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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
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MIKE GLEASON
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WILLIAM A. MUNDELL
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COMMISSIONER
GARY PIERCE
COMMISSIONER

IN THE MATTER OF THE APPLICATION OF GOLD CANYON SEWER COMPANY, AN ARIZONA CORPORATION, FOR A DETERMINATION OF THE FAIR VALUE OF ITS UTILITY PLANT AND PROPERTY AND FOR INCREASES IN ITS RATES AND CHARGES FOR UTILITY SERVICE BASED THEREON.	Docket No. SW-02519A-06-0015

NOTICE OF FILING

The Residential Utility Consumer Office ("RUCO") hereby provides notice of filing the Rehearing Supplemental Testimony of William A. Rigsby, CRRA in the above-referenced matter.

RESPECTFULLY SUBMITTED this 1st day of April 2008.

Arizona Corporation Commission
DOCKETED
APR -1 2008
DOCKETED BY MR

Daniel W. Pozefsky
Attorney

AN ORIGINAL AND THIRTEEN COPIES
of the foregoing filed this 1st day
of April 2008 with:

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, Arizona 85007

COPIES of the foregoing hand delivered/
mailed this 1st day of April 2008 to:

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Assistant Chief Administrative Law Judge
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Phoenix, Arizona 85007

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By Ernestine Gamble
Ernestine Gamble
Secretary to Daniel Pozefsky

GOLD CANYON SEWER COMPANY

DOCKET NO. SW-02519A-06-0015

REHEARING SUPPLEMENTAL TESTIMONY

OF

WILLIAM A. RIGSBY, CRRA

ON BEHALF OF

THE

RESIDENTIAL UTILITY CONSUMER OFFICE

APRIL 1, 2008

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INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is William A. Rigsby. I am a Public Utilities Analyst V employed by the Residential Utility Consumer Office ("RUCO") located at 1110 W. Washington, Suite 220, Phoenix, Arizona 85007.

Q. Have you filed any prior testimony in this rehearing proceeding on behalf of RUCO?

A. Yes I have. On September 28, 2007, I filed rehearing testimony which presented RUCO's hypothetical capital structure (and related cost of capital issues) which is being considered in this proceeding.

Q. Please state the purpose of your rehearing rebuttal testimony.

A. The purpose of my rehearing rebuttal testimony is to provide evidence that supports my position that Algonquin Power Income Fund, the parent company of Gold Canyon, has the ability to obtain debt financing in the capital markets if it chooses to do so.

ABILITY TO OBTAIN DEBT FINANCING

Q. Why are you presenting evidence that supports your position that the parent company of Gold Canyon has the ability to obtain debt financing in the capital markets?

A. The Company and I disagree over the appropriate capital structure that should be adopted by the Commission in this case. The Company has taken the position that it should have a capital structure comprised of 100 percent equity as opposed to the hypothetical capital structure that I have recommended which is comprised of 60 percent equity and 40 percent debt. The Company has argued that the fact that Gold Canyon has a parent company which has direct access to the capital markets is irrelevant in this case. I disagree with this position and believe that the Company's ability to obtain capital through the debt and equity markets is relevant and should be considered by the Commission in this case.

Q. What evidence do you have that supports your position that the Company's parent can obtain debt financing if it chooses to do so?

A. The Algonquin Power Income Fund's 2006 Annual Report (Attachment 1) supports my argument. Page 15 of this document contains a description of a convertible debenture offering which was completed on November 22, 2006. The offering involved the issuance of 60,000 convertible unsecured subordinated debentures at a price of $1,000 (Canadian) per debenture for gross proceeds of $60 million. The debentures are due in November

2016 and bear interest at a stated rate of 6.20 percent per annum payable semi-annually[1]. This information, in addition to the other evidence I have presented in this proceeding, makes the point that Gold Canyon's parent has the ability to obtain debt financing if it chooses to do so.

Q. Does the fact that Gold Canyon's parent has the ability to issue debt in the capital markets have an impact on the Company's capital structure?

