



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, 2007 Financial Results and Reserves

March 6, 2008

(TSX: AVN.UN, NYSE: AAV)

CALGARY, ALBERTA, March 6, 2008 – 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, 2007.

A conference call will be held on Friday, March 7, 2008 at 9:00 a.m. MST (11:00 a.m. EST). The conference call can be accessed toll-free at **1-866-334-4934** and a slide presentation is available on our website. A replay of the call will be available from approximately 2:00 p.m. EST on March 7, 2008 until approximately midnight, April 5, 2008 and can be accessed by dialing toll free **1-866-245-6755**. The passcode required for playback is **645732**. A live web cast of the conference call will be accessible via the Internet on Advantage's website at www.advantageincome.com.

Acquisition of Sound Energy Trust

- Advantage completed a highly synergistic and accretive acquisition of Sound Energy Trust which closed on September 5, 2007.
- The acquisition added proven plus probable reserves of 31.4 million boe at a cost of \$14.77 per boe.
- In addition, the acquisition significantly increased Advantage’s undeveloped land base, tax pools, and exposure to light oil. The acquisition provides a significant number of low risk drilling locations, facilities consolidation opportunities and 83 sections of land at Glacier in Northwest Alberta with potential for natural gas resource play development in the Montney formation.

Successful 2007 Drilling Program and Efficient Reserves Additions

- Overall, the Fund replaced 379% of annual production at a Finding, Development & Acquisition cost of \$ 15.19 per proven plus probable boe, excluding changes in future development capital, and \$15.90 per proven plus probable boe, including changes in future development capital.
- Drill bit reserve additions resulted in strong Finding & Development (“F&D”) costs of \$ 16.96 per proven plus probable boe, excluding changes in future development capital. The three year F&D average is \$15.91 per proven plus probable boe, excluding changes in future development capital. The Fund replaced 80% of its production through the drill bit.
- Strong operational execution throughout the year resulted in the drilling of 112 gross (64.8 net) wells in 2007 at a 99% success rate. During the fourth quarter of 2007 a total of 32 gross (16.6 net) wells were drilled at a 100% success rate.
- With the inclusion of Sound’s assets and opportunities, Advantage’s drilling inventory grew to over 750 locations representing over 5 years of drilling within our land base.
- The Fund’s proven plus probable reserve life index remains among the highest in the natural gas weighted sector at 12.1 years.
- The Fund’s Net Asset Value, before tax increased to \$12.96 per unit at a 10% discount factor.

Commodity Prices

- Crude oil prices strengthened in 2007 due to continued global demand growth which was partly offset by the rising Canadian dollar.
- Declining natural gas prices, the rising Canadian dollar and increased service costs were key factors leading to lower revenue and cash flow levels in the latter part of 2007 due to our natural gas production weighting. This was partly offset by our natural gas hedging program which generated gains of \$16.5 million in the second half of 2007.
- The outlook for gas prices has since improved with colder weather in early 2008. Key factors that are contributing to a more optimistic view on prices for the remainder of 2008 include a 7 year low in natural gas drilling activity in Canada, projections for lower LNG deliveries into the U.S. in 2008 and higher demand for natural gas fired electrical generation.

Hedging

- For 2008, we have secured approximately 51% of our net natural gas production at an average Canadian floor price of \$7.43 per mcf (currently equivalent to NYMEX US\$8.43 per mcf) and 38% of our oil production at an average floor price of Canadian \$94.07 per bbl (currently equivalent to NYMEX WTI US\$95.95 per bbl).
- The primary purpose of our hedging program is to i) reduce cash flow volatility and ii) ensure that our capital program is substantially funded out of cash flow.

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 has continued to create uncertainty among the Trust sector resulting in consolidation and a drive to consider alternate structures.
- Advantage remains in a very strong position given our considerable tax pool base of \$1.7 billion which is available to shield future taxes for many years after 2011 and also provides the Fund with more options as alternatives to the Royalty Trust structure are considered.
- It is the Fund's intention to continue to be a cash distributing entity after 2010. We will continue to closely monitor industry dynamics and are considering a number of alternative structures in order to maximize after-tax value for Unitholders.

Alberta's Royalty Program Changes

- On October 25, 2007, the Alberta Government issued a proposal to increase provincial royalties in 2009 on oil sands and conventional oil and natural gas production. Advantage's analysis indicates a minimal impact on the Fund due to the number of lower rate wells within our long life assets which will receive favorable treatment.

Advantage is Well positioned for 2008

- The market was filled with uncertainty in 2007 including reduced access to capital resulting from the Federal Government's October 2006 announcement and soft natural gas prices. Advantage responded in 2007 by completing a highly accretive acquisition, protecting our cash flow through commodity price hedging and adjusting our distributions to reduce the payout ratio to position the Fund for growth opportunities in 2008 and beyond.
- With our cash flow stream protected through commodity price hedging in 2008 and the current distribution level, we expect to substantially fund our capital program out of cash flow and preserve flexibility for additional opportunities throughout the year.
- Our 2008 capital program includes a strong suite of attractive development drilling locations at Martin Creek, Nevis, Willesden Green, Chip Lake, Sunset, Southern Alberta and Southeast Saskatchewan. In addition, further delineation drilling is planned for our Montney formation natural gas resource property at Glacier in Northwest Alberta (located directly adjacent to the very successful Swan Lake Pool development).
- Our underlying strengths continue to place Advantage in an enviable position:
 - Long-life asset base and stable production platform,
 - High quality drilling inventory that exceeds 5 years,
 - Superior technical and administrative team that is highly motivated to create Unitholder value,
 - Considerable tax pool base, and
 - Reduced payout ratio.

First Quarter 2008 Drilling Highlights

- Execution of the 2008 winter drilling program is on schedule and costs are on-track.
- At Martin Creek in Northeast British Columbia a 10 well drilling program is nearing completion and results are anticipated to meet expectations.
- At Glacier in Northwest Alberta, 4 vertical delineation wells have been drilled into the Montney formation where completions and testing are underway with an additional well currently drilling. Advantage's 83 section land block contains several existing Montney well penetrations and extensive 3-dimensional seismic coverage. Our plans for the balance of 2008 include additional vertical wells which will be required to assess the potential for future horizontal well development and production. This approach is similar to the development plan conducted at the adjacent Swan Lake and Tupper pool projects, where significant Montney development is occurring.
- At Nevis, Alberta horizontal drilling for light oil in the newer 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.
- To date 53 gross (31.2 net) wells have been drilled in 2008 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 and throughout 2008.

As a final remark, we wish to acknowledge the dedication and hard work from all of our directors, employees and personnel who continued to strive for success despite a year of commodity price and political uncertainty.

We look forward to 2008 with much optimism and confidence in our Fund.

Financial and Operating Highlights

Year ended December 31,	2007	2006	2005	2004	2003
Financial (\$000 except per unit and per boe amounts)					
Revenue before royalties ⁽¹⁾	557,358	419,727	376,572	241,481	166,075
per Trust Unit ⁽²⁾	4.66	5.18	6.65	5.89	5.44
per boe	50.97	48.41	51.27	38.92	36.81
Funds from operations	271,143	214,758	211,541	126,478	94,735
per Trust Unit ⁽³⁾	2.22	2.65	3.72	3.05	3.09
per boe	24.79	24.78	28.80	20.39	21.01
Net income (loss)	(7,535)	49,814	75,072	24,038	38,503
per Trust Unit ⁽²⁾	(0.06)	0.62	1.33	0.59	1.26
Distributions declared	215,194	217,246	177,366	117,655	83,382
per Trust Unit ⁽³⁾	1.77	2.66	3.12	2.82	2.71
Expenditures on property and equipment	148,725	159,487	103,229	107,893	76,212
Working capital deficit ⁽⁴⁾	28,087	42,655	31,612	56,408	47,143
Bank indebtedness	547,426	410,574	252,476	267,054	102,968
Convertible debentures (face value)	224,612	180,730	135,111	148,450	99,984
Trust Units outstanding at end of year	138,269	105,390	57,846	49,675	36,717
Basic weighted average Trust Units	119,604	80,958	56,593	41,008	30,536
Operating					
Daily Production					
Natural gas (mcf/d)	116,998	94,074	78,561	77,188	57,631
Crude oil and NGLs (bbls/d)	10,462	8,075	7,029	4,084	2,756
Total boe/d @ 6:1	29,962	23,754	20,123	16,949	12,361
Average pricing (including hedging)					
Natural gas (\$/mcf)	7.21	6.86	7.98	6.08	6.07
Crude oil & NGLs (\$/bbl)	65.38	62.44	57.58	46.58	38.14
Proved plus probable reserves ⁽⁵⁾					
Natural gas (bcf)	546.4	442.7	286.9	296.9	237.4
Crude oil & NGLs (mbbls)	61,131	47,524	36,267	34,316	13,697
Total mboe	152,203	121,317	84,082	83,799	53,271
Reserve life index (years) ⁽⁶⁾	12.1	11.4	12.0	9.9	9.1

(1) includes realized derivative gains and losses

(2) based on basic weighted average Trust Units outstanding

(3) based on Trust Units outstanding at each distribution record date

(4) working capital deficit excludes derivative assets and liabilities

(5) 2007, 2006, 2005 and 2004 represents company interest reserves with 2003 being gross working interest reserves

(6) based on Q4 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, 2007 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 will be available at www.advantageincome.com and www.sedar.com.

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

- The Fund's net asset value at December 31, 2007 is \$12.96 per Unit, (using a 10% discount factor).
- Proved plus probable ("P+P") reserve life index remains among the highest in the gas weighted sector at 12.1 years.
- Replaced 379% of annual production at an all-in Finding, Development & Acquisition ("FD&A") cost of \$15.19 per P+P boe before consideration of future development capital. Including future development capital, the FD&A cost was \$15.90 per P+P boe. This includes the acquisition of Sound Energy Trust, which was effective September 5, 2007.

	December 31, 2007	December 31, 2006
Proved plus probable reserves (mboe)	152,203	121,317
Present Value of reserves discounted at 10%, proved plus probable (\$000)	\$2,462,610	\$1,850,073
Net Asset Value per Unit discounted at 10%	\$12.96	\$12.29
Reserve Life Index (proved plus probable - years) ⁽¹⁾	12.1	11.4
Reserves per Unit (proved plus probable) ⁽²⁾	1.10	1.15
Bank debt per boe of reserves ⁽³⁾	\$3.60	\$3.38
Convertible debentures per boe of reserves ⁽³⁾	\$1.48	\$1.49

⁽¹⁾ Based on Q4 average production.

⁽²⁾ Based on 138.3 million Units outstanding at December 31, 2007, and 105.6 million Units 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, 2007

	Light & Medium Oil (mdbl)	Heavy Oil (mdbl)	Natural Gas Liquids (mdbl)	Natural Gas (mmcf)	Oil Equivalent (mboe)
Proved					
Developed Producing	22,222	1,840	6,714	288,398	78,842
Developed Non-producing	473	129	268	13,098	3,054
Undeveloped	3,622	297	941	52,927	13,680
Total Proved	26,317	2,266	7,923	354,423	95,576
Probable	17,540	3,282	3,803	192,013	56,627
Total Proved + Probable	43,857	5,548	11,726	546,436	152,203

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

	Before Income Taxes Discounted at		
	0%	5%	10%
Proved			
Developed Producing	\$ 2,680,441	\$ 1,904,687	\$ 1,526,798
Developed Non-producing	83,654	67,773	56,479
Undeveloped	298,697	217,260	155,502
Total Proved	3,062,792	2,189,720	1,738,779
Probable	2,038,534	1,100,986	723,831
Total Proved + Probable	\$ 5,101,326	\$ 3,290,706	\$ 2,462,610

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

	After Income Taxes Discounted at		
	0%	5%	10%
Proved			
Developed Producing	\$ 2,680,441	\$ 1,904,687	\$ 1,526,798
Developed Non-producing	83,654	67,773	56,479
Undeveloped	298,697	217,260	155,502
Total Proved	3,062,792	2,189,720	1,738,779
Probable	1,725,276	1,009,487	691,310
Total Proved + Probable	\$ 4,788,068	\$ 3,199,208	\$ 2,430,090

(1) Advantage's crude oil, natural gas and natural gas liquid reserves were evaluated using Sproule's product price forecast effective December 31, 2007 prior to, 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, 2007 was based upon crude oil and natural gas pricing assumptions prepared by Sproule effective December 31, 2007. 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 AECO-C Natural Gas (\$Cdn/mmbtu)	Henry Hub Natural Gas (\$US/mmbtu)	Exchange Rate (\$US/\$Cdn)
2008	89.61	88.17	6.51	7.56	1.00
2009	86.01	84.54	7.22	8.27	1.00
2010	84.65	83.16	7.69	8.74	1.00
2011	82.77	81.26	7.70	8.75	1.00
2012	82.26	80.73	7.61	8.66	1.00
2013	82.81	81.25	7.78	8.83	1.00
2014	84.46	82.88	7.96	9.01	1.00

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 before taxes ⁽¹⁾ - December 31, 2006	\$ 30.39	\$ 17.92	\$ 12.29
Present value proved and probable reserves	\$ 5,101,326	\$ 3,290,706	\$ 2,462,610
Undeveloped acreage and seismic ⁽²⁾	111,559	111,559	111,559
Working capital (deficit)	(9,634)	(9,634)	(9,634)
Convertible debentures	(224,612)	(224,612)	(224,612)
Bank debt	(547,426)	(547,426)	(547,426)
Net asset value - December 31, 2007	\$ 4,431,213	\$ 2,620,593	\$ 1,792,497
Net asset value per Unit after taxes⁽¹⁾ - December 31, 2007	\$ 32.05	\$ 18.95	\$ 12.96

⁽¹⁾ Based on 138.3 million Units outstanding at December 31, 2007, and 105.6 million Units outstanding at December 31, 2006.

