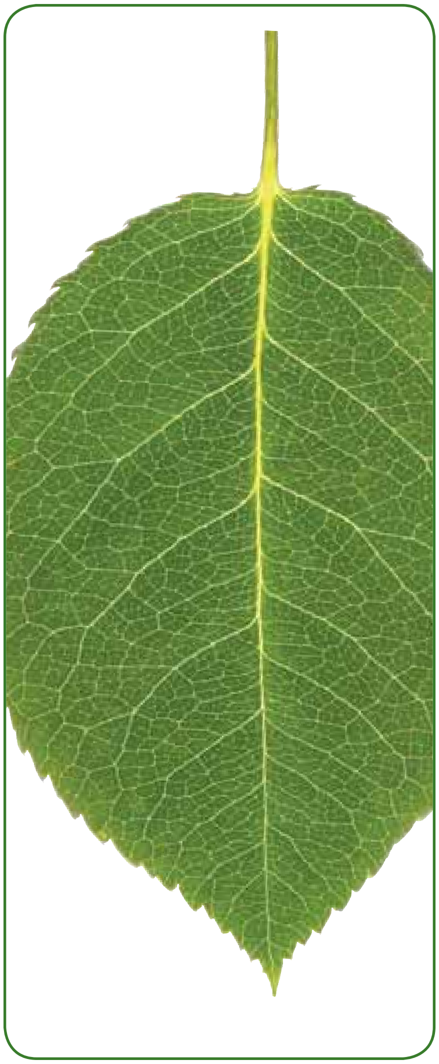
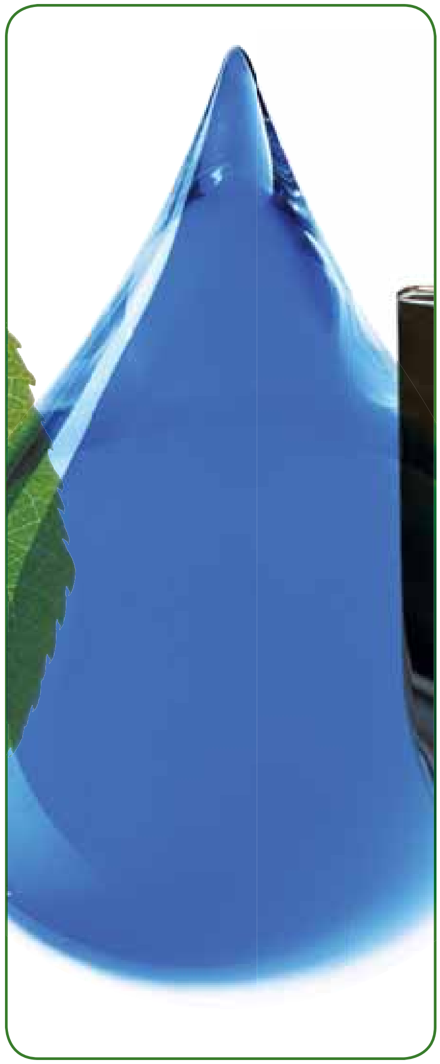
Annual Report

2007



POWER



UTILITIES

DEVELOPMENT

Algonquin Power

Financial Highlights

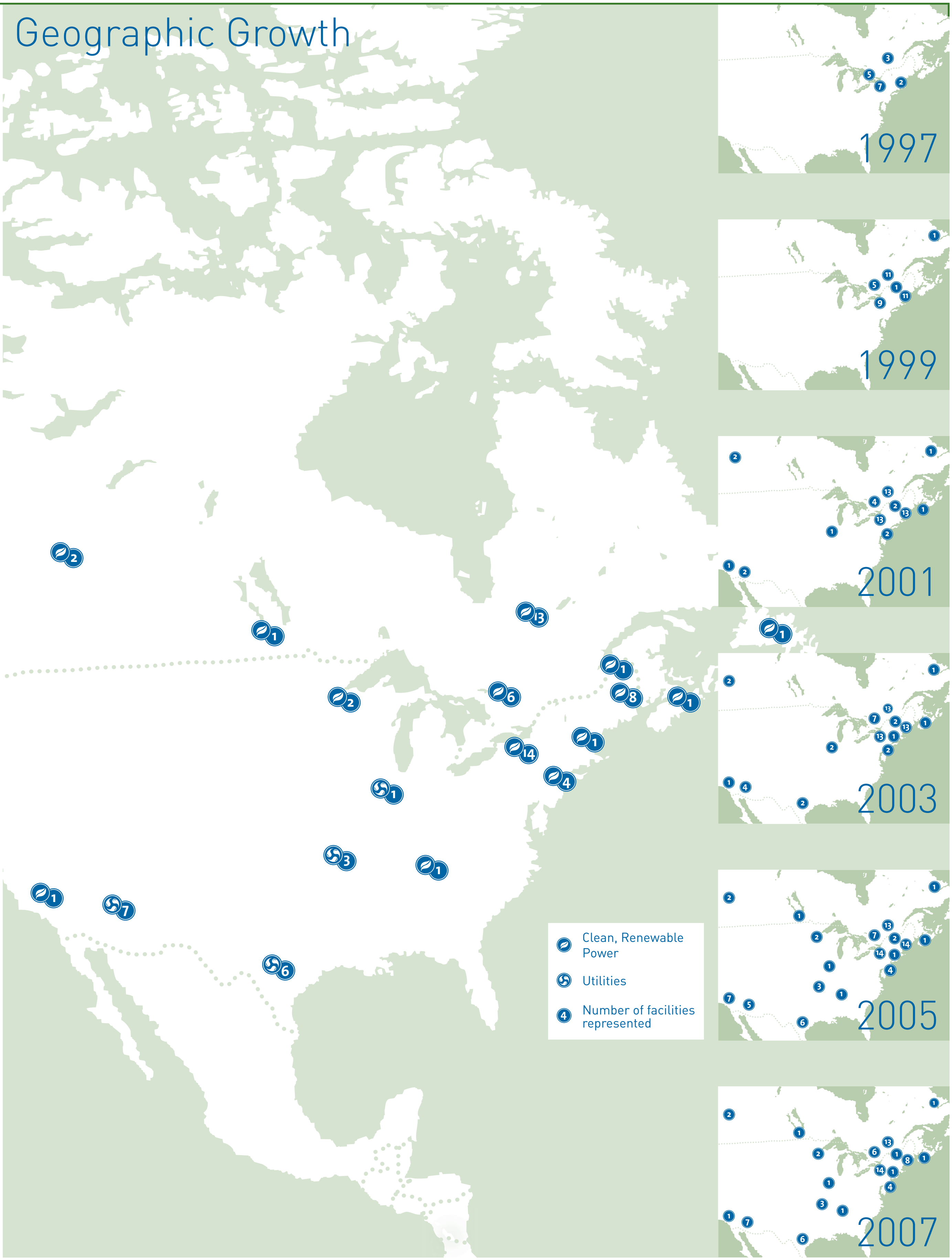
	2007	2006	2005	2004	2003	2002
Energy Sales						
Hydroelectric	41,023	45,066	44,102	43,268	44,413	40,681
Cogeneration	60,895	68,544	75,674	71,846	61,890	23,566
Alternative Fuels	14,647	9,675	16,262	7,867	6,423	4,994
Total Energy Sales	**116,565**	**123,285**	**136,038**	**122,981**	**112,726**	**69,241**
Waste Disposal	13,609	14,209	13,031	14,086	14,650	10,697
Water Distribution/Reclamation	33,699	35,464	28,371	23,456	20,237	7,974
Other Revenue	22,302	20,286	1,884	-	-	-
Total Revenue	**186,175**	**193,244**	**179,324**	**160,523**	**147,613**	**87,912**
Operating Profit (including interest, dividend and other income)						
Hydroelectric	27,362	31,334	28,344	26,383	29,045	26,985
Cogeneration	21,069	27,811	28,207	25,273	23,773	15,069
Alternative Fuels	29,581	21,620	10,773	8,181	9,328	7,292
Infrastructure	16,331	20,147	16,568	12,616	11,117	4,678
Other	1,926	113	139	4,373	278	851
Total Operating Profit	**96,269**	**101,025**	**84,031**	**76,826**	**73,541**	**54,875**
Earnings from continuing operations (before int exp, write-down of fixed & intangible assets and (gain) / loss on financial instruments)	**52,292**	**55,461**	**44,304**	**40,276**	**53,147**	**26,726**
Net Earnings from continuing operations	24,763	30,728	21,788	22,802	44,507	16,150
Net Earnings per Trust Unit	0.32	0.39	0.31	0.33	0.66	0.28
Distribution to Unitholders	69,923	66,955	64,061	63,370	62,402	55,192
Per Trust Unit	0.92	0.92	0.92	0.92	0.92	0.92
Cash Avail. for Distribution	72,349	67,491	64,892	59,887	58,368	44,742
Per Trust Unit	0.95	0.93	0.93	0.87	0.86	0.77
Balance Sheet Data						
Cash	10,361	13,465	11,363	34,348	21,238	24,838
Working Capital	1,217	(31,932)[1]	899	17,242	9,337	15,376
Capital and Intangible Assets & Long-Term Investments	890,253	952,428	761,989	742,994	751,904	674,495
Total Assets	**954,067**	**1,048,324**	**823,801**	**824,796**	**808,624**	**723,038**
Long-Term Liabilities & Revolving Credit Facility (includes debentures & current portion)	423,040	375,216	243,007	206,017	166,713	86,099
Unit Holders Equity	364,503	444,715	452,998	495,271	519,876	537,771
Number of Units Outstanding as of Dec. 31	73,644,356	72,874,211	69,691,592	69,691,592	67,887,612	67,887,612

(1) Amount includes $31.2 million of net working capital accruals related to the completion of the St. Leon Wind Energy facility.

Over Ten Years of Asset Growth

Year	Assets	Facilities	Capacity (MW)/ Connections
1997	Hydroelectric	17	19
1998	Hydroelectric	29	69
1999	Hydroelectric	38	101
2000	Hydroelectric	41	115
2001	Hydroelectric	47	141
	Cogeneration	Interest in 3	288
	Alternative Fuels	Interest in 3	66
	Infrastructure	2	4,500 connections
2002	Hydroelectric	47	141
	Cogeneration	Interest in 3	288
		Own/Operate 2	54
	Alternative Fuels	Interest in 3	66
		Own/Operate 2	13
	Infrastructure	5	13,500 connections
2003	Hydroelectric	47	141
	Cogeneration	Interest in 3	288
		Own/Operate 3	110
	Alternative Fuels	Interest in 3	66
		Own/Operate 2	13
	Infrastructure	6	36,800 connections
2004	Hydroelectric	47	141
	Cogeneration	Interest in 2	138
		Own/Operate 3	110
	Alternative Fuels	Interest in 4	165
		Own/Operate 14	49
	Infrastructure	6	40,000 connections
2005	Hydroelectric	48	143
	Cogeneration	Interest in 2	138
		Own/Operate 3	110
	Alternative Fuels	Interest in 4	165
		Own/Operate 13	46
	Infrastructure	15	56,000 connections
2006	Hydroelectric	48	143
	Cogeneration	Interest in 2	138
		Own/Operate 3	110
	Alternative Fuels	Interest in 3	66
		Own/Operate 14	145
	Infrastructure	15	61,000 connections
2007	Hydroelectric	41	140
	Cogeneration	Interest in 2	138
		Own/Operate 3	110
	Alternative Fuels	Interest in 3	66
		Own/Operate 5	118
	Infrastructure	17	65,000 connections

Geographic Growth



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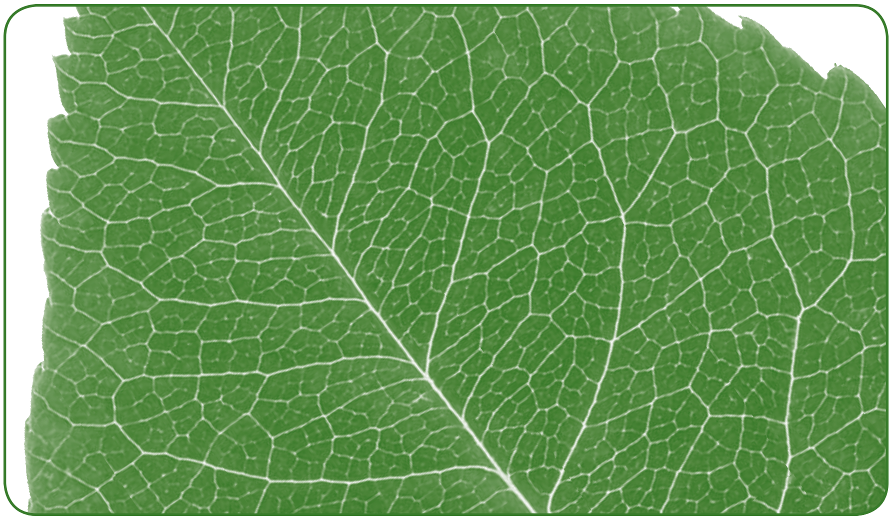
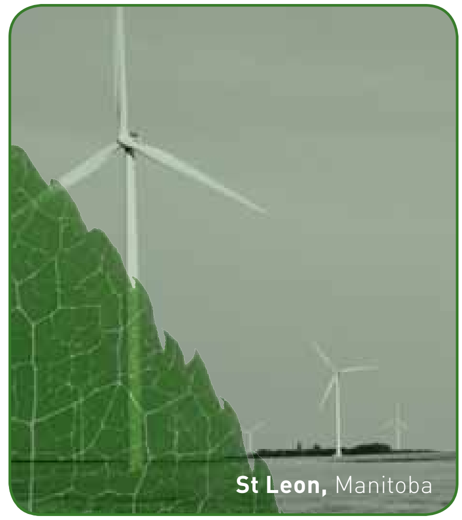
Algonquin Power owns and operates a diversified portfolio of electric generation and utility distribution assets with a strong emphasis on renewable energy and sustainable infrastructure investments. Algonquin Power delivers continuing growth through its expanding pipeline of greenfield and expansion renewable power and clean energy projects, organic growth within its regulated utilities and the aggressive pursuit of accretive acquisition opportunities. This focus enables Algonquin Power to be an innovative, respected and socially responsible participant in the renewable energy and utility business sectors.

Algonquin Power





St Leon, Manitoba

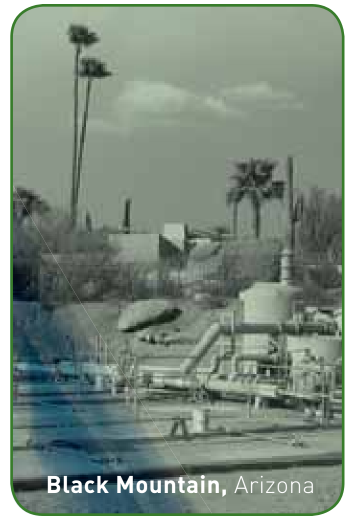
Power Generation

The Power Generation business unit is engaged in generating clean, renewable energy within the North American independent power generation industry. The business delivers attractive returns through the use of proven technologies and long term power purchase agreements across eleven geographic areas, making Algonquin Power one of the largest Canadian renewable power producers.

The Power Generation business unit delivers stable returns based on the effective use of clean renewable fuel sources including water, wind, municipal solid waste, landfill gas, and natural gas. Algonquin Power owns 41 run-of-river hydroelectric generating facilities, a 99 MW wind energy generating facility, a 500 tonne per day energy-from-waste facility, three landfill gas facilities and three natural gas cogeneration facilities. Revenue is derived from the sale of electricity and thermal energy, and fees at the Energy-from-Waste facility.

These facilities represent attractive investments from their low operating costs, proven technologies, increasingly predictable generation, and long term power purchase agreements. Unlike electricity generated by fossil fuels which are subject to potential price swings due to disruptions in supply or abnormal changes in demand, renewable power sources are not subject to commodity fuel price volatility or risk.

Both Canada and the United States are seeing an increasing demand for utilities to pursue environmentally sustainable options for generating electricity, with customers often willing to pay a premium for power generated by renewable resources. This translates into a growing opportunity for independent power producers generating electricity from sources including water, wind, municipal solid waste, landfill gas, and biomass. Algonquin Power continues to be an active participant in the expanding renewable energy marketplace, consistently evaluating these opportunities, and is currently pursuing several new wind projects, and an expansion of the energy-from-waste facility.



Black Mountain, Arizona

Utilities

The Utilities business unit is a leading provider of safe, reliable investor owned utility services including water distribution and waste-water treatment in the United States. The business delivers attractive, regulated returns for the Fund through the prudent management of 17 regulated water distribution and waste-water treatment facilities located in Arizona, Texas, Illinois and Missouri.

Revenue is generated from the distribution of water, the treatment of waste-water, and the subsequent sale of treated effluent. Water utilities offer a captive customer base within a regulated business environment, operating as geographic monopolies within the areas served, and are ideal for Algonquin Power as they represent an asset class which produces sustainable, predictable, long-lived earnings. Approved tariffs of the utilities are generally determined in conjunction with State or County regulators so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 10 to 12%.

The global market for water supply and treatment services has been growing rapidly over the last decade and currently constitutes over a third of the global market for environmental products and services. The trend toward growing private sector participation in water and wastewater utilities, has generated a continuing opportunity for Algonquin Power to expand its water services asset portfolio. The Utilities business unit strives to establish an active presence in the local communities where it operates, supported by strong, ongoing community relations and corporate responsibility. A strong local presence and community involvement complemented by high quality service helps the Utilities business unit to achieve high levels of customer satisfaction.

The Utilities business unit, by levering its utility management expertise gained in the water distribution and waste-water treatment sector may consider possible expansion into other regulated utility segments including natural gas and electricity distribution. Through the aggressive pursuit of both acquisition and organic growth opportunities, the Utilities business unit strives to expand its core group of assets and earnings growth in order to exceed the average of other North American public water, gas and electric distribution corporations of similar size.

Algonquin Power

St Leon, Manitoba

Development

Algonquin Power's Development group builds on over 20 years of experience in the development of renewable power and clean energy generation projects in North America with a commitment to working pro-actively with communities and other project stakeholders. Through its experienced management team, the Development group is well positioned to continue to be an active participant in the growing demand for environmentally sustainable sources of electrical generation.

Building on Algonquin Power's experience in power project development, the Development group continues to expand its growing pipeline of greenfield renewable power and clean energy projects as well as expansion of existing facilities.

As a highlight of the type of project achievements during 2007, the Development group successfully managed two growth projects, one at Algonquin Power's Sanger, California natural gas cogeneration facility, and one at the Energy-from-Waste facility located in Brampton, Ontario. In addition, the group pursued several new wind initiatives in Canada during the year.

Sanger

The Sanger cogeneration facility is a 42MW combined cycle natural gas fired generating station, and electrical output of the facility is sold pursuant to a long term power purchase agreement with Pacific Gas and Electric. The project involved a re-powering of the plant, replacing the original Westinghouse W251 B2 turbine-generator with a more modern, efficient and industry standard General Electric LM6000 turbine-generator. In the current environment of high natural gas prices the new turbine will position the Sanger Facility as one of the more efficient facilities operating today.

The LM6000 was successfully installed and commissioned, and is expected to achieve higher fuel efficiency, providing substantial fuel cost savings over the remaining life of the facility, with overall expected fuel savings of over $2 million. In addition, the Sanger facility will benefit from lower maintenance costs given the broad industry support for the LM6000 turbine. The total capital cost of the re-powering project was approximately US$23 million.

In addition to the benefits of fuel savings and lower maintenance costs, the higher energy output from the LM6000 turbine presents an opportunity to expand the generating capacity of the Sanger facility from 42MW to approximately 56MW. Management is focusing its efforts on securing a market for the additional capacity. Such capacity could be sold to its existing customer or to the market.

Brampton Cogeneration

The Algonquin Power Energy-from-Waste facility is designed to incinerate over 500 tonnes per day of municipal solid waste from the Region of Peel to produce approximately 100,000 pounds per hour of steam that is then used in the production of electricity. This facility effectively diverts more than 98,000 tonnes of municipal solid waste that would otherwise be taken to a landfill site.

A key part of Algonquin Power's strategy is to lever existing assets to create accretive returns to unitholders. A nearby recycled paper board manufacturing mill requires approximately 90,000 pounds per hour of steam in its manufacturing activities. The Brampton Cogeneration steam supply project transmits steam that is produced through the normal operation of the Algonquin Power Energy-from-Waste facility through a pipeline to the paper mill which is approximately 700 metres to the south of the facility.

Engineering, procurement and construction was initiated by Algonquin Power's Development group in 2006. The project consists of a 150,000 pound per hour gas-fired boiler, a water treatment system, pumps to support the boiler, a 12 inch diameter pipeline to supply steam to the paper mill and a six inch diameter pipeline for condensate return. The majority of the steam comes from the Algonquin Power Energy-from-Waste facility, with the gas fired auxiliary boiler supporting peak steam demand and full standby capacity during periods when the Energy-from-Waste facility is not in operation.

Algonquin Power Energy-from-Waste also continues to operate its steam turbine in order to supply the electrical needs of the plant, and to deliver electricity to the power grid under the facility's Power Purchase Agreement.

The project continues to move toward completion with a Spring 2008 commissioning target.

Wind Energy

The Development group has responsibility for Algonquin Power's non-binding proposals to construct wind generation projects with capacity of 165 MW in Manitoba, 240 MW in Quebec and is in the process of assessing further wind power development opportunities in Ontario, Quebec and Saskatchewan. Algonquin Power was selected to proceed to the next phase in Manitoba Hydro's Request for Proposal for wind powered electrical generation facilities with the 99 MW Glenwood Wind Energy Project and the 66 MW St. Leon Wind Energy II Project, both located in southern Manitoba. Algonquin Development anticipates that Manitoba Hydro will provide further information on the proposal process in 2008.

Report To Unitholders

Focused on Growth

The year 2007 was a year of growth opportunities, change, and performance achievements for Algonquin Power Income Fund. The Fund's management team and exceptional group of employees and associates spent 2007 working on many new initiatives, including, but not limited to wind development projects, the completion of St. Leon Wind Energy ("St. Leon"), the re-powering of the Sanger, California co-generation facility, acquisition projects, and welcoming a new CFO to the Fund.

In October 2007, the Fund was extremely pleased to announce the achievement of commercial operation at St. Leon, a 99 MW wind farm located 120 kilometres southwest of Winnipeg and Algonquin Power's largest renewable energy project to date. Commercial operation occurs when a project is substantially complete and ownership is formally transferred from the contractor to the owner of the project. Commercial operation pursuant to the power purchase agreement with Manitoba Hydro was attained in 2006 and St. Leon has been successfully generating renewable electricity since that time, enjoying a substantial and proven wind resource.

The St. Leon facility is the Fund's first facility located in Manitoba and marked a new relationship with Manitoba Hydro based on a 25 year Power Purchase Agreement with the utility. The Fund is excited at the prospect of expanding the relationship with Manitoba Hydro through two new development projects that have been selected to proceed to the next phase in Manitoba Hydro's Request for Proposal for the Potential Purchase of Output from Manitoba Wind Powered Electrical Generation Facilities. The two projects consist of the 99 MW Glenwood Wind Energy Project located in the Rural Municipality of Glenwood, near the Town of Souris, Manitoba, and the 66 MW St. Leon Wind Energy II Project located in the Rural Municipalities of Pembina and Lorne. This achievement is both exciting and significant to Algonquin Power's renewable energy project development pipeline in Canada.

In December of 2007, the Fund announced the successful on time, on budget commissioning of its 42 MW natural gas powered generating station located in Sanger, California following the major re-powering project that commenced in October 2006. The advances in turbine technology provided an opportunity to substantially improve fuel efficiency and the facility is expected to see an annual fuel requirement reduction of 23% or approximately $2 million in savings, demonstrating Algonquin Power's continuing commitment to the global environment and investment in technologies that reduce overall greenhouse gas emissions and reliance on fossil fuels. In addition, the facility is expected to benefit from lower maintenance costs given the broad industry support for the LM6000 turbine. This coupled with the future opportunity to expand generating capacity by 14 MW to 56 MW results in a successful growth project for Algonquin Power.

Also in December of 2007, Algonquin Power announced the sale of six landfill gas powered generating stations and other related landfill gas assets owned by the Fund for US$11.34 million. The landfill gas assets were comprised of six facilities representing approximately 18 MW of installed generating capacity, representing a relatively small investment for the Fund. These facilities were no longer considered strategic to the ongoing operations of the Fund and the accretive disposition of these assets is expected to narrow the focus of management efforts on other, larger renewable energy generation and sustainable infrastructure projects.

