issued 32,870,465 Trust Units as consideration for the acquisition of Ketch (note 3). Concurrent with the Ketch acquisition, Advantage internalized the external management contract structure and eliminated all related fees for total original consideration of 1,933,208 Advantage Trust Units initially valued at \$39.1 million and subject to escrow provisions (note 14). A total of 19,366 Trust Units related to the internalization have been forfeited since issuance. The Fund also issued 177,662 Trust Units, valued at \$2.4 million, to satisfy the final obligation related to the 2006 first quarter performance fee.

On July 24, 2006, Advantage announced that it adopted a Premium Distribution^(TM), Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "Plan"). The Plan commenced with the monthly cash distribution payable on August 15, 2006 to Unitholders of record on July 31, 2006. For eligible Unitholders that elect to participate in the Plan, Advantage will settle the monthly distribution obligation through the issuance of additional Trust Units at 95% of the Average Market Price (as defined in the Plan). Unitholder enrollment in the Premium Distribution^(TM) component of the Plan effectively authorizes the subsequent disposal of the issued Trust Units in exchange for a cash payment equal to 102% of the cash distributions that the Unitholder would otherwise have received if they did not participate in the Plan. During the year ended December 31, 2006, 2,005,499 Trust Units were issued under the Plan, generating \$27.7 million reinvested in the Fund.

On August 1, 2006, Advantage issued 7,500,000 Trust Units, plus an additional 1,125,000 Trust Units upon full exercise of the Underwriters' over-allotment option on August 4, 2006, at \$17.30 per Trust Unit for net proceeds of \$141.4 million (net of Underwriters' fees and other issue costs of \$7.8 million). The net proceeds of the offering were used to pay down bank indebtedness and to subsequently fund capital and general corporate expenditures.

(b) Trust Units Rights Incentive Plan

Effective June 25, 2002, a Trust Units Rights Incentive Plan for external directors of the Fund was established and approved by the Unitholders of Advantage. A total of 500,000 Trust Units have been reserved for issuance under the plan with an aggregate of 400,000 rights granted since inception. The initial exercise price of rights granted under the plan may not be less than the current market price of the Trust Units as of the date of the grant and the maximum term of each right is not to exceed ten years with all rights vesting immediately upon grant. At the option of the rights holder, the exercise price of the rights can be adjusted downwards over time based upon distributions paid by the Fund to Unitholders.

	Series A		Series B	
	Number	Price	Number	Price
Balance at December 31, 2004	85,000	\$ 5.05	225,000	\$ 16.75
Reduction of exercise price	-	(3.12)	-	(3.12)
Balance at December 31, 2005	85,000	1.93	225,000	13.63
Exercised	(85,000)	-	(37,500)	-
Reduction of exercise price	-	(1.93)	-	(2.66)
Balance at December 31, 2006	-	\$ -	187,500	\$ 10.97
Expiration date	August 16, 2006		June 17, 2008	

The Series A Trust Unit rights were issued in 2002 and the Fund was unable to determine the fair value for the rights granted under the Plan at that time. Several essential factors required to value such rights include expected future exercise price, distributions, exercise timeframe, volatility and risk-free interest rates. In determining these assumptions, both historical data and future expectations are considered. However, when the Series A Trust Unit rights were originally granted, Advantage had only been established during the prior year and there was little historical information available that may suggest future expectations concerning such assumptions. Therefore, it was concluded that a fair value determination at that time was not possible. The Fund has disclosed pro forma results as if the Fund followed the intrinsic value methodology in accounting for such rights. The intrinsic value methodology would result in recording compensation expense for the rights based on the underlying Trust Unit price at the date of exercise or at the date of the financial statements for unexercised rights as compared to the exercise price. All of the remaining 85,000 Series A Trust Units Rights were exercised July 7, 2006 in exchange for an equivalent number of Trust Units.