⁽²⁾ Internal estimate

Gross Working Interest Reserves - Summary as at December 31, 2007

	Light & Medium Oil (mbbl)	Heavy Oil (mbbl)	Natural Gas Liquids (mbbl)	Natural Gas (mmcf)	Oil Equivalent (mboe)
Proved					
Developed Producing	22,060	1,814	6,646	285,551	78,111
Developed Non-producing	473	126	266	12,814	3,001
Undeveloped	3,621	297	928	52,568	13,608
Total Proved	26,154	2,237	7,840	350,933	94,720
Probable	17,477	3,271	3,773	190,613	56,289
Total Proved + Probable	43,630	5,508	11,613	541,546	151,009

Gross Working Interest Reserves Reconciliation

	Light & Medium Oil (mbbl)	Heavy Oil (mbbl)	Natural Gas Liquids (mbbl)	Natural Gas (mmcf)	Oil Equivalent (mboe)
Proved					
Opening balance Dec. 31, 2006	19,935	1,908	7,375	292,779	78,015
Extensions	327	55	232	14,694	3,062
Improved recovery	678	0	197	14,716	3,328
Discoveries	24	0	9	636	139
Economic factors	370	1	(105)	(572)	170
Technical revisions	177	(562)	(95)	(2,710)	(930)
Acquisitions	7,348	1,083	1,093	74,094	21,872
Dispositions	0	0	0	0	0
Production	(2,705)	(248)	(866)	(42,704)	(10,936)
Closing balance at Dec. 31, 2007	26,154	2,237	7,840	350,933	94,720

Proved + Probable	Light & Medium Oil (mdbl)	Heavy Oil (mdbl)	Natural Gas Liquids (mdbl)	Natural Gas (mmcf)	Oil Equivalent (mboe)
Opening balance Dec. 31, 2006	33,521	2,596	11,208	439,345	120,549
Extensions	1,667	68	519	30,191	7,285
Improved recovery	1,322	0	546	44,193	9,234
Discoveries	41	0	11	795	184
Economic factors	493	2	(133)	1,048	537
Technical revisions	(1,271)	(674)	(1,110)	(32,510)	(8,472)
Acquisitions	10,562	3,764	1,438	101,188	32,628
Dispositions	0	0	0	0	0
Production	(2,705)	(248)	(866)	(42,704)	(10,936)
Closing balance at Dec. 31, 2007	43,630	5,508	11,613	541,546	151,009

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

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

	Proved	Proved + Probable
Capital expenditures (\$000)	\$ 148,725	\$ 148,725
Acquisitions net of dispositions (\$000)	479,955	479,955
Total capital (\$000)	\$ 628,680	\$ 628,680
Total mboe, end of period	94,720	151,009
Total mboe, beginning of period	78,015	120,549
Production, mboe	10,936	10,936
Reserve additions, mboe	27,641	41,396
FD&A costs (\$/boe)	\$ 22.74	\$ 15.19
Three year average FD&A Costs (\$/boe)	\$ 27.51	\$ 19.20
F&D costs (\$/boe)	\$ 25.78	\$ 16.96
Three year average F&D costs (\$/boe)	\$ 22.02	\$ 15.91

NI 51-101

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

	Proved	Proved + Probable
Capital expenditures (\$000)	\$ 148,725	\$ 148,725
Acquisitions net of dispositions (\$000)	479,955	479,955
Net change in Future Development Capital	6,517	29,517
Total capital (\$000)	\$ 635,197	\$ 658,197
Reserve additions, mboe	27,641	41,396
FD&A costs (\$/boe)	\$ 22.98	\$ 15.90
Three year average FD&A Costs (\$/boe)	\$ 27.94	\$ 20.21
F&D costs (\$/boe)	\$ 26.91	\$ 20.33
Three year average F&D costs (\$/boe)	\$ 23.21	\$ 19.68

⁽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.

Advantage Energy Income Fund

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, 2007

	Developed Acres		Undeveloped Acres	
	Gross	Net	Gross	Net
Alberta	1,238,745	647,934	789,914	429,360
British Columbia	159,486	73,877	109,807	64,153
Saskatchewan	50,660	38,312	226,301	192,071
Total Acreage	1,448,891	760,123	1,126,022	685,584

MANAGEMENT'S DISCUSSION & ANALYSIS

The following Management's Discussion and Analysis ("MD&A"), dated as of March 5, 2008, 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, 2007 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, funds from operations per Trust Unit and cash netbacks. 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 distribution record date. Cash netbacks are dependent on the determination of funds from operations and include the primary cash revenues and expenses on a per boe basis that comprise 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		
	2007	2006	% change	2007	2006	% change
Cash provided by operating activities	\$ 83,366	\$ 65,495	27%	\$ 249,132	\$ 229,087	9%
Expenditures on asset retirement	2,116	3,462	(39)%	6,951	5,974	16%
Changes in non-cash working capital	(4,963)	(6,220)	(20)%	15,060	(20,303)	(174)%
Funds from operations	\$ 80,519	\$ 62,737	28%	\$ 271,143	\$ 214,758	26%

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, royalty regimes 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 is 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.

Acquisition of Sound Energy Trust

On September 5, 2007, the previously announced acquisition of Sound Energy Trust (“Sound”) was completed. The financial and operational information for the quarter and year ended December 31, 2007 reflects operations from the Sound properties effective from the closing date, September 5, 2007.

The acquisition was accomplished through a Plan of Arrangement (the “Arrangement”) by the exchange of each Sound Trust Unit for 0.30 of an Advantage Trust Unit or, at the election of the holder of Sound Trust Units, \$0.66 in cash and 0.2557 of an Advantage Trust Unit. In addition, all Sound Exchangeable Shares were exchanged for Advantage Trust Units on the same ratio based on the conversion ratio in effect at the effective date of the Arrangement. Advantage issued 16,977,184 Trust Units and paid \$21.4 million cash as consideration to acquire Sound. The transaction is accretive to Advantage’s Unitholders on a production, cash flow, reserves and net asset value basis and has significantly increased Advantage’s tax pool position to a total of approximately \$1.7 billion, and Safe Harbour expansion room to approximately \$2.0 billion. Sound’s higher oil weighting, synergy with many of Advantage’s core properties and significant undeveloped land holdings of approximately 400,000 net undeveloped acres will further enhance the operating platform of Advantage.

Overview

	Three months ended December 31			Year ended December 31		
	2007	2006	% change	2007	2006	% change
Cash provided by operating activities (\$000)	\$ 83,366	\$ 65,495	27%	\$ 249,132	\$ 229,087	9%
Funds from operations (\$000)	\$ 80,519	\$ 62,737	28%	\$ 271,143	\$ 214,758	26%
per Trust Unit ⁽¹⁾	\$ 0.58	\$ 0.59	(2)%	\$ 2.22	\$ 2.63	(16)%
Net income (loss) (\$000)	\$ 13,795	\$ 8,736	58%	\$ (7,535)	\$ 49,814	(115)%
per Trust Unit - Basic	\$ 0.10	\$ 0.08	25%	\$ (0.06)	\$ 0.62	(110)%
- Diluted	\$ 0.10	\$ 0.08	25%	\$ (0.06)	\$ 0.61	(110)%

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

Cash provided by operating activities increased 27%, funds from operations increased 28%, and funds from operations per Trust Unit modestly decreased 2% for the three months ended December 31, 2007, as compared to the same period of 2006. For the year ended December 31, 2007, cash provided by operating activities increased 9%, funds from operations increased 26%, and funds from operations per Trust Unit decreased 16%. Cash provided by operating activities and funds from operations for the quarter and year were positively impacted by increased revenues due to additional production from the Sound acquisition and the year was further impacted by a full year of production from the Ketch acquisition that closed in 2006. Funds from operations per Trust Unit decreased during the periods due to a higher average number of Trust Units outstanding. The weighted average number of Trust Units has increased 32% for the three months and 48% for the year ended in 2007 compared to 2006, mainly due to the Sound acquisition, the Trust Unit financing in the first quarter of 2007 and the distribution reinvestment plan. When compared to the third quarter of 2007, funds from operations increased 29% due to production increases of 17% from the acquisition of Sound and stronger commodity prices. Natural gas prices, excluding hedging, increased 11% and crude oil and NGL prices, excluding hedging, increased 6% for the fourth quarter of 2007 as compared to the prior quarter. The Fund also realized net derivative gains of \$5.2 million in the three months and \$18.6 million for the year ended December 31, 2007 which also helped to strengthen cash provided by operating activities and funds from operations.

Net income for the quarter increased 58% over prior year due to higher crude oil prices and higher production from the Sound acquisition, offset somewhat by higher costs from the acquisition and general growth of the Fund. Net income for the year decreased to a net loss for the twelve months ended December 31, 2007 primarily due to higher operating costs, as well as non-cash expenses such as amortization of the management contract internalization and higher depletion and depreciation expense. The primary factor that causes significant variability of Advantage’s cash provided by operating activities, funds from operations, 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.

Distributions

	Three months ended December 31			Year ended December 31		
	2007	2006	% change	2007	2006	% change
Distributions declared (\$000)	\$ 57,875	\$ 58,791	(2)%	\$ 215,194	\$ 217,246	(1)%
per Trust Unit ⁽¹⁾	\$ 0.42	\$ 0.56	(25)%	\$ 1.77	\$ 2.66	(33)%

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

Total distributions declared decreased 2% for the three months and 1% for the year ended December 31, 2007 when compared to the same periods in 2006. Total distributions declared are slightly lower as a result of the decreases in the distribution per Trust Unit in January and December 2007. The decreases in per Trust Unit distributions are offset by additional distributions due to the increased Trust Units outstanding from the continued growth and development of the Fund. Since natural gas prices were very weak during the 2006/2007 winter season, we reduced the distribution level in January 2007 and as natural gas prices continued to show prolonged weakness throughout 2007, we decreased the distribution level further in December 2007 to more appropriately reflect the current commodity price environment. Distributions per Trust Unit were \$0.42 for the three months and \$1.77 for the year ended December 31, 2007, representing a decrease of 25% and 33% from same periods in 2006. The monthly distribution is currently \$0.12 per Trust Unit. To mitigate the persisting risk associated with lower commodity prices and the resulting negative impact on cash flows, the Fund implemented a hedging program with 51% of natural gas production and 38% of crude oil production, net of royalties, hedged for 2008. See “Commodity Price Risk” section for a more detailed discussion of our price risk management.

Distributions from the Fund to Unitholders are entirely discretionary and 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. Distributions are announced monthly and are based on the cash available after retaining a portion to meet such spending requirements. The level of 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 distributions will decline over time in a manner consistent with declining production from typical oil and natural gas reserves. Therefore, distributions are highly dependent upon our success in exploiting the current reserve base and acquiring additional reserves. Furthermore, monthly distributions we pay to Unitholders are highly dependent upon the prices received for such 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 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 and U.S. holders of Advantage Trust Units, the distributions paid for 2007 were 100% 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		
	2007	2006	% change	2007	2006	% change
Natural gas excluding hedging	\$ 73,662	\$ 74,309	(1)%	\$ 286,777	\$ 231,548	24%
Realized hedging gains	8,762	4,046	117%	20,933	4,164	403%
Natural gas including hedging	\$ 82,424	\$ 78,355	5%	\$ 307,710	\$ 235,712	31%
Crude oil and NGLs excluding hedging	\$ 87,079	\$ 48,051	81%	\$ 251,987	\$ 182,882	38%
Realized hedging gains (losses)	(3,552)	1,133	(414)%	(2,339)	1,133	(306)%
Crude oil and NGLs including hedging	\$ 83,527	\$ 49,184	70%	\$ 249,648	\$ 184,015	36%
Total revenue	\$ 165,951	\$ 127,539	30%	\$ 557,358	\$ 419,727	33%

Natural gas revenues, excluding hedging, have decreased 1% for the three months and increased 24% for the year ended December 31, 2007, compared to 2006. The decrease in natural gas revenues for the three months is mainly due to a 10% decrease in natural gas prices, excluding hedging, offset by an equivalent 10% increase in production, primarily from the Sound acquisition. Conversely, the increase in natural gas revenues for the 2007 year is mainly due to the inclusion of a full year of production from the Ketch merger that closed in 2006 and production from the Sound acquisition since September 5, 2007, while natural gas prices remained fairly constant. Crude oil and NGL revenues, excluding hedging, have increased by 81% for the three months and 38% for the year ended December 31, 2007, compared to 2006. Crude oil and NGL revenue increased due to additional production from the Sound acquisition and the inclusion of a full year of production from the Ketch merger combined with an increase in crude oil and NGL prices of 34% for the three months and 6% for the year ended December 31, 2007. For the three months and year ended December 31, 2007, the Fund recognized natural gas and crude oil net hedging gains of \$5.2 million and \$18.6 million primarily due to derivative contracts in place that offset commodity prices fluctuations which can jeopardize revenues and corresponding distributions.

Production

	Three months ended December 31			Year ended December 31		
	2007	2006	% change	2007	2006	% change
Natural gas (mcf/d)	128,556	117,134	10%	116,998	94,074	24%
Crude oil (bbls/d)	10,410	7,148	46%	8,090	6,273	29%
NGLs (bbls/d)	2,485	2,422	3%	2,372	1,802	32%
Total (boe/d)	34,321	29,092	18%	29,962	23,754	26%
Natural gas (%)	63%	67%		65%	66%	
Crude oil (%)	30%	25%		27%	26%	
NGLs (%)	7%	8%		8%	8%	

The Fund's total daily production averaged 34,321 boe/d for the three months and 29,962 boe/d for the year ended December 31, 2007, an increase of 18% and 26%, respectively, compared with the same periods of 2006. Natural gas production increased 10%, crude oil production increased 46%, and NGLs production increased 3% for the fourth quarter of 2007. For the year ended December 31, 2007, natural gas production increased 24%, crude oil production increased 29%, and NGLs production increased 32%. Production for the quarter increased due to the additional properties from the Sound acquisition. The increase in production for the year ended December 31, 2007 has been primarily attributed to a full year of production from the Ketch acquisition which closed June 23, 2006 and production from the Sound acquisition which closed September 5, 2007. Production for the fourth quarter increased 17% from the third quarter of 2007 also due to a full quarter of production from the acquisition of Sound.

Our successful first quarter 2007 drilling program at Martin Creek, followed by continued success at Sunset, Nevis, Willesden Green, as well as other areas in Southern Alberta and Saskatchewan throughout the year has helped offset natural declines. In addition, our flattening production platform, resulting from our continued focus on long life assets, is contributing to a stable operating foundation. For 2008 we expect production to average approximately 32,000 to 34,000 boe/d, weighted 62% to natural gas. Approximately 55% of our capital spending will be directed to natural gas and 45% toward light oil projects which will enable us to increase our crude oil production and capitalize on the stronger crude oil pricing environment.

Natural Gas

(\$/mcf)	Three months ended December 31			Year ended December 31		
	2007	2006	% change	2007	2006	% change
Realized natural gas prices						
Excluding hedging	\$ 6.23	\$ 6.90	(10)%	\$ 6.72	\$ 6.74	-
Including hedging	\$ 6.97	\$ 7.27	(4)%	\$ 7.21	\$ 6.86	5%
AECO monthly index	\$ 6.00	\$ 6.36	(6)%	\$ 6.61	\$ 6.98	(5)%

Realized natural gas prices, excluding hedging, decreased 10% for the three months and remained constant for the year ended December 31, 2007, as compared to 2006. The price of natural gas is primarily based on supply and demand fundamentals in the North American marketplace; however market speculation activity has increased price volatility. Natural gas prices declined for the current quarter and continued to remain weak for the entire 2007 year, as in 2006, due to exceedingly high storage levels, mild summer and winter weather and a lack of storm activity in the Gulf of Mexico. Fourth quarter natural gas inventory levels remained well above average, causing continued downward pressure on commodity prices. However, early 2008 has brought colder weather and significant inventory withdrawals have been experienced, resulting in a rebound of natural gas prices. Natural gas storage levels are now closer to expectation and only slightly above the five-year average. In addition, there has been a tighter supply of natural gas, putting further upward pressure on prices. These developments have been encouraging and 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 evidenced by the increase in proposed gas fired electrical generation facilities, (ii) significantly less natural gas drilling in Canada projected for 2008, which will reduce productivity to offset declines, (iii) the increasing focus on resource style natural gas wells, which have high initial declines and require a higher threshold economic price than conventional gas drilling and (iv) the demand for natural gas for the Canadian oil sands projects.