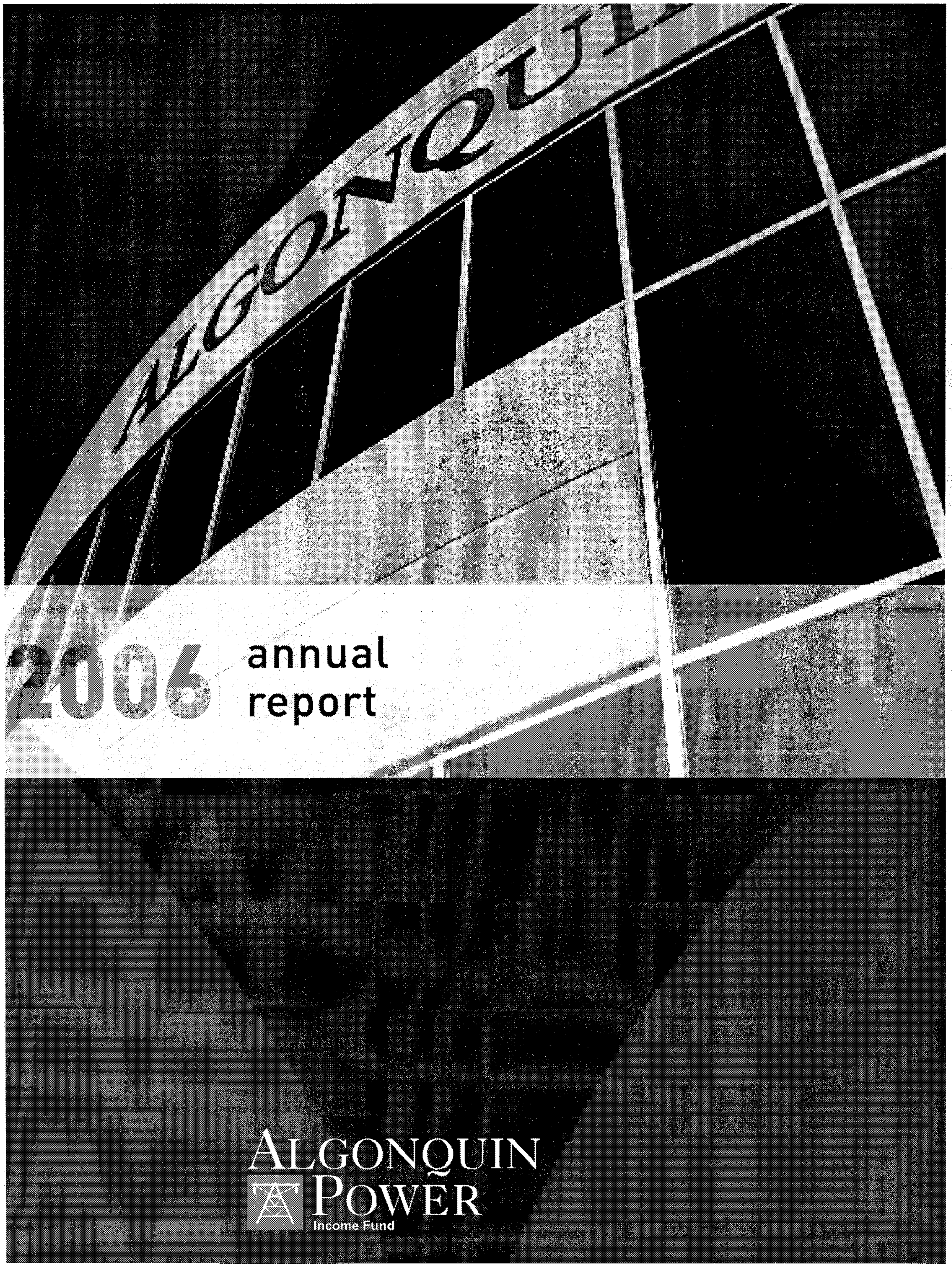
A. Yes. The fact that Algonquin Power Income Fund has the ability to obtain debt in the capital markets should be reflected in Gold Canyon's capital structure. In fact, the 6.20 percent yield on the debentures is lower than my recommended cost of debt of 8.45 percent. This means that Algonquin Power Income Fund has the ability to issue debt at a lower cost than what I have estimated in this case. In summary, I believe that the Commission should adopt RUCO's hypothetical capital structure which is comprised of 60 percent equity and 40 percent debt and RUCO's recommended 8.54 percent weighted cost of capital.