Pro Forma Results	Year ended	Year ended
	December 31, 2006	December 31, 2005
Net income, as reported	\$ 49,814	\$ 75,072
Less compensation expense for rights issued in 2002	(234)	300
Pro forma net income	\$ 50,048	\$ 74,772
Net income per Trust Unit, as reported		
Basic	\$ 0.62	\$ 1.33
Diluted	\$ 0.61	\$ 1.32
Net income per Trust Unit, pro forma		
Basic	\$ 0.62	\$ 1.32
Diluted	\$ 0.62	\$ 1.31

(c) Net Income per Trust Unit

The calculation of basic and diluted net income per Trust Unit are derived from both income available to Unitholders and weighted average Trust Units outstanding calculated as follows:

	Year ended December 31, 2006	Year ended December 31, 2005
Income available to Unitholders		
Basic	\$ 49,814	\$ 75,072
Exchangeable shares	-	232
Diluted	\$ 49,814	\$ 75,304
Weighted average Trust Units outstanding		
Basic	80,958,455	56,593,303
Trust Units Rights Incentive Plan – Series A	43,548	76,698
Trust Units Rights Incentive Plan – Series B	78,287	69,800
Exchangeable Shares	-	298,341
Management Internalization	113,556	-
Diluted	81,193,846	57,038,142

The calculation of diluted net income per Trust Unit excludes all series of convertible debentures as the impact would be anti-dilutive. Exchangeable Shares have been excluded for the year ended December 31, 2006 as the impact would have been anti-dilutive. Total weighted average Trust Units issuable in exchange for the convertible debentures and excluded from the diluted net income per Trust Unit calculation for the year ended December 31, 2006 were 7,182,276 (2005 - 7,288,894). As at December 31, 2006, the total convertible debentures outstanding were immediately convertible to 8,334,453 Trust Units (2005 – 6,818,833).

11. Income Taxes

The taxable income of the Fund is comprised of interest income related to the AOG Notes and royalty income from the AOG Royalty less deductions for Canadian Oil and Gas Property Expense, Trust Unit issue costs, and interest on convertible debentures. Given that taxable income of the Fund is allocated to the Unitholders, no provision for current income taxes relating to the Fund is included in these financial statements. On October 31, 2006, the Federal Government proposed changes to Canada's tax system that include altering the tax treatment of income trusts. The government proposed a two-tier tax structure, similar to that of corporations, whereby distributions paid by trusts will be subject to tax at the trust level in addition to personal tax as if they were dividends from a taxable Canadian corporation. The changes are proposed to take effect in 2011 for existing publicly-traded trusts. As the proposal was not considered substantially enacted at December 31, 2006, these changes are not reflected in the current financial statements. As at December 31, 2006, the Fund had unrecognized non-deductible temporary differences of \$601 million.

The provision for income taxes varies from the amount that would be computed by applying the combined Canadian federal and provincial income tax rates for the following reasons:

	Year ended December 31, 2006	Year ended December 31, 2005
Income before taxes	\$ 14,265	\$ 66,131
Canadian combined federal and provincial income tax rates	34.78%	37.98%
Expected income tax expense at statutory rates	4,961	25,080
Increase (decrease) in income taxes resulting from:		
Non-deductible Crown charges	6,925	12,406
Resource allowance	(8,108)	(15,390)
Management internalization	4,678	-
Change in enacted tax rates	(5,692)	(3,230)
Amounts included in trust income and other	(39,851)	(30,237)
Future income tax reduction	(37,087)	(11,371)
Income and capital taxes	1,509	2,198
	\$ (35,578)	\$ (9,173)

The components of the future income tax liability are as follows:

	December 31, 2006	December 31, 2005
Property and equipment in excess of tax basis	\$ 85,648	\$ 119,065
Asset retirement obligations	(10,141)	(7,230)
Non-capital tax loss carry forward	(8,851)	(11,228)
Other	(4,717)	(1,581)
Future income tax liability	\$ 61,939	\$ 99,026

AOG has a non-capital tax loss carry forward of approximately \$29.3 million of which \$1.2 million expires in 2010, \$27.4 million in 2011, and \$0.7 million in 2021.

12. Accumulated Deficit

Accumulated deficit consists of accumulated income and accumulated distributions for the Fund since inception as follows:

	December 31, 2006	December 31, 2005
Accumulated Income	\$ 227,523	\$ 177,709
Accumulated Distributions	(664,629)	(447,383)
Accumulated Deficit	\$ (437,106)	\$ (269,674)

For the year ended December 31, 2006 the Fund declared \$217.2 million in distributions, representing \$2.66 per distributable Trust Unit (2005 - \$177.4 million representing \$3.12 per distributable Trust Unit).