Crude Oil and NGLs

(\$/bbl)	Three months ended December 31			Year ended December 31		
	2007	2006	% change	2007	2006	% change
Realized crude oil prices						
Excluding hedging	\$ 74.19	\$ 56.10	32%	\$ 67.71	\$ 63.85	6%
Including hedging	\$ 70.48	\$ 57.82	22%	\$ 66.92	\$ 64.34	4%
Realized NGLs prices						
Excluding hedging	\$ 70.09	\$ 50.09	40%	\$ 60.12	\$ 55.81	8%
Realized crude oil and NGLs prices						
Excluding hedging	\$ 73.40	\$ 54.58	34%	\$ 65.99	\$ 62.05	6%
Including hedging	\$ 70.40	\$ 55.86	26%	\$ 65.38	\$ 62.44	5%
WTI (\$US/bbl)	\$ 90.63	\$ 60.21	51%	\$ 72.37	\$ 66.35	9%
\$US/\$Canadian exchange rate	\$ 1.02	\$ 0.88	16%	\$ 0.94	\$ 0.88	7%

Realized crude oil and NGLs prices, excluding hedging, increased 34% for the three months and 6% for the year ended December 31, 2007, as compared to the same periods of 2006. 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. For the three months and year ended December 31, 2007, WTI increased 51% and 9%, respectively, with momentous increases experienced in the fourth quarter of 2007. Advantage's realized crude oil price has not changed to the same extent as WTI due to the strengthening of the Canadian dollar relative to the US dollar and widened 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. Many developments have resulted in the current price levels, including significant continuing geopolitical issues and general market speculation. In fact, the impact of market fundamentals has diminished as geopolitical events and speculation has prevailed. As a result, prices have remained strong throughout 2007 and into early 2008. With the current high price levels, it is notable that demand has remained resilient even as the United States, the world's largest crude oil consumer, experiences an economic slowdown. Regardless whether the current price level is sustainable or just a short-term anomaly, 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 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 derivatives. These commodity price 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.

We have been active in entering new financial contracts to protect future cash flows and currently the Fund has the following derivatives in place:

Description of Derivative	Term	Volume	Average Price
Natural gas - AECO			
Fixed price	November 2007 to March 2008	7,109 mcf/d	Cdn\$9.54/mcf
Fixed price	April 2008 to October 2008	14,217 mcf/d	Cdn\$6.85/mcf
Fixed price	April 2008 to October 2008	9,478 mcf/d	Cdn\$7.25/mcf
Fixed price	April 2008 to October 2008	14,217 mcf/d	Cdn\$7.83/mcf
Fixed price	April 2008 to March 2009	14,217 mcf/d	Cdn\$7.10/mcf
Fixed price	April 2008 to March 2009	14,217 mcf/d	Cdn\$7.06/mcf
Fixed price	November 2008 to March 2009	14,217 mcf/d	Cdn\$7.77/mcf
Fixed price	November 2008 to March 2009	4,739 mcf/d	Cdn\$8.10/mcf
Collar	November 2007 to March 2008	9,478 mcf/d	Floor Cdn\$8.44/mcf Ceiling Cdn\$10.29/mcf
Collar	November 2007 to March 2008	7,109 mcf/d	Floor Cdn\$8.70/mcf Ceiling Cdn\$10.71/mcf
Crude oil - WTI			
Fixed price	February 2008 to January 2009	2,000 bbls/d	Cdn\$90.93/bbl
Fixed price	April 2008 to March 2009	2,500 bbls/d	Cdn\$97.15/bbl
Collar	February 2008 to January 2009	2,000 bbls/d	Sold put Cdn\$70.00/bbl Purchased call Cdn\$105.00/bbl Cost Cdn\$1.52/bbl

As at December 31, 2007 the fair value of the derivatives outstanding was a net asset of approximately \$2.2 million. For the year ended December 31, 2007, \$11.0 million was recognized in income as an unrealized derivative loss due to changes in the fair value and settlement of such contracts since December 31, 2006. For the same period we recognized in income a realized derivative gain of \$18.6 million upon the settlement of these financial contracts, which partially alleviated lower revenue from continued weak natural gas prices. As a result of the Sound acquisition, the Fund assumed several derivatives which had an estimated net fair value on closing of \$2.8 million. The change in fair value of these derivatives since acquisition to the end of the period has been recognized in income as an unrealized derivative gain or loss. The valuation of the derivatives is the estimated fair value to settle the contracts as at December 31, 2007 and is based on pricing models, estimates, assumptions and market data available at that time. The actual gain or loss realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices as compared to the valuation assumptions. The Fund does not apply hedge accounting and current accounting standards require changes in the fair value to be included in the consolidated statement of income and comprehensive income as an unrealized derivative gain or loss with a corresponding derivative asset and liability recorded on the balance sheet.

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

Commodity	Approximate Production Hedged, Net of Royalties	Average Floor Price	Average Ceiling Price
Natural gas - AECO			
January to March 2008	22%	Cdn\$8.85/mcf	Cdn\$10.19/mcf
April to June 2008	66%	Cdn\$7.22/mcf	Cdn\$7.22/mcf
July to September 2008	64%	Cdn\$7.22/mcf	Cdn\$7.22/mcf
October to December 2008	53%	Cdn\$7.32/mcf	Cdn\$7.32/mcf
Total 2008	51%	Cdn\$7.43/mcf	Cdn\$7.58/mcf
January to March 2009	46%	Cdn\$7.39/mcf	Cdn\$7.39/mcf
Crude Oil - WTI			
January to March 2008	13%	Cdn\$90.93/bbl	Cdn\$90.93/bbl
April to June 2008	47%	Cdn\$94.39/bbl	Cdn\$94.39/bbl
July to September 2008	46%	Cdn\$94.39/bbl	Cdn\$94.39/bbl
October to December 2008	46%	Cdn\$94.39/bbl	Cdn\$94.39/bbl
Total 2008	38%	Cdn\$94.07/bbl	Cdn\$94.07/bbl
January to March 2009	32%	Cdn\$95.84/bbl	Cdn\$95.84/bbl

Royalties

	Three months ended December 31			Year ended December 31		
	2007	2006	% change	2007	2006	% change
Royalties, net of Alberta Royalty Credit (\$000)	\$ 27,099	\$ 23,349	16%	\$ 98,614	\$ 76,456	29%
per boe	\$ 8.58	\$ 8.72	(2)%	\$ 9.02	\$ 8.82	2%
As a percentage of revenue, excluding hedging	16.9%	19.1%	(2.2)%	18.3%	18.4%	(0.1)%

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 for 2006 are shown net of the Alberta Royalty Credit, which was a royalty rebate provided by the Alberta government to certain producers and was eliminated effective January 1, 2007. Royalties have increased in total for the 2007 periods due to the increase in revenue from higher production related to acquisitions but remains comparable on a per boe basis. Royalties as a percentage of revenue, excluding hedging, remained consistent for the year as compared to 2006 but decreased in the fourth quarter of 2007 due to the lower natural gas prices experienced by Advantage during the last six months of the year. We expect the royalty rate to be in the range of 17% to 19% for 2008 given the current environment.

On October 25, 2007, the Alberta Provincial Government announced changes to royalties for conventional oil, natural gas and oil sands that will become effective January 1, 2009. Given the methodology used in the new royalty regime, royalties and as a result, cash flows will be affected by depths and productivity of wells. In addition, royalties are price sensitive with higher royalty levels applying when commodity prices are higher. A review of the initial information released by the Alberta Provincial Government indicates that lower rate natural gas wells will see a benefit of lower royalties while conventional oil will be subject to an increase in royalties but is again less punitive at lower rates. Commodity prices and individual well production rates are both key factors in the calculation. The majority of Advantage's production in Alberta comes from lower rate wells due to well-established large, long life properties. In addition, we have a significant presence in British Columbia and Saskatchewan. Therefore, early indications are that the impact may not be significant based on our current production and the current commodity price environment. Advantage continues to analyze the impact of the decision and will take the new royalty regime into consideration in preparing future development projects. Project economics are evaluated taking into consideration all relevant factors including the new royalty regime given the commodity pricing environment anticipated. Those projects that maximize return to Advantage Unitholders will continue to be selected for development.

Operating Costs

	Three months ended			Year ended		
	December 31			December 31		
	2007	2006	% change	2007	2006	% change
Operating costs (\$000)	\$ 39,330	\$ 27,803	41%	\$127,309	\$ 82,911	54%
per boe	\$ 12.46	\$ 10.39	20%	\$ 11.64	\$ 9.56	22%

Total operating costs increased 41% for the three months and 54% for the year ended December 31, 2007 as compared to 2006, mainly due to increased production from the Ketch acquisition which was completed June 23, 2006 and the Sound acquisition, which closed on September 5, 2007. Operating costs per boe increased 20% for the three months and 22% for the year ended December 31, 2007, mainly due to lower production levels related to third party turnaround activity, an extended spring break-up, increased service and supply costs as the industry experienced overall cost increases, and higher relative operating costs from recent acquisitions. However, fourth quarter 2007 per boe operating costs came in modestly lower than our expectation of \$12.50 to \$13.50, due to optimization initiatives put in place by the Fund in 2007. We will continue to be opportunistic and proactive in pursuing programs that will improve our operating cost structure. Consistent with this strategy, the Fund entered hedges for power costs, one of our more significant operating costs, of 3.0 MW at \$54.00/MWh for 2008. We expect that operating costs per boe will be in the range of \$12.50 to \$13.30 for the 2008 year.

General and Administrative

	Three months ended			Year ended		
	December 31			December 31		
	2007	2006	% change	2007	2006	% change
General and administrative expense (\$000)	\$ 7,173	\$ 4,586	56%	\$ 21,449	\$ 13,738	56%
per boe	\$ 2.27	\$ 1.71	33%	\$ 1.96	\$ 1.58	24%
Employees at December 31				172	135	27%

General and administrative (“G&A”) expense has increased 56% for the three months and year ended December 31, 2007, as compared to 2006. G&A per boe increased 33% for the three months and 24% for the year when compared to the same periods of 2006. G&A expense for the year ended December 31, 2007 has increased overall and per boe primarily due to an increase in staff levels that have resulted from the Ketch and Sound acquisitions and general 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, including unit-based compensation, which 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 a Restricted Trust Unit Plan (the “Plan”), as approved by the Unitholders on June 23, 2006, and Trust Units issuable for the retention of certain employees of the Fund. The purpose of the long-term compensation plans is to retain and attract employees, to reward and encourage performance, and to focus employees on operating and financial performance that results in lasting Unitholder return.

The Plan authorizes the Board of Directors to grant Restricted Trust Units (“RTUs”) to directors, officers, or employees of the Fund. The number of RTUs granted is based on the Fund’s Trust Unit return for a calendar year and compared to a peer group approved by the Board of Directors. The Trust Unit return is calculated at the end of the year and is primarily based on the year-over-year change in the Trust Unit price plus distributions. The RTU grants vest one third immediately on grant date, with the remaining two thirds vesting evenly on the following two yearly anniversary dates. The holders of RTUs may elect to receive cash upon vesting in lieu of the number of Trust Units to be issued, subject to consent of the Fund. Compensation cost related to the Plan is based on the “fair value” of the RTUs at the grant date and is recognized as compensation expense over the service period. This valuation incorporates the period end Trust Unit price, the estimated number of RTUs to vest, and certain management estimates. The maximum fair value of RTUs granted in any one calendar year is limited to 175% of the base salaries of those individuals participating in the Plan for such period. As the Fund did not meet the 2007 or 2006 grant thresholds, there were no RTU grants made during these years and no related compensation expense has been recognized.

For the year ended December 31, 2007, the Fund has accrued unit-based compensation expense of \$0.9 million in general and administrative expense and has capitalized \$0.3 million related to Trust Units issuable for the retention of certain employees of the Fund.

Management Fee, Performance Incentive, and Management Internalization

	Three months ended			Year ended		
	December 31			December 31		
	2007	2006	% change	2007	2006	% change
Management fee (\$000)	\$ -	\$ -	-	\$ -	\$ 887	(100)%
per boe	\$ -	\$ -	-	\$ -	\$ 0.10	(100)%
Performance incentive (\$000)	\$ -	\$ -	-	\$ -	\$ 2,380	(100)%
Management internalization (\$000)	\$ 2,534	\$ 5,497	(54)%	\$ 15,708	\$ 13,449	17%

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. 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, thereby eliminating the management fee and performance incentive effective April 1, 2006. The Trust Unit consideration issued in exchange for the outstanding shares of the Manager 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 management internalization is lower for the quarter since one third vested and was paid in June 2007 while two thirds remains outstanding.

Interest

	Three months ended			Year ended		
	December 31			December 31		
	2007	2006	% change	2007	2006	% change
Interest expense (\$000)	\$ 7,917	\$ 5,414	46%	\$ 24,351	\$ 18,258	33%
per boe	\$ 2.51	\$ 2.02	24%	\$ 2.23	\$ 2.11	6%
Average effective interest rate	6.2%	5.5%	0.7%	5.7%	5.1%	0.6%
Bank indebtedness at December 31 (\$000)				\$547,426	\$410,574	33%

Interest expense has increased 46% for the three months and 33% for the year ended December 31, 2007, as compared to 2006. Interest expense per boe has increased 24% for the three months and 6% for the year ended December 31, 2007. The increase in total 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 increased bank indebtedness assumed on the Ketch and Sound acquisitions. 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 only 5.7% for the year ended December 31, 2007. 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			Year ended		
	December 31			December 31		
	2007	2006	% change	2007	2006	% change
Interest on convertible debentures (\$000)	\$ 4,426	\$ 3,289	35%	\$ 14,867	\$ 11,210	33%
per boe	\$ 1.40	\$ 1.23	14%	\$ 1.36	\$ 1.29	5%
Accretion on convertible debentures (\$000)	\$ 721	\$ 604	19%	\$ 2,569	\$ 2,106	22%
per boe	\$ 0.23	\$ 0.23	-	\$ 0.23	\$ 0.24	(4)%
Convertible debentures maturity value at December 31 (\$000)				\$224,612	\$180,730	24%

Interest on convertible debentures has increased 35% for the three months and 33% for the year ended December 31, 2007, as compared to 2006. Accretion on convertible debentures has increased 19% for the three months and 22% for the year ended December 31, 2007. The increases in total interest and accretion are due to Advantage assuming Sound's 8.75% and 8.00% convertible debentures and Ketch's 6.50% convertible debentures in the 2006 merger. The increased interest and accretion from the additional debentures has been slightly offset due to the exchange of convertible debentures to Trust Units during 2006 that pay distributions rather than interest. Interest per boe for the quarter is higher as our convertible debentures outstanding have slightly increased relative to our level of production.

	Three months ended				Year ended			
	December 31				December 31			
	2007		2006		2007		2006	
	\$000	per boe	\$000	per boe	\$000	per boe	\$000	per boe
Revenue	\$ 160,741	\$ 50.91	\$ 122,360	\$ 45.72	\$ 538,764	\$ 49.27	\$ 414,430	\$ 47.80
Realized gain on derivatives	5,210	1.65	5,179	1.93	18,594	1.70	5,297	0.61
Royalties, net of Alberta Royalty Credit(27,099)	(8,58)	(8.58)	(23,349)	(8.72)	(98,614)	(9.02)	(76,456)	(8.82)
Operating costs	(39,330)	(12.46)	(27,803)	(10.39)	(127,309)	(11.64)	(82,911)	(9.56)
Operating	\$ 99,522	\$ 31.52	\$ 76,387	\$ 28.54	\$ 331,435	\$ 30.31	\$ 260,360	\$ 30.03
General and administrative ⁽¹⁾	(7,029)	(2.23)	(4,586)	(1.71)	(20,520)	(1.88)	(13,738)	(1.58)
Management fee	-	-	-	-	-	-	(887)	(0.10)
Interest	(7,917)	(2.51)	(5,414)	(2.02)	(24,351)	(2.23)	(18,258)	(2.11)
Interest on convertible debentures ⁽¹⁾	(3,536)	(1.12)	(3,289)	(1.23)	(13,977)	(1.28)	(11,210)	(1.29)
Income and capital taxes	(521)	(0.16)	(361)	(0.13)	(1,444)	(0.13)	(1,509)	(0.17)
Funds from operations	\$ 80,519	\$ 25.50	\$ 62,737	\$ 23.45	\$ 271,143	\$ 24.79	\$ 214,758	\$ 24.78

⁽¹⁾ General and administrative expense and interest on convertible debentures exclude unit-based compensation and non-cash interest expense.