Subsequent to the end of the year, in January 2008, Algonquin Power announced that it renewed its combined $175 million senior secured revolving operating and acquisition credit facilities for a new three year term. The renewal calls for a three year extension of the facilities and an accordion feature allowing an increase to $225 million. This renewal lowers the cost of financing and provides a secure source of financing to achieve future renewable

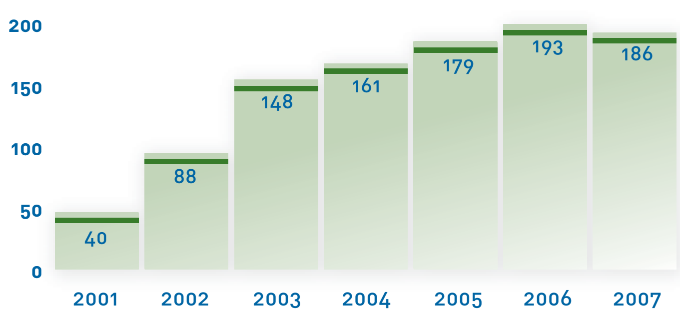
The Trustees:
Christopher Ball
George Steeves
Ken Moore

energy and infrastructure growth targets both organically and through acquisitions.

Financial Highlights

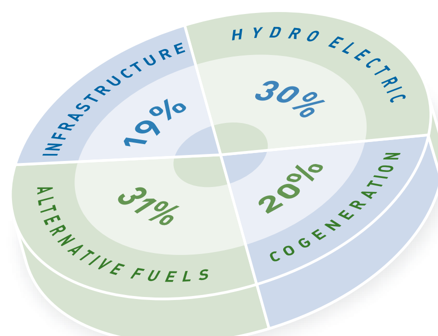
For the year 2007, the Fund's assets generated total revenue of $186.2 million. The Fund's diversification produces revenue in a well balanced manner with 22% of revenue generated by the Hydroelectric Division, 35% generated by the Cogeneration Division, 25% generated by the Alternative Fuels Division, and 18% of revenue generated by the Infrastructure Division in 2007.

Total Revenue



At the end of 2007, the Fund's operating profit continues to be well balanced with Hydroelectric making up 30% of operating profit, Cogeneration at 20%, Alternative Fuels at 31% and the Infrastructure Division assets including water distribution and waste-water facilities making up 19% of the Fund's operating profit mix.

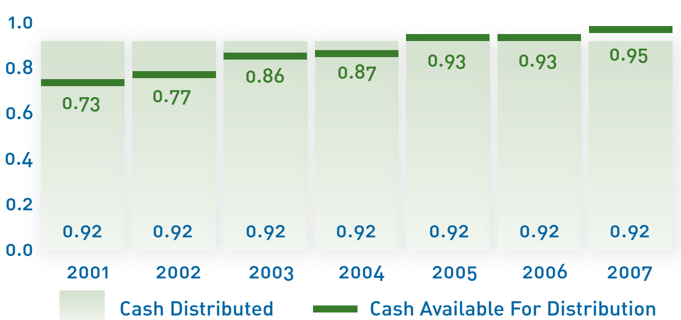
Percentage of Operating Profit by Division



During 2007, cash available for distribution was $72.3 million compared to $67.5 million in 2006. On a per unit basis, the Fund generated $0.95 of cash available for distribution per unit by the end of 2007 and $0.93 in 2006. In 2007, the Fund distributed $0.92 per unit, consistent with the $0.92 per unit per year that has been distributed since 2001. For the year ended December 31, 2007, the Fund's distribution as a percentage of cash available for distribution ("Payout Ratio") was 96.6%. The Fund achieved improving annual Payout Ratios of 106.9% in 2003, 105.8% in 2004, 98.7% in 2005, and 99.2% in 2006. The excess cash available for distribution is used to fund working capital and for other cash requirements of the Fund.

Report To Unitholders Cont'd

Cash Distributed vs Cash Available For Distribution



Business Highlights

In the Hydroelectric Division, hydrology remains naturally fluctuating and during 2007 the Fund's hydroelectric facilities generated electricity equal to 91% of long term averages. During 2007, the Hydroelectric Division produced sufficient energy to supply the equivalent of 32,000 homes with renewable power for a year.

In the Cogeneration Division, performance met Management's expectations for the year 2007, with overall production levels up from 2006. There was a decrease in energy sales primarily due to lower energy rates at the Windsor Locks facility and from the closure of the Crossroads facility. The Sanger facility experienced a decrease in production in the fourth quarter due to the planned commissioning of the new LM6000 turbine.

In the Alternative Fuels Division, the addition of the St. Leon Wind Energy facility during the second quarter of 2006 contributed to growth in overall production for 2007. At the Energy-from-Waste facility, overall improvements began to take effect during the end of 2007 and increased availability is expected to continue in 2008. The Alternative Fuels Division produced sufficient energy in 2007 to supply the equivalent of 20,000 homes with renewable power for a year and operations at the EFW facility resulted in the diversion of 98,500 tonnes of waste from landfill sites.

In the Infrastructure Division, the waste-water treatment customer base and water distribution customer base each grew organically by 3% in 2007. Performance decreased in 2007 when compared to 2006 primarily due to the stronger Canadian dollar, which was partially offset by the result of a rate case that was completed in July 2007 resulting in an increase in rates at the Fund's Gold Canyon facility. Rate cases ensure that a facility earns the rate of return on its capital investment as allowed by the regulatory authority under which the facility operates.

In Closing

As always, the Trustees of Algonquin Power Income Fund have taken steps to ensure that unitholders are well protected by approving and implementing clear Corporate Governance standards and practices. At least annually the trustees, in conjunction with their duties as members of the corporate governance committee, review the Fund's approach to Corporate Governance. More specifically, the committee reviews independence, committees, charters and evaluations, access to management and outside advisors, strategic planning, integrity of financial information, risk management, human resource management, verification of controls, ethics reporting, and full and fair disclosure.

In the 2006 Report to Unitholders we discussed the Canadian federal government proposal to impose a tax similar to corporations on "specified investment flow-throughs" ("SIFT"), which, under the definitions provided, would include Algonquin Power Income Fund. These proposals indicate that beginning in the 2011 taxation year, a SIFT will be subject to tax at a rate that is equivalent to the federal corporate tax rate, as well as provincial tax. Although these proposals currently remain as draft legislation, between now and 2011, Algonquin Power will be focused on minimizing the impact of the proposed changes on unitholders and looking for opportunities to enhance unitholder value. The Fund believes the impact of the proposed taxation changes on unitholders will be mitigated due to the proportion of income from U.S. assets, and the return of capital portion of distributions which are believed to be exempt under the proposed provisions.

Previously we have discussed Algonquin Power's plans to build on the strength the Fund has achieved since the initial public offering in 1997. In 2008, the Fund intends to pursue new growth initiatives, look for opportunities in the changing market environment, and continue our disciplined approach to achieving performance enhancements within the Fund's portfolio of long-lived renewable power and sustainable infrastructure assets. In its business activities, Algonquin Power focuses on earning and maintaining respect from our customers, employees, communities, competitors and financial markets, through sound, prudent and innovative business strategies and practices. Our thanks are extended to the Fund's unitholders, employees and associates for your continued support in this important endeavour.

(signed) Ken Moore

Ken Moore
Chairman

Management's Discussion and Analysis

(All figures are in thousands of Canadian dollars, except per trust unit and convertible debenture values or where otherwise noted)

The Management Group:
Chris Jarratt
David Kerr
Ian Robertson

Algonquin Power Income Fund (the "Fund") has prepared the following discussion and analysis to provide information to assist its Unitholders' understanding of the financial results for the three and twelve months ended December 31, 2007. This discussion and analysis should be read in conjunction with the Fund's consolidated financial statements for the years ended December 31, 2007 and 2006 and the notes thereto. This material is available on SEDAR at www.sedar.com and on the Fund's website at www.AlgonquinPower.com. Additional information about the Fund, including the Annual Information Form for the year ended December 31, 2007 can be found on SEDAR at www.sedar.com.

This Management's Discussion and Analysis ("MD&A") is based on information available to management as of February 29, 2008.

Caution Concerning Forward-Looking Statements

Certain statements contained in the information herein are forward-looking and reflect the views of the Fund and Algonquin Power Management Inc. ("APMI" or the "Manager") with respect to future events. Since forward-looking statements address future events and conditions, by their very nature, they involve inherent risks and uncertainties. Forward-looking statements are not guarantees of the Fund's future performance or results and are subject to various factors including, but not limited to, assumptions such as those relating to: the performance of the Fund's assets, commodity market prices, interest rates, and environmental and other regulatory requirements. Although the Fund and its Manager believe that the assumptions inherent in these forward-looking statements are reasonable, undue reliance should not be placed on these statements, which apply only as of the dates hereof. The Fund and its Manager are not obligated nor do either of them intend to update or revise any forward-looking statements, whether as a result of new information, future developments or otherwise.

For the quarter ended December 31, 2007, the Fund reported total revenue of $44.3 million as compared to $52.0 million during the same period in 2006. Revenue for the fourth quarter of 2007 decreased by a net amount of $2.1 million due to a combination of lower energy production and changes in the weighted average energy rates generated in the Hydroelectric Division and $0.4 million due to a combination of lower production and increased energy rates at the Sanger facility as compared to the same period in the prior year. The Fund reported lower revenue of $3.9 million from its operations in the United States ("U.S.") as a result of the stronger Canadian dollar. These amounts were partially offset by $1.0 million from higher revenues at the St. Leon Wind Energy facility ("St. Leon") and $0.5 million at the Gold Canyon facility due to the July 2007 rate increase combined with organic growth at existing facilities during the quarter as compared to the same period in the prior year. The comparative period includes revenue of $1.4 million from the Crossroads facility that was closed in December 2006 and includes a realized gain on foreign exchange forward contracts of $2.1 million was recorded as revenue. A more detailed analysis of these factors is presented within the divisional analysis.

Key Financial Information

(C$000)	Three months ended December 31		Year ended December 31		
	2007	2006	**2007**	2006	2005
Revenue [1]	**$ 44,317**	$ 52,003	**$ 186,175**	$ 193,244	$ 179,324
Net earnings from Continuing Operations	**8,762**	3,741	**24,763**	30,728	21,788
Net earnings	**7,559**	1,796	**23,671**	27,956	21,788
Total Assets	**954,067**	1,048,324	**954,067**	1,048,324	823,801
Long Term Debt	**281,725**	229,006	**281,725**	229,006	157,002
Distribution to Unitholders [2]	**17,481**	17,481	**69,923**	66,956	64,061
Cash available for distribution [3]	**19,924**	17,477	**72,349**	67,491	64,891
Cash provided by (used by) Operating Activities	**(610)**	17,907	**40,427**	69,332	55,679
Per trust unit					
Net earnings from continuing operations	**0.12**	0.06	**0.34**	0.43	0.31
Net earnings	**0.10**	0.02	**0.32**	0.39	0.31
Distribution to Unitholders	**0.23**	0.23	**0.92**	0.92	0.92
Cash available for distribution [3]	**0.26**	0.23	**0.95**	0.93	0.93
Cash provided by (used by) Operating Activities [4]	**(0.01)**	0.24	**0.53**	0.95	0.79

1 Prior period comparative amounts have been adjusted due to the classification of certain landfill-gas and New England hydroelectric facilities sold during the year as Discontinued Operations. This has been set out in more detail in Note 15 of the annual financial statements.
2 Includes distributions to non-controlling interest.
3 Non-GAAP measurement, see 'Cash Available for Distribution' in this MD&A.
4 The change in cash provided by (used in) operating activities in the quarter and year ended December 31, 2007 is primarily due to the final payments made to the turnkey construction contractor in respect of the completion of the St. Leon facility.

For the year ended December 31, 2007, the Fund reported revenue of $186.2 million as compared to $193.2 million during the same period in 2006. Revenue for the year ended December 31, 2007 decreased by a net amount of $3.0 million due to lower energy production and changes to the weighted average energy rates generated in the Hydroelectric Division as compared to the same period in the prior year. These amounts were partially offset by a net increase of $6.0 million due to increased energy production and changes to energy rates generated in the Cogeneration Division, an increase of $13.0 million due to the St. Leon facility and an increase of $3.1 million due to a combination of organic growth and the July 2007 rate increase at the Gold Canyon facility during the quarter as compared to the same period in the prior year. The Fund reported lower revenue of $5.8 million from its operations in the U.S. as a result of the stronger Canadian dollar. The comparative period includes revenue of $6.0 million from the Crossroads facility that was closed in December 2006, other revenue of $5.8 million from the sale of natural gas at the Sanger facility, which did not occur in 2007 and a realized gain of $7.9 million on foreign exchange forward contracts was recorded as revenue. A more detailed analysis of these factors is presented within the divisional analysis.

For the quarter ended December 31, 2007, the Fund experienced an average U.S. exchange rate of approximately $0.98 as compared to $1.14 in the same period in 2006. For the year ended December 31, 2007, the Fund experienced an average U.S. exchange rate of approximately $1.07 as compared to $1.13 in the same period in 2006. As such, any quarterly or annual variance to revenue or expenses, in local currency, at any of the Fund's U.S. entities may be affected by a change in the average exchange rate, upon conversion to the Fund's reporting currency. Although the stronger Canadian dollar has an impact on both revenue and expenses generated by its U.S. subsidiaries, the Fund has foreign exchange forward contracts in place, which partially mitigate the impact on cash available for distribution (see Risk Management – Currency Fluctuations).

For the quarter ended December 31, 2007, net earnings from continuing operations totalled $8.8 million as compared to $3.7 million during the same period in 2006. Net earnings from continuing operations for the fourth quarter of 2007 increased $4.1 million due to an increased income tax recovery booked in the quarter, $3.3 million due to foreign exchange gains on U.S. dollar denominated project debt and $3.1 million due to a decreased write down of assets related to the Across America Note. These items

Key Financial Information Cont'd

were partially offset by $3.0 million in lower reported earnings from operating facilities primarily due to the stronger Canadian dollar combined with lower average rates on its foreign exchange forward contracts exercised in the period, additional interest expense of $0.5 million due to increased average borrowings, reduced dividend and other income of $0.7 million and $0.8 million due to an incentive fee earned by APMI pursuant to its management agreement with the Fund as compared to the same period in 2006.

Net earnings from continuing operations for the year ended December 31, 2007 totalled $24.8 million as compared to $30.7 million during the same period in 2006. Net earnings from continuing operations for the year ended December 31, 2007 decreased $17.9 million due to an increased income tax expense booked in the year primarily relating to the substantive enactment of Bill C-52, additional interest expense of $4.3 million due to increased average borrowings over the year and increased amortization expense of $5.2 million primarily due to the inclusion of a full year of amortization at the St. Leon facility. Also affecting the results was $13.8 million in lower reported earnings from operating facilities in the U.S. primarily due to the stronger Canadian dollar combined with lower average rates on its foreign exchange forward contracts exercised in the period and $0.8 million due to an incentive fee earned by APMI pursuant to its management agreement with the Fund as compared to the same period in 2006. These amounts are partially offset by an increase of $10.5 million in earnings from continuing operations in the Alternative Fuels Division, primarily due to the addition of earnings from the St. Leon facility, $8.0 million due to increased foreign exchange gains on U.S. dollar denominated project debt, $15.0 million in unrealized gains of foreign exchange forward contracts, $2.5 million due to a decreased write down of assets related to the Across America Note and continued growth in the Infrastructure Division as compared to the same period in 2006. A more detailed analysis of these factors is presented within the divisional analysis.

Net earnings from continuing operations per trust unit totalled $0.10 for the quarter ended December 31, 2007 as compared to $0.06 during the same period in 2006. For the year ended December 31, 2007, net earnings from continuing operations per trust unit totalled $0.34 as compared to $0.43 during 2006.

The Fund generated $0.26 per trust unit of cash available for distribution for the quarter ended December 31, 2007, as compared to $0.23 per trust unit during 2006. The increase in cash available for distribution and per trust unit during the quarter was primarily due to the gain on sale of assets during the quarter, and a payment from the turnkey construction contractor of the St. Leon facility as part of the final settlement to resolve all outstanding issues with the facility.

For the year ended December 31, 2007, the Fund generated $0.95 per trust unit of cash available for distribution, as compared to $0.93 in the same period in 2006. The increase in cash available for distribution per unit during the year was due to the gain on sale of assets, a payment from the turnkey construction contractor of the St. Leon facility as part of the final settlement to resolve all outstanding issues with the facility, and the termination fee arising from the Fund's offer to acquire all the outstanding trust units and convertible debentures of Clean Power Income Fund ("CPIF").

During the quarter ended December 31, 2007 cash used by operating activities totalled $0.6 million or $0.01 per trust unit as compared to cash provided by operating activities of $17.9 million or $0.24 per trust unit during 2006. During the year ended December 31, 2007 cash provided by operating activities totalled $40.4 million or $0.53 per trust unit as compared to $69.3 million or $0.95 per trust unit during 2006. The change in cash provided by operating activities in the quarter and year ended December 31, 2007 is primarily due to the final payments made to the turnkey construction contractor in respect of the completion of the St. Leon facility.

During the quarter ended December 31, 2007, the Fund maintained distributions at $0.23 per trust unit, consistent with distributions in same quarter in 2006. For the year ended December 31, 2007, the Fund maintained distributions of $0.92 per trust unit, consistent with distributions in 2006.

The term 'cash available for distribution' is used throughout this Management's Discussion and Analysis. Management uses this calculation to monitor the amount of cash generated by the Fund as compared to the amount of cash distributed by the Fund. The term 'cash available for distribution' is not a recognized measure under accounting principles generally accepted in Canada. The Fund's method of calculating 'cash available for distribution' may differ from methods used by other companies and accordingly may not be comparable to similar measures presented by other companies. A calculation and analysis of 'cash available for distribution' can be found in this Management's Discussion and Analysis.

St. Leon, Manitoba

Outlook

The Fund's core business is providing the essential services of electrical generation, transportation and delivery of water and treatment of waste-water, natural gas and electricity distribution and the ownership of a portfolio of the assets involved in their delivery. To more effectively position itself to compete in its chosen business sectors, commencing in 2008, Management will re-align the business affairs of the Fund into three distinct Business Units; Algonquin Power Generation, Algonquin Utilities and Algonquin Development.

Through these three Business Units, the Fund will own and operate a diversified portfolio of electric generation and utility distribution assets with a strong emphasis on renewable energy and sustainable infrastructure investments. The Fund intends to deliver continuing growth through its expanding pipeline of greenfield and expansion renewable power and clean energy projects, organic growth within its regulated utilities and the aggressive pursuit of accretive acquisition opportunities.

Algonquin Power Generation will participate in the renewable power and clean energy electrical generation business sector, delivering attractive returns through the use of proven technologies and long term power purchase agreements. Algonquin Power Generation will be responsible for all of the Fund's electrical generation business activities. It expects to deliver stable returns based on average long term hydrologic conditions, the achievement of average wind projections at the St. Leon facility, operational improvements at the Algonquin Power Energy-from-Waste facility ("EFW") and the continued stable performance of its natural gas powered generating facilities.

Algonquin Power Generation continues to review opportunities at the EFW facility as a result of an expected growing local demand for Municipal waste disposal. It is also considering a plant expansion to increase EFW facility throughput and has embarked on a feasibility study in cooperation with the Region of Peel to assess expected capital and operating costs of such an expanded facility.

Algonquin Utilities will continue to provide predictable and stable returns through its position as the leading provider of safe, reliable utility services in its service areas including levering its utility management expertise gained in the water distribution and waste-water treatment sector through possible expansion into natural gas and electricity distribution. Through the aggressive pursuit of appropriate growth opportunities, Algonquin Utilities will strive to have expansion of assets and earnings growth exceed the average of other North American public water, gas and electric distribution corporations of similar size.

Outlook Cont'd

Algonquin Utilities anticipates continued growth in the number of customers in its regulated water and wastewater utilities in the United States and intends to optimize financial returns by commencing rate case applications in a number of key utilities in 2008.

Algonquin Development will focus its experienced management team on the development of renewable power and clean energy generation projects in North America with a commitment to working pro-actively with communities and other stakeholders. Algonquin Development is well positioned to benefit from the growing demand for environmentally sustainable sources of electrical generation.

Building on the Fund's experience in power project development, Algonquin Development will continue to expand its growing pipeline of greenfield and expansion renewable power and clean energy projects. Algonquin Development will assume responsibility for the Fund's current non-binding proposals to construct wind generation projects with capacity of over 350 MW in Manitoba, 240 MW in Quebec and is in the process of assessing further wind power development opportunities in Ontario, Quebec and Saskatchewan. In December 2007, the Fund was selected to proceed to the next phase in Manitoba Hydro's Request for Proposal ("RFP") 025089, Potential Purchase of Output from Manitoba Wind Powered Electrical Generation Facilities. The 99 MW Glenwood Wind Energy Project located in the Rural Municipality of Glenwood, near the Town of Souris, Manitoba, and the 66 MW St. Leon Wind Energy II Project located in the Rural Municipalities of Pembina and Lorne were selected for further participation in the RFP process. Algonquin Development anticipates that Manitoba Hydro will provide further information on the RFP process in the second quarter of 2008.

Summary

In all of its Business Units, Management is committed to the growth and development of the Fund's team through various training programs, challenging assignments and learning opportunities. In addition, the Fund ensures continuous environmental, health and safety training for its operations and maintenance staff. Management will continue to invest in information technology to reduce operating and administrative costs.

Overall, Management anticipates that the Fund's Business Units will continue to generate cash available for distribution for 2008 in line with historic performance. These Business Units will focus on priorities that enable the Fund to be an innovative, respected and socially responsible participant in the renewable energy, power and utility business sectors. With a mix of complementary regulated and non-regulated businesses, the Fund strives to enhance shareholder value through stable earnings, cash distributions and a managed risk profile.

Significant Events and Transactions

In order to strengthen the Fund's asset base and diversify the Fund's portfolio of power generating assets and investments, the Fund completed the following significant transactions during 2007:

1. Sanger Repowering

In December 2007, the major re-powering project of the 42 MW natural gas powered generating station located in Sanger, California (the "Sanger facility") saw the new LM6000 turbine installed and is now producing power. The project commenced in October 2006. The project is on budget with the total investment in the repowering project being approximately $25.0 million (U.S. $23 million). The Sanger facility generating the expected revenues from electricity production, and is now completing its commissioning phase. It is expected that the project will be fully commissioned in early 2008.

The Fund expects a reduction in fuel consumption of 23% at the facility representing approximately $2.0 million in annual savings. In addition, the Fund expects the Sanger facility to benefit from a longer useful life of the facility as well as lower maintenance costs given the broad industry support for the new turbine.

As a result of the retrofit, the Sanger facility has approximately 14 MW of capacity in excess of its current PPA requirement. Management is reviewing its options with regards to marketing this additional energy and is focusing its efforts on securing a market for the additional capacity. Such capacity could be sold to its existing customer or to the market.

2. St. Leon Wind Energy

On September 18, 2007, the Fund reached an agreement (the "Agreement") with Vestas-Canadian Wind Technology, Inc. ("Vestas") to achieve commercial operation ("Commercial Operation") pursuant to the Turnkey Construction Contract ("TCC") at the St. Leon facility. In addition the Agreement resulted in a mutually acceptable payment to the Fund as part of the final settlement to resolve all outstanding issues with the facility which positively impacted distributable cash for the Fund.

Commercial Operation, as defined in the TCC, occurs when a project is "substantially complete" and ownership is formally transferred from the contractor to the owner of the project. This also marks the commencement of the five year warranty period with Vestas. Under the warranty agreement with Vestas, the projected availability of the project is guaranteed by Vestas and the turbine equipment is warranted against defects. The declaration of Commercial Operation was pending the resolution of certain outstanding construction related issues under the TCC. The project achieved commercial operation pursuant to the power purchase agreement with Manitoba Hydro in 2006 and St. Leon has been generating renewable electricity since that time.

The Agreement with Vestas established Commercial Operation and provided the framework and timing under which Vestas has agreed to resolve the facility's outstanding issues under the TCC. By November 2007, Vestas had resolved one of theses issues by virtue of substantially completing repairs to the turbine blades. Under the terms of the Agreement, Vestas is required to resolve the outstanding issues by certain dates. It is Management's belief that the Agreement resolves the potential issues that might have limited the overall production of the facility. The Fund continues to hold financial security posted by Vestas in respect of its obligations under the Agreement to rectify the remaining outstanding issues. It is Management's belief that such financial security is sufficient to rectify the outstanding issues in the event Vestas fails to complete the necessary work.