Q. Does this conclude your rehearing supplemental testimony on Gold Canyon?

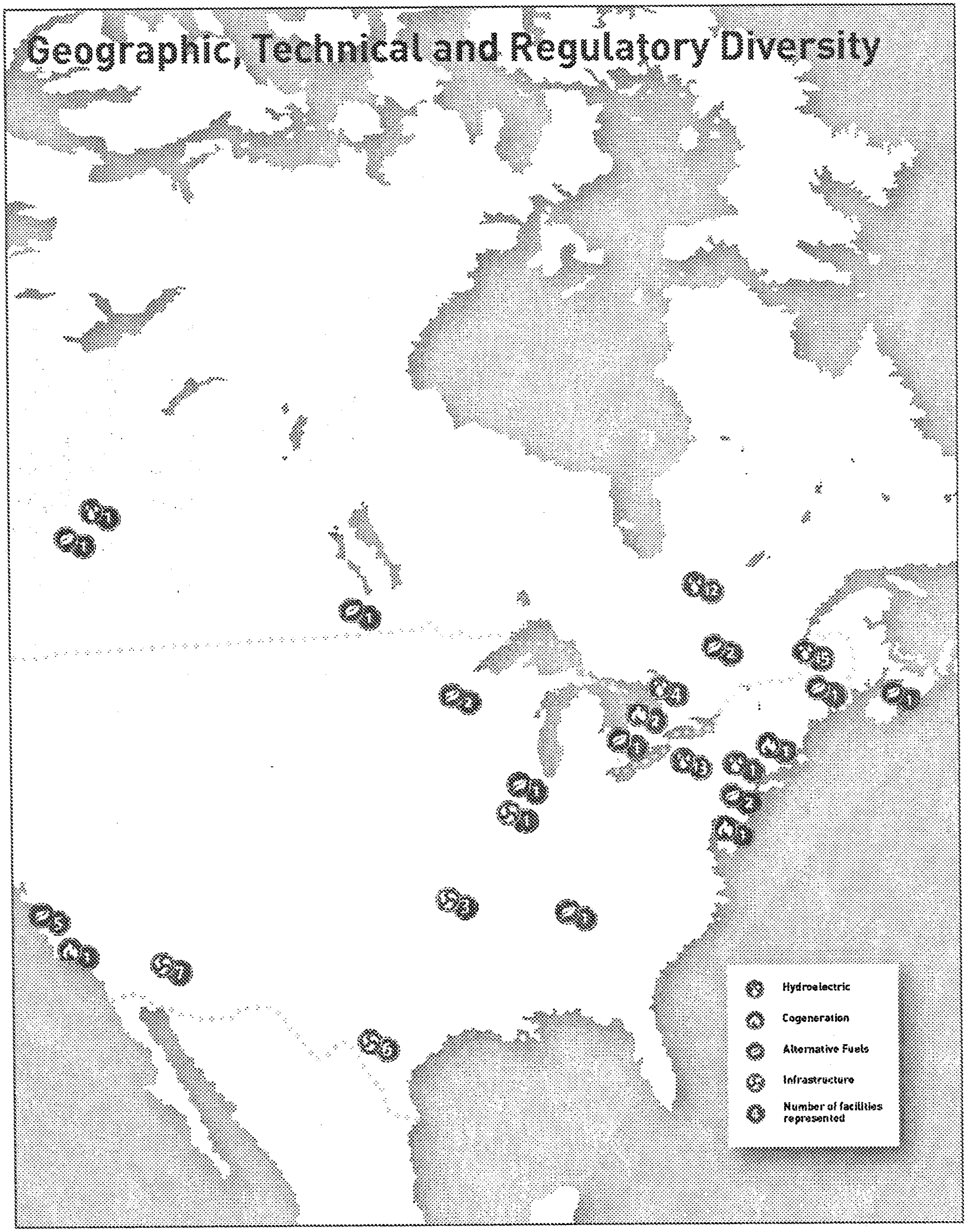
A. Yes, it does.