Funds from operations of Advantage for the quarter ended December 31, 2007 increased to \$80.5 million from \$62.7 million in the prior year. Funds from operations for the year ended December 31, 2007 increased to \$271.1 million from \$214.8 million compared to 2006. The cash netback per boe for the three months ended December 31, 2007 increased 9% from \$23.45 to \$25.50 for the quarter, but remained comparable for the year ended December 31, 2007. The higher cash netback per boe for the three months ended December 31, 2007 is primarily due to higher revenues, resulting from additional production from the accretive Sound acquisition and strong oil prices offset somewhat by lower natural gas prices as well as higher operating and general and administrative costs. Operating costs have steadily increased over the past year due to significantly higher field costs associated with supplies and services that have resulted from the high level of industry activity, an overall industry labour cost increase, and higher relative operating costs from recent acquisitions. However, it is noteworthy that due to several of our initiatives this year, operating costs for the quarter were less than anticipated. The increased general and administrative costs are due to higher staff levels and general growth of the Fund. When compared to the third quarter of 2007, funds from operations per boe increased 10%, again mainly due to the acquisition of Sound.

Depletion, Depreciation and Accretion

	Three months ended			Year ended		
	December 31			December 31		
	2007	2006	% change	2007	2006	% change
Depletion, depreciation & accretion (\$000)	\$ 78,149	\$ 63,521	23%	\$272,175	\$194,309	40%
per boe	\$ 24.75	\$ 23.73	4%	\$ 24.89	\$ 22.41	11%

Depletion and depreciation of fixed assets is provided on the “unit-of-production” method based on total proved reserves. Accretion represents the increase in the asset retirement obligation liability each reporting period due to the passage of time. The depletion, depreciation and accretion (“DD&A”) provision has increased 23% for the three months and 40% for the year ended December 31, 2007. The higher DD&A is due to considerable increases in daily production volumes, mainly from the Ketch and Sound acquisitions and the increase in the DD&A rate per boe compared to the prior year. The increased DD&A rate per boe was due to a higher valuation assigned for reserves from recent acquisitions than accumulated from prior acquisitions and development activities. We evaluate the recoverability of our petroleum and natural gas assets each reporting period to ensure the carrying amount does not exceed the fair value. When the carrying amount is not assessed to be recoverable, an impairment loss is recognized. There has been no impairment of the Fund’s petroleum and natural gas properties under Canadian GAAP since inception.

Taxes

Current taxes paid or payable for the quarter ended December 31, 2007 amounted to \$0.5 million, comparable to the \$0.4 million expensed for the same period of 2006. The higher current taxes are due to the increased Saskatchewan properties and activity within these properties from the Ketch and Sound acquisitions. Current taxes primarily represent Saskatchewan resource surcharge, which 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 assets and liabilities. For the year ended December 31, 2007, the Fund recognized a future income tax reduction of \$24.6 million compared to \$37.1 million for 2006. Under the Fund's current structure, payments are made between the operating company and the Fund transferring income tax obligations to Unitholders and as a result no cash income taxes would be paid by the operating company or the Fund prior to 2011. However, the Specified Investment Flow-Through Entity ("SIFT") tax legislation was enacted on June 22, 2007 altering the tax treatment by subjecting income trusts to a two-tier tax structure, similar to that of corporations, whereby the taxable portion of distributions paid by trusts will be subject to tax at the trust level and at the Unitholder level. The rules are effective for tax years beginning in 2011 for existing publicly-traded trusts. The impact of the new tax law is reflected in 2007 and resulted in an additional future income tax expense of \$42.9 million. As at December 31, 2007, we had a future income tax liability balance of \$66.7 million, compared to \$61.9 million at December 31, 2006. 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. It further requires that a future tax liability be recorded on an acquisition when a corporation acquires assets with associated tax pools that are less than the purchase price. As a result of the Sound acquisition, Advantage recorded a future tax liability of \$29.4 million.

On December 14, 2007, the Federal government enacted legislation phasing in corporate income tax rate reductions which will reduce federal tax rates from 22.1% to 15.0% by 2012. Rate reductions will also apply to the new tax on distributions of income trusts and other specified investment flow-through entities as of 2011, reducing the tax rate in 2011 to 29.5% and in 2012 to 28.0%. These rates include a deemed provincial rate of 13%.

The Fund has approximately \$1.7 billion in tax pools and deductions at December 31, 2007, which can be used to reduce the amount of taxes paid by Advantage. The Fund and Advantage Oil & Gas Ltd. ("AOG") had the following estimated tax pools in place at December 31, 2007:

December 31, 2007	
Estimated Tax Pools	
(\$ millions)	
Undepreciated Capital Cost	\$ 641
Canadian Oil and Gas Property Expenses	462
Canadian Development Expenses	435
Canadian Exploration Expenses	65
Non-capital losses	76
Other	<u>25</u>
	<u>\$ 1,704</u>

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	2008	2009	2010	2011	2012
Building leases	\$ 16.6	\$ 5.3	\$ 4.1	\$ 4.1	\$ 1.8	\$ 1.3
Capital leases	8.1	1.9	2.1	2.2	1.9	-
Pipeline/transportation	6.0	4.4	1.3	0.3	-	-
Convertible debentures ⁽¹⁾	224.6	5.4	87.0	69.9	62.3	-
Total contractual obligations	\$ 255.3	\$ 17.0	\$ 94.5	\$ 76.5	\$ 66.0	\$ 1.3

⁽¹⁾ As at December 31, 2007, Advantage had \$224.6 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 either directly or indirectly through the issuance of Trust Units.

⁽²⁾ Bank indebtedness of \$547.4 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, 2007
Bank indebtedness (long-term)	\$ 547,426
Working capital deficit ⁽¹⁾	28,087
Net debt	\$ 575,513
Trust Units outstanding (000)	138,269
Trust Unit closing market price (\$/Trust Unit)	\$ 8.73
Market value	\$ 1,207,088
Capital lease obligations (long-term)	\$ 5,653
Convertible debentures maturity value (long-term)	219,220
Total capitalization	\$ 2,007,474

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

Unitholders' Equity and Convertible Debentures

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

As at December 31, 2007, the Fund had 138.3 million Trust Units outstanding. 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 \$104.1 million (net of Underwriters' fees and other issue costs of \$6.0 million). The net proceeds of the offering were used to pay down bank indebtedness and to subsequently fund capital and general corporate expenditures. On September 5, 2007, Advantage issued 16,977,184 Trust Units as partial consideration for the acquisition of Sound. As at March 5, 2008, Advantage had 139.0 million Trust Units issued and outstanding.

On July 24, 2006, Advantage adopted a Premium Distribution^(TM), Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "Plan"). 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, 2007, 4,028,252 Trust Units were issued as a result of the Plan, generating \$46.7 million reinvested in the Fund and representing an approximate 18% participation rate.

As at December 31, 2007, the Fund had \$224.6 million convertible debentures outstanding that were convertible to 9.8 million Trust Units based on the applicable conversion prices. During the year ended December 31, 2007, \$24,000 debentures were converted resulting in the issuance of 1,386 Trust Units and all of the remaining \$1,470,000 10% convertible debentures matured on November 1, 2007 and were settled with the issuance of 127,493 Trust Units.

Due to the acquisition of Sound, \$59,513,000 8.75% and \$41,035,000 8.00% convertible debentures were assumed by Advantage on September 5, 2007. As a result of the change in control of Sound, the Fund was required by the debenture indentures to make an offer to purchase all of the outstanding convertible debentures assumed from Sound as at a price equal to 101% of the principal amount plus accrued and unpaid interest. On October 17, 2007, the expiry date of the offer, 911,709 Trust Units were issued and \$19.9 million in total cash consideration was paid in exchange for \$29,665,000 8.75% convertible debentures and 2,220,289 Trust Units were issued in exchange for \$25,507,000 8.00% convertible debentures. As at March 5, 2008, the convertible debentures have not changed from December 31, 2007.

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, 37,500 Series B Trust Unit Rights were exercised in the second quarter of 2007. As at March 5, 2008, 150,000 Series B Trust Unit Rights remain outstanding.

As a result of the new SIFT tax legislation, 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 from October 31, 2006 to January 1, 2011, which we believe is adequate for any growth we expect to incur.

Bank Indebtedness, Credit Facility and Other Obligations

At December 31, 2007, Advantage had bank indebtedness outstanding of \$547.4 million. The Fund has a \$710 million credit facility agreement consisting of a \$690 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, 2007, Advantage had a working capital deficiency of \$28.1 million. Our working capital includes items expected for normal operations such as trade receivables, prepaids, deposits, trade payables and accruals as well as the current portion of capital lease obligations and convertible debentures. 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.

In the second quarter of 2007, Advantage entered a new lease arrangement that resulted in the recognition of a fixed asset addition and capital lease obligation of \$4.1 million. The lease obligation bears interest at 5.8% and is secured by the related equipment. The lease term expires June 2011 with a final purchase obligation of \$1.5 million at which time ownership of the equipment will transfer to Advantage. We entered a second lease arrangement during the third quarter of 2007 that resulted in the recognition of a fixed asset addition and capital lease obligation of \$1.8 million. This lease obligation bears interest at 6.7% and is also secured by the related equipment. The lease term expires August 2010 with a final payment obligation of \$0.7 million. Distributions to Unitholders are not permitted if the Fund is in default of this capital lease.

On September 5, 2007, Advantage assumed two capital lease obligations in the acquisition of Sound resulting in the recognition of capital lease obligations of \$1.6 million. Both of the assumed lease obligations bear interest at 5.6% and are secured by the related equipment. The lease terms expire December 2009 and April 2010 with a total final payment obligation of \$0.9 million.

(\$000)	Three months ended December 31		Year ended December 31	
	2007	2006	2007	2006
Land and seismic	\$ 64	\$ 522	\$ 3,270	\$ 5,261
Drilling, completions and workovers	30,020	42,612	94,786	113,146
Well equipping and facilities	9,971	17,690	48,296	39,437
Other	878	285	2,373	1,643
	\$ 40,933	\$ 61,109	\$ 148,725	\$ 159,487
Acquisition of Sound Energy Trust	(67)	-	22,307	-
Property acquisitions	3,200	46	16,051	244
Property dispositions	(610)	-	(1,037)	(8,727)
Total capital expenditures	\$ 43,456	\$ 61,155	\$ 186,046	\$ 151,004

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 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 and Sound 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 a high level of flexibility to distribute its capital program and ensure a risk-balanced platform of projects. 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, 2007, the Fund spent a net \$40.9 million and drilled a total of 16.6 net (32 gross) wells at a 100% success rate. Total capital spending in the quarter included \$7.1 million at Nevis, \$5.7 million at Chip Lake, \$5.3 million at Martin Creek, \$3.9 million at Southeast Saskatchewan and \$3.4 million at Willesden Green. For the year ended December 31, 2007, the Fund spent a net \$148.7 million and drilled a total of 64.8 net (112 gross) wells at a 99% success rate. Total capital spending for the year included \$33.6 million at Martin Creek, \$26.2 million at Nevis, \$17.5 million at Willesden Green, \$10.5 million in Southeast Saskatchewan, \$8.5 million at Chip Lake, and \$7.2 million at Sunset.

Property acquisitions year to date include a \$12.9 million property acquisition in the first quarter for producing properties and undeveloped land at the Fund's core area, Nevis, and a \$3.2 million property acquisition in the Boundary Lake area during the fourth quarter. Costs of \$22.3 million were incurred related to the Sound acquisition representing the cash portion paid due to the exercise of the cash option offered to Sound Unitholders and other costs.

The following table summarizes the various funding requirements during the years ended December 31, 2007 and 2006 and the sources of funding to meet those requirements.

Sources and Uses of Funds

(\$000)	Year ended December 31	
	2007	2006
Sources of funds		
Funds from operations	\$ 271,143	\$ 214,758
Units issued, net of costs	104,215	141,908
Increase in bank indebtedness	28,893	-
Property dispositions	1,037	8,727
Decrease in working capital	-	27,222
	\$ 405,288	\$ 392,615
Uses of funds		
Distributions to Unitholders	\$ 170,915	\$ 185,015
Expenditures on property and equipment	148,725	159,487
Acquisition of Sound Energy Trust	22,307	-
Debentures redeemed	19,406	-
Increase in working capital	17,749	-
Property acquisitions	16,051	244
Expenditures on asset retirement	6,951	5,974
Reduction of capital lease obligations	3,184	1,019
Decrease in bank indebtedness	-	30,767
Acquisition of Ketch Resources Trust	-	10,109
	\$ 405,288	\$ 392,615

Annual Financial Information

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

	Year ended Dec. 31, 2007	Year ended Dec. 31, 2006	Year ended Dec. 31, 2005
Total revenue (before royalties) (\$000)	\$ 557,358	\$ 419,727	\$ 376,572
Net income (loss) (\$000)	\$ (7,535)	\$ 49,814	\$ 75,072
per Trust Unit - Basic	\$ (0.06)	\$ 0.62	\$ 1.33
- Diluted	\$ (0.06)	\$ 0.61	\$ 1.32
Total assets (\$000)	\$ 2,422,280	\$ 1,981,587	\$ 1,012,847
Long term financial liabilities (\$000) ⁽¹⁾	\$ 768,060	\$ 581,698	\$ 379,903
Distributions declared per Trust Unit	\$ 1.77	\$ 2.66	\$ 3.12

⁽¹⁾ Long term financial liabilities exclude asset retirement obligations and future income taxes.