3. Sale of Landfill Gas and Hydroelectric Facilities

On December 21, 2007 the Fund completed the sale of six landfill gas ("LFG") powered generating facilities for proceeds of approximately $11.3 million, representing approximately 18 MW of installed capacity. These LFG facilities, located in California and New Hampshire were no longer considered strategic to the ongoing operations of the Fund.

On December 28 2007, based on a review of its smaller hydroelectric generating facilities, the Fund completed the sale of six facilities in the New England region for proceeds of approximately $1.5 million. These facilities no longer fit the Fund's preferred asset profile.

The operating results from these facilities have been excluded from the Alternative Fuels and the Hydroelectric Divisions and have been classified as discontinued operations in the financial statements.

4. Subsequent Event – renewal of senior secured credit facilities

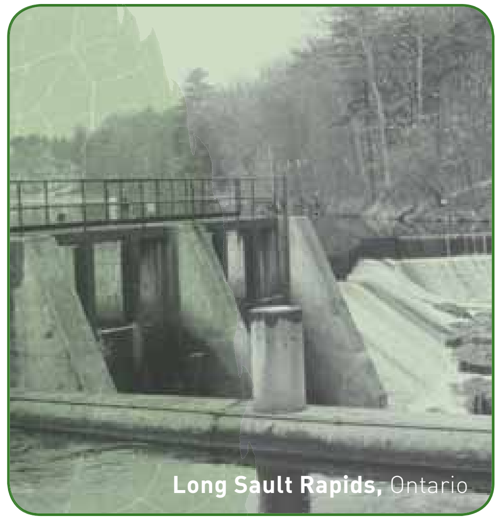
On January 16, 2008, the Fund completed a renewal of its combined $175 million senior secured revolving operating and acquisition credit facilities (the "Facilities") with its Canadian bank syndicate for a new term. Under terms of the renewal, the Facilities are extended for a three year term with a maturity date of January 14, 2011. The renewed Facilities also contain an accordion feature allowing the Facilities to increase to $225 million to accommodate future growth and acquisitions.

As part of the renewal of the Facilities, Algonquin Power's bank syndicate has also expanded from three to four financial institutions. The Facilities are being led by National Bank of Canada. The other syndicate members are The Toronto-Dominion Bank, Bank of Montreal, and the recently added Canadian Imperial Bank of Commerce.

The renewal of the Facilities will result in reduced borrowing costs and provide a secure source of financing over the three year term of the agreement.

Hydro Electric Division


Beaver Falls, New York


Long Sault Rapids, Ontario

The Hydroelectric Division produced sufficient renewable energy to supply the equivalent of 29,000 homes with renewable power in the fourth quarter of 2007 and the equivalent of 32,000 homes with renewable power in the 2007 fiscal year. Using new standards of thermal generation, renewable energy production saved the equivalent of 70,000 tons of CO_2 gas from entering the atmosphere in the fourth quarter of 2007 and 320,000 tons of CO_2 gas from entering the atmosphere in the year.

For the quarter ended December 31, 2007, revenue in the Hydroelectric Division totalled $9.3 million as compared to $11.7 million during the same period in 2006. During the fourth quarter of 2007, the Hydroelectric Division generated electricity equal to 81% of long term averages as compared to 115% during the same period in 2006. All regions experienced below long term average hydrology in the fourth quarter of 2007. This compares to the same period in 2006 when all regions, with the exception of the Ontario region, experienced above long term average hydrology. The decrease in revenue as compared to the fourth quarter of 2006 was primarily the result of a decrease of $1.1 million resulting from lower energy production in the U.S. regions, a decrease of $0.4 million resulting from lower energy production in the Canadian regions and a decrease of $1.1 million resulting from lower weighted average energy rates in the Canadian regions, partially offset by $0.5 million from higher weighted average energy rates in the U.S. regions. The division reported lower revenue of $0.5 million from U.S. operations as a result of the stronger Canadian dollar.

For the year ended December 31, 2007, revenue from the Hydroelectric Division totalled $41.0 million compared to $45.1 million during the same period in 2006. During the year ended December 31, 2007, the Hydroelectric Division generated electricity equal to 91% of long term averages as compared to 103% of long term averages in 2006. The decrease in revenue as compared to the year ended December 31, 2006 was primarily the result of a decrease of $2.6 million resulting from lower energy production in the U.S. regions, a decrease of $1.2 million resulting from lower weighted average energy rates in the Canadian regions and partially offset by $0.8 million from higher weighted average energy rates in the U.S. regions. The division reported lower revenue of $0.7 million from U.S. operations as a result of the stronger Canadian dollar.

For the quarter ended December 31, 2007, operating expenses totalled $4.4 million as compared to $4.2 million the same period in 2006. Operating expenses were impacted by a $0.2 million increase in property taxes assessed on the Fund's facilities and an increase of $0.2 million in operating costs as compared to the same period in 2006, offset by a decrease of $0.2 million in repairs and maintenance projects initiated in the year and a decrease in reported expenses from U.S. operations as a result of a stronger Canadian dollar.

For the year ended December 31, 2007, operating expenses totalled $15.0 million as compared to $15.6 million in the prior year. The decrease in operating expenses was primarily due to a decrease of $0.5 million in repairs and maintenance projects initiated in the year, a decrease of $0.3 million in costs directly related to energy production as compared to the same period in 2006 and $0.3 million due to lower reported expenses from U.S. operations as a result of a stronger Canadian dollar. This was partially offset by an increase of $0.3 million in operating costs incurred during the year as compared to the same period in 2006.

Financial Summary

(C$000)	Three months ended December 31		Year ended December 31	
	2007	2006	**2007**	2006
Performance (MW-hrs sold)				
Quebec Region	**70,353**	88,510	**275,863**	305,656
Ontario Region	**22,578**	31,370	**113,917**	126,239
New England Region *	**10,248**	20,410	**52,607**	74,928
New York Region	**17,715**	31,364	**72,841**	95,062
Western Region	**8,193**	16,437	**67,685**	66,953
Total	**129,087**	188,091	**582,913**	668,838
Revenue				
Energy sales *	**$ 9,255**	$ 11,660	**$ 41,023**	$ 45,066
Expenses				
Operating expenses *	**(4,445)**	$ (4,188)	**(14,993)**	(15,565)
Other income	**425**	812	**1,332**	1,833
Division operating profit (including other income)	**$ 5,235**	$ 8,284	**$ 27,362**	$ 31,334

* Prior period comparative amounts have been adjusted due to the classification of certain New England facilities as Discontinued Operations. This has been set out in more detail in Note 15 of the annual financial statements.

In the fourth quarter of 2007, based on its review of its smaller hydroelectric generating facilities, the Fund completed the sale of six smaller facilities in the New England region that no longer fit the Fund's preferred asset profile. The operating results from these facilities have been excluded from the Hydroelectric Division and have been classified as discontinued operations in the financial statements.

For the quarter ended December 31, 2007, operating profit totalled $5.2 million as compared to $8.3 million during the same period of 2006. For the year ended December 31, 2007, operating profit totalled $27.4 million as compared to $31.3 million in 2006. For both the quarter and the year ended December 31, 2007, operating profit was below Management's expectations due to lower hydrology.

Outlook

Based on long term average hydrological conditions, the Hydroelectric Division will produce sufficient renewable energy in fiscal 2008 to supply the equivalent of 36,000 homes with renewable power for an entire year. Using new standards of thermal generation, renewable energy production in 2008 is expected to save the equivalent of 355,000 tons of CO2 gas from entering the atmosphere. The Hydroelectric Division is expected to perform at or above long term average hydrological conditions in the first quarter of 2008. In addition, the facilities in the New England region are expected to benefit from improved market rates as compared to the rates experienced in 2007.

As a result of certain legislation passed in Quebec (Bill C93), the Fund is required to undertake technical assessments of eleven of the twelve hydroelectric facility dams owned or leased within the Province of Quebec. The Fund anticipates incurring approximately $0.6 million during 2008 to complete the required assessments. Upon completion of these assessments, the Fund will be required to submit plans for undertaking any remedial measures that may be identified to comply with the legislation. As a result of three completed and eight partially completed assessments underway, Management has initially identified remedial measures estimated to cost approximately $8.2 million. Management is exploring several alternatives to mitigate the costs of modifications including cost sharing with other stakeholders and revenue enhancements which can be achieved through the modifications.

Several capital projects aimed at increasing production have been earmarked in 2008 and include such items as automated trash rack cleaning machines and an inflatable dam at one our the U.S. plants which will allow increased production at the facility.

The Fund will continue to seek accretive hydroelectric acquisitions throughout 2008, with emphasis placed on the acquisition of facilities that provide diversification of regional hydrologic and market conditions. In addition, the Fund has an ongoing program to assess all facilities for their continued fit with the Fund's preferred asset profile.

Cogeneration Division

Sanger, California

For the quarter ended December 31, 2007, revenue from the Cogeneration Division totaled $13.7 million as compared to $19.3 million during the same period in 2006. For the quarter ended December 31, 2007, the division's performance decreased as compared to the same period in 2006, due to a decrease of 11,000 MW-hrs of production resulting from the closing of the Crossroads facility in December 2006 and a decrease of 9,000 MW-hrs of production at the Sanger facility due to the planned outage to allow for the installation of the LM6000 turbine, as part of the Sanger re-powering project.

For the quarter ended December 31, 2007, revenue from energy sales totalled $12.9 million as compared to $18.2 million during the same period in 2006. Revenue from energy sales decreased $1.3 million as a result of lower production at the Sanger facility due to the repowering project and $1.4 million as a result of the closure of the Crossroads facility, partially offset by $0.9 million as a result of increased energy rates at the Sanger facility resulting from higher fuel costs, which are passed on to the customer in the energy price. The division reported lower revenue of $2.3 million from operations as a result of the stronger Canadian dollar. In the comparable quarter in 2006, a realized gain on foreign exchange forward contracts of $1.4 million was recorded as revenue.

For the quarter ended December 31, 2007, other revenue totalled $0.9 million compared to $1.1 million during the same period in 2006. Other revenue remained consistent with the prior period.

For the year ended December 31, 2007, revenue from the Cogeneration Division totalled $64.7 million compared to $77.8 million during the same period in 2006. For the year ended December 31, 2007, the division's production increased as compared to the same period in 2006, due to an increase of 24,000 MW-hrs of production from the Windsor Locks facility and an increase of 26,000 MW-hrs of production at the Sanger facility. In the comparable period in 2006, Sanger had no production from January to April as the facility was voluntarily shutdown in favour of selling natural gas. The division's overall production decreased by 43,000 MW-hrs as a result of the closure of the Crossroads facility in December 2006

For the year ended December 31, 2007, revenue from energy sales totalled $60.9 million as compared to $68.5 million during the same period in 2006. Revenue from energy sales decreased $0.8 million as a result of lower energy rates realized at the Windsor Locks facility where decreased fuel costs are passed on to the customer in the form of lower energy prices and $6.0 million resulting from the closure of the Crossroads facility. These reductions were partially offset by $4.2 million resulting from increased production at the Sanger Facility and $2.6 million resulting from increased production at the Windsor Locks facility. The division reported lower revenue of $3.4 million from operations as a result of the stronger Canadian dollar. In the comparable quarter in 2006, a realized gain on foreign exchange forward contracts of $4.3 million was recorded as revenue.

For the twelve months ended December 31, 2007, other revenue totalled $3.8 million as compared to $9.2 million during the same period in 2006. Other revenue in the comparable period in 2006 primarily consisted of the sale of natural gas at the Sanger facility which did not occur in 2007.

Financial Summary

(C$000)	Three months ended December 31 2007	2006	Year ended December 31 2007	2006
Performance (MW-hrs sold)	**109,620**	131,567	**484,297**	477,132
Revenue				
Energy sales	**$ 12,871**	$ 18,189	**$ 60,895**	$ 68,544
Other revenue	**865**	1,061	**3,774**	9,247
Total Revenue	**$ 13,736**	$ 19,250	**$ 64,669**	$ 77,791
Expenses				
Operating expenses	**$ (10,111)**	$ (13,639)	**$ (46,822)**	$ (53,362)
Interest and dividend income	**824**	732	**3,222**	3,382
Gain on financial instruments	**2,155**	-	**5,303**	-
Division operating profit (including interest and dividend income)	**$ 6,604**	$ 6,343	**$ 26,372**	$ 27,811

For the quarter ended December 31, 2007, the Fund earned $0.8 million in dividend income from its portfolio investments, as compared to $0.7 million during the same period in 2006. The Fund earned $3.2 million from its portfolio investments for the year ended December 31, 2007 as compared to $3.4 million in 2006.

For the quarter ended December 31, 2007, operating expenses totalled $10.1 million as compared to $13.6 million during the same period in 2006. Operating expenses decreased $0.4 million as a result of lower gas expense and $1.6 million as a result of the closure of the Crossroads facility. The division reported lower expenses of $1.6 million from U.S. operations as a result of the stronger Canadian dollar.

For the year ended December 31, 2007, operating expenses totalled $46.8 million as compared to $53.4 million during the same period in 2006. Operating expenses decreased $6.4 million as a result of the closure of the Crossroads facility, partially offset by increased gas expense of $2.4 million. The division reported lower expenses of $2.6 million from U.S. operations as a result of the stronger Canadian dollar.

Gain on financial instruments consist of realized gains on the foreign exchange forward contracts settled in the fourth quarter of 2007 and the year ended December 31, 2007. These amounts were recorded in revenue in the comparable periods in 2006.

For the quarter ended December 31, 2007, operating profit totalled $6.6 million as compared to $6.3 million during the same period in 2006. Operating profit for the year ended December 31, 2007 totalled $26.4 million as compared to $27.8 million in 2006. Operating profit in the Cogeneration Division for the quarter and year ended December 31, 2007 met Management's expectations.

On December 5, 2007, a new LM6000 turbine was installed and is now producing power at the 42MW natural gas powered Sanger facility as part of a major re-powering project for the facility that commenced in October 2006. The project is on budget with a total cost of approximately $25.0 million (U.S. $23 million).

Outlook

The Windsor Locks facility is expected to continue to operate through 2008 in line with management's long term expectations. The facility has no planned major outages in the first quarter of 2008 and output levels are forecasted to remain within historical ranges.

With the substantial completion of the Sanger re-powering project, the Fund expects a fuel requirement reduction of 23% at the facility representing approximately $2.0 million in annual savings and an increase in the energy output of the facility beginning in 2008. The increased output is associated with the greater economic availability of the new unit under the Sanger facility's current Power Purchase Agreement ("PPA"). In addition, the Fund expects the Sanger facility to benefit from a longer useful life of the facility as well as from lower maintenance costs given the broad industry support for the new turbine.

As a result of the retrofit, the facility has approximately 14 MW of capacity in excess of its current PPA requirement. Management is reviewing its options with regards to marketing this additional energy and is focusing its efforts on securing a market for the additional capacity. Such capacity could be sold to its existing customer or to the general market.

Management is reviewing the potential opportunities of contracting the output from the Crossroads facility to the New Jersey power market. It is anticipated that a contracting strategy will be completed by the second quarter of 2008.

Alternative Fuels Division

Algonquin Power Energy-from-Waste,, Ontario

The Alternative Fuels Division produced sufficient renewable energy to supply the equivalent of 21,000 homes with renewable power for the three months ended December 31, 2007 and the equivalent of 20,000 homes with renewable power for the 2007 fiscal year. Operations at the EFW facility resulted in the diversion of 28,000 tonnes of waste from landfill sites in the fourth quarter of 2007 and the diversion of 98,500 tonnes of waste from landfill sites for the 2007 fiscal year. Using new standards of thermal generation, renewable energy production saved the equivalent of 51,000 tons of CO_2 gas from entering the atmosphere in the fourth quarter of 2007 and 195,000 tons of CO_2 gas from entering the atmosphere in the year.

For the quarter ended December 31, 2007, revenue in the Alternative Fuels Division totalled $13.3 million as compared to $11.8 million during the same period in 2006. During the quarter ended December 31, 2007, the division's performance was 13,000 MW-hrs below expectations as a result of blade repair and other maintenance being performed at the St. Leon facility. Under the Agreement with Vestas an availability guarantee compensates the Fund for lost production and resulting revenue in this event. For the quarter ended December 31, 2007 revenue from energy increased $5.1 million due to the St. Leon facility achieving Commercial Operation on September 18, 2007, when liquidated damages (recorded as 'Other Revenue') ceased and energy sales commenced to be earned by the facility. As a result of the St. Leon facility achieving Commercial Operation, other revenue decreased $3.9 million from the comparable period in 2006. Revenue from waste disposal for the quarter ended December 31, 2007 increased $0.4 million due to increased throughput at the EFW facility. In the comparable quarter in 2006, a realized gain on foreign exchange forward contracts of $0.2 million was recorded as revenue.

Other revenue consists of primarily of liquidated damages earned by the St. Leon facility. Liquidated damages were intended to approximate the expected revenue of the facility once it is fully operational and are meant to minimize any downside to the owners of delays in project completion. The St. Leon facility achieved Commercial Operation on September 18, 2007. Therefore, liquidated damages ceased being earned by the facility subsequent to this date.

For the year ended December 31, 2007, revenue totalled $46.8 million as compared to $34.9 million during the same period in 2006. During the year ended December 31, 2007, the division's performance increased 180,000 MW-hrs due to the inclusion of production from the St. Leon facility. For the year ended December 31, 2007, throughput at the EFW facility decreased 13,000 tonnes primarily due to operational issues experienced in the second quarter of 2007, as compared to the same period in 2006. Revenue from energy for the year ended December 31, 2007 increased $5.0 million due to the St. Leon facility achieving Commercial Operation, partially offset by $1.1 million due to lower production and reduced average energy prices from the two remaining LFG facilities, as compared to the same period in 2006. Other revenue increased $7.5 million from the comparable period in 2006 primarily as a result of the St. Leon facility earning liquidated damages during the majority of the year ended December 31, 2007. Revenue from

Financial Summary

(C$000)	Three months ended December 31		Year ended December 31	
	2007	2006	**2007**	2006
Performance (MW-hrs sold) *	**115,023**	133,617	**441,542**	286,679
Performance (tonnes of waste processed)	**40,088**	38,928	**140,618**	153,887
Revenue				
Energy sales *	**$ 7,265**	$ 2,199	**$ 14,647**	$ 9,675
Waste disposal sales	**3,923**	3,562	**13,609**	14,209
Other revenue	**2,147**	6,017	**18,528**	11,039
Total revenue	**$ 13,335**	$ 11,778	**$ 46,784**	$ 34,923
Expenses				
Operating expenses *	**$ (5,157)**	$ (5,034)	**$ (20,098)**	$ (18,783)
Interest and other income	**148**	552	**2,895**	5,480
Gain on financial instruments	**773**	-	**1,009**	-
Division operating profit (including interest and dividend income)	**$ 9,099**	$ 7,296	**$ 30,590**	$ 21,620

* Prior period comparative amounts have been adjusted due to the classification of certain LFG facilities as Discontinued Operations. This has been set out in more detail in Note 15 of the annual financial statements.

waste disposal for the year ended December 31, 2007 decreased $0.6 million due to reduced throughput at the EFW facility. In the comparable twelve month period in 2006, a realized gain on foreign exchange forward contracts of $0.6 million was recorded as revenue.

For the quarter ended December 31, 2007, operating expenses totalled $5.2 million as compared to $5.0 million during the same period in 2006. The increase in operating expenses for the quarter was primarily due to a $0.3 million increase in repair and maintenance costs at the EFW facility as compared to the same period in 2006. The division reported lower operating expenses from U.S. operations as a result of a stronger Canadian dollar.

For the year ended December 31, 2007, operating expenses totalled $20.1 million as compared to $18.8 million during 2006. The increase in operating expenses for the year was due to an increase of $1.1 million due to the inclusion of a full year of operating expenses from the St. Leon facility, increased operating costs of $0.6 million at the Fund's EFW facility and an increase in repair and maintenance costs of $0.7 million at the EFW facility, partially offset by a non-recurring reduction in operating expenses at the St. Leon facility, as compared to the same period in 2006. The division reported $0.2 million in lower operating expenses from U.S. operations as a result of a stronger Canadian dollar.

During the quarter ended December 31, 2007, the Fund earned less interest and other income on its investments within the Alternative Fuels Division as compared to the same period in 2006 primarily as a result of the write down of the Across America Note to its net realizable value.

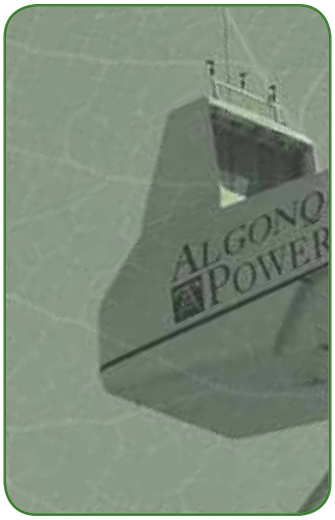
During the year ended December 31, 2007, the Fund earned lower interest and other income on its investments within the Alternative Fuels Division as compared to the same period in 2006, primarily as a result of the acquisition of AirSource Power Fund I LP ("AirSource") and consequently consolidating AirSource into the Fund. As a result, the Fund recognized no income from the note in the year ended December 31, 2007 as compared to $2.9 million in the same period in 2006. This reduction was partially offset by the recognition of interest income earned by the St. Leon facility on unpaid liquidated damages up to Commercial Operation in the third quarter of 2007.

Also included in other income for the year ended December 31, 2007 was $0.2 million related to landfill gas production tax credits associated with the LFG facilities, as compared to $1.2 million in 2006. The production tax credit program does not extend past December 31, 2007. The value of the tax credits to the Fund was negatively impacted by the increase in the average price of crude oil in the year.

Gain on financial instruments consists of realized gains on the foreign exchange forward contracts settled in the fourth quarter of 2007 and twelve months ended December 31, 2007. These amounts were recorded in revenue in the comparable periods in 2006.

For the quarter ended December 31, 2007, operating profit totalled $9.1 million as compared to $7.3 million during the same

Alternative Fuels Division



St Leon, Manitoba

Financial Summary Cont'd

period in 2006. Operating profit for the year ended December 31, 2007 totalled $30.6 million as compared to $21.6 million in 2006. Operating profit met management's expectations for the quarter and year ended December 31, 2007.

On September 18, 2007, the Fund reached an Agreement with Vestas to achieve Commercial Operation pursuant to the TCC at the St. Leon facility. Commercial Operation as defined in the TCC occurs when a project is "substantially complete" and ownership is formally transferred from the contractor to the owner of the project. This also marks the commencement of the five year warranty period with Vestas. Under the warranty agreement with Vestas, the projected availability of the project is guaranteed by Vestas and the turbine equipment is warranted against defects. The facility achieved commercial operation pursuant to the power purchase agreement with Manitoba Hydro in 2006 and St. Leon has been generating renewable electricity since that time, enjoying a substantial and proven wind resource. The declaration of Commercial Operation pursuant to the TCC was pending the resolution of certain outstanding construction related issues under the TCC.

The Agreement with Vestas established Commercial Operation and provided the framework and timing under which Vestas has agreed to resolve the facility's outstanding issues under the TCC. Vestas has resolved two of these issues and is required to resolve the remaining issues by certain dates. It is Management's belief that the Agreement resolves the potential issues that might have limited the overall production of the facility. The Fund continues to hold financial security posted by Vestas in respect of its obligations under the Agreement. It is Management's belief that such financial security is sufficient to rectify the outstanding issues in the event Vestas fails to complete the necessary work.

Outlook

The St. Leon facility is expected to continue to perform at or above a 97% availability target throughout 2008, meeting Management's expectations. Based on current wind studies, the St. Leon facility is expected to produce sufficient renewable energy in 2008 to supply the equivalent of 21,000 homes with renewable power for a year. Using new standards of thermal generation, renewable energy production is expected to save the equivalent of 205,000 tons of CO_2 gas from entering the atmosphere in the 2008 fiscal year.

Throughput at the EFW facility had increased throughout the fourth quarter of 2007. With the continuous focus on operational improvements, management expects that this improved availability will continue in 2008. The operations of the EFW facility in 2008 are expected to result in the diversion of 100,000 tonnes of waste from landfill sites. Management is reviewing its options to improve the results at the facility through participation in the Ontario Power Authority's Standard Offer for Combined Heat and Power Projects in the second quarter of 2008.