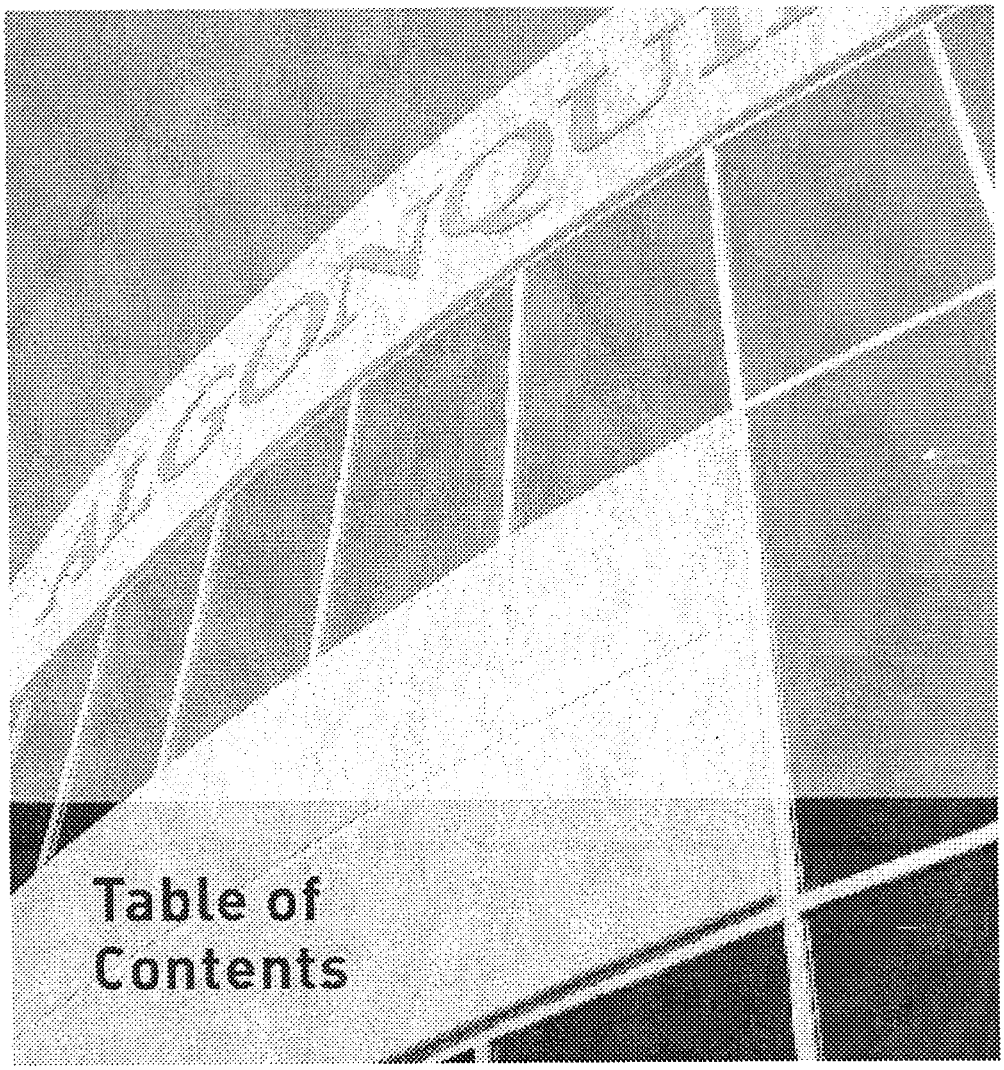
[1] The Debentures are currently being traded on the Toronto Stock Exchange under the symbol APF.DB.A (Algonquin Pwr 6.2%Db)

ATTACHMENT 1


2006 annual report
ALGONQUIN
POWER
Income Fund

Geographic, Technical and Regulatory Diversity





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Algonquin Power History of Assets

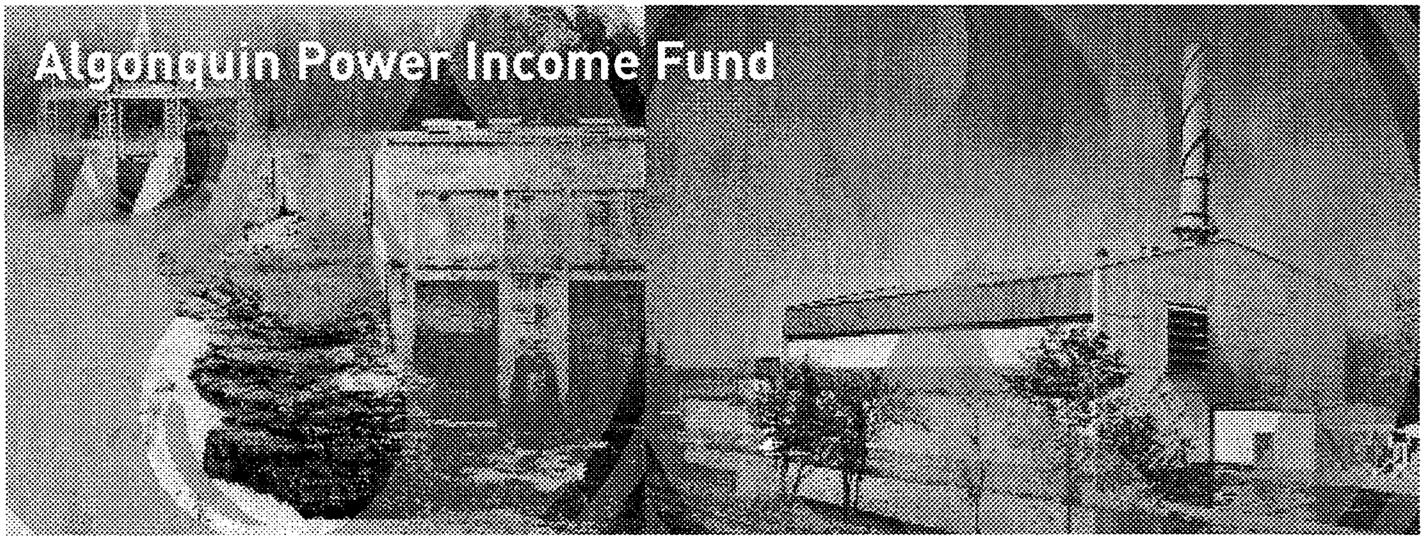
Year	Assets	Facilities	Capacity(MW)/Connections
1997	Hydroelectric	17	19
1998	Hydroelectric	29	69
1999	Hydroelectric	38	101
2000	Hydroelectric	41	115
2001	Hydroelectric	47	141
	Cogeneration	Interest in 3	288
	Alternative Fuels	Interest in 3	66
	Infrastructure	2	4,500 connections
2002	Hydroelectric	47	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