Quarterly Performance

(\$000, except as otherwise indicated)	2007				2006			
	Q4	Q3	Q2	Q1	Q4	Q3	Q2	Q1
Daily production								
Natural gas (mcf/d)	128,556	115,991	108,978	114,324	117,134	122,227	70,293	65,768
Crude oil and NGLs (bbls/d)	12,895	10,014	8,952	9,958	9,570	9,330	6,593	6,760
Total (boe/d)	34,321	29,346	27,115	29,012	29,092	29,701	18,309	17,721
Average prices								
Natural gas (\$/mcf)								
Excluding hedging	\$ 6.23	\$ 5.62	\$ 7.54	\$ 7.61	\$ 6.90	\$ 5.89	\$ 6.18	\$ 8.69
Including hedging	\$ 6.97	\$ 6.35	\$ 7.52	\$ 8.06	\$ 7.27	\$ 5.90	\$ 6.18	\$ 8.69
AECO monthly index	\$ 6.00	\$ 5.62	\$ 7.37	\$ 7.46	\$ 6.36	\$ 6.03	\$ 6.28	\$ 9.31
Crude oil and NGLs (\$/bbl)								
Excluding hedging	\$ 73.40	\$ 69.03	\$ 61.84	\$ 56.84	\$ 54.58	\$ 67.77	\$ 68.69	\$ 58.26
Including hedging	\$ 70.40	\$ 68.51	\$ 61.93	\$ 58.64	\$ 55.86	\$ 67.77	\$ 68.69	\$ 58.26
WTI (US\$/bbl)	\$ 90.63	\$ 75.33	\$ 65.02	\$ 58.12	\$ 60.21	\$ 70.55	\$ 70.75	\$ 63.88
Total revenues (before royalties)	\$ 165,951	\$ 130,830	\$ 125,075	\$ 135,502	\$ 127,539	\$ 124,521	\$ 80,766	\$ 86,901
Net income (loss)	\$ 13,795	\$ (26,202)	\$ 4,531	\$ 341	\$ 8,736	\$ 1,209	\$ 23,905	\$ 15,964
per Trust Unit- basic	\$ 0.10	\$ (0.22)	\$ 0.04	\$ 0.00	\$ 0.08	\$ 0.01	\$ 0.38	\$ 0.27
- diluted	\$ 0.10	\$ (0.22)	\$ 0.04	\$ 0.00	\$ 0.08	\$ 0.01	\$ 0.38	\$ 0.27
Funds from operations	\$ 80,519	\$ 62,345	\$ 62,634	\$ 65,645	\$ 62,737	\$ 63,110	\$ 42,281	\$ 46,630
Distributions declared	\$ 57,875	\$ 55,017	\$ 52,096	\$ 50,206	\$ 58,791	\$ 60,498	\$ 53,498	\$ 44,459

The table above highlights the Fund's performance for the fourth quarter of 2007 and also for the preceding seven quarters. Production significantly increased in the third quarter of 2006 as the Ketch acquisition that closed on June 23, 2006 was fully integrated with Advantage. The second quarter of 2007 encountered a temporary production decrease as expected due to several facility turnarounds that had been planned for that period. The third quarter of 2007 includes the financial and operating results from the acquired Sound properties for 26 days, and fourth quarter of 2007 includes the full integration of the Sound properties. Advantage's revenues and funds from operations increased significantly beginning in the third quarter of 2006 primarily due to the production from the merger with Ketch and surged again in the fourth quarter of 2007 due to the Sound acquisition, partially offset by lower natural gas prices. Net income was lower in the first three quarters of 2007 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 and Sound mergers. Net income increased in the fourth quarter of 2007 due to the full integration of the Sound acquisition and stronger crude oil prices.

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 fixed assets, the provision for asset retirement costs and related accretion expense, and impairment calculations for fixed assets 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.

Management's process of determining the provision for future income taxes, the provision for asset retirement obligation costs and related accretion expense, and the fair values assigned to any acquired company's assets and liabilities in a business combination is based on estimates. These estimates are significant and can include reserves, future production rates, future crude oil and natural gas prices, future costs, future interest rates, future tax rates and other relevant assumptions. Revisions or changes in any of these estimates can have either a positive or a negative impact on asset and liability values and net income.

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 released a detailed implementation plan in May 2007 and the Fund will consider the effects that this implementation plan might have on the consolidated financial statements during the transition period.

Capital Disclosures

The CICA has issued section 1535 "Capital Disclosures", which will be effective January 1, 2008 for the Fund. Section 1535 will require the Fund to provide additional disclosures relating to capital and how it is managed. It is not anticipated that the adoption of section 1535 will impact the amounts reported in the Fund's financial statements as they primarily relate to disclosure.

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 operations, 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 2007, 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.

The Fund's Management is responsible for establishing and maintaining effective internal control over financial reporting. 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, 2007. 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 and Audit Committee each have three members, all of whom are independent. The Human Resources, Compensation and Corporate Governance Committee has 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 four 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; (iii) submit an executed annual written affirmation, as well as an interim affirmation each time a change occurs to the audit committee; and (iv) 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's 2008 Budget, as approved by the Board of Directors, retains a high degree of activity and focus on drilling in many of our key properties where a high level of success was realized through 2007. Capital has also been directed to delineate a natural gas resource play at Glacier in Northwest Alberta and to accommodate facility expansions and 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 throughout 2007. 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 fourth quarter of 2007, production was on-track and operating costs were lower than expected. We realized some impact to our production due to third party related facilities outages in December, however, continued efforts in operating cost optimization is providing efficiency gains. For 2008, we are forecasting production to be in the range of 32,000 to 34,000 boe/d. Advantage's 2008 capital expenditures budget is estimated to be approximately \$125 to \$145 million with approximately 143 gross (88 net) wells. An active winter program at Martin Creek, Glacier, Nevis and Willesden Green will be followed by a relatively even paced program in Q3 and Q4 of 2008. Capital spending is estimated to be split evenly between oil and gas activities.

Per unit operating costs on an annual basis are expected to range between the \$12.50 to \$13.30/boe range. Advantage is continuing with several operating cost reduction initiatives throughout 2008 to help offset these increases and we have begun to realize some key achievements in this area. We expect industry servicing and maintenance costs to generally remain stable in 2008 with some potential for natural gas related costs to increase during the latter part of 2008 if natural gas prices strengthen at that time.

On October 25, 2007, the Alberta Provincial Government announced changes to royalties for conventional oil, natural gas and oil sands that will become effective January 1, 2009. Preliminary indications are that the changes will have a negligible impact on Advantage since we have a significant number of lower rate wells within our long life properties producing in Alberta. Advantage also has a significant Horseshoe Canyon coal bed methane drilling inventory that can be pursued which will also have a favorable royalty treatment due to lower rate per well characteristics. Our exposure in Northeast British Columbia and Saskatchewan also affords us further flexibility with mitigating the royalty impact in our capital program. We expect our royalty rates to range from 17% to 19% in 2008.

Advantage's funds from operations in 2008 will continue to be impacted by the volatility of crude oil and natural gas prices and the \$US/\$Canadian exchange rate. Additional hedging has been completed for 2008 to i) stabilize cash flows and ii) ensure that the Fund's capital program is substantially funded out of cash flow. Approximately 51% of our natural gas production, net of royalties, is now hedged for the 2008 calendar year at a floor of \$7.43/mcf. Advantage has also hedged 38% of its 2008 crude oil production, net of royalties, at an average price of \$94.07/bbl.

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 and Sound mergers.

Looking forward, Advantage's high quality assets combined with a greater than five 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.

Sensitivities

The following table displays the current estimated sensitivity on funds from operations and funds from operations per Trust Unit to changes in production, commodity prices, exchange rates and interest rates for 2008.

	Annual Funds from Operations (\$000)	Annual Funds from Operations per Trust Unit (\$/Trust Unit)
Natural gas		
AECO monthly price change of \$1.00/mcf	\$ 17,800	\$ 0.12
Production change of 6.0 mmcf/d	\$ 7,200	\$ 0.05
Crude oil and NGLs		
WTI price change of US\$10.00/bbl	\$ 27,900	\$ 0.20
Production change of 1,000 bbls/d	\$ 22,200	\$ 0.16
\$US/\$Canadian exchange rate change of \$0.01	\$ 5,900	\$ 0.04
Interest rate change of 1%	\$ 5,600	\$ 0.04

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 FINANCIAL STATEMENTS

Consolidated Balance Sheets

(thousands of dollars)

December 31, 2007

December 31, 2006

Assets

Current assets

Accounts receivable	\$ 95,474	\$ 79,537
Prepaid expenses and deposits	21,988	16,878
Derivative asset (note 12)	7,027	9,840

	124,489	106,255
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Deposit on property acquisition	-	1,410
Derivative asset (note 12)	174	593
Fixed assets (note 4)	2,177,346	1,753,058
Goodwill (note 3)	120,271	120,271

	\$ 2,422,280	\$ 1,981,587
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Liabilities

Current liabilities

Accounts payable and accrued liabilities	\$ 122,087	\$ 116,109
Distributions payable to Unitholders	16,592	18,970
Current portion of capital lease obligations (note 5)	1,537	2,527
Current portion of convertible debentures (note 6)	5,333	1,464
Derivative liability (note 12)	2,242	-

	147,791	139,070
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Derivative liability (note 12)	2,778	-
Capital lease obligations (note 5)	5,653	305
Bank indebtedness (note 7)	547,426	410,574
Convertible debentures (note 6)	212,203	170,819
Asset retirement obligations (note 8)	60,835	34,324
Future income taxes (note 9)	66,727	61,939

	1,043,413	817,031
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Unitholders' Equity

Unitholders' capital (note 10)	2,027,065	1,592,758
Convertible debentures equity component (note 6)	9,632	8,041
Contributed surplus (note 10)	2,005	863
Accumulated deficit (note 11)	(659,835)	(437,106)

	1,378,867	1,164,556
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	\$ 2,422,280	\$ 1,981,587
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Commitments (note 14)

see accompanying Notes to Consolidated Financial Statements

**Consolidated Statements of Income (Loss),
 Comprehensive Income and Accumulated Deficit**

(thousands of dollars, except for per Trust Unit amounts)	Year ended December 31, 2007	Year ended December 31, 2006
Revenue		
Petroleum and natural gas	\$ 538,764	\$ 414,430
Realized gain on derivatives (note 12)	18,594	5,297
Unrealized gain (loss) on derivatives (note 12)	(11,049)	10,242
Royalties, net of Alberta Royalty Credit	(98,614)	(76,456)
	447,695	353,513
Expenses		
Operating	127,309	82,911
General and administrative	21,449	13,738
Management fee (note 13)	-	887
Performance incentive (note 13)	-	2,380
Management internalization (note 13)	15,708	13,449
Interest	24,351	18,258
Interest and accretion on convertible debentures	17,436	13,316
Depletion, depreciation and accretion	272,175	194,309
	478,428	339,248
Income (loss) before taxes and non-controlling interest	(30,733)	14,265
Future income tax reduction (note 9)	(24,642)	(37,087)
Income and capital taxes (note 9)	1,444	1,509
	(23,198)	(35,578)
Net income (loss) before non-controlling interest	(7,535)	49,843
Non-controlling interest	-	29
Net income (loss) and comprehensive income (loss)	(7,535)	49,814
Accumulated deficit, beginning of year	(437,106)	(269,674)
Distributions declared	(215,194)	(217,246)
Accumulated deficit, end of year	\$ (659,835)	\$ (437,106)
Net income (loss) per Trust Unit (note 10)		
Basic	\$ (0.06)	\$ 0.62
Diluted	\$ (0.06)	\$ 0.61

see accompanying Notes to Consolidated Financial Statements

Consolidated Statements of Cash Flows

(thousands of dollars)	Year ended December 31, 2007	Year ended December 31, 2006
Operating Activities		
Net income (loss)	\$ (7,535)	\$ 49,814
Add (deduct) items not requiring cash:		
Unrealized loss (gain) on derivatives	11,049	(10,242)
Unit-based compensation	929	-
Performance incentive	-	2,380
Management internalization	15,708	13,449
Non-cash interest expense	890	-
Accretion on convertible debentures	2,569	2,106
Depletion, depreciation and accretion	272,175	194,309
Future income tax	(24,642)	(37,087)
Non-controlling interest	-	29
Expenditures on asset retirement	(6,951)	(5,974)
Changes in non-cash working capital	(15,060)	20,303
Cash provided by operating activities	249,132	229,087
Financing Activities		
Units issued, net of costs (note 10)	104,215	141,908
Debentures redeemed (note 6)	(19,406)	-
Increase (decrease) in bank indebtedness	28,893	(30,767)
Reduction of capital lease obligations	(3,184)	(1,019)
Distributions to Unitholders	(170,915)	(185,015)
Cash used in financing activities	(60,397)	(74,893)
Investing Activities		
Expenditures on property and equipment	(148,725)	(159,487)
Property acquisitions	(16,051)	(244)
Property dispositions	1,037	8,727
Acquisition of Sound Energy Trust (note 3)	(22,307)	-
Acquisition of Ketch Resources Trust (note 3)	-	(10,109)
Changes in non-cash working capital	(2,689)	6,919
Cash used in investing activities	(188,735)	(154,194)
Net change in cash	-	-
Cash, beginning of year	-	-
Cash, end of year	\$ -	\$ -
Supplementary Cash Flow Information		
Interest paid	\$ 42,017	\$ 34,680
Taxes paid	\$ 2,062	\$ 1,783

see accompanying Notes to Consolidated Financial Statements

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

December 31, 2007

All tabular amounts in thousands except as otherwise indicated

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. Distributions from the Fund to Unitholders are entirely discretionary and 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. Distributions are announced monthly and are based on the cash available after retaining a portion to meet such spending requirements. The level of 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 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 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 affect 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) Fixed assets

(i) Petroleum and natural gas properties

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. There has been no impairment of the Fund’s petroleum and natural gas properties since inception.

(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 since inception.

(d) Distributions

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

(e) Financial instruments

Effective January 1, 2007, the Fund adopted CICA Handbook sections 3855 “Financial Instruments - Recognition and Measurement”, 3862 “Financial Instruments – Disclosures”, 3863 “Financial Instruments – Presentation”, and 3865 “Hedges”.

Section 3855 “Financial Instruments - Recognition and Measurement” establishes criteria for recognizing and measuring financial instruments including financial assets, financial liabilities and non-financial derivatives. Under this standard, all financial instruments must initially be recognized at fair value on the balance sheet. Measurement of financial instruments subsequent to the initial

recognition, as well as resulting gains and losses, are recorded based on how each financial instrument was initially classified. The Fund has classified each identified financial instrument into the following categories: held for trading, loans and receivables, held to maturity investments, available for sale financial assets, and other financial liabilities. Held for trading financial instruments are measured at fair value with gains and losses recognized in earnings immediately. Available for sale financial assets are measured at fair value with gains and losses, other than impairment losses, recognized in other comprehensive income and transferred to earnings when the asset is derecognized. Loans and receivables, held to maturity investments and other financial liabilities are recognized at amortized cost using the effective interest method and impairment losses are recorded in earnings when incurred. Upon adoption and with all new financial instruments, an election is available that allows entities to classify any financial instrument as held for trading. Only those financial assets and liabilities that must be classified as held for trading by the standard have been classified as such by the Fund. As the Fund frequently utilizes non-financial derivative instruments to manage market risk associated with volatile commodity prices, such instruments must be classified as held for trading and recorded on the balance sheet at fair value as derivative assets and liabilities. Section 3865 “Hedges” provides an alternative to recognizing gains and losses on derivatives in earnings if the instrument is designated as part of a hedging relationship and meets the necessary criteria. Under the alternative hedge accounting treatment, gains and losses on derivatives classified as effective cash flow hedges are included in other comprehensive income until the time at which the hedged item is realized. The Fund does not utilize derivative instruments for speculative purposes but has elected not to apply hedge accounting. Therefore, gains and losses on these instruments are recorded as unrealized gains and losses on derivatives in the consolidated statement of income, comprehensive income and accumulated deficit in the period they occur and as realized gains and losses on derivatives when the contracts are settled. Since unrealized gains and losses on derivatives are non-cash items, there is no impact on the statement of cash flows as a result of their recognition.

In some instances, derivative financial instruments can be embedded within other contracts. Embedded derivatives within a host contract must be recorded separately from the host contract when their economic characteristics and risks are not clearly and closely related to those of the host contract, the terms of the embedded derivatives are the same as those of a freestanding derivative, and the combined contract is not classified as held for trading or designated at fair value. The Fund selected January 1, 2003, as its accounting transition date for any potential embedded derivatives and has not identified any embedded derivatives that would require separation from the host contract and fair value accounting.

Transaction costs are frequently attributed to the acquisition or issue of a financial asset or liability. Section 3855 requires that such transaction costs incurred on held for trading financial instruments be expensed immediately. For other financial instruments, an entity can adopt an accounting policy of either expensing transaction costs as they occur or adding such transaction costs to the fair value of the financial instrument. The Fund has chosen a policy of adding transaction costs to the fair value initially recognized for financial assets and liabilities that are not classified as held for trading.