On April 2nd 2008, the labour agreement with the National Automobile, Aerospace, Transportation General Workers Union of Canada ("CAW") local 252 will expire. The CAW local 252 represents approximately 45 members at the EFW facility. Contract negotiations with the CAW commenced in February of 2008.

The steam supply project is on schedule and expected to be completed in the first quarter of 2008 with the commissioning to be completed shortly after. The project utilizes the steam generated through the incineration process at the EFW facility and sells it to a nearby industrial customer.

Infrastructure Division

Litchfield Park, Arizona

Gold Canyon, Arizona

During the quarter ended December 31, 2007, water utilities in the Infrastructure Division provided approximately 1.4 billion U.S. gallons of water to its customers, treated approximately 508 million U.S. gallons of sewage and sold approximately 230 million U.S. gallons of treated effluent. During the year ended December 31, 2007, water utilities in the Infrastructure Division provided approximately 5.65 billion U.S. gallons of water to customers, treated approximately 2.0 billion U.S. gallons of sewage and sold 689 million U.S. gallons of treated effluent.

For the quarter ended December 31, 2007, revenue in the Infrastructure Division totalled $8.0 million as compared to $8.6 million during the same period in 2006. The division's waste-water treatment and water distribution customer base grew marginally during the quarter ended December 31, 2007, consistent with the same period in 2006. Both the division's waste-water treatment and water distribution customer base grew by approximately 3% during the year ended December 31, 2007 as compared to 12% and 7% respectively in the same period in 2006. The increase in water distribution customers includes approximately 1,200 customers related to assets and regulatory licenses near the town of Sierra Vista, Arizona ("Sunrise"), acquired in the first quarter of 2007. The division reported lower revenue for the quarter ended December 31, 2007 of $1.1 million from operations as a result of the stronger Canadian dollar. This was partially offset by increased revenue of $0.5 million at the Gold Canyon facility due to the July 2007 rate increase combined with organic growth at existing facilities during the quarter as compared to the same period in 2006. In the comparable period in 2006, realized gain on foreign exchange forward contracts of $0.5 million was recorded as revenue.

Revenue for the year ended December 31, 2007 totalled $33.7 million as compared to $35.5 million during the same period in 2006. The division reported lower revenue for the year ended December 31, 2007 of $1.7 million from operations as a result of the stronger Canadian dollar. This was partially offset by increased revenue of $1.3 million at the Gold Canyon facility primarily due to the July 2007 rate increase, an increase of approximately $1.0 million resulting from growth and increased usage at existing facilities and an increase of $0.6 million from the acquisition of Sunrise during the first quarter of 2007 as compared to the same period in 2006. In the comparable period in 2006, realized gain on foreign exchange forward contracts of $3.0 million was recorded as revenue.

For the quarter ended December 31, 2007, operating expenses totalled $4.2 million as compared to $4.1 million during the same period in 2006. The increase in operating expenses was due to an increase of $0.2 million due to the acquisition of Sunrise in the first quarter of 2007 and an increase of $0.6 million as the result of customer growth combined with increased costs of regulatory compliance, additional personnel, utilities, property taxes, arsenic treatment and other operational expenses incurred by the division, as compared to the same period in 2006. The division reported lower expenses from operations of $0.7 million as a result of a stronger Canadian dollar, which partially offset the increases.

For the year ended December 31, 2007, operating expenses totalled $17.4 million as compared to $15.4 million during the same period in 2006. The increase in operating expenses was due to an increase of $0.5 million due to the acquisition of Sunrise in the first quarter of 2007 and an increase of $2.5 million as the result of factors

Financial Summary

(C$000)	Three months ended December 31		Year ended December 31	
	2007	2006	**2007**	2006
Number of				
Waste-water customers	**29,907**	28,911	**29,907**	28,911
Water distribution customers	**34,685**	32,524	**34,685**	32,524
Revenue				
Waste-water and distribution	**$ 7,991**	$ 8,598	**$ 33,699**	$ 35,464
Expenses				
Operating expenses	**$ (4,210)**	$ (4,085)	**$ (17,401)**	$ (15,370)
Other income	**-**	17	**33**	53
Gain on financial instrument	**1,134**	-	**3,296**	-
Division operating profit (including other income)	**$ 3,781**	$ 4,530	**$ 16,331**	$ 20,147

indicated in the discussion of the fourth quarter results above, as compared to the same period in 2006. The division reported lower expenses from operations of $1.0 million as a result of a stronger Canadian dollar, which partially offset the increases.

Gain on financial instruments consists of realized gains on the foreign exchange forward contracts settled in the fourth quarter of 2007 and twelve months ended December 31, 2007. These amounts were recorded in revenue in the comparable periods in 2006.

For the quarter ended December 31, 2007, operating profit totalled $3.8 million as compared to $4.5 million during the same period in 2006. Operating profit for the year ended December 31, 2007 totalled $16.3 million from $20.1 million in 2006. Operating profit did not met management's expectations for the quarter and year ended December 31, 2007.

Outlook

The Infrastructure Division is expecting a reduced organic growth rate of approximately 4% average organic growth during 2008 due to the slowdown in the U.S. housing market. However, the Infrastructure Division continues to service one of the faster growing counties in the United States. The Division anticipates providing approximately 6.0 billion U.S. gallons of water to customers, treating approximately 2.1 billion U.S. gallons of sewage and selling 700 million U.S. gallons of treated effluent in the year ended December 31, 2008.

The Fund anticipates initiating rate cases at its Litchfield Park ("LPSCo"), Black Mountain and Bella Vista facilities during 2008 and a rate case at Sunrise in late 2008 or early 2009. It is anticipated that regulatory review of the rates and tariffs for the above noted facilities would be completed in the second half of 2009. The Fund's likelihood of achieving an increase in the rates and tariffs charged by its facilities and the amount of such increase is unknown at this time as the rate case process is in the early stages. Rate cases ensure that the respective facility earns the rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. The resolution of rate cases is expected to positively impact results in the division. The Fund will continue to evaluate the effective returns on each of its utility investments to determine the appropriate time to file rate cases in order to ensure it earns the regulatory approved return on investment.

Federal drinking water legislation in the United States requires all drinking water systems to meet standards respecting levels of naturally occurring arsenic in drinking water. Arsenic treatment systems scheduled for installation in 2007 on certain LPSCo facility well sites have been completed and further systems will be installed in the second quarter of 2008 and early 2009. The phased installation of the systems ensures continued full compliance with the regulatory requirements.

Capital projects are planned in the LPSCo service area during 2008. In particular, these projects are expected to increase the water distribution storage and pumping/distribution capacity and waste-water treatment capacity within the utility's jurisdiction, in order to meet the demands of existing customers as well as expected growth.

The Fund continues to pursue accretive opportunities to expand the Infrastructure Division in areas where the Fund already operates and to acquire other utilities in high growth areas in the United States.

Administrative Expenses

(C$000)	Three months ended December 31		Year ended December 31	
	2007	2006	**2007**	2006
Administrative expenses	**$ 2,389**	$ 2,060	**$ 8,463**	$ 8,014
Management costs	**991**	217	**1,637**	869
Withholding taxes	**-**	104	**-**	104
Loss / (Gain) on foreign exchange	**(742)**	2,547	**(7,688)**	216
Interest expense	**6,901**	6,341	**26,565**	22,281
Write down of fixed and intangible asset and note receivable	**128**	3,263	**726**	3,263
Interest, dividend and other Income	**(63)**	(38)	**(1,926)**	(113)
Loss (Gain) on hedging instruments	**3,858**	(155)	**(4,862)**	497
Income tax expense (recovery)	**(5,615)**	(1,485)	**15,108**	(2,766)

During the quarter ended December 31, 2007, administrative expenses totalled $2.4 million as compared to $2.1 million in the same period in 2006. The increase for the quarter was due to added requirements to administer the Fund, including additional staff. During the year ended December 31, 2007, administrative expenses totalled $8.5 million as compared to $8.0 million in the same period in 2006. The increase for the year relates to the factors discussed above. The Fund incurred expenses in an amount of $0.9 million associated with an offer to purchase the outstanding units of Clean Power Income Fund ("CPIF") in the first quarter of 2007. This amount was reimbursed by CPIF during the second quarter of 2007, resulting in no impact on administrative expenses for the year ended December 31, 2007.

During the quarter ended December 31, 2007, management expenses totalled $1.0 million as compared to $0.2 million in the same period in 2006. The increase for the quarter was due to the inclusion of a $0.8 million incentive fee earned by the Manager, pursuant to its management agreement with the Fund, of 25% of all distributable cash generated in excess of $0.92. During the year ended December 31, 2007, management expenses totalled $1.6 million as compared to $0.9 million in the same period in 2006. Management expenses increased for the reasons discussed in the quarterly analysis, above.

Foreign exchange gains and losses primarily represent unrealized gains or losses on U.S. dollar denominated debt and do not impact cash available for distribution. For the quarter ended December 31, 2007 the Fund reported a foreign exchange gain of $0.7 million as compared to a loss of $2.5 million during same period in 2006. For the year ended December 31, 2007 the Fund reported a foreign exchange gain of $7.7 million versus a loss of $0.2 million in 2006. At the end of the fourth quarter, the Fund had approximately $33.5 million in U.S. dollar denominated debt.

For the quarter ended December 31, 2007, interest expense increased to $6.9 million as compared to $6.3 million during the same period in 2006. For the year ended December 31, 2007, interest expense increased to $26.6 million as compared to $22.3 million in 2006. The increase was due to increased average levels of debt held by the Fund during the year, additional interest due as a result of the convertible debenture issue in November 2006, the project financing related to the St. Leon facility and a higher interest rate charged on the Fund's credit facility.

For the year ending December 31, 2007, interest, dividend and other income primarily represents a termination fee of $1.75 million received in connection with the Fund's offer to purchase the outstanding units of CPIF. The Fund allowed its offer to expire during the second quarter.

Gains or losses on hedging instruments represent changes in the unrealized value of the Fund's interest rate swap and foreign currency hedges and do not impact cash available for distribution. Realized gains or losses on hedging instruments are included in the divisional results. As the Fund discontinued hedge accounting in 2006, the change in value of the foreign currency hedges was not included in the comparable figures.

An income tax recovery of $5.6 million was booked in the fourth quarter of 2007, as compared to $1.5 million during the same period in 2006. An income tax expense of $15.1 million was booked in the year ended December 31, 2007 as compared to a recovery

Administrative Expenses Cont'd

of $2.8 million in 2006. The recovery in the fourth quarter was the result of decreased future income tax expense resulting from a reduction in expected future taxes due to a reduction in future tax rates and the impact of tax losses generated by certain facilities of the Fund. The expense in the year ended December 31, 2007 was primarily the result of a non-recurring non-cash charge of $27.9 million relating to the substantive enactment of Bill C-52, offset by the factors discussed in the quarterly results.

Cash Available for Distribution

(C$000)	Three months ended December 31		Year ended December 31	
	2007	2006	**2007**	2006
Cash provided by (used in) Continuing Operations [1]	**$ (610)**	$ 17,953	**$ 40,427**	$ 69,332
Changes in working capital	**16,333**	631	**30,744**	951
	15,723	18,584	**71,171**	70,283
Receipt of principal on notes receivable	**236**	954	**1,319**	3,608
Repayment of long term liabilities	**(467)**	(445)	**(1,305)**	(1,254)
Maintenance capital expenditures [2]	**(886)**	(908)	**(4,121)**	(3,714)
Other – non-recurring [3]	**5,318**	(662)	**5,285**	(1,429)
Cash available for distribution	**$ 19,924**	$ 17,477	**$ 72,349**	$ 67,491
Add Back:				
Maintenance capital expenditures	**886**	908	**4,121**	3,714
Deduct:				
Net growth, maintenance and other capital expenditures	**(12,680)**	(14,803)	**(40,561)**	(54,371)
Cash available for distribution after growth and maintenance capital expenditures	**$ 8,130**	$ 3,582	**$ 35,909**	$ 16,834
Distribution to Unitholders	**$ 17,481**	$ 17,481	**$ 69,923**	$ 66,955
Per Trust Unit				
Cash provided by (used in) Continuing Operations	**$ (0.01)**	$ 0.24	**$ 0.53**	$ 0.95
Cash available for distribution	**$ 0.26**	$ 0.23	**$ 0.95**	$ 0.93
Cash available for distribution after net growth and maintenance capital expenditures	**$ 0.11**	$ 0.05	**$ 0.47**	$ 0.23
Distributions to Unitholders	**$ 0.23**	$ 0.23	**$ 0.92**	$ 0.92
Distributions declared during the period	**$ 0.23**	$ 0.23	**$ 0.92**	$ 0.92

1 Prior period comparative amounts have been adjusted due to the classification of certain LFG and New England Hydroelectric facilities as Discontinued Operations. This has been set out in more detail in Note 15 of the audited annual financial statements.

2 Maintenance capital expenditures includes capital expenditures capitalized in accordance with GAAP, which are of a replacement or regulatory nature or represent a major maintenance cost intended to maintain the Fund's current operations and current level of distributable cash and refunds of developer contributions in the Infrastructure Division. The expenditures are amortized over the expected life of the respective asset and the amount amortized in the period is deducted in the calculation of cash available for distribution.

3 Other includes various non-recurring adjustments including cash available from or used in discontinued operations, final adjustments related to the Fund's investment in the St. Leon Facility, and gain on sale of capital assets.

Cash Available for Distribution Cont'd

The preceding tables are derived from and should be read in conjunction with the Consolidated Statement of Cash Flows. This supplementary disclosure is intended to clarify disclosures related to cash available for distribution and provides additional information related to the cash flows of the Fund including the amount of cash available for distribution to Unitholders. Investors are cautioned that these measures should not be construed as an alternative to the Canadian generally accepted accounting principles ("GAAP") consolidated statement of cash flows. The terms "cash available for distribution" and "cash available for distribution before distributable cash reserve and after growth and maintenance capital expenditures" are not terms defined under GAAP and there is no standardized measure of these terms. Consequently, these terms, as presented, may not be comparable to similar measures presented by other income funds. Management believes that presentation of this measure will enhance an investor's understanding of the Fund's operating performance.

During the quarter ended December 31, 2007 the Fund used $0.6 million in cash provided by Continuing Operations as compared to generating $17.9 million for the same period in 2006. During the year ended December 31, 2007, the Fund generated $40.4 million in cash provided by Continuing Operations as compared to $69.3 million for the same period in 2006. The change in cash generated in the quarter and year ended December 31, 2007 is primarily due to the final payments made in respect of the St. Leon facility TCC.

During the quarter ended December 31, 2007 the Fund generated $19.9 million or $0.26 per trust unit in cash available for distribution as compared to $17.5 million or $0.23 per trust unit for the same period in 2006. The Fund distributed $17.5 million or $0.23 per trust unit during the quarter ended December 31, 2007, consistent with the same period in 2006.

During the year ended December 31, 2007, the Fund generated $72.3 million or $0.95 per trust unit in cash available for distribution as compared to $67.5 million or $0.93 per trust unit for the same period in 2006. The Fund distributed $69.9 million or $0.92 per trust unit during the year ended December 31, 2007 as compared to $67.0 million or $0.92 per trust unit during the same period in 2006.

The Fund's distribution as a percentage of 'Cash available for distribution' ("Payout Ratio") was 87.7% during the fourth quarter of 2007 and 96.6% during the year ended December 31, 2007. The Fund achieved improving annual Payout Ratios of 123.4% in 2002, 106.9% in 2003, 105.8% in 2004, 98.7% in 2005 and 99.2% in 2006. The Fund has generated more cash available for distribution than it distributed for the previous three consecutive years.

Distributions paid can be different from distributions declared during a period. Monthly distributions are declared by the Fund for Unitholders of record on the last business day of each month and are paid within 45 days following each month end.

Excess (deficiency) Cash Flows and Net Income Over Distributions Paid

The following chart presents excess or deficiency in cash flows from operating activities and net income over distributions paid for the quarter and the year ended December 31, 2007 and for the years ended December 31, 2006 and 2005.

(C$000)	Three months and year ended December 31, 2007		Year ended December 31 2006	2005
Cash flow from operating activities	$ (610)	$ 40,427	$ 69,332	$ 55,679
Distributions paid during the period	$ 17,481	$ 69,923	$ 66,955	$ 64,061
Excess (shortfall) of cash flows from operating activities over cash distributions paid	$ (18,091)	$ (29,496)	$ 2,377	$ (8,382)
Net income from continuing operations	$ 8,762	$ 24,763	$ 30,728	$ 21,788
Distributions paid during the period	$ 17,481	$ 69,923	$ 66,955	$ 64,061
Excess (shortfall) of net income over cash distributions paid	$ (8,719)	$ (45,160)	$ (36,227)	$ (42,273)

Excess (deficiency) Cash Flows and Net Income Over Distributions Paid

The shortfall of net income over cash distributions and of cash flows from operating activities over cash distributions have been funded though working capital management, cash on hand or additional borrowings under the Fund's revolving credit facility.

The Fund considers the amount of cash generated by the business in determining the amount of distributions to its Unitholders. In general, the Fund does not take into account quarterly working capital fluctuations as these tend to be temporary in nature. The Fund does not generally consider net income in setting the level of distributions as this is a non-cash calculation and does not reflect the level of cash flow generated by the Fund. This is particularly apparent when considering the Fund's relatively high level of depreciation and amortization expense as well as significant volatility in the Funds income due to fluctuations in the market value of the Fund's hedging instruments and interest rate swaps.

Summary of Capital Expenditures by Segment

(C$000)	Three months ended December 31		Year ended December 31	
	2007	2006	**2007**	2006
Hydro-electric Division				
Maintenance capital expenditures	**$ 796**	$ 669	**$ 1,199**	$ 709
Growth and other capital expenditures	**-**	39	**-**	994
Total	**$ 796**	$ 708	**$ 1,199**	$ 1,703
Co-Generation Division				
Maintenance capital expenditures	**$ 343**	$ 34	**$ 637**	$ 3,771
Growth and other capital expenditures	**5,981**	10,088	**13,139**	10,221
Total	**$ 6,324**	$ 10,122	**$ 13,776**	$ 13,992
Alternative Fuels Division				
Maintenance capital expenditures	**$ 169**	$ 1,127	**$ 2,260**	$ 3,026
Growth and other capital expenditures	**(2,145)**	55	**3,925**	21,085
Total	**$ (1,976)**	$ 1,182	**$ 6,185**	$ 24,111
Infrastructure Division				
Maintenance capital expenditures	**$ -**	$ -	**$ -**	$ -
Growth and other capital expenditures	**7,384**	2,616	**19,087**	14,347
Total	**$ 7,384**	$ 2,616	**$ 19,087**	$ 14,347
Consolidated (includes Administration)				
Maintenance capital expenditures	**$ 1,460**	$ 2,044	**$ 4,410**	$ 7,724
Growth and other capital expenditures	**11,220**	12,759	**36,151**	46,647
Total	**$ 12,680**	$ 14,803	**$ 40,561**	$ 54,371

During the quarter ended December 31, 2007, the Fund incurred growth and other capital expenditures of $11.3 million, as compared to $12.7 million during the comparable period in 2006. During the year ended December 31, 2007, the Fund incurred growth and other capital expenditures of $36.2 million, as compared to $45.3 million during the comparable period in 2006.

During the quarter ended December 31, 2007, the change in the Alternative Fuels Division's growth and other capital expenditures primarily relates to the final adjustments related to the Fund's investment in the St. Leon Facility having achieved commercial operations status in 2007. During the year ended December 31, 2007 the Alternative Fuels Division's growth and other capital expenditures also included the capital investment in the Fund's

Summary of Capital Expenditures by Segment Cont'd

steam sales supply project. The steam sale project is substantially complete and is not expected to require significant additional capital in the 2008 fiscal year. 'Acquisition of operating Entities' in the 2006 comparative period primarily relates to the acquisition of the St. Leon facility.

During the quarter and year ended December 31, 2007 as well as the comparative periods, the Cogeneration Division's growth and other capital expenditures primarily relates to the Sanger re-powering project. The re-powering project is substantially complete and is not expected to require significant additional capital in the 2008 fiscal year. 'Maintenance capital expenditures' in the 2006 comparative period primarily relates to a planned major maintenance at the Windsor Locks facility.

During the quarter and year ended December 31, 2007 as well as the comparative periods, the Infrastructure Division's growth capital expenditures primarily relates to investment in additional wells, engineering work regarding the waste water treatment capacity and arsenic treatment at the LPSCo facility.

Capital expenditure requirements are anticipated to be approximately $30.0 million during fiscal 2008, including $0.8 million related to the completion of the Sanger re-powering project, $2.2 million related to the steam sale project and $20.0 million related to ongoing growth and regulatory requirements in the Infrastructure Division.

The Fund intends to finance its capital expenditures and other commitments through working capital, its revolving credit facility and through additional trust unit and/or debenture offerings.

Liquidity and Capital Reserves

For the quarter ended December 31, 2007, the Fund had $10.4 million of cash and cash equivalents. As at December 31, 2007, the Fund had net working capital of $1.2 million. For purposes of this calculation, working capital excludes cash and cash equivalent, current portion of notes receivable, current portion of derivative assets, current portion of long term liabilities and cash distributions payable.

Long term debt increased to $281.7 million at December 31, 2007 as compared to $229.0 million at December 31, 2006. The increase in long term debt is primarily due to the Fund's major growth capital projects including the Sanger re-powering, the steam sale project and the water reservoir and waste water capacity expansion projects in the Infrastructure Division. Long term liabilities primarily consist of project level debt of approximately $155.7 million and an amount of $126.0 million drawn on the Fund's revolving credit facility compared to project level debt of $162.0 million and an amount of $67.0 million drawn on the Fund's revolving credit facility at the end of the fourth quarter of 2006. In the fourth quarter of the comparable period in 2006, the Fund filed an amended prospectus for the sale and issue of $60.0 million in convertible debentures, resulting in net proceeds to the Fund of $57.1 million. The Fund used the proceeds of this convertible debenture offering in 2006 to reduce the balance outstanding on its credit facility. Project debt is paid at the project level where adequate cash flows are available to fund project debt requirements and the debt is generally non-recourse to the Fund. Project debt repayments are deducted in the calculation of cash available for distribution.

The Fund has in place a $175 million revolving credit facility of which $155 million is to be used for acquisitions, investments and letters of credit and $20 million is to be used for operating requirements. On January 16, 2008, the Fund completed a renewal of its combined $175 million senior secured revolving operating and acquisition credit facilities (the "Facilities") with its Canadian bank syndicate for a new three year term. Under terms of the renewal, the Facilities are extended for a three year term with a maturity date of January 14, 2011. The renewed Facilities also contain an accordion feature allowing the Facilities to increase to $225 million to accommodate future growth and acquisitions.

The renewal of the Facilities will result in reduced borrowing costs and provide a secure source of financing over the three year term of the agreement. At the quarter ended December 31, 2007, the Fund had drawn $126.0 million on its revolving credit facility in addition to letters of credit.

For the quarter ended December 31, 2007 the Fund maintained a long term debt-to-equity ratio (including long term liabilities, other long term liabilities, and convertible debentures) of 115%. The exchangeable trust units issued in conjunction with the purchase of AirSource have been included in equity for purposes of this calculation. The Fund may settle the outstanding convertible debentures, at its option, in cash, or, subject to certain conditions, in Fund units. Accordingly, if the convertible debentures are excluded from debt and included in equity in this calculation as at December 31, 2007 this ratio would be reduced to 58%.

Contractual Obligations

Information concerning contractual obligations as of February 27, 2008 is shown below:

(C$000)	Total	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years
Long term debt obligations	$ 283,453	$ 1,728	$ 6,417	$ 134,576	$ 140,732
Other obligations	16,931	3,204	880	553	12,296
Total obligations	$ 300,384	$ 4,932	$ 7,297	$ 135,129	$ 153,028

Long term obligations normally include regular payments related to long term debt and other obligations. These payments are included as a reduction to cash available for distribution. Included in the other obligations 'due in less than one year' is the Fund's commitment, as of February 27, 2008 of $2.2 million regarding the installation of the additional steam generation and transmission assets required for the sale of steam from the EFW facility and $0.8 million related to the completion of the Sanger re-powering project

Unitholders' Equity and Convertible Debentures

As at December 31, 2007, the Fund had 73,644,356 issued and outstanding trust units with a total of 76,070,057 trust units issued and outstanding on a fully diluted basis.