13. Financial Instruments

Financial instruments of the Fund include accounts receivable, deposits, accounts payable and accrued liabilities, distributions payable, and bank indebtedness. As at December 31, 2006, there were no significant differences between the carrying amounts reported on the balance sheet and the estimated fair values of these financial instruments due to the short terms to maturity and the floating interest rate on the bank indebtedness. Substantially all of the Fund's accounts receivable are due from customers and joint venture partners in the oil and gas industry and are subject to normal industry credit risks. Credit risk is mitigated by entering into sales contracts with only stable, creditworthy parties and through frequent reviews of exposures to individual entities. The carrying value of accounts receivable reflects Management's assessment of the associated credit risks. The Fund is further exposed to interest rate risk to the extent that bank indebtedness is at a floating rate of interest.

In addition, the Fund has outstanding convertible debenture obligations that are financial liabilities. The convertible debentures have different fixed terms and interest rates (note 7) resulting in fair values that will vary over time as market conditions change. As at December 31, 2006, the estimated fair value of the total outstanding convertible debenture obligation was \$180.0 million (2005 - \$137.5 million).

As current and future practice, Advantage has established a financial hedging strategy and may manage the risk associated with changes in commodity prices by entering into financial derivatives. To the extent that Advantage engages in risk management activities related to commodity prices, it will be subject to credit risk associated with counterparties with which it contracts. Credit risk is mitigated by entering into contracts with only stable, creditworthy parties and through frequent reviews of exposure to individual entities. As the fair value of the contracts varies with commodity prices, they give rise to financial assets or liabilities. As at December 31, 2006 the Fund had the following financial derivatives in place:

Description of Financial Derivative	Term	Volume	Average Price	
Natural gas - AECO				
Fixed price	November 2006 to March 2007	5,687 mcf/d		Cdn\$8.70/mcf
Fixed price	November 2006 to March 2007	3,791 mcf/d		Cdn\$10.02/mcf
Collar	November 2006 to March 2007	9,478 mcf/d	Floor	Cdn\$8.18/mcf
			Ceiling	Cdn\$11.24/mcf
Collar	November 2006 to March 2007	4,739 mcf/d	Floor	Cdn\$8.44/mcf
			Ceiling	Cdn\$12.40/mcf
Collar	November 2006 to March 2007	4,739 mcf/d	Floor	Cdn\$8.18/mcf
			Ceiling	Cdn\$11.66/mcf
Collar	November 2006 to March 2007	4,739 mcf/d	Floor	Cdn\$8.44/mcf
			Ceiling	Cdn\$12.29/mcf
Collar	November 2006 to March 2007	5,687 mcf/d	Floor	Cdn\$7.91/mcf
			Ceiling	Cdn\$9.81/mcf
Collar	November 2006 to March 2007	9,478 mcf/d	Floor	Cdn\$8.44/mcf
			Ceiling	Cdn\$13.82/mcf
Crude oil - WTI				
Collar	October 2006 to March 2007	1,250 bbls/d	Floor	US\$65.00/bbl
			Ceiling	US\$87.40/bbl
Collar	October 2006 to September 2007	1,000 bbls/d	Floor	US\$65.00/bbl
			Ceiling	US\$90.00/bbl
Electricity – Alberta Pool Price				
Fixed price	April 2006 to December 2007	0.5 MW		Cdn\$60.79/MWh
Fixed price	January 2007 to December 2007	3.0 MW		Cdn\$56.00/MWh
Fixed price	January 2008 to December 2008	3.0 MW		Cdn\$54.00/MWh

As at December 31, 2006 the settlement amount of the financial derivatives outstanding was an asset of approximately \$10,433,000. For the year ended December 31, 2006, \$10,242,000 was recognized in income as an unrealized derivative gain. As a result of the Ketch merger, the Fund assumed several contracts which had an estimated fair market value of \$191,000 on closing.