The Fund has adopted the new standards prospectively as required which allows amendments to the carrying values of financial instruments, effective as of the adoption date, to be recognized as an adjustment to the beginning balance of accumulated deficit. As the new standards have not resulted in any significant changes to the recognition and measurement of the Fund’s financial instruments, no adjustment to accumulated deficit was required. The new standards also require several additional disclosures in the notes to the financial statements. Among the disclosures required, the Fund must disclose the exposure to various risks associated with financial instruments and the policies that exist to manage these risks.

(f) Comprehensive income

Effective January 1, 2007, the Fund adopted CICA Handbook section 1530 “Comprehensive Income”. Comprehensive income consists of net income and other comprehensive income (“OCI”) with amounts included in OCI shown net of tax. Accumulated other comprehensive income is a new equity category comprised of the cumulative amounts of OCI. To date, the Fund does not have any adjustments in OCI and therefore comprehensive income is currently equal to net income.

(g) 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.

(h) 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 fixed assets. 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. 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.

(i) 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 substantially 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.

(j) Unit-based compensation

Advantage accounts for compensation expense based on the “fair value” of rights granted under its unit-based compensation plans. The Fund has Trust Units held in escrow relating to the management internalization (note 13) as well as a unit-based compensation plan for external directors of the Fund, a Restricted Trust Unit Plan and Trust Units issuable for the retention of certain employees of the Fund (note 10).

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 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.

Awards under the external directors’ unit-based compensation plan vest immediately with associated compensation expense recognized in the current period earnings and estimated forfeiture rates are not incorporated in 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.

Advantage’s current employee compensation includes a Restricted Trust Unit Plan (the “Plan”), as approved by the Unitholders on June 23, 2006, and Trust Units issuable for the retention of certain employees of the Fund. The Plan authorizes the Board of Directors to grant Restricted Trust Units (“RTUs”) to directors, officers, or employees of the Fund. The number of RTUs granted is based on the Fund’s Trust Unit return for a calendar year and compared to a peer group approved by the Board of Directors. The Trust Unit return is calculated at the end of the year and is primarily based on the year-over-year change in the Trust Unit price plus distributions. The RTU grants vest one third immediately on grant date, with the remaining two thirds vesting evenly on the following two yearly anniversary dates. The holders of RTUs may elect to receive cash upon vesting in lieu of the number of Trust Units to be issued, subject to consent of the Fund. Compensation cost related to the Plan is recognized as compensation expense over the service period and incorporates the period end Trust Unit price, the estimated number of RTUs to vest, and certain management estimates. The maximum amount of RTUs granted in any one calendar year is limited to 175% of the base salaries of those individuals participating in the Plan for such period.

(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, impairment calculations for fixed assets and goodwill, derivative fair value calculations, future income tax provisions, as well as fair values assigned to any identifiable assets and liabilities in business combinations 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, 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) Accounting changes

Effective January 1, 2007, the Fund adopted the revised recommendations of CICA section 1506 “Accounting Changes”. The new recommendations permit voluntary changes in accounting policy only if they result in financial statements which provide more reliable and relevant information. Accounting policy changes are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively and changes in accounting estimates are applied prospectively by including the changes in earnings. The guidance was effective for all changes in accounting policies, changes in accounting estimates and corrections of prior period errors initiated in periods beginning on or after January 1, 2007.

(o) Recent accounting pronouncements issued but not implemented

The CICA has issued section 1535 “Capital Disclosures”, which will be effective January 1, 2008 for the Fund. Section 1535 will require the Fund to provide additional disclosures relating to capital and how it is managed. It is not anticipated that the adoption of section 1535 will impact the amounts reported in the Fund’s financial statements as they primarily relate to disclosure.

(p) Comparative figures

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

3. Acquisitions

(a) Sound Energy Trust

On September 5, 2007, Advantage acquired all of the issued and outstanding Trust Units and Exchangeable Shares of Sound Energy Trust (“Sound”) for \$21.4 million cash consideration, 16,977,184 Advantage Trust Units and \$0.9 million of acquisition costs. Sound Unitholders and Exchangeable Shareholders could elect to receive 0.30 Advantage Trust Units for each Sound Trust Unit or receive \$0.66 in cash and 0.2557 Advantage Trust Units for each Sound Trust Unit. All of the Sound Exchangeable Shares were exchanged for Advantage Trust Units on the same ratio as the Sound Trust Units based on the conversion ratio in effect at the effective date of the acquisition. Sound 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:	
Fixed assets	\$ 509,656	16,977,184 Trust Units issued	\$ 228,852
Accounts receivable	27,433	Cash	21,403
Prepaid expenses and deposits	3,873	Acquisition costs incurred	904
Derivative asset, net	2,797		<u>\$ 251,159</u>
Bank indebtedness	(107,959)		
Convertible debentures	(101,553)		
Accounts payable and accrued liabilities	(35,396)		
Future income taxes	(29,430)		
Asset retirement obligations	(16,695)		
Capital lease obligations	(1,567)		
	<u>\$ 251,159</u>		

The value of the Trust Units 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. The allocation of the

purchase price has been revised due to the realization of estimates and is subject to further refinement as additional cost estimates and tax balances are finalized.

(b) 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:	
Fixed assets	\$ 877,463	32,870,465 Trust Units issued	\$ 688,636
Goodwill	74,798	Acquisition costs incurred	<u>10,109</u>
Accounts receivable	55,806		\$ 698,745
Prepaid expenses and deposits	6,406		
Cash	2,713		
Bank indebtedness	(191,578)		
Convertible debentures	(69,952)		
Accounts payable	(46,834)		
Asset retirement obligations	(7,930)		
Capital lease obligation	<u>(2,147)</u>		
	\$ 698,745		

The value of the Trust Units 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, 2007	Cost	Accumulated Depletion and Depreciation	Net Book Value
Petroleum and natural gas properties	\$ 3,016,243	\$ 844,671	\$2,171,572
Furniture and equipment	10,548	4,774	5,774
	\$ 3,026,791	\$ 849,445	\$2,177,346

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

During the year ended December 31, 2007, Advantage capitalized general and administrative expenditures directly related to exploration and development activities of \$9,653,000 (2006 - \$6,444,000).

Costs of \$60,238,000 (2006 - \$43,467,000) for unproved properties have been excluded from the calculation of depletion expense, and future development costs of \$190,146,000 (2006 - \$123,464,000) have been included in costs subject to depletion.

The Fund performed a ceiling test calculation at December 31, 2007 to assess the recoverable value of fixed assets. 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)
2008	\$ 89.61	\$ 1.00	\$ 6.51
2009	\$ 86.01	\$ 1.00	\$ 7.22
2010	\$ 84.65	\$ 1.00	\$ 7.69
2011	\$ 82.77	\$ 1.00	\$ 7.70
2012	\$ 82.26	\$ 1.00	\$ 7.61
2013	\$ 82.81	\$ 1.00	\$ 7.78
Approximate escalation rate after 2013	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 fixed assets. Future minimum lease payments at December 31, 2007 consist of the following:

2008	\$ 1,906
2009	2,040
2010	2,200
2011	1,925
	8,071
Less amounts representing interest	(881)
	7,190
Current portion	(1,537)
	\$ 5,653

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%.

During the second quarter of 2007, Advantage entered a new lease arrangement that resulted in the recognition of a fixed asset addition and capital lease obligation of \$4.1 million. The lease obligation bears interest at 5.8% and is secured by the related equipment. The lease term expires June 2011 with a final purchase obligation of \$1.5 million at which time ownership of the equipment will transfer to Advantage.

Effective September 4, 2007, Advantage entered a new lease arrangement that resulted in the recognition of a fixed asset addition and capital lease obligation of \$1.8 million. The lease obligation bears interest at 6.7% and is secured by the related equipment. The lease term expires August 2010 with a final payment obligation of \$0.7 million. Distributions to Unitholders are not permitted if the Fund is in default of such capital lease.

On September 5, 2007, Advantage assumed two capital lease obligations in the acquisition of Sound (note 3) resulting in the recognition of capital lease obligations of \$1.6 million. Both of the lease obligations bear interest at 5.6% and are secured by the related equipment. The lease terms expire December 2009 and April 2010 with a total final payment obligation of \$0.9 million.

Fixed assets subject to capital leases are depreciated 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 is included in depletion and depreciation expense.

6. 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%	8.75%	
Trading symbol	AVN.DB	AVN.DBA	AVN.DBB	AVN.DBF	
Issue date	Oct. 18, 2002	July 8, 2003	Dec. 2, 2003	June 10, 2004	
Maturity date	Matured	Aug. 1, 2008	Feb. 1, 2009	June 30, 2009	
Conversion price	Matured	\$ 17.00	\$ 16.50	\$ 34.67	
Liability component	\$ 52,722	\$ 28,662	\$ 56,802	\$ 48,700	
Equity component	2,278	1,338	3,198	11,408	
Gross proceeds	55,000	30,000	60,000	60,108	
Issuance costs	(2,495)	(1,444)	(2,588)	-	
Net proceeds	\$ 52,505	\$ 28,556	\$ 57,412	\$ 60,108	
	7.50%	6.50%	7.75%	8.00%	Total
Trading symbol	AVN.DBC	AVN.DBE	AVN.DBD	AVN.DBG	
Issue date	Sep. 15, 2004	May 18, 2005	Sep. 15, 2004	Nov. 13, 2006	
Maturity date	Oct. 1, 2009	June 30, 2010	Dec. 1, 2011	Dec. 31, 2011	
Conversion price	\$ 20.25	\$ 24.96	\$ 21.00	\$ 20.33	
Liability component	\$ 71,631	\$ 66,981	\$ 47,444	\$ 14,884	\$ 387,826
Equity component	3,369	2,971	2,556	26,561	53,679
Gross proceeds	75,000	69,952	50,000	41,445	441,505
Issuance costs	(3,190)	-	(2,190)	-	(11,907)
Net proceeds	\$ 71,810	\$ 69,952	\$ 47,810	\$ 41,445	\$ 429,598

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
9.00%	After August 1, 2007 and before August 1, 2008	\$1,025
8.25%	After February 1, 2007 and on or before February 1, 2008	\$1,050
	After February 1, 2008 and before February 1, 2009	\$1,025
8.75%	After June 30, 2007 and on or before June 30, 2008	\$1,050
	After June 30, 2008 and before June 30, 2009	\$1,025
7.50%	After October 1, 2007 and on or before October 1, 2008	\$1,050
	After October 1, 2008 and before October 1, 2009	\$1,025
6.50%	After June 30, 2008 and on or before June 30, 2009	\$1,050
	After June 30, 2009 and before June 30, 2010	\$1,025
7.75%	After December 1, 2007 and on or before December 1, 2008	\$1,050
	After December 1, 2008 and on or before December 1, 2009	\$1,025
	After December 1, 2009 and before December 1, 2011	\$1,000
8.00%	After December 31, 2009 and on or before December 31, 2010	\$1,050
	After December 31, 2010 and before December 31, 2011	\$1,025

The balance of debentures outstanding at December 31, 2007 and changes in the liability and equity components during the years ended December 31, 2007 and 2006 are as follows:

	10.00%	9.00%	8.25%	8.75%
Debentures outstanding	\$ -	\$ 5,392	\$ 4,867	\$ 29,839
Liability component:				
Balance at Dec. 31, 2005	\$ 2,453	\$ 7,259	\$ 8,150	\$ -
Assumed on Ketch acquisition	-	-	-	-
Accretion of discount	30	107	103	-
Converted to Trust Units	(1,019)	(2,131)	(3,577)	-
Balance at Dec. 31, 2006	1,464	5,235	4,676	-
Assumed on Sound acquisition	-	-	-	48,700
Accretion of discount	22	98	91	96
Converted to Trust Units	(1,486)	-	-	(8)
Redeemed for cash	-	-	-	(19,406)
Balance at Dec. 31, 2007	\$ -	\$ 5,333	\$ 4,767	\$ 29,382
Equity component:				
Balance at Dec. 31, 2005	\$ 100	\$ 323	\$ 441	\$ -
Assumed on Ketch acquisition	-	-	-	-
Converted to Trust Units	(41)	(94)	(193)	-
Balance at Dec. 31, 2006	59	229	248	-
Assumed on Sound acquisition	-	-	-	11,408
Converted to Trust Units	-	-	-	(10,556)
Expired	(59)	-	-	-
Balance at Dec. 31, 2007	\$ -	\$ 229	\$ 248	\$ 852

	7.50%	6.50%	7.75%	8.00%	Total
Debentures outstanding	\$ 52,268	\$ 69,952	\$ 46,766	\$ 15,528	\$ 224,612
Liability component:					
Balance at Dec. 31, 2005	\$ 62,321	\$ -	\$ 45,898	\$ -	\$ 126,081
Assumed on Ketch acquisition	-	66,981	-	-	66,981
Accretion of discount	897	380	589	-	2,106
Converted to Trust Units	(13,436)	-	(2,722)	-	(22,885)
Balance at Dec. 31, 2006	49,782	67,361	43,765	-	172,283
Assumed on Sound acquisition	-	-	-	14,884	63,584
Accretion of discount	889	731	595	47	2,569
Converted to Trust Units	-	-	-	-	(1,494)
Redeemed for cash	-	-	-	-	(19,406)
Balance at Dec. 31, 2007	\$ 50,671	\$ 68,092	\$ 44,360	\$ 14,931	\$ 217,536
Equity component:					
Balance at Dec. 31, 2005	\$ 2,865	\$ -	\$ 2,430	\$ -	\$ 6,159
Assumed on Ketch acquisition	-	2,971	-	-	2,971
Converted to Trust Units	(617)	-	(144)	-	(1,089)
Balance at Dec. 31, 2006	2,248	2,971	2,286	-	8,041
Assumed on Sound acquisition	-	-	-	26,561	37,969
Converted to Trust Units	-	-	-	(25,763)	(36,319)
Expired	-	-	-	-	(59)
Balance at Dec. 31, 2007	\$ 2,248	\$ 2,971	\$ 2,286	\$ 798	\$ 9,632

As part of the acquisition of Ketch (note 3), the 6.50% convertible debentures, originally issued May 18, 2005, were assumed by Advantage on June 23, 2006.

Due to the acquisition of Sound (note 3), 8.75% and 8.00% convertible debentures were assumed by Advantage on September 5, 2007. As a result of the change in control of Sound, the Fund was required by the debenture indentures to make an offer to purchase all of the outstanding convertible debentures assumed from Sound at a price equal to 101% of the principal amount plus accrued and unpaid interest. On October 17, 2007, the expiry date of the offer, 911,709 Trust Units were issued and \$19.9 million in total cash consideration was paid in exchange for \$29,665,000 8.75% convertible debentures and 2,220,289 Trust Units were issued in exchange for \$25,507,000 8.0% convertible debentures.

During the year ended December 31, 2007, \$24,000 debentures (2006 - \$24,333,000) were converted resulting in the issuance of 1,386 Trust Units (2006 - 1,286,901 Trust Units) and all of the remaining \$1,470,000 10% convertible debentures matured on November 1, 2007 and were settled with the issuance of 127,493 Trust Units.

7. Bank Indebtedness

Advantage has a credit facility agreement with a syndicate of financial institutions which provides for a \$690 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 with the next renewal due in June 2008. 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 3.5:1, 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, 2007, the effective interest rate on the outstanding amounts under the facility was approximately 5.7% (2006 - 5.1%).