Pursuant to the takeover bid of AirSource, on September 29, 2006, the Fund issued trust units and a subsidiary issued trust units which are exchangeable into trust units of the Fund at the holder's option (the "Exchangeable Units"). During the fourth quarter of 2007, 78,817 trust units of the Fund were issued pursuant to the conversion of Exchangeable Units. During the year ended December 31, 2007, 768,643 trust units of the Fund were issued pursuant to the conversion of Exchangeable Units and 1,502 trust units of the Fund were issued pursuant to the exercise of the conversion option on its convertible debentures. As at December 31, 2007 there were 2,425,701 trust units of the Fund remaining to be issued pursuant to the conversion of Exchangeable Units. Subsequent to December 31, 2007 a further 35,358 trust units of the Fund were issued pursuant to the conversion of Exchangeable Units.

The Fund may issue an unlimited number of trust units. Each trust unit is transferable and represents an equal, undivided beneficial interest in any distribution from the Fund and the net assets of the Fund. All units are of the same class and with equal rights and privileges and are not subject to future calls or assessments. Each unit entitles the holder to one vote at all meetings of Unitholders.

In 2004, the Fund issued 85,000 convertible unsecured debentures at a price of $1,000 for each debenture. The debentures bear interest at 6.65% per annum and are convertible into trust units of the Fund at the option of the holder at a conversion price of $10.65 per trust unit, being a ratio of approximately 93.9 trust units for each $1,000 principal. The debentures may not be redeemed by the Fund prior to July 31, 2007. During the period of July 31, 2007 until July 30, 2009, the debentures may be redeemed by the Fund if the underlying trust unit price is equal to or exceeds a price of $13.31 (125% of the conversion price of $10.65). During the period of July 31, 2009 until the debenture's maturity, the Fund can redeem the debentures for 100% of the face value of debenture with cash or for 105% of the face value of debenture with additional trust units. During the third quarter of 2007, an investor exercised their option on $16 of convertible debentures. As at December 31, 2007, no additional convertible debentures had been presented for conversion and there were 84,964 convertible debentures outstanding.

In November 2006, the Fund issued 60,000 convertible unsecured debentures at a price of $1,000 for each debenture maturing on November 30, 2016. The debentures bear interest at 6.2% per annum and are convertible into trust units of the Fund at the option of the holder at a conversion price of $11.00 per trust unit, being a ratio of approximately 90.9 trust units for each $1,000 principal. The debentures may not be redeemed by the Fund prior to November 30, 2010. During the period of November 30, 2010

Unitholders' Equity and Convertible Debentures Cont'd

until November 29, 2012, the debentures may be redeemed by the Fund if the underlying trust unit price is equal to or exceeds a price of $13.75 (125% of the conversion price of $11.00). During the period of November 30, 2012 until the debenture's maturity, the Fund can redeem the debentures for 100% of the face value of debenture with cash or for 105% of the face value of debenture with additional trust units. As at December 31, 2007 no convertible debentures had been presented for conversion.

Dealings with Algonquin Power Group

The following related party transactions occurred during the year ended December 31, 2007 and are discussed in Notes 5 and 14 of the Fund's audited financial statements for the year ended December 31, 2007:

- APMI provides management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. In 2007 and 2006, APMI was paid on a cost recovery basis for all costs incurred and charged $867 (2006 – $869). APMI is also entitled to an incentive fee of 25% on all distributable cash (as defined in the management agreement) generated in excess of $0.92 per trust unit. During 2007 $770 (2006 – nil) was earned by APMI as an incentive fee.
- As part of the project to re-power the Sanger facility, the Fund entered into an agreement with APMI to undertake certain construction management services on the project. APMI is entitled to a development supervision fee plus a contingency fee for its construction management role on the project. During 2007, APMI was paid $98 (2006 – nil).
- The Fund has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Base lease costs for 2007 were $296 (2006 – $296) and additional rent representing operating costs was nil (2006 – $89).
- The Fund utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. In 2004, the Fund entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for the Fund's business use of the aircraft. Under the terms of this arrangement, the Fund will have priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft; such direct operating costs do not provide the affiliate with any profit or return on or of the capital committed to the aircraft. During the year, the Fund incurred costs in connection with the use of the aircraft of $422 (2006 – $403) and amortization expense related to the advance against expense reimbursements of $168 (2006 – $136).
- The Fund has project debt from Highground Capital Corporation ("HCC") (previously Algonquin Power Venture Fund) in an amount of $3.0 million related to the St. Leon facility. HCC advanced $1.6 million at a rate of 11.25% as part of the initial financing of the St. Leon facility which matures December 31, 2011 and advanced $1.4 million at a rate of 9.25% during the first quarter of 2007 which matures September 30, 2014. Both amounts are secured by the underlying assets of the St. Leon facility. During 2007, HCC was paid $258 (2006 – $86) in interest related to debt associated with the St. Leon facility. Some of the directors and shareholders of the Manager are also directors, officers and shareholders of the manager of HCC.
- In accordance with the construction services agreement related to the St. Leon facility GWAP, a company controlled by APMI, was paid $845 (2006 – $141) in 2007 for construction services. In 2007, the Fund also paid $1,353 (2006 – $517) to GWAP on a cost recovery basis related to ongoing operating expenses of the project. There remains a final payment of $134 to GWAP in respect of construction services. This amount will be paid in the first quarter 2008.
- AirSource has agreed to reimburse AirSource Power Fund GP Inc (the "General Partner") of the AirSource Power Fund I LP for reasonable costs incurred by it in acting as registrar and transfer agent and in attending to the administration of the Partnership, as required in the Partnership Agreement. The general partner was paid $11 during the year ended December 31, 2007 (2006 – $65).
- The Fund has entered into an agreement to sell steam from the EFW facility to an industrial customer located in close proximity to the EFW facility. To affect such sales, the Fund will incur the costs of certain additional steam generation and transmission assets. The Fund has committed to contractual arrangements to complete the project totaling approximately $15 million. The Fund has incurred amounts totaling $10,196 (2006 – $2,873) included in assets under construction of which $353 is capitalized interest (2006 – $0). APMI is entitled to 50% of the cash flow above 15% return on investment pursuant to its project management contract.

Discontinued Operations

(C$000)	Three months ended December 31		Year ended December 31	
	2007	2006	**2007**	2006
Performance (MW-hrs sold)	**19,149**	30,706	**97,613**	125,553
Revenue				
Energy sales	**$ 1,233**	1,735	**$ 6,651**	$ 8,171
Expenses				
Operating	**$ (1,549)**	$ (2,006)	**$ (8,077)**	$ (9,265)
Operating Loss	**(316)**	(271)	**(1,426)**	(1,094)
Interest expense	**(20)**	(4)	**(72)**	(8)
Amortization of capital and intangible assets	**(1,192)**	(418)	**(1,192)**	(1,670)
Current income tax expense	**(1,336)**	-	**(1,336)**	-
Future income tax recovery	**342**	-	**342**	-
Gain on sale of capital assets and intangible assets	**1,414**	-	**2,592**	-
Net income (loss) from discontinued operations (including interest and other income)	**$ (1,108)**	$ (693)	**$ (1,092)**	$ (2,772)
Net assets held for sale	**$ -**	$ 14,077	**$ -**	$ 14,077

On December 21, 2007 the Fund completed the sale of six landfill gas ("LFG") powered generating facilities for proceeds of approximately $11.3 million, representing approximately 18 MW of installed capacity. These LFG facilities, located in California and New Hampshire, were no longer considered strategic to the ongoing operations of the Fund.

On December 28, 2007, based on its earlier review of its smaller hydroelectric generating facilities, the Fund completed the sale of six smaller hydroelectric generating facilities in the New England region for proceeds of approximately $1.5 million. These facilities were no longer considered strategic to the ongoing operations of the Fund.

For the quarter ended December 31, 2007, revenue from Discontinued Operations totalled $1.2 million as compared to $1.7 million during the same period in 2006. For the year ended December 31, 2007, revenue totalled $6.7 million compared to $8.2 million during the same period in 2006. Reported energy sales revenue from U.S. operations was lower due to reduced production, the sale of the Burnsville facility in the second quarter of 2007 and the stronger Canadian dollar.

For the quarter ended December 31, 2007, operating expenses totalled $1.5 million as compared to $2.0 million during the same period in 2006. For the year ended December 31, 2007, operating expenses totalled $8.1 million compared to $9.3 million during the same period in 2006. Operating expenses decreased due to the sale of the Burnsville facility in the second quarter of 2007 and the stronger Canadian dollar as compared to the same period in 2006.

For the three months ended December 31, 2007, gain on sale of discontinued operations represents a gain related to the sale of the LFG and hydroelectric facilities in December 2007. For the year ended December 31, 2007, gain on sale of discontinued operations also includes a gain related to the sale of the Burnsville facility in the second quarter of 2007.

For the quarter ended December 31, 2007, operating loss totalled $0.3 million, consistent with the comparable period in 2006. Operating loss for the year ended December 31, 2007 totalled $1.5 million as compared to an operating loss of $1.1 million during the same period in 2006.

Risk Management

The Fund proactively manages its risk exposures in a prudent manner. The Fund maintains adequate insurance on all of its facilities. This includes property and casualty, boiler and machinery, and liability insurance. It has also initiated a number of programs and policies such as employee health and safety programs, environmental safety programs, currency hedging policies to manage its risk exposures.

There are a number of risk factors relating to the business of the Fund. Some of these risks include the dependence upon Fund businesses, regulatory climate and permits, U.S. versus Canadian dollar exchange rates, tax related matters, commodity prices, gross capital requirements, labour relations, reliance on key customers and environmental health and safety considerations. The risks discussed below are not intended as a complete list of all exposures that the Fund may encounter. A further assessment of the Fund's business risks is also set out in the 2007 Annual Information Form.

Mechanical risk

The Fund is entirely dependant upon the operations and assets of the Fund businesses. Accordingly, distributions to Unitholders are dependent upon the profitability of each of the Fund businesses. This profitability could be impacted by equipment failure, the failure of a major customer to fulfill its contractual obligations under its power purchase agreement, reductions in average energy prices, a strike or lock-out at a facility and expenses related to claims or clean-up to adhere to environmental and safety standards. These risks are mitigated through the diversification of the Fund's operations, both operationally (Hydro, Cogeneration, Alternative Fuels and Infrastructure) and geographically (Canada and U.S.), the use of regular maintenance programs, maintaining adequate insurance and the establishment of reserves for expenses. In addition, the Fund's existing long term power purchase agreements minimize the risk of reductions in average energy pricing.

Regulatory risk

Profitability of the Fund businesses is in part dependent on regulatory climates. In the case of some hydroelectric facilities, water rights are generally owned by governments who reserve the right to control water levels which may affect revenue. The water distribution and waste-water facilities are highly regulated and are subject to rate settings by state regulators. Management continually works with these authorities to manage the affairs of the business.

Seasonal fluctuations and hydrology

The hydroelectric operations of the Fund are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. The ability of these assets to generate income may be impacted by changes in water availability or other material hydrologic events within a watercourse. It is, however, anticipated that due to the geographic diversity of the facilities, variability of total revenues will be minimized.

Wind resource

The strength and consistency of the wind resource will vary from the estimate set out in the initial wind studies that were relied upon to determine the feasibility of the Facility. If weather patterns change or the historical data proves not to accurately reflect the strength and consistency of the actual wind, the assumptions underlying the financial projections as to the amount of electricity to be generated by the facility may be different and distributable cash could be impacted.

St. Leon facility completion risks

There remain certain completion risks associated with the St. Leon facility. It is Management's belief that the Agreement with Vestas substantially mitigates the risks associated with the completion of the project.

Foreign currency risk

Currency fluctuations may affect the cash flows the Fund would realize from its operations, as certain of the Fund businesses sell electricity or provide water distribution and waste water treatment services in the United States and receive proceeds from such sales in U.S. dollars. Such Fund businesses also incur costs in U.S. dollars. At the Fund's current exchange rate, approximately 50% of EBITDA and 60% of distributable cash is generated in U.S. dollars. The Fund estimates that, on an unhedged basis, a $0.01 change in the Canadian/US exchange rate impacts distributable cash by $0.005 per trust unit on an annual basis.

The Fund attempts to manage this risk through the use of forward contracts. At December 31, 2007, the Fund had effectively hedged 89% of its expected 2008 U.S. dollar cash flow at $1.22 and 41% of its expected 2009 U.S. dollar cash flow at $1.19. The Fund has total forward contracts to sell U.S. dollars from fiscal 2008 to fiscal 2011 totalling U.S. $68.6 million carrying an average rate of $1.16. Subsequent to December 31, 2007, the Fund entered into U.S. $ 35.2 million of additional forward contracts. This increased the Fund's effective hedge of its 2008 and 2009 expected U.S. dollar cash flow to 92% and 61% respectively and increased its total forward contracts to U.S. $103.8 million carrying an average rate of $1.12. The Fund's policy is not to utilize derivative financial instruments for trading or speculative purposes.

Credit risk

The Fund has a credit facility and project specific debt of approximately $281.7 million. In the event that the Fund was required to replace these facilities with borrowings having less favourable terms or higher interest rates, the level of cash generated for distribution may be negatively impacted. The Fund attempts to manage the risk associated with floating rate interest loans through the use of interest rate swaps. The Fund has a fixed for floating interest rate swap on its St. Leon project specific debt until September 2015 in the amount of $73.3 million in order to minimize volatility in the interest expense on this debt facility. The Fund has effectively fixed its interest expense on its senior debt facility at 5.47%. At December 31, 2007, the mark to market value of the interest rate swap was $0.1 million (loss of $0.5 million on December 31, 2006).

The cash available for distribution generated from several of the Fund's facilities are subordinated to senior debt. In the event that there was a breach of covenants or obligations with regards to any of these particular loans which was not remedied, the loan could go into default which could result in the lender realizing on its security and the Fund losing its investment in such facility. The Fund actively manages its operations to minimize the risk of this possibility.

Changes to income tax laws

Changes to income tax laws and the current tax treatment of mutual fund trusts could negatively impact the Fund. Although the Fund is of the view that it currently qualifies under current legislation as a mutual fund trust, there can be no assurance that the legislation will not be changed in the future or that Canada Revenue Agency ("CRA") will agree with this position. If the Fund ceases to qualify as a mutual fund trust, the return to Unitholders may be adversely affected.

On June 22, 2007, Bill C-52 which included legislation to impose a tax on and in respect of distributions from certain publicly traded income trusts and partnerships (the "SIFT Rules"). The SIFT Rules apply to "specified investment flow-throughs" ("SIFT") which includes trusts resident in Canada whose units are listed or traded on a stock exchange or other public market if the trust holds one or more "non-portfolio properties".

The Fund is a SIFT trust as defined by the SIFT Rules. The Fund would have been a SIFT trust on October 31, 2006 and had the SIFT Rules been in force on that date, the SIFT rules will not apply to the Fund until its first taxation year that ends in, on or after the earlier of 2011 and the first day after December 15, 2006 on which the Fund exceeds normal growth guidelines (the "Guidelines") issued by the Department of Finance on December 15, 2006 as amended from time to time. Provided the Fund does not exceed normal growth as determined by the Guidelines, the SIFT Rules will apply to the Fund starting with the 2011 taxation year.

Based on the current legislation, a possible interpretation of the SIFT Rules exists under which the Fund's subsidiary trusts and partnerships may also be viewed as SIFTs. The precise impact of these technical issues cannot be determined until the Canada Revenue Agency provides administrative policies regarding the interpretation of the SIFT Rules and their application to trusts and partnerships in which a publicly traded trust holds a direct or indirect interest. On December 20, 2007, the Minister of Finance announced his intention to introduce technical amendments to the SIFT definition to exclude certain flow through subsidiaries of a SIFT that are able to meet certain ownership conditions. Specifically, the SIFT definition will be amended to exclude trusts and partnership whose equity is not publicly traded, and is wholly owned by a SIFT, a REIT, a taxable Canadian corporation, another entity meeting this test, or any combination of these types of entities. The Fund had a subsidiary partnership that may not meet this ownership requirement and therefore this entity may be subject to SIFT tax commencing in 2011. The impact of the announced technical amendments cannot be assessed until detailed legislation is released.

Once the SIFT Rules apply, the Fund will not be entitled to any deduction in computing its income in respect of any part of its distributions to Unitholders that are attributable either to a business it carries on in Canada or to income (other than dividends from taxable Canadian corporations) from, or capital gains in respect of, non-portfolio properties ("non-portfolio earnings"). Non-portfolio properties include investments in a "subject entity". The main kinds of subject entities are corporations and trusts resident in Canada and partnerships which meet certain residence related criteria. Generally, a subject entity will be a non-portfolio property if the Fund holds securities of the entity that have a fair market value that is greater than 10% of the entity's equity value or more than 50% of the equity value of the Fund is attributable to the subject entity and affiliated entities.

Once the SIFT Rules apply, the Fund will be subject to tax in respect of non-portfolio earnings which it distributes at a rate that is equivalent to the federal general corporate tax rate plus 13% on account of provincial tax and any non-portfolio earnings distributed by the Fund trust will be taxable to the Unitholder as if the distribution were a taxable dividend from a taxable Canadian corporation and will be deemed to be an "eligible dividend" eligible for the enhanced gross-up and tax credit. The 2008 Federal Budget tabled on February 26, 2008 contains a proposal to replace the 13% provincial component of such tax for 2009 and subsequent taxation years with a rate generally based on the general provincial corporate income tax rate in each province in which the SIFT has a permanent establishment.

If the SIFT Rules apply to the Fund in 2011 it is anticipated that generally the tax paid by the Fund and a Unitholder who is a taxable Canadian resident individual on distributed non-portfolio earnings would be substantially equivalent to the tax that would be payable on such distributions by such Unitholders if the SIFT Rules were

Risk Management Cont'd

not enacted. Non-resident Unitholders and Canadian resident Unitholders which are exempt from tax would be negatively affected by the application of the SIFT Rules based on the Fund's current investments.

Although the Fund is of the view that all expenses being claimed by the Fund are reasonable and that the cost amount of the Fund's depreciable properties have been correctly determined, there can be no assurance that CRA or the Internal Revenue Service will agree. A successful challenge by either agency regarding the deductibility of such expenses or the correctness of such cost amounts could impact the return to Unitholders.

Obligations to serve

The Fund's water distribution and waste-water utilities may be located within areas of the United States experiencing growth. These utilities may have an obligation to service new residential, commercial and industrial customers. While expansion to serve new customers will likely result in increased future cash flows, it may require significant capital commitments in the immediate term. Accordingly, the Fund may be required to access capital markets or obtain additional borrowings to finance these future construction obligations.

Commodity price risk

The Fund's EFW facility is the Fund's only natural gas exposure as all other facilities have pass through provisions in their energy agreements. Natural gas at the EFW facility will be re-contracted on a rolling basis.

Critical Accounting Estimates

The Fund prepared its Consolidated Financial Statements in accordance with GAAP. As understanding of the Fund's accounting policies is necessary for a complete analysis of results, financial position, liquidity and trends. Refer to note 1 to the Consolidated Financial Statements for additional information on accounting principles. The Consolidated Financial Statements are presented in Canadian dollars rounded to the nearest thousand, except per unit amounts and except where otherwise noted.

Financial statements prepared in accordance with GAAP require management to make estimates and assumptions relating to reported amounts of revenue and expenses, reported amounts of assets and liabilities and disclosure of contingent assets and liabilities. Management regularly evaluates the assumptions and estimates that are used in the preparation of the Fund's Consolidated Financial Statements. Estimates and assumptions used by management are based on past experience and other factors deemed reasonable in the circumstances. Since these estimates and assumptions involve varying degrees of judgment and uncertainty, the amounts reported in the financial statements could in the future prove to be inaccurate.

The Fund recognizes revenue derived from energy sales at the time energy is delivered. Water reclamation and distribution revenue is recognized when processed and delivered to customers. Revenue from waste disposal is recognized on an actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts are recognized based on actual tonnage at the expected price for the contract year and any amount billed in excess of the expected is deferred.

The Fund records as other liabilities amounts received by the Infrastructure Division which relate to advances from developers for water distribution and water reclamation main extensions received. These advances usually carry repayment terms based on the revenue generated by the development in question ranging over a specified period of time. At the end of the payment term, the unpaid portion of the advance converts to contribution in aid of construction and is not required to be repaid to the developer. The Fund amount recorded as other liabilities is based on the Fund's expected repayments as determined by historical experience and industry practice.

Estimates are also made related to the useful life of long-lived assets. These estimates are used to determine amortization expense. Estimates of an asset's useful life are based on past experience with similar assets taking into account technological or other changes. If these estimates prove to be inaccurate, management may have to shorten the anticipated useful life of the assets recorded in the financial statements resulting in higher amortization expense in future periods or possibly an impairment charge to reflect the write-down in the value of the asset.

Management also regularly assesses whether there has been an impairment to long term investments, notes receivable, capital and intangible assets, and recoverability of future tax assets based on circumstances that may indicate the Fund will not be able to recover the assets entire carrying value. Should impairment be deemed to have occurred, the Fund would reduce the carrying value of that asset in the financial statements and deduct this amount from

Critical Accounting Estimates Cont'd

earnings. The Fund cannot predict future events that could create impairment, or how future events might affect the carrying value of the assets' values reported in the financial statements.

Other than the normal estimates required in the application of GAAP, there are no other critical estimates included in the Consolidated Financial Statements.

Controls and Procedures

The Fund's management is responsible for preparation and presentation of the Consolidated Financial Statements and MD&A. The Fund's Consolidated Financial Statements have been prepared in accordance with GAAP. This MD&A has been prepared in accordance with the requirements of the Ontario Securities Commission including Nation Instrument 51-102 of the Canadian Securities Administrators.

Disclosure Control and Procedures

In accordance with the requirements of the Securities Act (Ontario) and other provincial securities legislation, the CEO and CFO of the Fund certify interim quarterly and annual filings that they have designed the Fund's disclosure controls and have evaluated their effectiveness for the applicable period. Disclosure controls are those controls and procedures which ensure that information that is required to be disclosed by Multilateral Instrument 52-109, the Ontario Securities Commission and other provincial regulators is recorded, processed and reported within the time frames specified by regulators. Disclosure controls and procedures are designed to ensure that information required to be disclosed by the Fund is appropriately accumulated and communicated to Management to allow timely decisions regarding required disclosure. During this quarter, an evaluation of the effectiveness of the design and operation of the Fund's disclosure controls and procedures was carried out, under the supervision and with the participation of Management, the CEO and CFO, and was presented to the Disclosure Committee and to the Audit Committee. Based on that evaluation, the CEO and CFO concluded that disclosure controls and procedures were effective.

Internal Control over Financial Reporting

The CEO and CFO of the Fund are responsible for designing internal controls over financial reporting or causing them to be designed under their supervision in order to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with Canadian generally accepted accounting principles.

Internal control over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations. Internal control over financial reporting is a process that involves human diligence and compliance and is subject to lapses in judgment and breakdowns resulting from human failures. Internal control over financial reporting also can be circumvented by collusion or improper management override. Because of such limitations, there is a risk that material misstatements may not be prevented or detected on a timely basis by internal control over financial reporting. However, these inherent limitations are known features of the financial reporting process. Therefore, it is possible to design into the process safeguards to reduce, though not eliminate, this risk.

Changes in Internal Control over Financial Reporting

During the third quarter in 2007, the Fund hired a replacement for the CFO who resigned in the second quarter of 2007. As such, the responsibilities for operating certain controls were reallocated within the finance department during this period of vacancy. There were no other changes made in our internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2007.