Financial Highlights

	2006	2005	2004	2003	2002	2001
Energy Sales						
Hydroelectric	45,945	44,102	43,268	44,413	40,681	36,270
Cogeneration	68,544	75,674	71,846	61,890	23,566	-
Alternative Fuels	15,492	16,262	7,867	6,423	4,994	1,020
Total Energy Sales	**129,981**	**136,038**	**122,981**	**112,726**	**69,241**	**37,290**
Waste Disposal	14,209	13,031	14,086	14,650	10,697	-
Water Distribution/Reclamation	35,464	28,371	23,456	20,237	7,974	2,522
Other Revenue	21,761	1,884	-	-	-	-
Total Revenue	**201,415**	**179,324**	**160,523**	**147,613**	**87,912**	**39,812**
Operating Profit (including interest, dividend and other income)						
Hydroelectric	31,069	28,344	26,383	29,045	26,985	24,835
Cogeneration	27,811	28,207	25,273	23,773	15,069	1,166
Alternative Fuels	20,791	10,773	8,181	9,328	7,292	719
Infrastructure	20,147	16,568	12,616	11,117	4,678	1,199
Other	113	139	4,373	278	851	2,530
Total Operating Profit	**99,931**	**84,031**	**76,826**	**73,541**	**54,875**	**30,449**
Earnings (before int exp, write-down of fixed & intangible assets and minority interest)	**52,696**	**44,304**	**40,276**	**53,147**	**26,726**	**18,662**
Net Earnings	27,955	21,788	22,802	44,507	16,150	6,864
Net Earnings per Trust Unit	0.39	0.31	0.33	0.66	0.28	0.17
Distribution to Unitholders	66,955	64,061	63,370	62,402	55,192	37,302
Per Trust Unit	0.92	0.92	0.92	0.92	0.92	0.92
Cash Avail. for Distribution	67,491	64,892	59,887	58,368	44,742	28,813
Per Trust Unit	0.93	0.93	0.87	0.86	0.77	0.73
Balance Sheet Data						
Cash and Cash Equivalents	13,465	11,363	34,348	21,238	24,838	31,713
Working Capital	(31,932)[1]	899	17,242	9,337	15,376	19,011
Capital and Intangible Assets & Long-Term Investments	952,428	761,989	742,994	751,904	674,495	467,312
Total Assets	**1,048,324**	**823,801**	**824,796**	**808,624**	**723,038**	**512,384**
Long-Term Liabilities & Revolving Credit Facility (includes debentures & current portion)	374,016	243,007	206,017	166,713	86,099	50,665
Unit Holders Equity	444,715	452,998	495,271	519,876	537,771	411,613
Number of Units Outstanding as of Dec. 31	72,874,211	69,691,592	69,691,592	67,887,612	67,887,612	50,875,772

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

Algonquin Power Income Fund



Algonquin Power Income Fund is an open-ended investment trust that owns and has interests in a diverse portfolio of power generating and infrastructure assets across North America, including 47 hydroelectric facilities, five natural gas-fired cogeneration facilities, 17 alternative fuels facilities and 17 water supply and waste-water facilities. Algonquin Power Income Fund was established in 1997 to provide unitholders with sustainable, highly stable cash