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 \$243.9 million which will be incurred between 2008 to 2057. A credit-adjusted risk-free rate of 7% and an inflation factor of 2% were 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, 2007	Year ended December 31, 2006
Balance, beginning of year	\$ 34,324	\$ 21,263
Accretion expense	2,795	1,684
Assumed in Sound acquisition (note 3)	16,695	-
Assumed in Ketch acquisition (note 3)	-	7,930
Liabilities incurred	13,972	9,421
Liabilities settled	(6,951)	(5,974)
Balance, end of year	\$ 60,835	\$ 34,324

9. 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 December 14, 2007, the Federal government enacted legislation phasing in corporate income tax rate reductions which will reduce federal tax rates from 22.1% to 15.0% by 2012. Rate reductions will also apply to the new tax on distributions of income trusts and other specified investment flow-through entities as of 2011, reducing the tax rate in 2011 to 29.5% and in 2012 to 28.0%. These rates include a deemed provincial rate of 13%.

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, 2007	Year ended December 31, 2006
Income (loss) before taxes	\$ (30,733)	\$ 14,265
Canadian combined federal and provincial income tax rates	32.57%	34.78%
Expected income tax expense (recovery) at statutory rates	(10,011)	4,961
Increase (decrease) in income taxes resulting from:		
Amounts included in trust income	(57,766)	(39,940)
Change in enacted tax rates	550	(5,692)
Management internalization	4,554	4,678
Specified Investment Flow-Through	42,862	-
Non-deductible Crown charges	-	6,925
Resource allowance	-	(8,108)
Other	(4,831)	89
Future income tax reduction	(24,642)	(37,087)
Income and capital taxes	1,444	1,509
	\$ (23,198)	\$ (35,578)

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

	December 31, 2007	December 31, 2006
Fixed assets in excess of tax basis	\$ 29,240	\$ 85,648
Asset retirement obligations	(16,330)	(10,141)
Non-capital tax loss carry forward	(20,369)	(8,851)
Trust assets in excess of tax basis	82,642	-
Other	(8,456)	(4,717)
Future income tax liability	\$ 66,727	\$ 61,939

AOG has a non-capital tax loss carry forward of approximately \$76 million of which \$1 million expires in 2008, \$18 million in 2011, \$11 million in 2012 and \$46 million after 2020.

10. Unitholders' Equity

(a) Unitholders' capital

(i) Authorized

Unlimited number of voting Trust Units

(ii) Issued

	Number of Units	Amount
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
Issued for 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
Balance at December 31, 2006	105,390,470	1,618,025
Issued on conversion of debentures	128,879	1,494
Issued on exercise of Trust Unit rights	37,500	562
Issued for cash, net of costs	8,600,000	104,094
Distribution reinvestment plan	4,028,252	46,657
Issued for Sound acquisition, net of costs (note 3)	16,977,184	228,583
Issued on offer to purchase Sound debentures (note 6)	3,131,998	37,209
Management internalization forfeitures	(24,909)	(503)
	138,269,374	\$ 2,036,121
Management internalization escrowed Trust Units		(9,056)
Balance at December 31, 2007		\$ 2,027,065

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 over a 3-year period, vesting one-third each year beginning June 23, 2007 (note 13). For the year ended December 31, 2007, a total of 24,909 Trust Units issued for the management internalization were forfeited (2006 – 19,366 Trust Units) and \$15.7 million has been recognized as management internalization expense (2006 - \$13.4 million). As at December 31, 2007, 1,193,622 Trust Units remain held in escrow (December 31, 2006 – 1,822,098 Trust Units). The Fund also issued 117,662 Trust Units on June 23, 2006, 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, 2007, 4,028,252 Trust Units (2006 - 2,005,499 Trust Units) were issued under the Plan, generating \$46.7 million (2006 - \$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.

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 \$104.1 million (net of Underwriters' fees and other issue costs of \$6.0 million).

On September 5, 2007, Advantage issued 16,977,184 Trust Units, valued at \$228.9 million, as partial consideration for the acquisition of Sound (note 3). Trust Unit issuance costs of \$0.3 million were incurred for the Sound acquisition.

Due to the acquisition of Sound (note 3), 8.75% and 8.00% convertible debentures were assumed by Advantage on September 5, 2007. As a result of the change in control of Sound, the Fund was required by the debenture indentures to make an offer to purchase all of the outstanding convertible debentures assumed from Sound at a price equal to 101% of the principal amount plus accrued and unpaid interest. On October 17, 2007, the expiry date of the offer, 911,709 Trust Units were issued and \$19.9 million in total cash consideration was paid in exchange for \$29,665,000 8.75% convertible debentures and 2,220,289 Trust Units were issued in exchange for \$25,507,000 8.0% convertible debentures.

(b) Contributed surplus

	Year ended December 31, 2007	Year ended December 31, 2006
Balance, beginning of year	\$ 863	\$ 1,036
Unit-based compensation	1,255	-
Expiration of convertible debentures equity component	59	-
Exercise of Trust Unit Rights	(172)	(173)
Balance, end of year	\$ 2,005	\$ 863

(c) 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 B	
	Number	Price
Balance at December 31, 2005	225,000	\$ 13.63
Exercised	(37,500)	-
Reduction of exercise price	-	(2.66)
Balance at December 31, 2006	187,500	10.97
Exercised	(37,500)	-
Reduction of exercise price	-	(1.77)
Balance at December 31, 2007	150,000	\$ 9.20
Expiration date	June 17, 2008	

(d) Unit-based compensation

Advantage's current employee compensation includes a Restricted Trust Unit Plan (the "Plan"), as approved by the Unitholders on June 23, 2006, and Trust Units issuable for the retention of certain employees of the Fund. The purpose of the long-term compensation plans is to retain and attract employees, to reward and encourage performance, and to focus employees on operating and financial performance that results in lasting Unitholder return.

The Plan authorizes the Board of Directors to grant Restricted Trust Units ("RTUs") to directors, officers, or employees of the Fund. The number of RTUs granted is based on the Fund's Trust Unit return for a calendar year and compared to a peer group approved by the Board of Directors. The Trust Unit return is calculated at the end of the year and is primarily based on the year-over-year change in the Trust Unit price plus distributions. The RTU grants vest one third immediately on grant date, with the remaining two thirds vesting evenly on the following two yearly anniversary dates. The holders of RTUs may elect to receive cash upon vesting in lieu of the number of Trust Units to be issued, subject to consent of the Fund. As the Fund did not meet the 2007 or 2006 grant thresholds, there were no RTU grants made during these years.

For the year ended December 31, 2007, the Fund has accrued unit-based compensation expense of \$0.9 million recorded in general and administrative expense (December 31, 2006 – nil) and has capitalized \$0.3 million (December 31, 2006 – nil) related to Trust Units issuable for the retention of certain employees of the Fund.

(e) Net income (loss) per Trust Unit

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

	Year ended December 31, 2007	Year ended December 31, 2006
Income (loss) available to Unitholders		
Basic and Diluted	\$ (7,535)	\$ 49,814
Weighted average Trust Units outstanding		
Basic	119,604,019	80,958,455
Trust Units Rights Incentive Plan – Series A	-	43,548
Trust Units Rights Incentive Plan – Series B	-	78,287
Management Internalization	-	113,556
Diluted	119,604,019	81,193,846

The calculation of diluted net income per Trust Unit excludes all series of convertible debentures for the years as the impact would be 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, 2007 were 9,083,663 (2006 – 7,182,276). As at December 31, 2007, the total convertible debentures outstanding were immediately convertible to 9,847,253 Trust Units (2006 – 8,334,453).

All of the Series B Trust Unit Rights and Management Internalization escrowed Trust Units have been excluded from the calculation of diluted net income per Trust Unit for the year ended December 31, 2007, as the impact would be anti-dilutive. Total weighted average Trust Units issuable in exchange for the Series B Trust Unit Rights and Management Internalization escrowed Trust Units and excluded from the diluted net income per Trust Unit calculation for the year ended December 31, 2007 were 42,918 and 582,861, respectively. All of the remaining Series A Trust Unit Rights were exercised July 7, 2006.

Exchangeable Shares have been excluded from the calculation of diluted net income per Trust Unit for the year ended December 31, 2006 as the impact would have been anti-dilutive. All of the remaining Exchangeable Shares were redeemed May 9, 2006. Total weighted average Trust Units issuable in exchange for the Exchangeable Shares and excluded from the diluted net income per Trust Unit calculation for the year ended December 31, 2006 were 36,448.

11. Accumulated Deficit

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

	December 31, 2007	December 31, 2006
Accumulated Income	\$ 219,988	\$ 227,523
Accumulated Distributions	(879,823)	(664,629)
Accumulated Deficit	\$ (659,835)	\$ (437,106)

The Fund has historically paid distributions in excess of accumulated income as distributions are typically based on cash flows generated in the period while accumulated income is based on such cash flows less other non-cash charges such as depletion, depreciation, and accretion expense recorded on the original investment in petroleum and natural gas properties and management internalization expense. For the year ended December 31, 2007 the Fund declared \$215.2 million in distributions representing \$1.77 per distributable Trust Unit (2006 - \$217.2 million in distributions representing \$2.66 per distributable Trust Unit).

12. Financial Instruments

Financial instruments of the Fund include accounts receivable, deposits, accounts payable and accrued liabilities, distributions payable to Unitholders, bank indebtedness, convertible debentures and derivative assets and liabilities.

Accounts receivable and deposits are classified as loans and receivables and measured at amortized cost. Accounts payable and accrued liabilities, distributions payable to Unitholders and bank indebtedness are all classified as other liabilities and similarly measured at amortized cost. As at December 31, 2007, 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.

The Fund has convertible debenture obligations outstanding, of which the liability component has been classified as other liabilities and measured at amortized cost. The convertible debentures have different fixed terms and interest rates (note 6) resulting in fair values that will vary over time as market conditions change. As at December 31, 2007, the estimated fair value of the total outstanding convertible debenture obligation was \$215.4 million (December 31, 2006 - \$180.0 million). The fair value of the liability component of convertible debentures was determined primarily based on a discounted cash flow model assuming no future conversions and continuation of current interest and principal payments as well as taking into consideration the current public trading activity of such debentures. The Fund applied discount rates of between 7 and 8% considering current available market information, assumed credit adjustments, and various terms to maturity.

Advantage has an established strategy to manage the risk associated with changes in commodity prices by entering into derivatives, which are recorded at fair value as derivative assets and liabilities with gains and losses recognized through earnings. As the fair value of the contracts varies with commodity prices, they give rise to financial assets and liabilities. The fair values of the derivatives are determined through valuation models completed by third parties. Various assumptions based on current market information were used in these valuations, including settled forward commodity prices, interest rates, foreign exchange rates, volatility and other relevant factors. The actual gains and losses realized on eventual cash settlement can vary materially due to subsequent fluctuations in commodity prices as compared to the valuation assumptions.

Credit Risk

Accounts receivable, deposits, and derivative assets are subject to credit risk exposure and the carrying values reflect Management's assessment of the associated maximum exposure to such credit risk. Substantially all of the Fund's accounts receivable are due from customers and joint operation partners concentrated in the Canadian oil and gas industry. As such, accounts receivable are subject to normal industry credit risks. Advantage mitigates such credit risk by closely monitoring significant counterparties and dealing with a broad selection of partners that diversify risk within the sector. The Fund's deposits are primarily due from the Alberta Provincial government and are viewed by Management as having minimal associated credit risk. To the extent that Advantage enters derivatives to manage commodity price risk, it may 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. In addition, the Fund generally enters into derivative contracts with investment grade institutions that are members of Advantage's credit facility syndicate to further mitigate associated credit risk.

Liquidity Risk

The Fund is subject to liquidity risk attributed from accounts payable and accrued liabilities, distributions payable to Unitholders, bank indebtedness, convertible debentures, and derivative liabilities. Accounts payable and accrued liabilities, distributions payable to Unitholders and derivative liabilities are primarily due within one year of the balance sheet date and Advantage does not anticipate any problems in satisfying the obligations due to the strength of cash provided by operating activities and the existing credit facility. The Fund's bank indebtedness is subject to a \$710 million credit facility agreement which mitigates liquidity risk by enabling Advantage to manage interim cash flow fluctuations. The credit facility constitutes 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 terms of the credit facility are such that it provides Advantage adequate flexibility to evaluate and assess liquidity issues if and when they arise. Additionally, the Fund regularly monitors liquidity related to obligations by evaluating forecasted cash flows, optimal debt levels, capital spending activity, working capital requirements, and other potential cash expenditures. This continual financial assessment process further enables the Fund to mitigate liquidity risk.

Advantage has several series of convertible debentures outstanding that mature from 2008 to 2011 (note 6). Interest payments are made semi-annually with excess cash provided by operating activities. As the debentures become due, the Fund can satisfy the obligations in cash or issue Trust Units at a price determined in the applicable debenture agreements. This settlement alternative allows the Fund to adequately manage liquidity, plan available cash resources and implement an optimal capital structure.

To the extent that Advantage enters derivatives to manage commodity price risk, it may be subject to liquidity risk as derivative liabilities become due. While the Fund has elected not to follow hedge accounting, derivative instruments are not entered for speculative purposes and Management closely monitors existing commodity risk exposures. As such, liquidity risk is mitigated since any losses actually realized are subsidized by increased cash flows realized from the higher commodity price environment.

Interest Rate Risk

The Fund is exposed to interest rate risk to the extent that bank indebtedness is at a floating rate of interest and the Fund's maximum exposure to interest rate risk is based on the effective interest rate and the current carrying value of the bank indebtedness. The Fund monitors the interest rate markets to ensure that appropriate steps can be taken if interest rate volatility compromises the Fund's cash flows. A 1% interest rate fluctuation for the year ended December 31, 2007 could potentially have impacted net income by approximately \$3.0 million for that period.

Price and Currency Risk

Advantage's derivative assets and liabilities are subject to both price and currency risks as their fair values are based on assumptions including forward commodity prices and foreign exchange rates. The Fund enters derivative financial instruments to manage commodity price risk exposure relative to actual commodity production and does not utilize derivative instruments for speculative purposes. Changes in the price assumptions can have a significant effect on the fair value of the derivative assets and liabilities and thereby impact net income. It is estimated that a 10% change in the forward natural gas prices used to calculate the fair value of the natural gas derivatives at December 31, 2007 could impact net income by approximately \$8.7 million for the year ended December 31, 2007. As well, a change of 10% in the forward crude oil prices used to calculate the fair value of the crude oil derivatives at December 31, 2007 could impact net income by \$3.7 million for the year ended December 31, 2007. A change of 10% in the forward power prices used to calculate the fair value of the power derivatives at December 31, 2007 could impact net income by \$0.1 million for the year ended December 31, 2007. A similar change in the currency rate assumption underlying the derivatives fair value does not have a material impact on net income.