Millions of dollars (except per trust unit amounts)	1st Quarter 2007	2nd Quarter 2007	3rd Quarter 2007	4th Quarter 2007	Total
Revenue	$ 47.6	$ 47.8	$ 46.5	$ 44.3	$ 186.2
Net earnings / (loss) from continuing operations	6.7	(3.2)	12.5	8.8	24.8
Net earnings /(loss)	6.2	(2.3)	12.2	7.6	23.7
Net earnings / (loss) from continuing operations per trust unit	0.08	(0.03)	0.17	0.12	0.34
Net earnings / (loss)	0.08	(0.03)	0.17	0.10	0.32
Total Assets	1,035.8	1,049.0	1,024.1	954.1	954.1
Long term debt*	401.8	410.0	421.0	445.1	445.1
Distribution per trust unit	0.23	0.23	0.23	0.23	0.92

	1st Quarter 2006	2nd Quarter 2006	3rd Quarter 2006	4th Quarter 2006	Total
Revenue	$ 47.2	$ 44.9	$ 49.3	$ 52.0	$ 193.4
Net earnings from continuing operations	7.9	14.4	5.8	2.5	30.7
Net earnings	7.3	13.8	5.0	1.8	28.0
Net earnings from continuing operations per trust unit	0.11	0.20	0.08	0.03	0.43
Net earnings per trust unit	0.11	0.20	0.07	0.02	0.39
Total Assets	839.0	1,030.0	1,024.2	1,048.3	1,048.3
Long term debt*	300.1	376.6	379.6	411.0	411.0
Distribution per trust unit	0.23	0.23	0.23	0.23	0.92

* Long term debt includes long term liabilities, convertible debentures, other long term obligations and deferred credits.

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this MD&A.

Quarterly revenues have fluctuated between $44.3 million and $52.0 million over the prior two year period. A number of factors impact quarterly results including seasonal fluctuations, hydrology and winter and summer rates built into power purchase agreements. There are two additional significant factors impacting revenues year over year. The strengthening Canadian dollar has resulted in lower reported revenue from U.S. operations during 2007, as well as realized gains on financial instruments were recorded as revenue in the comparable quarters of 2006. Additionally, revenue has generally trended up due to facility acquisitions, including the St. Leon wind facility in September 2006, and organic growth in the Fund's Infrastructure division.

Quarterly net earnings have fluctuated between $13.8 million and a net loss of $2.3 million over the prior two year period. Recent earnings have been significantly impacted by non cash factors such as future tax expense due to the enactment of Bill C-52 and gains and losses on financial instruments due to the Fund's adoption of Section 3855 and the discontinuation of hedge accounting under Section 3865.

Changes in Accounting Policies

The Fund's accounting policies are described in Note 1 to the consolidated financial statements for the year ended December 31, 2007. There have been no changes to the critical accounting policies as disclosed in the Fund's annual Consolidated Financial Statements for the year ended December 31, 2007, except as discussed below.

Effective January 1, 2007, the Fund adopted three new Canadian Institute of Chartered Accountants accounting standards ("CICA"): CICA Handbook Section 3855, Financial Instruments – Recognition and Measurement; CICA Handbook Section 3865, Hedges; and CICA Handbook Section 1530, Comprehensive Income. These sections apply to fiscal years beginning on or after October 1, 2006. CICA Handbook Section 1530 establishes standards for reporting and presenting comprehensive income, which is defined as the change in equity from transactions and other events from non-owner sources. Other comprehensive income refers to items recognised in comprehensive income that are excluded from net income calculated in accordance with generally accepted accounting principles. Under the new standards, policies followed for periods prior to the effective date generally are not reversed and therefore, the comparative figures have not been restated.

Under the new standards, financial instruments must be classified into one of the following five categories; held-for-trading, held to maturity, loans and receivables, available-for-sale financial assets or other financial liabilities. Initially all financial assets and financial liabilities are recorded on the consolidated balance sheet at fair value. After initial recognition, the financial instruments are measured at amortized cost except for held-for-trading and available-for-sale financial assets which are measured at their fair values. The effective interest related to the financial liabilities and the gain or loss arising from the change in the fair value of a financial asset or liability classified as held-for-trading is included in net income for the period in which it arises. Available for sale instruments are measured at fair value with gains and losses, net of tax, recognized in other comprehensive income until the financial asset is derecognised and all cumulative gains or losses are then recognised in net income.

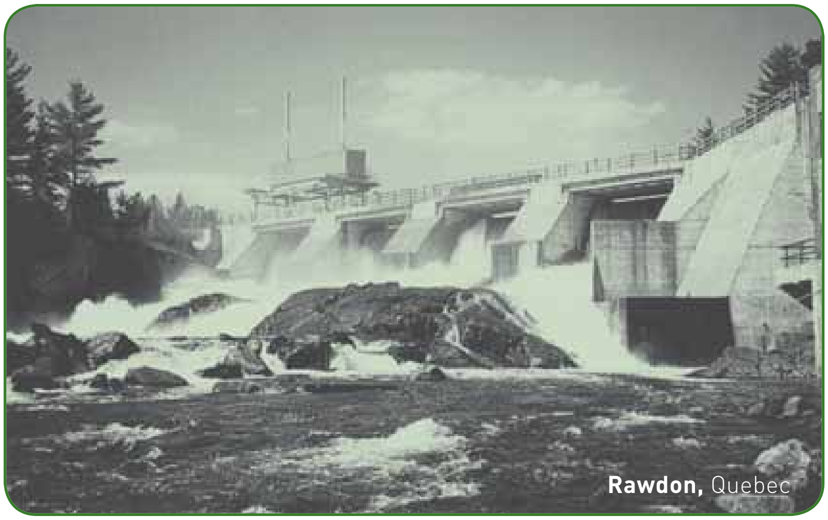
The Fund has classified its cash and cash equivalents, accounts receivable, restricted cash, accounts payable and distribution payable as held-for-trading, which are measured at fair value. Long-term investments are classified as loans and receivables, which are measured at amortized cost or as available-for-sale, and are measured at cost as there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are classified as other financial liabilities, which are measured at amortized cost, using the effective interest method.

Transaction costs and commitment fees paid to financial institutions that are directly attributable to the acquisition or issuance of financial assets or liabilities are accounted for as part of the respective asset or liability's carrying value at inception and are amortized on a straight-line basis over the term of the debt facility. Transaction costs for items classified as held-for-trading are expensed immediately. With respect to the transaction costs attributable to long-term debt, the impact as at January 1, 2007 was a decrease in deferred costs of $272, a decrease in long-term debt of $119, and an increase in deficit of $153; with respect to transaction costs attributable to convertible debentures, the impact as at January 1, 2007 was a decrease in deferred costs of $5,171, a decrease in convertible debentures of $5,536 and a decrease in deficit of $365.

The Fund has entered into forward foreign exchange contracts to manage its exposure to the US dollar as significant cash flows are generated in the US. The Fund sells specific amounts of currencies at predetermined dates and exchange rates which are matched with the anticipated operational cash flows. At December 31, 2006 the Fund ceased designating its forward selling US funds as hedges and recorded the fair value of those contracts of $11,167 as other assets and deferred credits; on the adoption of the new standards on financial instruments the deferred credits balance was transferred into Accumulated Other Comprehensive Income of $11,167. These contracts are measured at fair value and the change in fair value is included in the statement of earnings; the Fund recorded a gain of on these contracts of $6,950 in 2007 (2006 – $ Nil). The balances from Accumulated Other Comprehensive Income are released as the contracts are settled.

In 2006, AirSource entered into a fixed for floating interest rate swap until September 2015 in the notional amount of $73,300 in order to reduce the interest rate variability on its senior debt facility. The Fund has elected not to use hedge accounting for the swap transaction and records the fair value of the swap on the balance sheet. Any gain or loss in fair value is recognized in the statement of earnings.

Recent Accounting Pronouncements



Rawdon, Quebec

Capital Disclosures

In December 2006, the CICA issued Handbook Section 1535, Capital Disclosures, which establishes standards for disclosing information about an entity's capital and how it is managed. The entity's disclosure should include information about its objectives, policies and processes for managing capital and disclose whether or not it has complied and the consequences of non-compliance with any capital requirements to which it is subject. The new standard will become effective on January 1, 2008 for the Fund. The Fund is currently evaluating the impact of the adoption of this new section on the consolidated financial statements.

Financial Instruments – Disclosures and Financial Instruments – Presentation

In December 2006, the CICA Handbook Sections 3862, Financial Instruments – Disclosures, and 3863, Financial Instruments – Presentation. Section 3862 modifies the disclosure requirements of Section 3861, Financial Instruments – Disclosure and Presentation, including required disclosure for the assessment of the significance of financial instruments for an entity's financial position and performance and of the extent of risks arising from financial instruments to which the Fund is exposed and how the Fund manages those risks, whereas Section 3863 carries forward the presentation related requirements of Section 3861. The new standards will become effective on January 1, 2008 for the Fund. The Fund is currently evaluating the impact of the adoption of Section 3862 while the Fund does not expect the adoption of 3863 to have a significant effect on the consolidated financial statements.

Auditors' Report to the Unitholders

We have audited the consolidated balance sheets of Algonquin Power Income Fund as at December 31, 2007 and 2006 and the consolidated statements of earnings, comprehensive income / (loss), changes in unitholders' equity and accumulated other comprehensive income / (loss) and cash flows for the years then ended. These financial statements are the responsibility of the Fund's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Fund as at December 31, 2007 and 2006 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

Chartered Accountants,
Licensed Public Accountants

Toronto, Canada
March 6, 2008

Consolidated Balance Sheets

December 31, 2007 and 2006
(thousands of Canadian dollars)

	2007	2006
ASSETS		
Current assets:		
Cash	$ 10,361	$ 13,465
Accounts receivable	26,597	41,291
Prepaid expenses	3,052	2,777
Current portion of notes receivable (note 4)	421	2,337
Current portion of derivative assets (note 7)	7,857	6,205
	48,288	66,075
Long-term investments and notes receivable (note 4)	30,047	29,976
Future non-current income tax asset (note 13)	2,416	7,639
Capital assets (note 5)	760,677	797,440
Intangible assets (note 6)	99,529	110,935
Assets held for sale (note 15)	-	14,077
Restricted cash	6,105	6,753
Deferred costs (note 2)	80	5,951
Other assets	2,737	2,295
Derivative assets (note 7)	4,188	7,183
	$ 954,067	$ 1,048,324
LIABILITIES AND UNITHOLDERS' EQUITY		
Current liabilities:		
Accounts payable and accrued liabilities	$ 27,007	$ 75,011
Cash distribution payable	11,649	11,659
Current portion of long-term liabilities (note 9 and 11)	1,915	1,876
Current income tax liability (note 13)	669	141
Future income tax liability (note 13)	756	848
	41,996	89,535
Long-term liabilities (notes 8 and 9)	281,725	229,006
Convertible debentures (notes 10)	139,587	144,501
Other long-term liabilities (note 11)	23,771	26,339
Deferred credits	-	11,167
Future non-current income tax liability (note 13)	80,785	71,257
Non controlling interest (note 3 (c))	21,700	31,804
Unitholders' equity:		
Trust units (note 12)	691,734	684,414
Equity component of convertible debentures	479	479
Deficit	(283,820)	(240,178)
Accumulated other comprehensive income	(43,890)	-
	364,503	444,715
Commitments and contingencies (note 16)		
Subsequent events (notes 7, 8 and 12)		
	$ 954,067	$ 1,048,324

See accompanying notes to consolidated financial statements

	(signed) George Steeves	(signed) Ken Moore
Approved by the Trustees	George Steeves	Ken Moore

Consolidated Statements of Changes in Unitholders' Equity and Accumulated Other Comprehensive Income / (Loss)

For the years ended December 31, 2007 and 2006
(thousands of Canadian dollars)

	2007	2006
Trust units:		
Balance, beginning of period	**$ 684,414**	$ 654,176
Issued on acquisition of AirSource Power Fund I LP	**-**	22,639
Issued on conversion of Algonquin (AirSource) Power LP exchangeable units	**7,304**	7,579
Conversion of convertible debentures	**16**	20
Balance, end of period	**$ 691,734**	$ 684,414
Equity component of convertible debentures	**$ 479**	$ 479
Deficit:		
Balance, beginning of period	**$ (240,178)**	$ (201,178)
Changes in accounting policies (note 2)	**211**	-
Balance, beginning of period as adjusted	**(239,967)**	(201,178)
Net earnings / (loss)	**23,671**	27,956
Distributions	**(67,524)**	(66,956)
Balance, end of period	**$ (283,820)**	$ (240,178)
Accumulated other comprehensive income / (loss):		
Balance, beginning of the period	**$ -**	$ -
Change in accounting policy (note 2)	**11,167**	-
Balance, beginning of period as adjusted	**$ 11,167**	$ -
Other comprehensive income / (loss)	**(55,057)**	
Balance, end of the period	**$ (43,890)**	$ -

Consolidated Statements of Comprehensive Income / (Loss)

For the years ended December 31, 2007 and 2006
(thousands of Canadian dollars)

	2007	2006
Net earnings	**$ 23,671**	$ -
Other comprehensive income (loss):		
Deferred gains on forward exchange contracts settled in the period	**$ (6,206)**	$ -
Translation of self sustaining foreign operations	**(48,851)**	-
Other comprehensive income (loss):	**(55,057)**	-
Total comprehensive income / (loss)	**$ (31,386)**	$ -

See accompanying notes to consolidated financial statements

Consolidated Statements of Earnings

For the years ended December 31, 2007 and 2006
(thousands of Canadian dollars, except per unit amounts)

	2007	2006
Revenue		
Energy sales	$ 116,565	$ 123,285
Waste disposal fees	13,609	14,209
Water reclamation and distribution	33,699	35,464
Other revenue (note 21)	22,302	20,286
	186,175	193,244
Expenses		
Operating	99,314	103,080
Amortization of capital assets	34,278	30,609
Amortization of intangible assets	7,287	5,752
Management costs (note 14)	1,637	869
Administrative expenses	8,463	8,014
Withholding taxes	-	104
(Gain) / loss on foreign exchange	(7,688)	216
	143,291	148,644
Earnings before undernoted	42,884	44,600
Interest expense	26,565	22,281
Interest, dividend income and other income (note 20)	(9,408)	(10,861)
Write down of note receivable (note 4)	726	3,263
(Gain) / loss on financial instruments	(14,469)	497
	3,414	15,180
Earnings from operations before income taxes, minority interest and discontinued operations	39,470	29,420
Income tax provision (recovery) (note 13)		
Current	(310)	861
Future	15,418	(3,627)
	15,108	(2,766)
Minority interest	(401)	1,458
Net earnings from continuing operations	24,763	30,728
Net earnings / (loss) from discontinued operations (note 15)	(1,092)	(2,772)
Net earnings	$ 23,671	$ 27,956
Basic net earnings from continuing operations per trust unit (note 19)	$ 0.34	$ 0.43
Diluted net earnings from continuing operations per trust unit (note 19)	$ 0.32	$ 0.43
Basic and diluted net earnings / (loss) from discontinued operations per trust unit (note 19)	$ (0.01)	$ (0.04)
Basic net earnings per trust unit (note 19)	$ 0.32	$ 0.39
Diluted net earnings per trust unit (note 19)	$ 0.31	$ 0.39

See accompanying notes to consolidated financial statements

Consolidated Statements of Cash Flows

For the years ended December 31, 2007 and 2006

(thousands of Canadian dollars)

	2007	2006
Cash Provided By (used in):		
Operating Activities:		
Net earnings from continuing operations	$ 24,763	$ 30,728
Items not affecting cash:		
Amortization of capital assets	34,278	30,609
Amortization of intangible assets	7,287	5,752
Other amortization	2,039	1,526
Future income taxes	15,418	(3,627)
Loss / (gain) on financial instruments	(4,862)	497
Minority interest	(401)	1,458
Write down of note receivable (note 4)	726	3,263
Unrealized (gain) / loss on foreign exchange	(8,077)	77
	71,171	70,283
Changes in non-cash operating working capital	(30,744)	(951)
	40,427	69,332
Financing Activities:		
Cash distributions	(67,416)	(64,901)
Cash distributions non controlling interest	(2,516)	(1,071)
Convertible debenture issue	-	60,000
Expenses of convertible debenture issue	-	(2,900)
Deferred financing costs	(158)	(358)
Increase in long term liabilities	71,400	-
Decrease in long term liabilities	(11,836)	(3,718)
Increase / (decrease) in other long term liabilities	(1,345)	375
	(11,871)	(12,573)
Investing Activities:		
Increase in restricted cash	(295)	(3,281)
Increase in other assets	(1,241)	(1,114)
Receipt of principal on notes receivable	1,319	4,552
Increase in long term investments	(950)	(322)
Proceeds received from sale of power purchase agreement	-	1,021
Proceeds from sale of capital assets and intangible assets	14,083	-
Net additions to capital assets	(39,571)	(30,934)
Acquisitions of operating entities (note 3)	(990)	(23,433)
	(27,645)	(53,511)
Effect of exchange rate differences on cash	(1,181)	(44)
Increase /(decrease) in cash from continuing operations	(270)	3,204
Increase/ (decrease) in cash from discontinued operations (note 15)	(2,834)	(1,102)
Cash, beginning of the period	13,465	11,363
Cash, end of the period	$ 10,361	$ 13,465
Supplemental disclosure of cash flow information:		
Cash paid during the period for interest expense	$ 25,599	$ 20,702
Cash paid during the period for income taxes	$ 515	$ 1,060

See accompanying notes to consolidated financial statements

December 31, 2007 and 2006

(in thousands of Canadian dollars except as noted and per trust unit)

Algonquin Power Income Fund (the "Fund") is an open-ended, unincorporated trust established pursuant to its Declaration of Trust dated September 8, 1997, as amended, under the laws of the Province of Ontario. The Fund's principal activity is the ownership, directly or indirectly, of generating and infrastructure facilities, through investments in securities of subsidiaries including limited partnerships and other trusts which carry on these businesses. The activities of the subsidiaries may be financed through equity contributions, interest bearing notes and third party project debt as described in the notes to the consolidated financial statements. The revolving credit facility and the convertible debentures are direct obligations of the Fund.

Distributions are made on a monthly basis at the discretion of the Trustees of the Fund (note 18).

The Fund is managed by Algonquin Power Management Inc. ("APMI"). An entity owned by the majority of the shareholders of APMI is the general partner of Algonquin Airlink Limited Partnership which owns an aircraft that the Fund charters. An entity owned by the shareholders of APMI is the general partner of Algonquin Property LP which leases the corporate office to the Fund. GreenWing Algonquin Power Development Inc. ("GWAP"), an entity majority owned by APMI, provides construction services. Collectively, these entities are referred to as the Algonquin Power Group.

1. Significant accounting policies

(a) Basis of consolidation:

The consolidated financial statements of the Fund have been prepared in accordance with accounting principles generally accepted in Canada and include the consolidated accounts of all of its subsidiaries and variable interest entities.

All significant intercompany transactions and balances have been eliminated.

(b) Cash and cash equivalents:

Cash and cash equivalents include cash deposited at banks and highly-liquid investments with original maturities of 90 days or less.

(c) Restricted cash:

Cash reserves segregated from the Fund's cash balances are maintained in accounts administered by a separate agent and disclosed separately in these consolidated financial statements as the Fund cannot access this cash without the prior authorization of parties not related to the Fund.

(d) Capital assets:

Capital assets, consisting of land, facilities and equipment, are recorded at cost. Development costs, including the cost of acquiring or constructing facilities together with the related interest costs during the period of construction are capitalized. Improvements that increase or prolong the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred.

The facilities and equipment, which include overhauls, are amortized on a straight-line basis over their estimated useful lives. For facilities these periods range from 15 to 40 years. Facility equipment is amortized over 2 to 10 years.

Interest of $997 was capitalized to capital assets in 2007 (2006 – $nil).

(e) Intangible assets:

Power purchase contracts acquired are amortized on a straight-line basis over the remaining term of the contract. These periods range from 6 to 25 years from date of acquisition.

Customer relationships are amortized on a straight-line basis over 40 years.

(f) Impairment of long-lived assets:

The Fund reviews capital assets and intangible assets for impairment whenever events or changes in circumstances indicate the carrying amount may not be recoverable. Recoverability is measured by comparing the carrying amount of an asset to expected future cash flows. If the carrying amount exceeds the expected future cash flows, the asset is written down to its fair market value.

(g) Other long-term liabilities:

Other long-term liabilities include advances in aid of construction. Certain of the Fund's water and wastewater utilities are provided with advances through contributions from customers, real estate developers and builders for water and sewage main extensions in order to extend water and sewer service to their properties. The amounts advanced are generally repayable over a prescribed period based on revenues generated by the housing or development in the area being developed as new customers are connected to and take service from the utilities. Generally, advances not refunded within the prescribed period are not required to be repaid. The estimated amount of contributions that are ultimately not refunded is credited to Capital Assets. The Fund also receives contributions in aid of construction with no repayment requirements in which case the full amount is immediately treated as a capital grant and netted against Capital Assets. The estimated amount of contributions that are ultimately refunded is recorded as Advances in Aid of Construction in Other long-term liabilities.

Other long-term liabilities also include deferred water rights. Deferred water rights result from a hydroelectric generating facility which has a fifty year water lease with the first ten years of the water lease requiring no payment. An average rate was estimated over the life of the lease and a deferral was booked based on this estimate which is being drawn down in the last forty years.

Other long term liabilities also include customer deposits. Customer deposits result from the Infrastructure Division utilities' obligation by its respective state regulator to collect a deposit from each customer of its facilities when services are connected. The deposits are refundable when allowed under the facilities' regulatory agreement.

(h) Deferred costs:

In 2007, deferred costs consist of the costs of arranging the Fund's credit facility. In addition, in 2006, deferred costs include costs associated with the issuance of convertible debentures and costs of arranging other facility level debt.

(i) Long-term investments:

Investments in which the Fund has significant influence but not control or joint control are accounted using the equity method. The Fund records its share in the income or loss of its investees in interest, dividend and other income in the consolidated statement of earnings and deficit. All other equity investments where the Fund does not have significant influence or control are accounted for under the cost method. Under the cost method of accounting investments are carried at cost and are adjusted only for other-than-temporary declines in value and additional investments.

(j) Recognition of revenue:

Revenue derived from energy sales, which are mostly under long-term power purchase contracts, is recorded at the time electrical energy is delivered.

Water reclamation and distribution revenues are recorded when processed and delivered to customers.

Revenue from waste disposal is recognized on actual tonnage of waste delivered to the plant at prices specified in the contract. Certain contracts include price reductions if specified thresholds are exceeded. Revenue for these contracts are recognized based on actual tonnage at the expected price for the contract year and any amount billed in excess of the expected rate is deferred.

Interest and dividend income from long-term investments is recorded as earned.

1. Significant accounting policies (cont'd)

(k) Foreign currency translation:

The Fund's policy for translation of foreign operations depends on whether the foreign operations are considered integrated or self-sustaining. Prior to October 1, 2007, all of the Fund's foreign operations were considered integrated and translated into Canadian dollars using the temporal method whereby current rates of exchange are used for monetary assets and liabilities, historical rates of exchange for non-monetary assets and liabilities and average rates of exchange for revenues and expenses, except amortization which was translated at the rates of exchange applicable to the related assets. Gains and losses resulting from these translation adjustments were included in income.

The ongoing review of the economic factors to be considered in determining whether foreign operations are integrated or self-sustaining has resulted in the determination that the Fund's operating entities in the Infrastructure Division have changed to self-sustaining. This change was made as a result of the Infrastructure Division entities' increasing proportion of operating, financing and investing transactions that are denominated in currencies other than the Canadian dollar. This change in method was effective at October 1, 2007 and was applied prospectively. These self-sustaining operations are translated into Canadian dollars using the current rate method, whereby assets and liabilities are translated at the rate prevailing at the balance sheet date while revenues and expenses are converted using average rates for the period. Unrealized gains or losses arising as a result of the translation of the operations of self-sustaining operations are reported as a component of Other Comprehensive Income in the Consolidated Statement of Comprehensive Income.

The Fund's remaining United States subsidiaries and partnership interests continue to be considered to be functionally integrated with the Canadian operations and accounted for as integrated foreign operations.

(l) Asset retirement obligations:

The fair value of estimated asset retirement obligations is recognized in the consolidated balance sheet when identified and a reasonable estimate of fair value can be made. The asset retirement cost, equal to the estimated fair value of the asset retirement obligation, is capitalized as part of the cost of the related long-lived asset. The asset retirement costs are depreciated over the asset's estimated useful life and included in amortization expense on the consolidated statement of earnings and deficit. Increases in the asset retirement obligation resulting from the passage of time are recorded as accretion of asset retirement obligation in the consolidated statement of earnings and deficit. Actual expenditures incurred are charged against the accumulated obligation. No provision for retirement obligations has been recorded in 2007 and 2006.

(m) Income taxes:

Income taxes are accounted for using the asset and liability method. Future tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases. Future tax assets and liabilities are measured using enacted or substantively enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on future tax assets and liabilities of a change in tax rates is recognized in earnings in the year that includes the date of enactment or substantive enactment.