Hydroelectric

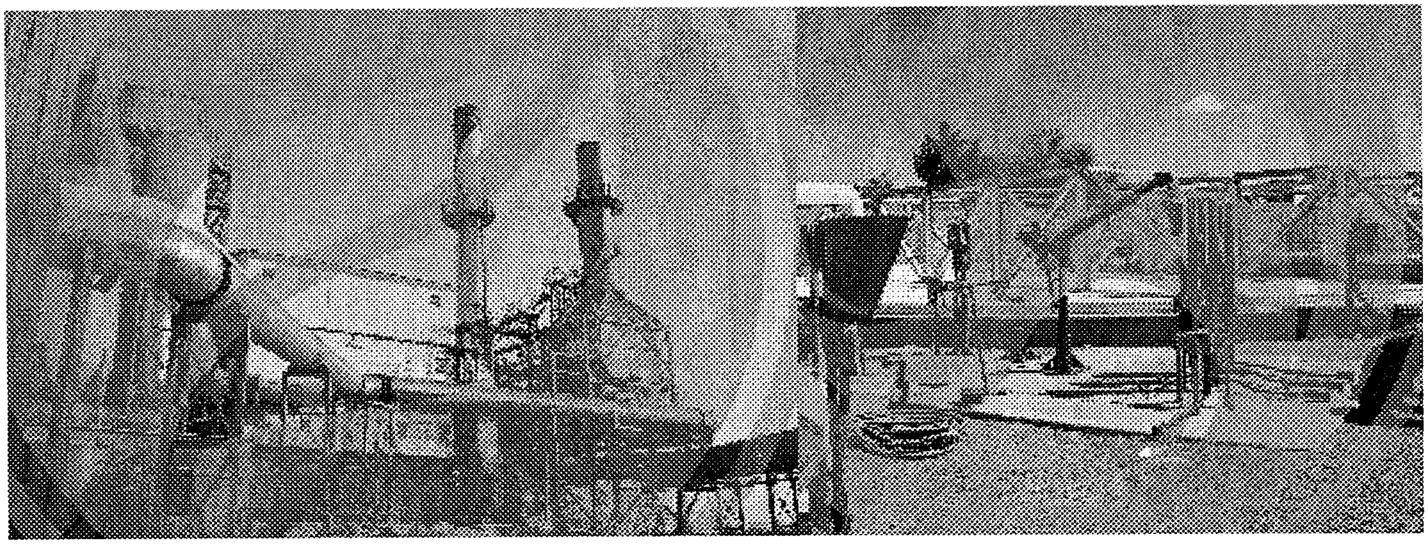
The Hydroelectric Division is comprised of 47 run-of-river hydroelectric generating facilities located in Ontario, Quebec, New York, New England, and Alberta. These facilities primarily operate on natural river flows and generally do not store water for later use. The Division's gross revenue is derived from the combination of energy production and power purchase rates. Benefits of hydroelectric facilities include low operating costs, proven technology, and virtually perpetual asset life. Combined with long-term power purchase agreements, these benefits provide the Fund with strong assets that deliver predictable cash flows.

47 hydroelectric facilities, 143 MW, average power purchase agreement life of 16 years.

Cogeneration

Algonquin Power has an interest in two and also owns three cogeneration facilities located in Ontario, New Jersey, California and Connecticut. Cogeneration is the simultaneous production of electricity and thermal energy from a single fuel source, in this case, natural gas. Revenue is generated through the sale of both thermal energy and electricity. Benefits of cogeneration technology include predictable generation, low technology risk and long term power purchase agreements. Cogeneration facilities are not subject to naturally occurring fluctuations and therefore provide efficient and predictable cash flows to the Fund.

Five natural gas fired cogeneration facilities, 248 MW, average power purchase agreement life of 11.3 years.



flows through a diversified portfolio of energy and infrastructure assets. Algonquin Power Income Fund's units and convertible debentures are traded on the Toronto Stock Exchange under the symbols APF.UN and APF.DB/APF.DB.A respectively, and units are included in the S&P/TSX Composite Index.

Alternative Fuels

The Alternative Fuels Division consists of a 500-tonne/day energy-from-waste facility in Ontario, a 99 MW wind energy generating facility in Manitoba, interest in approximately 70 MW of Biomass production in Alberta, Quebec and Nova Scotia, and an interest in 12 landfill gas-powered generating stations in the United States, representing approximately 36 MW of installed capacity.

Revenue is generated primarily from the sale of electricity, fees at the energy-from-waste facility, and interest and investment income from the other assets.

Alternative Fuels facilities including Wind, Energy-from-Waste, Biomass and Landfill Gas, 216 MW, average power purchase agreement life of 18.5 years.

Infrastructure Division

The Infrastructure Division includes 17 regulated water supply and waste-water treatment facilities located in Arizona, Texas, Illinois and Missouri. Revenue from these facilities is generated from the sale of water and the treatment of waste-water. Infrastructure facilities have a captive customer base within a regulated environment. These infrastructure assets are ideal for the Fund as they represent an asset class which produces stable, predictable, virtually perpetual cash-flows.

The Infrastructure Division experienced approximately 9% growth in 2006 and Management expects this growth to continue at similar rates in 2007.

Infrastructure assets include 17 facilities serving 32,500 water supply customers and 25,900 waste-water customers.