14. Management Fee, Performance Incentive, and Management Internalization

Concurrent with the Ketch acquisition (note 3), Advantage internalized the external management contract structure and eliminated all related fees. The Fund reached an agreement with Advantage Investment Management Ltd. (“AIM” or the “Manager”) to purchase all of the outstanding shares of AIM pursuant to the terms of the Plan of Arrangement for total original consideration of 1,933,208 Advantage Trust Units. The Trust Units were initially valued at \$39.1 million using the weighted average trading value for Advantage Trust Units on the Unitholder approval date of June 22, 2006 and are subject to escrow provisions over a 3-year period, vesting one-third each year beginning in 2007. The management internalization consideration is being deferred and amortized into income as management internalization expense over the specific vesting periods during which employee services are provided, including an estimate of future Trust Unit forfeitures. A total of \$13.4 million has been included as management internalization expense for the year ended December 31, 2006 with 19,366 Trust Units forfeited since issuance. The Fund also issued 117,662 Trust Units to satisfy

the final obligation related to the 2006 first quarter performance fee along with \$0.9 million in cash to settle the first quarter management fee. AIM agreed to forego fees from the period April 1, 2006 to the closing of the Arrangement.

Prior to the internalization, the Manager received both a management fee and a performance incentive fee as compensation pursuant to the Management Agreement approved by the Board of Directors. Management fees were calculated based on 1.5% of operating cash flow defined as revenues less royalties and operating costs. Management fees were paid quarterly and \$1.0 million was payable and included in accrued liabilities at December 31, 2005.

The Manager was entitled to earn an annual performance incentive fee when the Fund's total annual return exceeded 8%. The total annual return was calculated at the end of the year by dividing the year-over-year change in Unit price plus cash distributions by the opening Unit price, as defined in the Management Agreement. The 2005 opening and closing Unit prices were \$21.71 and \$22.19, respectively. Cash distributions for the 2005 year amounted to \$3.12 per Trust Unit. Ten percent of the amount of the total annual return in excess of 8% was multiplied by the market capitalization (defined as the opening Unit price multiplied by the weighted average number of Trust Units outstanding during the year) to determine the performance incentive fee. The performance incentive fee payable and included in accrued liabilities at December 31, 2005 was \$10.5 million. The Management Agreement provided an option to the Manager to receive the performance incentive fee in equivalent Trust Units. The Manager exercised the option and on January 20, 2006, the Fund issued 475,263 Advantage Trust Units at the closing Unit price of \$22.19 to satisfy the 2005 performance fee obligation. The Manager did not receive any form of compensation in respect of acquisition or divestiture activities nor was there any form of stock option or bonus plan for the Manager or the employees of Advantage outside of the management and performance fees prior to the internalization. The management fees and performance fees were shared amongst all management and employees.

15. Commitments

Advantage has lease commitments relating to office buildings. The estimated annual minimum operating lease rental payments for the buildings, after deducting sublease income, are as follows:

2007	\$ 2,256
2008	1,385
2009	779
2010	779
2011	195
	<hr/>
	\$ 5,394

16. Subsequent Event

On February 14, 2007 Advantage issued 7,800,000 Trust Units, plus an additional 800,000 Trust Units upon exercise of the Underwriters' over-allotment option on March 7, 2007, at \$12.80 per Trust Unit for approximate net proceeds of \$104.2 million (net of Underwriters' fees and other issue costs of \$5.9 million).

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Advisory

The information in this release contains certain forward-looking statements. These statements relate to future events or our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of words such as "seek", "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "predict", "potential", "targeting", "intend", "could", "might", "should", "believe", "would" and similar expressions. These statements involve substantial known and unknown risks and uncertainties, certain of which are beyond Advantage's control, including: the impact of general economic

conditions; industry conditions; changes in laws and regulations including the adoption of new environmental laws and regulations and changes in how they are interpreted and enforced; fluctuations in commodity prices and foreign exchange and interest rates; stock market volatility and market valuations; volatility in market prices for oil and natural gas; liabilities inherent in oil and natural gas operations; uncertainties associated with estimating oil and natural gas reserves; competition for, among other things, capital, acquisitions, of reserves, undeveloped lands and skilled personnel; incorrect assessments of the value of acquisitions; changes in income tax laws or changes in tax laws and incentive programs relating to the oil and gas industry and income trusts; geological, technical, drilling and processing problems and other difficulties in producing petroleum reserves; and obtaining required approvals of regulatory authorities. Advantage's actual results, performance or achievement could differ materially from those expressed in, or implied by, such forward-looking statements and, accordingly, no assurances can be given that any of the events anticipated by the forward-looking statements will transpire or occur or, if any of them do, what benefits that Advantage will derive from them. Except as required by law, Advantage undertakes no obligation to publicly update or revise any forward-looking statements.