A valuation allowance is recorded against future tax assets to the extent that it is considered more likely than not that the future tax asset will not be realized.

(n) Financial instruments

The Fund has classified its cash and cash equivalents, accounts receivable, restricted cash, accounts payable and distribution payable as held-for-trading, which are measured at fair value. Notes receivable are classified as loans and receivables, which are measured at amortized cost or as available-for-sale, and are measured at cost as there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are classified as other financial liabilities, which are measured at amortized cost, using the effective interest method.

Transaction costs that are directly attributable to the acquisition or issuance of financial assets or liabilities are accounted for as part of the respective asset or liability's carrying value at inception. Transaction costs for items classified as held-for-trading are expensed immediately. Costs considered as commitment fees paid to financial institutions are recorded in deferred costs, and amortized on a straight-line basis over the term of the debt facility.

The Fund has entered into forward foreign exchange contracts to manage its exposure to the US dollar as significant cash flows are generated in the US. The Fund sells specific amounts of currencies at predetermined dates and exchange rates which are then matched with the anticipated operational cash flows. These contracts are measured at fair value and the change in fair value is included in the Consolidated Statement of Earnings.

At December 31, 2006, the Fund ceased designating its foreign exchange contracts as hedges and recorded the fair value of those contracts of $11,167 as derivative assets and deferred credits. Upon the adoption of the new standards on financial instruments on January 1, 2007, the deferred credits balance of $11,167 was transferred into Accumulated Other Comprehensive Income. The balances from Accumulated Other Comprehensive Income are released as the contracts are settled.

In 2006, AirSource entered into a fixed for floating interest rate swap until September 2015 in the notional amount of $73,300 in order to reduce the interest rate variability on its senior debt facility. The Fund has selected not to use hedge accounting for the swap transaction and records the fair value of the swap on the Consolidated Balance Sheet. Any gain or loss in fair value is recognized in the Consolidated Statement of Earnings.

(o) Use of estimates

The preparation of financial statements requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of these financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the years presented, management has made a number of estimates and valuation assumptions, including the useful lives and recoverability of capital assets and intangible assets, the recoverability of notes receivable and long-term investments, the recoverability of future tax assets, the portion of aid-in construction payments that will not be repaid, and the fair value of financial instruments and derivatives. These estimates and valuation assumptions are based on present conditions and management's planned course of action, as well as assumptions about future business and economic conditions. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

2. Change in accounting policies and recent accounting pronouncements

(a) Financial Instruments and Comprehensive Income

Effective January 1, 2007, the Fund adopted three new Canadian Institute of Chartered Accountants accounting standards ("CICA"): CICA Handbook Section 3855, Financial Instruments – Recognition and Measurement; CICA Handbook Section 3865, Hedges; and CICA Handbook Section 1530, Comprehensive Income. These sections apply to fiscal years beginning on or after October 1, 2006. CICA Handbook Section 1530 establishes standards for reporting and presenting comprehensive income, which is defined as the change in equity from transactions and other events from non-owner sources. Other comprehensive income refers to items recognised in comprehensive income that are excluded from net income calculated in accordance with generally accepted accounting principles. Under the new standards, policies followed for periods prior to the effective date generally are not reversed and therefore, the comparative figures have not been restated.

Under the new standards, financial instruments must be classified into one of the following five categories; held-for-trading, held to maturity, loans and receivables, available-for-sale financial assets or other financial liabilities. Initially all financial assets and financial liabilities are recorded on the Consolidated Balance Sheet at fair value. After initial recognition, the financial instruments are measured at amortized cost except for held-for-trading and available-for-sale financial assets which are measured at their fair values. The effective interest related to the financial liabilities and the gain or loss arising from the change in the fair value of a financial asset or liability classified as held-for-trading is included in net income for the period in which it arises. Available for sale instruments are measured at fair value with gains and losses, net of tax, recognized in other comprehensive income until the financial asset is derecognised and all cumulative gains or losses are then recognised in net income.

2. Change in accounting policies and recent accounting pronouncements (cont'd)

The Fund has classified its cash and cash equivalents, accounts receivable, restricted cash, accounts payable and distribution payable as held-for-trading, which are measured at fair value. Long-term investments are classified as loans and receivables, which are measured at amortized cost or as available-for-sale, and are measured at cost as there is no liquid market for these investments. Long-term liabilities, convertible debentures, and other long-term liabilities are classified as other financial liabilities, which are measured at amortized cost, using the effective interest method.

Transaction costs that are directly attributable to the acquisition or issuance of financial assets or liabilities are accounted for as part of the respective asset or liability's carrying value at inception and are amortized using the effective interest rate method over the term of the debt facility. Transaction costs for items classified as held-for-trading are expensed immediately. With respect to the transaction costs attributable to long-term debt, the impact as at January 1, 2007 was a decrease in deferred costs of $272, a decrease in long-term debt of $119, and an increase in deficit of $153; with respect to transaction costs attributable to convertible debentures, the impact as at January 1, 2007 was a decrease in deferred costs of $5,171, a decrease in convertible debentures of $5,536 and a decrease in deficit of $365.

The Fund has entered into forward foreign exchange contracts to manage its exposure to the US dollar as significant cash flows are generated in the US. The Fund sells specific amounts of currencies at predetermined dates and exchange rates which are matched with the anticipated operational cash flows. At December 31, 2006 the Fund ceased designating its forward selling US funds as hedges and recorded the fair value of those contracts of $11,167 as other assets and deferred credits; on the adoption of the new standards on financial instruments the deferred credits balance was transferred into Accumulated Other Comprehensive Income of $11,167. These contracts are measured at fair value and the change in fair value is included in the statement of earnings; the Fund recorded a gain of on these contracts of $6,950 in 2007 (2006 – $ Nil). The balances from Accumulated Other Comprehensive Income are released as the contracts are settled.

The components of accumulated other comprehensive income / (loss) as at December 31, 2007 consist of the following:

Deferred gains on forward exchange contracts	$ 4,961
Unrealized loss on translation of self sustaining foreign operations	(48,851)
Total	**$ (43,890)**

(b) Recent accounting pronouncements

(i) Capital Disclosures

In December 2006, the CICA issued Handbook Section 1535, Capital Disclosures, which establishes standards for disclosing information about an entity's capital and how it is managed. The entity's disclosure should include information about its objectives, polices and processes for managing capital and disclose whether or not it has complied and the consequences of non-compliance with any capital requirements to which it is subject. The new standard will become effective on January 1, 2008 for the Fund.

The Fund is currently evaluating the impact of the adoption of this new section on the consolidated financial statements.

(ii) Financial Instruments – Disclosures and Financial Instruments – Presentation

In December 2006, the CICA issued Handbook Section 3862, Financial Instruments – Disclosures, and 3863, Financial Instruments – Presentation. Section 3862 modifies the disclosure requirements of Section 3861, Financial Instruments – Disclosure and Presentation, including required disclosure of the assessment of the significance of financial instruments for an entity's financial position and performance and of the extent of risks arising from financial instruments to which the Fund is exposed and how the Fund manages those risks. Section 3863 carries forward the presentation related requirements of Section 3861. The new standards will become effective on January 1, 2008 for the Fund.

The Fund is currently evaluating the impact of the adoption of Section 3862. The Fund does not expect the adoption of 3863 to have a significant effect on the consolidated financial statements.

3. Acquisitions

(a) Assets and regulatory licences near the Town of Sierra Vista, Arizona

On February 13, 2007 Southern Sunrise Water Company Inc, and Northern Sunrise Water Company Inc. both indirect wholly owned subsidiaries of the Fund, completed the acquisition of the assets and regulatory licences related to the provision of water distributions utility services to approximately 1,500 water distribution customers located near the Town of Sierra Vista, Arizona for cash consideration of $816 (US$698). The Fund also incurred $348 (US$300) of acquisition costs. At December 31, 2006, the Fund had $582 (US$498) in escrow pending the approval of regulatory authorities. A deposit in the amount of $234 (US$200) was paid in 2004 which was recorded in deferred costs.

The acquisitions have been accounted for using the purchase method, with earnings from operations included since the date of acquisition. The consideration paid by the Fund has been allocated to net assets acquired as follows:

Fixed assets	$	1,164
Total purchase price	$	1,164
Consideration:		
Prior year deposit paid	$	234
Funds released from escrow		582
Acquisition costs		348
Total purchase price consideration	$	1,164

(b) Litchfield Park Service Company, Woodmark Utility Company, and Rio Rico Utilities

In accordance with the purchase and sale agreements of Litchfield Park Service Company ("LPSCO"), Woodmark Utility Company ("Woodmark"), and Rio Rico Utilities ("Rio Rico"), the Fund is required to make additional payments to the previous owners for each additional customer connected to the facilities. For LPSCO and Woodmark, no further payments are required after 2007. For Rio Rico these payments continue until 2008. As of December 31, 2007 the fund accrued $731 (2006 – $2,802) as a growth premium, and increased intangible assets by a similar amount including an amount calculated for future income taxes of $171 (2006 – $1,166).

		2007		2006
Litchfield Park	**$**	**271**	$	1,855
Woodmark		**103**		131
Rio Rico		**357**		816
	$	**731**	$	2,802
In United States dollars	**$**	**668**	$	2,460

(c) AirSource Power Fund I LP

On June 29, 2006, the Fund completed the acquisition of 92.37% of the outstanding partnership units of AirSource Power Fund I LP ("AirSource"). AirSource has constructed the St. Leon Wind Energy facility, comprised of 63, 1.65 megawatt turbines totalling approximately 99 megawatts of installed capacity located near the Town of St. Leon Manitoba. The Fund issued 2,099,255 trust units of the Fund ("Trust Units") and Algonquin (AirSource) Power LP ("Algonquin AirSource"), a subsidiary of the Fund, issued 3,863,554 exchangeable units ("Exchangeable Units"). During the third quarter of 2006, the Fund issued an additional 283,717 Trust Units and Algonquin AirSource issued an additional 206,818 Exchangeable Units to acquire the remaining 496,090 AirSource Units not acquired on June 29, 2006. Total unit consideration for the acquisition is valued at $60,600. Total purchase price, including acquisition costs, was $101,700.

The Exchangeable Units entitle the holders to receive distributions, and the Fund intends that such distributions be equivalent to Fund distributions, as long as the facility generates adequate cash flow. Exchangeable units are classified on the Fund's balance sheet as 'Non controlling interest'. At December 31, 2007, there were 2,473,187 exchangeable units outstanding for a value of $23,044. From the date of the acquisition to December 31, 2007, 1,597,185 Algonquin AirSource Units were exchanged for 1,566,519 Trust Units. The exchange agreement will continue until there are no outstanding Exchangeable Units.

3. Acquisitions (cont'd)

The acquisitions have been accounted for using the purchase method, with earnings from operations included since the date of acquisition. The consideration paid by the Fund has been allocated to net assets acquired as follows:

Working capital (net of cash received $ 1,662)	$	(35,691)
Capital assets		183,036
Intangible assets		38,219
Other assets		5,863
Current portion of long term debt		(397)
Long term debt		(74,503)
Non current future tax liability		(16,515)
Purchase price		100,012
Add: cash acquired		1,662
Total purchase price	$	101,674
Consideration:		
Trust and exchangeable units issued	$	60,564
Advances to AirSource		40,000
Cash		1,110
Total purchase price consideration	$	101,674

Intangible assets represent the value of the power purchase and interconnect agreements with Manitoba Hydro, entered into by AirSource in 2004, and wind power production incentives. These assets will be amortized over their expected useful lives being 25 and 10 years respectively.

During 2006, the Fund provided $19,500 of financing to AirSource. As of June 29, 2006, the Fund had advanced $40,000 to AirSource as well as providing letters of credit of $15,400, for a total of $55,400.

4. Long-term investments and notes receivable

		2007		2006
Long term investments:				
Interests in four power generating facilities, record at cost	**$**	**23,902**	$	24,704
A 45% partnership interest in the Algonquin Power (Rattle Brook) Partnership		**3,838**		3,699
A 50% partnership interest in the Campbellford Limited Partnership		**715**		555
		28,455		28,958
Notes receivable:				
Across America		**-**		1,948
Airlink Advance (note 13)		**908**		1,076
Other		**1,105**		331
		2,013		3,355
		30,468		32,313
Less: current portion		**(421)**		(2,337)
Total long term investments and notes receivable	**$**	**30,047**	$	29,976

The above notes are secured by the underlying assets of the respective facilities.

In 2007, the Fund wrote off the remaining principle balance of the Across America which matured January 31, 2008.

5. Capital assets

	2007			2006		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Land	**$ 10,008**	**$ -**	**$ 10,008**	$ 11,446	$ -	$ 11,446
Facilities	**895,674**	**156,460**	**739,214**	904,217	129,262	774,955
Equipment	**26,390**	**14,935**	**11,455**	21,052	10,013	11,039
	$ 932,072	**$ 171,395**	**$ 760,677**	$ 936,715	$ 139,275	$ 797,440

Facilities include cost of $94,606 (2006 – $94,606) and accumulated amortization of $20,400 (2006 – $17,817) under capital lease and $55,146 (2006 – $22,431) of construction in process. Amortization expense of facilities under capital lease was $2,583 (2006 – $2,536). In addition $2,009 (2006 – $2,010) of contributions received in aid of construction have been credited to facilities cost. Equipment includes cost of $3,946 (2006 – $3,556) and accumulated amortization of $1,314 (2006 – $1,139) of equipment under capital lease. Amortization expense of equipment under capital lease was $175 (2006 – $218).

The Fund has entered into an agreement to sell steam from the Peel Energy-from-Waste facility to an industrial customer located in close proximity to the Peel Energy-from-Waste facility. To affect such sales, the Fund will incur the costs of certain additional steam generation and transmission assets. The Fund has committed to contractual arrangements to complete the project totaling approximately $2,050. The Fund has incurred amounts totaling $10,196 (2006 – $2,873) included in assets under construction of which $353 is capitalized interest (2006 – $nil). APMI is entitled to 50% of the cash flow above a 15% return on investment pursuant to its project management contract.

The Fund has substantially completed a major capital project to re-power its co-generation facility at Sanger, California in the forth quarter of 2007. Included in the cost to complete the project is a development supervision fee and a contingency fee to APMI for its construction management of the project (see note 14).

6. Intangible assets

	2007			2006		
	Cost	**Accumulated amortization**	**Net book value**	Cost	Accumulated amortization	Net book value
Power purchase contracts	**$ 120,226**	**$ 37,948**	**$ 82,278**	$ 119,212	$ 30,355	$ 88,857
Customer relationships	**18,696**	**1,501**	**17,195**	23,348	1,385	21,963
Licenses and agreements	**696**	**640**	**56**	696	581	115
	$ 139,618	**$ 40,089**	**$ 99,529**	$ 143,256	$ 32,321	$ 110,935

During 2006, the Fund exercised its option to sell the power purchase agreement for the Crossroads facility located in New Jersey. The proceeds received from the sale were equal to the net book value.

7. Derivative Assets

On November 1, 2005, AirSource entered into a fixed for floating interest rate swap until September 2015 in the notional amount of $73,300 in order to reduce the interest rate variability on its senior debt facility. AirSource has effectively fixed its interest expense on its senior debt facility at 5.47%. The Fund recognized a loss of $2,088 for 2007 (2006 – $497) which represented the mark to market adjustment of the interest rate swap. At the time of the acquisition of AirSource the swap had a fair value of $2,719 which has been included in the purchase price allocation. The Fund has not designated the swap as a hedge for accounting purposes. The fair value of the interest swap at December 31, 2007 was $134 (2006 – $2,221).

The Fund has entered into foreign exchange contracts to manage its exposure to the U.S. dollar as significant cash flows are generated in the U.S. The Fund sells specific amounts of currencies at predetermined dates and exchange rates which are matched with the anticipated operational cash flows. Contracts in place at December 31, 2007 amounted to U.S. $68,556 until 2011 at a weighted average exchange rate of $1.16. The fair value of the outstanding futures contracts is $11,911 at December 31, 2007 (2006 – $11,167).

The current portion of derivative assets is $7,857 (2006 – $6,205).

The foreign exchange contracts settle according to the following table:

	Amount	Average exchange rate
2008	$ 33,921	$ 1.22
2009	18,510	1.19
2010	11,125	1.04
2011	5,000	0.97
	$ 68,556	$ 1.16

Subsequent to the year end, the Fund entered into U.S. $35,200 of additional forward contracts, increasing its total forward contracts to U.S. $103,756 carrying an average rate of $1.12.

8. Revolving credit facility

The Fund's revolving credit facility with its senior lenders has available credit of $175,000 which includes a $20,000 operating line. At December 31, 2007, $126,000 (2006 – $67,000) (see note 9 – Long-term liabilities) has been drawn on the revolving credit facility and no amount was outstanding on the operating line. In addition, the availability of the revolving credit facility has been reduced by $24,986 (2006 – $44,122) for certain outstanding letters of credit. The terms of the credit agreement require the Fund to pay a standby charge of 0.30% on the unused portion of the revolving credit facility and maintain certain financial covenants. The facility is secured by a fixed and floating charge over all Fund entities.

On January 16, 2008 the Fund renewed its combined $175,000 senior secured revolving operating and acquisition credit facilities (the "Facilities") for a new three year term with its Canadian bank syndicate. Under terms of the renewal, the Facilities are extended for a three year term with a maturity date of January 14, 2011. The renewed Facilities also contain an accordion feature allowing the Facilities to increase to $225,000 to accommodate future growth and acquisitions.

9. Long-term liabilities

	2007	2006
Senior Debt Long Sault Rapids: Interest at rates varying from 10.16% to 10.21% repayable in monthly blended installments of $402, maturing December, 2027.	**$ 41,835**	$ 42,379
Senior Debt Chute Ford: Interest rate of 11.55% repayable in monthly blended installments of $64, maturing April, 2020.	**4,991**	5,180
Sanger Bonds: U.S. $19,200 California Pollution Control Finance Authority Variable Rate Demand Resource Recovery Revenue Bonds Series 1990A, interest payable monthly, maturing September, 2020. The variable interest rate is determined by the remarketing agent. The effective interest rate for 2007 is 3.65% (2006 – 3.47%).	**18,972**	22,374
Bella Vista Water Loans: Water Infrastructure Financing Authority of Arizona Interest rates of 6.26% and 6.10% repayable in monthly and quarterly installments (U.S. $15 and U.S. $4) maturing March, 2020 and December, 2017. The balance of these notes at December 31, 2007 was US$1,650 and US$119 respectively (2006 – US$1,729 and US$127).	**1,748**	2,162
Litchfield Park Service Company Bonds: 1999 and 2001 IDA Bonds. Interest rates of 5.87% and 6.71% repayable in semi-annual installments, maturing October 2023 and October 2031. The balance of these notes at December 31, 2007 was U.S. $4,720 and U.S. $8,171, respectively (2006 – U.S. $4,908 and U.S. $8,255).	**12,738**	15,340
Revolving credit facility (Note 8): Revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus 1.125 %. The effective rate of interest for 2007 was 5.51% (2006 – 5.36%).	**126,000**	67,000
Bonds Payable: Obligation to the City of Sanger due October 1, 2011 at interest rates varying from 5.15% to 5.55%. U.S. $845 (2006 – U.S. $1,030).	**835**	1,200
AirSource Senior Debt Financing: Interest rate is equal to bankers' acceptance plus 1% and matures on October 31, 2011. Interest payments only until April 2008 and quarterly interest and principal payments of $1,368 made commencing June 2008. The effective rate of interest for 2007 was 5.50%. (2006 – 5.41%).	**73,207**	73,300
AirSource Development Debt: Financing from Highground Capital Corporation Inc. which bears interest at 11.25% per annum. Prior to December 31, 2008, payments in respect of development debt financing will consist of interest only. The debt will mature on December 31, 2011.	**1,600**	1,600
AirSource Participation Agreement: Financing from Highground Capital Corporation Inc. which bears interest at 9.25% per annum. The debt will mature on September 30, 2014.	**1,400**	-
Other	**127**	180
	$ 283,453	$ 230,715
Less: current portion	**(1,728)**	(1,709)
	$ 281,725	$ 229,006

9. Long-term liabilities (cont'd)

Total long term debt is reported net of deferred financing charges. Each of the facility level debt is secured by the respective facility with no other recourse to the Fund. The loans have certain financial covenants, which must be maintained on a quarterly basis. Non compliance with the covenants could restrict cash distributions to the Fund from specific facilities. As at December 31, 2007 the Fund was in compliance with all debt covenants.

Interest paid on the long-term liabilities was $15,748 (2006 – $14,732).

Principal payments due in the next five years and thereafter are:

2008	$ 1,728
2009	3,091
2010	3,326
2011	131,109
2012	3,467
Thereafter	140,732
	$ 283,453

10. Convertible Debentures

In 2006, the Fund issued 60,000 of convertible unsecured subordinated debentures at a price of $1 per debenture for gross proceeds of $60,000 and net proceeds of $57,100. The debentures are recorded on the financial statements net of issue costs of $2,900, resulting in an effective interest rate of 7.05%. The debentures are due November 30, 2016 and bear interest at 6.20% per annum, payable semi-annually in arrears on May 31 and November 30 each year. The convertible debentures are convertible into trust units of the Fund at the option of the holder at a conversion price of $11.00 per trust unit, being a ratio of approximately 90.9091 trust units per $1 principal amount of debentures. The debentures may not be redeemed by the Fund prior to November 30, 2010. During the period of November 30, 2010 until November 29, 2012, the debentures may be redeemed by the Fund if the underlying trust unit price is equal to or exceeds a price of $13.75 (125% of the conversion price of $11.00). During the period of November 30, 2012 until the debenture's maturity, the Fund can redeem the debentures for 100% of the face value of debenture with cash or for 105% of the face value of debenture with additional trust units. The Fund performed an evaluation of the embedded holder option and determined that its value was $479 and as a result this portion of the debenture is classified as equity with the remaining amount classified as a liability. The liability component of convertible debentures increases to its face value over the term of the debenture. The offsetting charge to earnings is classified as debt accretion expense on the Consolidated Statements of Earnings.

In 2004, the Fund issued 85,000 convertible unsecured subordinated debentures at a price of $1 per debenture for gross proceeds of $85,000 and net proceeds of $81,105. The debentures are recorded on the financial statements net of issue costs of $3,895, resulting in an effective interest rate of 7.55%. The debentures are due July 31, 2011 and bear interest at 6.65% per annum, payable semi-annually in arrears on January 31 and July 31 each year. The convertible debentures are convertible into trust units of the Fund at the option of the holder at a conversion price of $10.65 per trust unit, being a ratio of approximately 93.8967 trust units per $1 principal amount of debentures. The debentures may not be redeemed by the Fund prior to July 31, 2007.

During the period of July 31, 2007 until July 30, 2009, the debentures may be redeemed by the Fund if the underlying trust unit price is equal to or exceeds a price of $13.31 (125% of the conversion price of $10.65). During the period of July 31, 2009 until the debenture's maturity, the Fund can redeem the debentures for 100% of the face value of debenture with cash or for 105% of the face value of debenture with additional trust units. The Fund performed an evaluation of the embedded holder option and determined that its value was nominal and as a result the entire amount of the debenture is classified as a liability.

During 2007, 16 (2006 – 20) of 2004 convertible debentures were converted into 1,502 (2006 – 1,877) units which resulted in an increase in units of $16 (2006 – $20) and a decrease in convertible debentures by a similar amount.

Total interest paid on the convertible debentures in 2007 was $9,448 (2006 – $6,049).

11. Other long-term liabilities

	2007	2006
Capital Leases		
Obligation for equipment leases. Interest rates varying from 5.75% to 12.25%, monthly interest and principal payments with varying dates of maturity from March 2008 to October 2024	**2,504**	2,351
Advances in aid of construction	**10,789**	12,186
Customer Deposits	**2,622**	3,248
Deferred water rights	**3,252**	2,934
Other	**4,791**	5,787
	23,958	26,506
Less: current portion	**(187)**	(167)
	$ 23,771	$ 26,339

Principal payments due in the next five years and thereafter are:

2008	$ 187
2009	69
2010	33
2011	32
2012	-
Thereafter	23,637
	$ 23,958

Interest paid on other long-term liabilities was $46 (2006 – $42).

12. Trust units

Authorized trust units

The Declaration of Trust provides that an unlimited number of units may be issued. Each unit represents an undivided beneficial interest in any distribution from the Fund and in the net assets in the event of termination or wind-up. All units are the same class with equal rights and privileges.