Report to Unitholders

Achievements in 2006:

Revenue increased to $201.4 million from $179.3 million

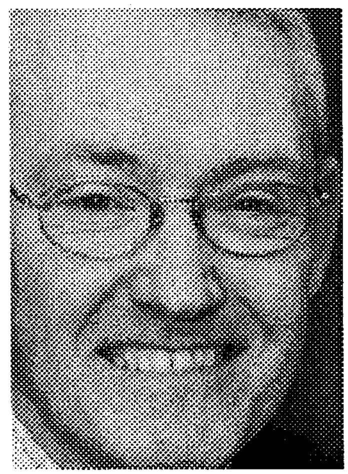
Algonquin Power Income Fund had a successful year in 2006 rounded out by a strong fourth quarter. The Fund's Manager and exceptional group of employees and associates spent 2006 focused on performance improvements of the Fund's diversified portfolio of power generation and infrastructure assets, and in June added the St. Leon Wind Energy facility to the growing portfolio. This transaction represents the Fund's operational entry into the fast-growing wind power generation industry which, similar to hydroelectric energy, generates electrical energy from a renewable natural resource.

The addition of St. Leon Wind Energy, initially through an investment in 2004 and then through the acquisition of AirSource Power Fund I LP in 2006, contributes to the strategic diversification of markets, technology, geography and regulatory environments that began in 2001. The St. Leon Wind Energy facility is the Fund's first facility located in Manitoba and initiates a new relationship with Manitoba Hydro through a 25 year Power Purchase Agreement with the utility. The Fund has significant operational experience that lends itself well to wind energy generating technology, which contributes to the delivery of reliable, stable and sustainable results.

Cash available for distribution increased to $67.5 million from $64.9 million

Over the course of 2006, the Fund's assets continued to contribute to the stability of cash available for distribution. The Fund's distribution as a percentage of cash available for distribution ("Payout Ratio") was 99.2% for the year ended December 31, 2006. The Fund has 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.

In the Report to Unitholders in the 2005 Annual Report, Algonquin Power Income Fund's plans and intentions to build on the balance and strength that has been achieved through the diversification strategy over the past few years was discussed. This was certainly the focus of 2006, with many activities and initiatives started during the year. As part of this initiative the Fund announced the appointment of a Chief Operating Officer in June whose role is, among other things, to oversee the profitable operation of the Fund's assets and to identify opportunities to leverage economies of scale that may exist across the four divisions of the Fund. Other Fund initiatives are geared toward creating efficiencies, leveraging skills across the organization, and implementing continuous improvement plans. We look forward to communicating the results of these initiatives in the future.



Cash available for distribution per trust unit was $0.93

Algonquin Power Income Fund distributed $0.92 per trust unit during 2006.

During the fourth quarter of 2006, the Fund announced a trust unit and convertible debenture offering, which was then postponed in light of an announcement made on October 31, 2006 by the federal Minister of Finance with respect to the taxation of income trusts and the ensuing impact on the capital markets. The Fund's financing strategy involves periodic access of the capital markets to repay indebtedness incurred in respect of its continuing growth initiatives. The planned use of proceeds from the proposed offerings was to retire a portion of this growth related debt, however the completion of the offering at that time was considered discretionary. In late November, the Fund did complete a convertible debenture offering resulting in proceeds of $60 million. The proceeds were then used to retire debt related to the St. Leon facility.

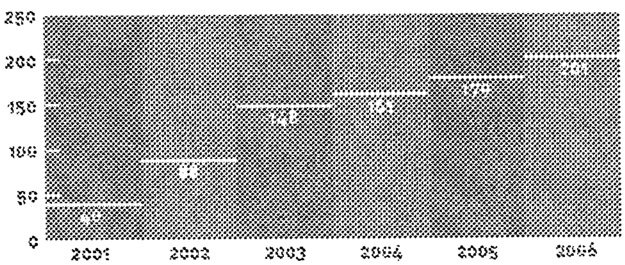
Following the initial October 31, 2006 announcement made by the Minister of Finance, on December 21, 2006, the federal government announced proposals to impose a tax similar to corporations on "specified investment flow-throughs" ("SIFT"), which, under the definitions provided, would include Algonquin 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 have not yet been legislated, between now and 2011, Algonquin Power Income Fund will evaluate opportunities to minimize the impact of the proposals on unitholders while continuing its strategic focus. The Fund believes any impact on its unitholders of the proposed taxation changes will be mitigated due to the proportion of distributions which are a return of capital, which is believed to be exempt under the proposed provisions.

In November of 2006, the Fund announced plans to retrofit the Sanger facility with a General Electric LM6000 turbine, estimated for completion during the fourth quarter of 2007. The retrofit is expected to result in improved fuel efficiency, increased output, ease of maintenance and an extension of the useful life of the facility. The projected cost of the retrofit program is approximately US$23 million, of which approximately $8.8 million was incurred in the fourth quarter of 2006. The layout of the Sanger facility allows for the installation of the LM6000 turbine concurrently with continued operation of the facility, which is expected to minimize revenue loss during construction.