As at December 31, 2007 the Fund had the following derivatives in place:

Description of Derivative	Term	Volume	Average Price
Natural gas - AECO			
Fixed price	November 2007 to March 2008	7,109 mcf/d	Cdn\$9.54/mcf
Fixed price	April 2008 to October 2008	14,217 mcf/d	Cdn\$6.85/mcf
Fixed price	April 2008 to March 2009	14,217 mcf/d	Cdn\$7.10/mcf
Fixed price	April 2008 to March 2009	14,217 mcf/d	Cdn\$7.06/mcf
Fixed price	November 2008 to March 2009	14,217 mcf/d	Cdn\$7.77/mcf
Collar	November 2007 to March 2008	9,478 mcf/d	Floor Cdn\$8.44/mcf Ceiling Cdn\$10.29/mcf
Collar	November 2007 to March 2008	7,109 mcf/d	Floor Cdn\$8.70/mcf Ceiling Cdn\$10.71/mcf
Crude oil – WTI			
Fixed price	February 2008 to January 2009	2,000 bbls/d	Cdn\$90.93/bbl
Collar	February 2008 to January 2009	2,000 bbls/d	Sold put Cdn\$70.00/bbl Purchase call Cdn\$105.00/bbl Cost Cdn\$1.52/bbl
Electricity – Alberta Pool Price			
Fixed price	January 2008 to December 2008	3.0 MW	Cdn\$54.00/MWh

As at December 31, 2007, the fair value of the derivatives outstanding resulted in an asset of approximately \$7,201,000 (December 31, 2006 – \$10,433,000) and a liability of approximately \$5,020,000 (December 31, 2006 – nil). For the year ended December 31, 2007, \$11,049,000 was recognized in income as an unrealized derivative loss (December 31, 2006 - \$10,242,000 unrealized derivative gain) and \$18,594,000 was recognized in income as a realized derivative gain (December 31, 2006 – \$5,297,000).

As a result of the Sound acquisition (note 3), the Fund assumed several derivatives, which had an estimated net fair market value of \$2,797,000 on closing.

13. 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. For the year ended December 31, 2007, a total of 24,909 Trust Units issued for the management internalization were forfeited (2006 – 19,366 Trust Units) and \$15.7 million has been recognized as management internalization expense (2006 - \$13.4 million). As at December 31, 2007, 1,193,622 Trust Units remain held in escrow (2006 – 1,822,098 Trust Units). 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 and were paid quarterly.

The Manager of the Fund was also 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 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.

14. Commitments

Advantage has several lease commitments relating to office buildings. The Fund has assumed office lease commitments from prior corporate acquisitions and has renegotiated leases to accommodate the growth of the Fund. The estimated annual minimum operating lease rental payments for buildings are as follows:

2008	\$ 5,319
2009	4,111
2010	4,127
2011	1,731
2012	1,314
	<hr/>
	\$16,602

15. Reconciliation of Financial Statements to United States Generally Accepted Accounting Principles

The consolidated financial statements of Advantage have been prepared in accordance with accounting principles generally accepted in Canada. Canadian GAAP, in most respects, conforms to generally accepted accounting principles in the United States. Any differences in accounting principles between Canadian GAAP and US GAAP, as they apply to Advantage, are not material, except as described below.

(a) Unit-based compensation

Advantage accounts for compensation expense based on the fair value of the equity awards on the grant date and the initial fair value is not subsequently remeasured. Advantage's unit-based compensation consists of a Trust Units Rights Incentive Plan, Trust Units held in escrow subject to service requirement provisions, and Trust Units issuable for the retention of certain employees of the Fund. The initial fair value is expensed over the vesting period of the Trust Units or rights granted.

Under US GAAP, the Fund adopted SFAS 123(R) "Share-Based Payment" on January 1, 2006 using the modified prospective approach and applies the fair value method of accounting for all Unit-based compensation granted after January 1, 2006. A US GAAP difference exists as unit-based compensation grants are considered liability awards for US GAAP and equity awards for Canadian GAAP. Under US GAAP, the fair value of a liability award is measured at the grant date and is subsequently remeasured at each reporting period. When the rights are exercised and the Trust Units vested, the amount recorded as a liability is recognized as temporary equity and the fair value at adoption of the new standard has been charged to income as the cumulative effect of a change in accounting policy.

(b) Convertible debentures

The Fund applies CICA 3863 "Financial Instruments – Presentation" in accounting for convertible debentures which results in their classification as liabilities. The convertible debentures also have an embedded conversion feature which must be 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, net of issuance costs, as compared to maturity value is accreted by the effective interest method over the debenture term. As debentures are converted to Trust Units, an appropriate portion of the liability and equity components are transferred to Unitholders' capital. Interest and accretion expense on the convertible debentures are shown on the Consolidated Statements of Income.

Under US GAAP, the entire convertible debenture balance would be shown as a liability. The embedded conversion feature would not be accounted for separately as a component of equity. Additionally, under US GAAP, issuance costs are generally shown as a deferred charge rather than netted from the convertible debenture balance. As a result of these US GAAP differences, the convertible debenture balance in liabilities represents the actual maturity value of the outstanding debentures. Issuance costs are shown separately as a deferred charge and are amortized to interest expense over the term of the debenture. Given that the convertible debentures are carried at maturity value, it is not necessary to accrete the balance over the term of the debentures which results in an expense reduction. Interest and accretion on convertible debentures represents interest expense on the convertible debentures and amortization of the associated deferred issuance costs.

(c) Depletion and depreciation

For Canadian GAAP, depletion of petroleum and natural gas properties and depreciation of lease and well equipment is provided on accumulated costs using the unit-of-production method based on estimated net proved petroleum and natural gas reserves, before royalties, based on forecast prices and costs.

US GAAP provides for a similar accounting methodology except that estimated net proved petroleum and natural gas reserves are net of royalties and based on constant prices and costs. Therefore, depletion and depreciation under US GAAP will be different since changes to royalty rates will impact both proved reserves and production and differences between constant prices and costs as compared to forecast prices and costs will impact proved reserve volumes. Additionally, differences in depletion and depreciation will result in divergence of net book value for Canadian GAAP and US GAAP from year-to-year and impact future depletion and depreciation expense as well as the net book value utilized for future ceiling test calculations.

(d) Ceiling test

Under Canadian GAAP, petroleum and natural gas assets are evaluated each reporting period to determine that the carrying amount 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 cash flows are estimated using expected future product prices and costs and are discounted using a risk-free interest rate. For Canadian GAAP purposes, Advantage has not recognized an impairment loss since inception.

Under US GAAP, the carrying amounts of petroleum and natural gas assets, net of deferred income taxes, shall not exceed an amount equal to the sum of the present value of estimated net future after-tax cash flows of proved reserves (at current prices and costs as of the balance sheet date) computed using a discount factor of ten percent plus the lower of cost or estimated fair value of unproved properties. Any excess is charged to expense as an impairment loss. Under US GAAP, Advantage recognized an impairment loss of \$49.5 million in 2001, \$28.3 million net of tax, and an impairment loss of \$535.4 million in 2006, \$477.8 million net of tax. The impairment loss decreases net book value of property and equipment which reduces depletion and depreciation expense subsequently recorded as well as future ceiling test calculations.

(e) Income tax

The future income tax accounting standard under Canadian GAAP is substantially similar to the deferred income tax approach as required by US GAAP. Pursuant to Canadian GAAP, substantively enacted tax rates are used to calculate future income tax, whereas US GAAP applies enacted tax rates. However, there were no tax rate differences for the years ended December 31, 2007 and 2006. The differences between Canadian GAAP and US GAAP relate to future income tax impact on GAAP differences for fixed assets.

Under US GAAP, an entity that is subject to income tax in multiple jurisdictions is required to disclose income tax expense in each jurisdiction. The total amount of income taxes in 2006 and 2007 is entirely at the provincial level.

(f) Unitholders' equity

Unitholders' equity of Advantage consists primarily of Trust Units. The Trust Units are redeemable at any time on demand by the holders, which is required for the Fund to retain its Canadian mutual fund trust status. The holders are entitled to receive a price per Trust Unit equal to the lesser of: (i) 85% of the simple average of the closing market prices of the Trust Units, on the principal market on which the Trust Units are quoted for trading, during the 10 trading-day period commencing immediately after the date on which the Trust Units are surrendered for redemption; and (ii) the closing market price on the principal market on which the Trust Units are quoted for trading on the redemption date. For Canadian GAAP purposes, the Trust Units are considered permanent equity and are presented as a component of Unitholders' equity.

Under US GAAP, it is required that equity with a redemption feature be presented as temporary equity between the liability and equity sections of the balance sheet. The temporary equity is shown at an amount equal to the redemption value based on the terms of the Trust Units. Changes in the redemption value from year-to-year are charged to deficit. All components of Unitholders' equity related to Trust Units are eliminated. When calculating net income per Trust Unit, increases in the redemption value during a period results in a reduction of net income available to Unitholders while decreases in the redemption value increases net income available to Unitholders. For the years ended December 31, 2007 and 2006, net income available to Unitholders was increased by \$390.3 million and \$898.0 million corresponding to changes in the Trust Units redemption value for the respective periods.

A continuity schedule of significant equity accounts for each reporting period is required disclosure under US GAAP. The following table is a continuity of deficit, the Fund's only significant equity account:

Deficit (thousands of Canadian dollars)	Year ended December 31, 2007	Year ended December 31, 2006
Balance, beginning of year	\$ (402,158)	\$ (665,627)
Net income (loss) and comprehensive income (loss)	50,610	(417,274)
Distributions declared	(215,194)	(217,246)
Change in redemption value of temporary equity	390,349	897,989
Balance, end of year	\$ (176,393)	\$ (402,158)

(g) Balance Sheet Disclosure

US GAAP requires disclosure of certain line items for balances that would be aggregated in the Canadian GAAP financials. The following are the additional line items to be disclosed for accounts receivable and accounts payable:

(thousands of Canadian dollars)	December 31, 2007	December 31, 2006
Accounts receivable		
Trade receivables	\$ 94,959	\$ 78,698
Other receivables	515	839
Total accounts receivable	\$ 95,474	\$ 79,537

(thousands of Canadian dollars)	December 31, 2007	December 31, 2006
Accounts payable and accrued liabilities		
Accounts payable	\$ 72,691	\$ 75,500
Accrued liabilities	48,994	39,999
Other payables	402	610
Total accounts payable and accrued liabilities	\$ 122,087	\$ 116,109

(h) Statements of cash flow

The differences between Canadian GAAP and US GAAP have not resulted in any significant variances concerning the statements of cash flows as reported.

(i) Ketch acquisition

On June 23, 2006, Advantage acquired all of the issued and outstanding Trust Units of Ketch to benefit from an increase in property diversification, the ability to pursue a greater range of high impact growth opportunities available to a larger entity and complimentary summer/winter drilling programs. The merger provides increased liquidity and presence in the Canadian markets as well as greater exposure to the United States capital markets for previous Ketch Unitholders through Advantage's NYSE listing.

The purchase price for the acquisition and resulting goodwill is due to both US and Canadian GAAP requiring the purchase price to be determined using Trust Unit prices at the announcement date, while the fair value of the assets and liabilities is determined at the closing date of the acquisition. As commodity prices decreased significantly between the announcement and closing dates, the fair value of the assets acquired also decreased and as a result, goodwill was recorded.

(j) Sound acquisition

On September 5, 2007, Advantage acquired all of the issued and outstanding Trust Units and Exchangeable Shares of Sound. The accounting for business combinations is effectively the same under US and Canadian GAAP. However, the purchase price under US GAAP is different as a result of AOG realizing a future income tax asset from previously unrecognized temporary differences. The purchase price under US GAAP has been allocated as follows:

Net assets acquired and liabilities assumed:		Consideration:	
Fixed assets	\$ 480,226	16,977,184 Trust Units issued	\$ 228,852
Future income tax asset	29,430	Cash	21,403
Accounts receivable	27,433	Acquisition costs incurred	<u>904</u>
Prepaid expenses and deposits	3,873		<u>\$ 251,159</u>
Derivative asset, net	2,797		
Bank indebtedness	(107,959)		
Convertible debentures	(101,553)		
Accounts payable and accrued liabilities	(35,396)		
Future income tax liability	(29,430)		
Asset retirement obligations	(16,695)		
Capital lease obligations	<u>(1,567)</u>		
	<u>\$ 251,159</u>		

(k) Recent US Accounting Pronouncements Issued But Not Implemented

SFAS 157 Fair Value Measurements: This Statement defines fair value, establishes a framework for measuring fair value in GAAP, and expands disclosures about fair value measurements. This Statement applies under other accounting pronouncements that require or permit fair value measurements. Accordingly, this Statement does not require any new fair value measurements. The implementation effective date for this standard is as of the beginning of the first interim or annual reporting period that begins after November 15, 2007. The Fund has assessed the impact of this interpretation and does not anticipate any significant impact on the consolidated financial statements.

SFAS 141 (R) Business Combinations: This Statement requires assets and liabilities acquired in a business combination, contingent consideration, and certain acquired contingencies to be measured at their fair values as of the date of acquisition. In addition, acquisition-related and restructuring costs are to be recognized separately from the business combination. This standard applies to business combinations entered into after January 1, 2009. The Fund has not yet assessed the full impact, if any, of this standard on the consolidated financial statements.

The application of US GAAP would have the following effect on net income as reported:

Consolidated Statements of Income and Comprehensive Income (thousands of Canadian dollars, except for per Trust Unit amounts)	Year ended December 31, 2007	Year ended December 31, 2006
Net income (loss) – Canadian GAAP, as reported	\$ (7,535)	\$ 49,814
US GAAP Adjustments:		
General and administrative – note 15 (a)	606	1,453
Management internalization – note 15(a)	7,450	4,684
Interest and accretion on convertible debentures – note 15(b)	1,741	1,254
Depletion, depreciation and accretion – notes 15(c) and (d)	72,990	(528,734)
Future income tax reduction – note 15(e)	(24,642)	55,526
Net income (loss) before cumulative effect of a change in accounting principle	50,610	(416,003)
Cumulative effect of a change in accounting principle – note 15(a)	-	(1,271)
Net income (loss) and comprehensive income (loss) – US GAAP	\$ 50,610	\$(417,274)
Net income (loss) per Trust Unit before cumulative effect of a change in accounting principle – US GAAP:		
Basic	\$ 0.42	\$ (5.14)
Diluted	\$ 0.42	\$ (5.14)
Net income (loss) per Trust Unit before change in redemption value of Trust Units – US GAAP:		
Basic	\$ 0.42	\$ (5.15)
Diluted	\$ 0.42	\$ (5.15)
Net income per Trust Unit – US GAAP:		
Basic	\$ 3.69	\$ 5.94
Diluted	\$ 3.54	\$ 5.59

The application of US GAAP would have the following effect on the balance sheets as reported:

Consolidated Balance Sheets (thousands of Canadian dollars)	December 31, 2007		December 31, 2006	
	Canadian GAAP	US GAAP	Canadian GAAP	US GAAP
Assets				
Deferred charge – note 15(b)	\$ -	\$ 1,984	\$ -	\$ 2,810
Fixed assets, net - notes 15(c) and (d)	2,177,346	1,673,251	1,753,058	1,205,465
Liabilities and Unitholders' Equity				
Current portion of convertible debentures - note 15(b)	5,333	5,392	1,464	1,485
Trust Unit liability – note 15(a)	-	7,515	-	7,633
Convertible debentures – note 15(b)	212,203	219,674	170,819	179,245
Future income taxes – note 15(e)	66,727	-	61,939	-
Temporary equity – note 15(f)	-	1,104,831	-	1,067,790
Unitholders' capital – note 15(f)	2,027,065	-	1,592,758	-
Convertible debentures equity component - note 15(b)	9,632	-	8,041	-
Contributed surplus – note 15(a)	2,005	-	863	-
Accumulated deficit – note 15(f)	(659,835)	(176,393)	(437,106)	(402,158)

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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.