Trust units are redeemable at the holder's option at amounts related to market prices at the time subject to a maximum of $250 in cash redemptions in any particular calendar month, subject to the ability of the Fund to waive the maximum and pay further amounts by way of cash. Redemptions in excess of this amount shall be paid by way of a distribution in kind of a pro rata amount of certain of the Fund's assets, including the securities purchased by the Fund, but not to include the generating facilities.

Issued trust units

	Number of units	Amount
Balance as at December 31, 2005	69,691,592	$ 654,176
Convertible Debentures exchanged for Trust Units March 2006	1,877	20
Acquisition of outstanding partnership units of AirSource Power Fund I LP	3,180,742	30,218
Balance as at December 31, 2006	72,874,211	$ 684,414
Issued on conversion of Algonquin (AirSource) Power LP exchangeable units	768,643	7,304
Conversion of convertible debentures	1,502	16
Balance as at December 31, 2007	73,644,356	$ 691,734

Subsequent to the end of the year, the Fund issued 35,358 trust units pursuant to the conversion provisions for exchangeable units.

13. Income taxes

The Fund is an unincorporated trust and is subject to current income taxes on taxable income not distributed to its Unitholders. For 2007 the Fund made distributions to Unitholders of its current taxable income and plans to continue to distribute all future current taxable income to its Unitholders. Consequently, no provision for current income taxes or for future income taxes on temporary differences reversing prior to 2011 has been made in these financial statements for income of the Fund and its flow-through subsidiaries as these will be the responsibility of the Unitholders. Current and future income taxes have been provided in respect of taxable income and temporary differences related to the corporate subsidiaries of the Fund.

The provision for income taxes in the consolidated statements of earnings represents an effective tax rate different than the Canadian enacted statutory rate of 32.05% (2006 – 32.31%). The differences are as follows:

	2007	2006
Earnings from continuing operations before income tax and minority interest	**$ 39,470**	$ 29,420
Computed income tax expense at Canadian statutory rate	**12,650**	9,506
Increase (decrease) resulting from:		
Income of the Fund taxed directly to unitholders	**(12,122)**	(12,926)
Future tax related to changes in tax law and rates	**17,162**	(1,674)
Change in valuation allowances	**10,041**	(239)
Foreign exchange loss on intercompany items	**(12,600)**	74
Other	**(23)**	2,493
Income tax expense / (recovery)	**$ 15,108**	$ (2,766)

The tax effect of temporary differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis that give rise to rise to significant portions of the future tax assets and future tax liabilities at December 31, 2007 and 2006 are presented below:

	2007	2006
Future tax assets:		
Non-capital loss, debt restructuring charges and currently non-deductible interest carry forwards	**$ 19,561**	$ 20,241
Unrealized foreign exchange differences on US entity debt	**30,003**	17,403
Customer advances in aid of construction	**4,414**	5,007
Total future tax assets	**53,978**	42,651
Less: Valuation allowance	**(42,996)**	(32,955)
Total future tax assets	**10,982**	9,696
Future tax liabilities:		
Capital assets	**(81,567)**	(57,112)
Intangible assets	**(8,174)**	(16,589)
Other	**(366)**	(461)
Total future tax liabilities	**(90,107)**	(74,162)
Net future tax liability	**$ (79,125)**	$ (64,466)

Classified in the financial statements as:

	2007	2006
Future current income tax asset	**$ -**	$ -
Future non-current income tax asset	**2,416**	7,639
Future current income tax liability	**(756)**	(848)
Future non-current income tax liability	**(80,785)**	(71,257)
	$ (79,125)	$ (64,466)

On June 22, 2007 legislation ("the SIFT Rules") relating to the federal income taxation of publicly-traded trusts and partnerships received royal assent. Under transitional relief the SIFT Rules apply to a publicly-traded trust or partnership that is a "specified investment flow through entity" (a "SIFT") which was listed before November 1, 2006 ("Existing Trust") commencing with taxation years ending in or after 2011. The SIFT Rules do not affect the current and future tax amounts of the Fund's corporate subsidiaries.

Under the SIFT Rules, distributions of certain income by a SIFT will not be deductible in computing the SIFT's taxable income, and the SIFT will be subject to tax on such income at a rate that is substantially equivalent to the general tax rate applicable to Canadian corporations. A SIFT's income that is dividends or income received directly from foreign sources will continue to be taxed to unitholders under the existing rules and distributions paid by a SIFT as returns of capital will not be subject to this tax. An Existing Trust may lose its transitional relief where its equity capital grows beyond certain dollar limits measured by reference to the Existing Trust's market capitalization at the close of trading on October 31, 2006 in which case application of this tax to an Existing Trust may commence before 2011.

The Fund is a SIFT as defined in the SIFT Rules. Accordingly commencing January 1, 2011 the Fund will be subject to taxes on certain income earned from investments in its subsidiaries. The tax payable by the Fund on that income will result in a corresponding decrease to the cash flow available to be distributed to the Unitholders. The Fund has recognized future income tax assets and liabilities with respect to the temporary differences of its assets and liabilities and those of its flow-through subsidiaries that are expected to reverse in or after 2011. The Fund expects that its income will not be subject to tax prior to 2011 and accordingly has not provided future income taxes on its temporary differences and that of its flow through subsidiaries that are expected to reverse before 2011.

Under the SIFT Rules, flow-through subsidiaries of the Fund may also themselves be SIFTs although the intent and interpretation of the legislation is not entirely clear. The Fund has concluded that even if it is determined that these flow-through subsidiaries meet the definition of a SIFT, there should be no material impact on the income tax provision and future tax assets and liabilities of the Fund. On December 20, 2007, the Minister of Finance announced his intention to introduce technical amendments to the SIFT definition to exclude certain flow-through subsidiaries of a SIFT that are able to meet certain ownership conditions. Under such technical amendments, if enacted in the form announced, the majority of the Fund's flow-through subsidiaries would not themselves be SIFTs.

The Fund and its flow-through subsidiaries have assets with an accounting basis which exceeds their tax bases by $7,853 (2006 – $64,803) which are not included in future tax assets and liabilities reported above.

The Fund has $39,384 of tax losses that are expiring between 2009 and 2027.

14. Algonquin Power Group

In addition to the transaction described in note 5 with APMI, the following related party transactions occurred:

APMI provides management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. In 2007 and 2006, APMI was paid on a cost recovery basis for all costs incurred and charged $867 (2006 – $869). APMI is also entitled to an incentive fee of 25% on all distributable cash (as defined in the management agreement) generated in excess of $0.92 per trust unit. During 2007 $770 (2006 – nil) was earned by APMI as an incentive fee.

As part of the project to re-power the Sanger facility, the Fund entered into an agreement with APMI to undertake certain construction management services on the project. APMI is entitled to a development supervision fee plus a contingency fee for its construction management role on the project. During 2007, APMI was paid $98 (2006 – nil).

The Fund has leased its head office facilities since 2001 from an entity owned by the shareholders of APMI on a net basis. Base lease costs for 2007 were $296 (2006 – $296) and additional rent representing operating costs was nil (2006 – $89).

The Fund utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. In 2004, the Fund entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursements (including engine utilization reserves) for the Fund's business use of the aircraft. Under the terms of this arrangement, the Fund will have priority access to make use of the aircraft for a specified number of hours at a cost equal solely to the third party direct operating costs incurred when flying the aircraft; such direct operating costs do not provide the affiliate with any profit or return on or of the capital committed to the aircraft. During the year, the Fund incurred costs in connection with the use of the aircraft of $422 (2006 – $403) and amortization expense related to the advance against expense reimbursements $168 (2006 – $136).

The Fund has project debt from Highground Capital Corporation ("HCC") (previously Algonquin Power Venture Fund) in an amount of $3.0 million related to the St. Leon facility. HCC advanced $1.6 million at a rate of 11.25% as part of the initial financing of the St. Leon facility which matures December 31, 2011 and advanced $1.4 million at a rate of 9.25% during the first quarter of 2007 which matures September 30, 2014. Both amounts are secured by the underlying assets of the St. Leon facility. During 2007, HCC was paid $258 (2006 – $86) in interest related to debt associated with the St. Leon facility. Some of the directors and shareholders of the Manager are also directors, officers and shareholders of the manager of HCC.

In accordance with the construction services agreement related to the St. Leon facility GWAP, a company controlled by APMI, was paid $845 (2006 – $141) in 2007 for construction services. In 2007, the Fund also paid $1,353 (2006 – $517) to GWAP on a cost recovery basis related to ongoing operating expenses of the project. There remains a final payment of $134 to GWAP in respect of construction services. This amount will be paid in the first quarter 2008.

AirSource has agreed to reimburse AirSource Power Fund GP Inc (the "General Partner") of the AirSource Power Fund I LP for reasonable costs incurred by it in acting as registrar and transfer agent and in attending to the administration of the Partnership, as required in the Partnership Agreement. The general partner was paid $11 during the year ended December 31, 2007 (2006 – $65).

15. Discontinued Operations

During 2007, the Fund disposed of certain landfill gas and hydroelectric facilities that were no longer considered strategic to the ongoing operations of the Fund for gross proceeds of $14,083. The result of operations from these facilities are disclosed as net earnings / (loss) from discontinued operations on the consolidated statement of earnings as discontinued operations.

The results of the discontinued operations which have been included in the consolidated statement of earnings were as follows:

	2007	2006
Revenue	**$ 6,651**	$ 8,171
Expenses	**8,077**	9,265
Operating loss	**(1,426)**	(1,094)
Interest expense	**72**	8
Amortization of capital and intangible assets	**1,192**	1,670
Current income tax expense	**1,336**	-
Future income tax recovery	**(342)**	-
Gain on sale of capital assets and intangible assets	**(2,592)**	-
Net earnings/(loss) from discontinued operations	**(1,092)**	(2,772)
Add:		
Amortization of capital and intangible assets	**1,192**	1,670
Less:		
Future income tax recovery	**(342)**	-
Gain on sale of capital assets and intangible assets	**(2,592)**	-
Net cashflow from discontinued operations	**$ (2,834)**	$ (1,102)
Assets held for sale consist of the following:		
Capital assets	**$ -**	$ 13,035
Intangible assets	**-**	1,042
	$ -	$ 14,077

16. Commitments and Contingencies

(a) Land and Water Leases

Certain of the operating entities, including AirSource, have entered into agreements to lease either the land and/or the water rights for the hydroelectric generating facility or to pay in lieu of property tax an amount based on electricity production. The terms of these leases continue up to 2048. These payments typically have a fixed and variable component. The variable fee is generally linked to actual power production or gross revenue. The Fund incurred $2,493 during 2007 (2006 – $2,702) in respect of these agreements for the consolidated facilities.

(b) Contingencies

The Fund and its subsidiaries are involved in various claims and litigation arising out of the ordinary course and conduct of its business. Although such matters cannot be predicted with certainty, management does not consider the Fund's exposure to such litigation to be material to these financial statements.

Pursuant to legislation in the Province of Quebec requiring technical assessments of all dams within the province and remediation of any technical deficiencies identified, the Fund is in the process of conducting the assessments as required. Based on preliminary assessments to date, the Fund has initially estimated potential remedial measures involving capital expenditures of approximately $8,200 which may be required to comply with the legislation. The Fund is currently exploring several alternatives to reduce or mitigate these potential capital expenditures, including technical alternatives and cost sharing with other stakeholders. Accordingly it is not determinable at this time the amount of remedial capital expenditures that might ultimately have to be borne by the Fund, nor the time frame within which these capital expenditures may need to be completed.

16. Commitments and Contingencies (cont'd)

(c) Commitments

An AirSource affiliate, St. Leon Wind Energy LP ("St. Leon LP") has entered into right-of-way agreements (collectively, the "Land Rights"), with approximately 50 local landowners, providing for a minimum term of 40 years. The Land Rights agreements provide for an annual rent payable per MW-hr generated from turbines installed on the land rented, subject to a minimum payment per wind turbine. Land without wind turbines is leased at a cost on a per acre basis. The total commitment over the term of the St. Leon PPA is estimated at $5,150.

17. Fair Value of Financial instruments and Derivatives

The carrying amount of the Fund's cash and cash equivalents, accounts receivable, restricted cash, accounts payable and accrued liabilities, due to Algonquin Power Group and cash distribution payable, approximate fair market value.

The carrying amount of the Fund's long-term investments is dependant on the underlying operations and accordingly a fair value is not readily available. The Fund has long-term liabilities at fixed interest rates or variable rates. The fair value of these long-term liabilities at current rates would be $286,445 (2006 – $231,697). The book value of these long-term liabilities is $283,452 (2006 – $230,715). The fair value of other long-term liabilities approximates their carrying value.

Advances in aid of construction included in other long-term liabilities (note – 1 (g)) do not bear interest and the amount to be repaid is uncertain and not determinable. The carrying value is estimated based on historical payments patterns.

18. Cash distributions

Distributable income is distributed monthly. Distributions are declared to Unitholders of record on the last day of the month and are distributed 45 days after declaration. The monthly distribution for 2007 was $0.0766 per trust unit for each month for a total of $0.92 for 2007, the same as 2006.

19. Basic and diluted net earnings per trust unit

Basic and diluted earnings per trust unit have been calculated on the basis of the weighted average number of units outstanding during the year. The weighted average number of units outstanding during the year are as follows:

	2007	2006
Weighted average trust units – basic	**73,423,639**	71,085,930
Trust units issuable on conversion of exchangeable units	**2,703,593**	1,783,751
Weighted average trust units – diluted	**76,127,232**	72,869,681

Trust units issuable on conversion of exchangeable units are calculated based on the weighted average exchangeable units outstanding during the year at the year end exchange rate.

An adjustment for the year ended December 31, 2007 is required in the diluted earnings per unit calculation to provide for earnings attributable to non-controlling interest. The effect of conversion was anti-dilutive for the year ended December 31, 2006. Units potentially issuable on the conversion of the convertible debentures are anti-dilutive and are not included in the calculation of diluted weighted average units for the years ended December 31, 2007 and 2006.

20. Interest, dividend and other income

Other income includes the following items:

	2007	2006
Interest income	**$ 2,379**	$ 4,184
Dividend income	**3,222**	3,382
Termination fee	**1,750**	-
Equity income	**390**	538
Other	**1,667**	2,757
	$ 9,408	$ 10,861

During 2007, the Fund allowed its offer to acquire all the outstanding trust units and convertible debentures of the Clean Power Income Fund ("CPIF") to expire. In connection with the expiry of the offer, a termination fee of $1,750 was paid to the Fund. The Fund was reimbursed $850 from CPIF for its expenses.

21. Other revenue

Other revenue includes the following items:

	2007	2006
St. Leon wind energy facility liquidated damages	**$ 17,123**	$ 11,039
Natural gas sales	**1,405**	6,275
Hydro mulch sales	**3,774**	2,972
	$ 22,302	$ 20,286

22. Segmented Information

Geographic Segments

The Fund and its subsidiaries operate in the independent power and utility industries in both Canada and the United States. Information on operations by geographic area is as follows:

	2007	2006
Revenue		
Canada	**$ 76,146**	$ 65,209
United States	**110,029**	128,035
	$ 186,175	$ 193,244
Capital assets		
Canada	**$ 467,991**	$ 490,969
United States	**292,686**	306,471
	$ 760,677	$ 797,440
Intangible assets		
Canada	**$ 56,142**	$ 60,711
United States	**43,387**	50,224
	$ 99,529	$ 110,935
Other assets		
Canada	**$ 1,484**	$ 938
United States	**1,253**	1,356
	$ 2,737	$ 2,295

Revenues are attributable to the two countries based on the location of the underlying generating and infrastructure facilities.

22. Segmented Information (cont'd)

Operational segments

The Fund identifies four business categories it operates in: hydro, natural gas cogeneration, alternative fuels and infrastructure assets. The operations and assets for these segments are as follows:

	Year ended December 31, 2007					
	Hydro	Co-generation	Alternative Fuel	Infra-structure	Admin-istration	Total
Revenue						
Energy sales	$ 41,023	$ 60,895	$ 14,647	$ -	$ -	$ 116,565
Waste disposal fees	-	-	13,609	-	-	13,609
Water reclamation and distribution	-	-	-	33,699	-	33,699
Other revenue	-	3,774	18,528	-	-	22,302
Total revenue	41,023	64,669	46,784	33,699	-	186,175
Operating expenses	14,993	46,822	20,098	17,401	-	99,314
	26,030	17,847	26,686	16,298	-	86,861
Other administration costs	(343)	-	(298)	(211)	(1,560)	(2,412)
Interest expense	(4,944)	(1,085)	(4,708)	(1,011)	(14,817)	(26,565)
Interest, dividend and other income	1,332	3,222	2,895	33	1,926	9,408
Gain / (loss) on hedging instrument	-	5,303	(1,079)	3,296	6,949	14,469
Write down of note receivable	-	-	(726)	-	-	(726)
Amortization of capital assets	(9,504)	(6,588)	(11,324)	(6,862)	-	(34,278)
Amortization of intangible assets	(1)	(1,991)	(4,481)	(814)	-	(7,287)
Earnings from continuing operations before income taxes, minority interest and comprehensive income	12,570	16,708	6,965	10,729	(7,502)	39,470
Loss from discontinued operations	(126)	-	(966)	-	-	(1,092)
Net earnings before income taxes, minority interest and comprehensive income	12,444	16,708	5,999	10,729	(7,502)	38,378
Capital assets	$ 253,636	$ 101,953	$ 263,970	$ 141,118	$ -	$ 760,677
Intangible assets	17	17,087	56,086	26,339	-	99,529
Capital expenditures	1,199	13,776	6,185	18,097	314	39,571
Acquisition of operating entities	-	-	-	990	-	990
Total assets	$ 269,256	$ 146,841	$ 342,507	$ 174,143	$ 21,377	$ 954,124

	Year ended December 31, 2006					
	Hydro	Co-generation	Alternative Fuel	Infra-structure	Admin-istration	Total
Revenue						
Energy sales	$ 45,066	$ 68,544	$ 9,675	$ -	$ -	$ 123,285
Waste disposal fees	-	-	14,209	-	-	14,209
Water reclamation and distribution	-	-	-	35,464	-	35,464
Other revenue	-	9,247	11,039	-	-	20,286
Total revenue	45,066	77,791	34,923	35,464	-	193,244
Operating expenses	15,565	53,362	18,783	15,370	-	103,080
	29,501	24,429	16,140	20,094	-	90,164
Other administration costs	(473)	-	10	(167)	(8,573)	(9,203)
Interest expense	(5,029)	(1,121)	(2,557)	(1,014)	(12,560)	(22,281)
Interest, dividend and other income	1,833	3,382	5,480	53	113	10,861
Loss on hedging instrument	-	-	(497)	-	(497)	
Write down of note receivable	-	-	(3,263)	-	-	(3,263)
Amortization of capital assets	(9,748)	(6,405)	(7,903)	(6,553)	-	(30,609)
Amortization of intangible assets	(1)	(2,195)	(2,730)	(826)	-	(5,752)
Earnings from continuing operations before income taxes and minority interest	$ 16,083	$ 18,090	$ 4,680	$ 11,587	$ (21,020)	$ 29,420
Loss from discontinued operations	(265)	-	(2,507)	-	-	(2,772)
Net earnings before income taxes, minority interest and comprehensive income	15,818	18,090	2,173	11,587	(21,020)	26,648
Capital assets	$ 277,416	$ 85,114	$ 263,150	$ 171,760	$ -	$ 797,440
Intangible assets	18	19,078	60,600	31,239	-	110,935
Capital expenditures	1,703	13,992	3,481	11,542	216	30,934
Asset held for sale	1,502	-	12,575	-	-	14,077
Acquisition of operating entities	-	-	20,628	2,805	-	23,433
Total assets	$ 297,257	$ 133,146	$ 379,220	$ 211,664	$ 27,037	$ 1,048,324

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2007 or 2006: Hydro Québec 16% (2006 – 16%), Pacific Gas and Electric 14% (2006 – 11%), and Connecticut Light and Power 24% (2006 – 22%). The Fund has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

23. Comparative figures

Certain of the comparative figures have been reclassified to conform with the financial statement presentation adopted in the current year.

Corporate Information

Trustees

The Management Group

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David C. Kerr, Director

Ian E. Robertson, Director

Algonquin Power Income Fund

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Annual General Meeting

April 24, 2008, 4:00 p.m.

Blake, Cassels & Graydon LLP

199 Bay Street, Floor 23

Toronto, Ontario

Stock Exchange

The Toronto Stock Exchange: APF.UN, APF.DB, APF.DB.A

Auditors

KPMG LLP

Toronto, Ontario

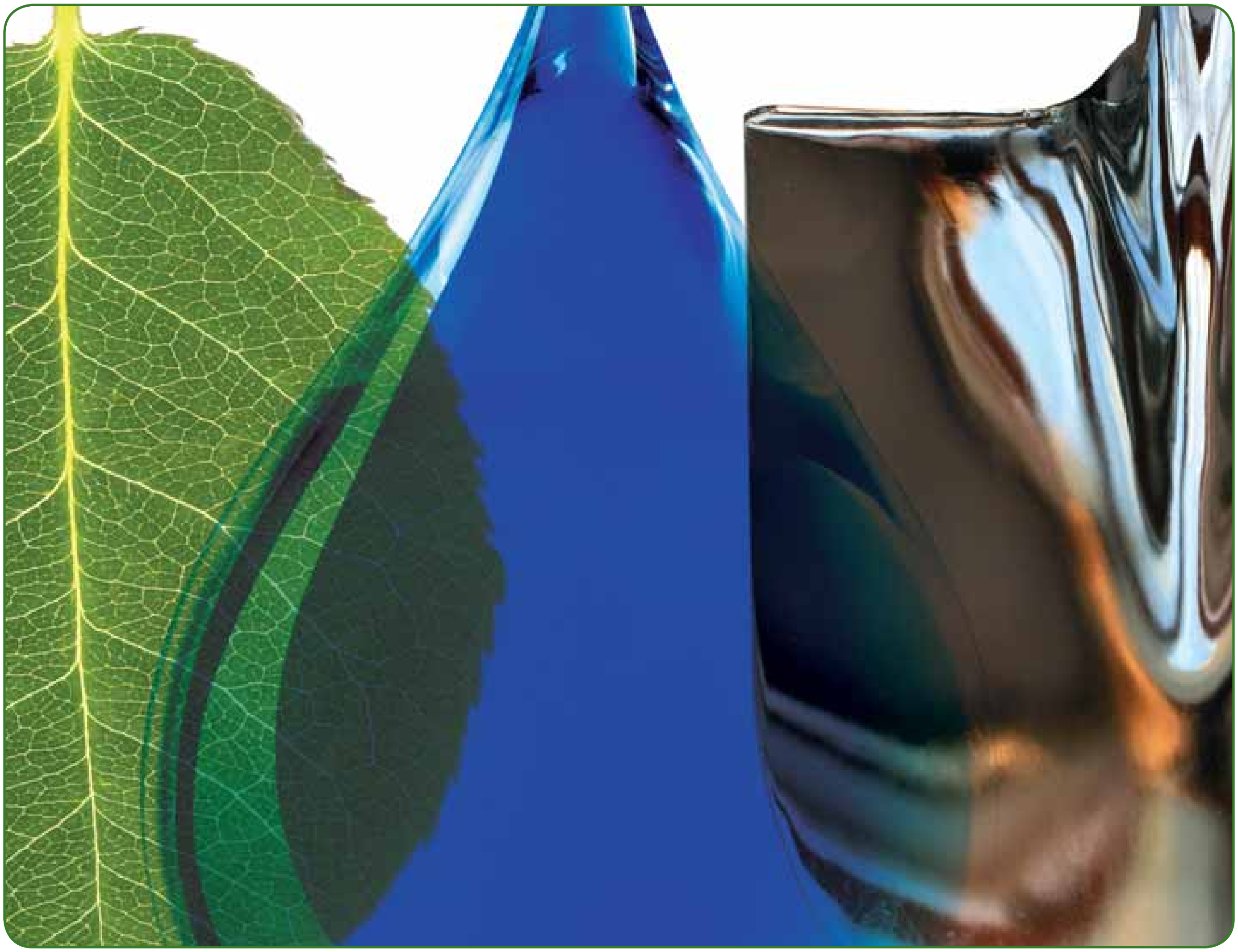
Legal Counsel

Blake, Cassels & Graydon LLP

Toronto, Ontario

Annual Report

2007



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