Financial Review

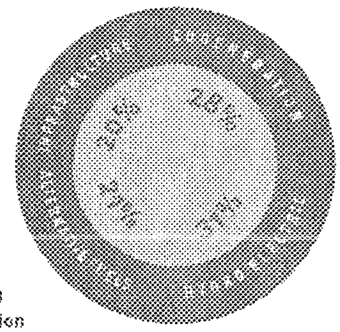
Since 2001, the Fund has improved overall risk exposure inherent in natural resource-based power generation, resulting in sustainable cash distributions during 2006. The move toward a more stable foundation is also evident through the Fund's revenue and operating profit.

For the year 2006, the Fund's assets generated total revenue of $201.4 million, growing 12% over revenue of $179.3 million in 2005. The technical, geographic and regulatory diversification of the Fund's assets produces revenue in a well balanced manner with 23% of revenue generated by the Hydroelectric Division, 38% generated by the Cogeneration Division, 21% of revenue generated by the Alternative Fuels Division, and 18% of overall revenue generated by the Infrastructure Division in 2006.



Revenue ($ Millions)

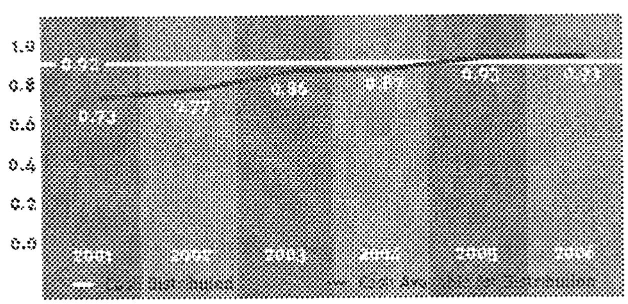
At the end of 2006, the Fund's asset distribution based on operating profit continues to be well balanced across the four divisions with Hydroelectric making up 31% of the asset base, Cogeneration at 28%, Alternative Fuels at 21% and the Infrastructure Division assets including water distribution and waste-water facilities making up 20% of the Fund's asset mix.



2006 Operating Profit By Division

The Fund's strength and stability is evident through cash available for distribution generated by the diverse asset portfolio. During 2006, cash available for distribution was $67.5 million compared to $64.9 million in 2005. On a per unit basis, the Fund generated $0.93 per unit by the end of 2006, remaining unchanged from 2005.

The Fund's cash distributions have been stable at $0.92 per unit per year since 2001, with cash available for distribution growing at an average annual rate of approximately 5%.



Cash Distributed vs. Cash Available Per Unit

Divisional Highlights

In the Hydroelectric Division, hydrology is naturally fluctuating, however during 2006, the Fund's facilities in the Quebec, Ontario and New York experienced improved hydrology as compared to the previous year, generating electricity equal to 103% of long term averages. The Fund anticipates average hydrology during the first two quarters of 2007.

In the Cogeneration Division, performance remained in line with 2005. There was a decrease in energy sales, primarily due to reduced production at the Windsor Locks facility during a planned overhaul that was completed in the second quarter of 2006. Also during the first half of 2006 the Fund continued to benefit from the opportunity to temporarily shut down the gas turbine at the Sanger facility and sell the fixed price natural gas normally consumed by the facility at favourable fixed prices.

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 2006. At the Energy-from-Waste and Landfill Gas facilities, overall facility improvements aimed at increasing production and availability continued during the year.

In the Infrastructure Division, performance increased in 2006 when compared to 2005 primarily due to the inclusion of the Rio Rico facility that was purchased in December 2005, and continued growth at existing facilities during 2006. In December 2006, the rate case initiated for the Black Mountain facility was approved, resulting in a 20% increase in waste-water rates. In addition, pursuant to the rates and tariff schedule approved in 2004, the Rio Rico facility implemented a 9% waste-water rate increase in November 2006. 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 summary

The diversification strategy initiated in 2001 has created a strong balance in the Fund, providing stability and sustainability in cash distributions to Algonquin Power Income Fund unitholders. The Fund extends this commitment into 2007, continuing to pursue opportunities to acquire long-lived assets with low operating costs, low risk technology, and long-term power purchase agreements. In addition, the Manager of the Fund will continue the focused and disciplined approach to maximize the performance of Fund assets throughout 2007.

In its business activities, Algonquin Power Income Fund strives to be a participant within the power Income Fund sector, with a focus on earning and maintaining respect from our customers, communities, competitors and financial markets, through sound, prudent and innovative business strategies and practices. As always, the underlying motivation is the enhancement of unitholder value.

For the year 2006, our gratitude and appreciation extends to the Fund's unitholders, employees and associates for their commitment, support, and enthusiastic interest in the Fund. For the year 2007, we will continue to work on delivering on the commitments of Algonquin Power Income Fund and working to maximize operational performance.

K. Moore

Ken Moore

Chairman

Corporate Governance

Ensuring trust

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.

Independence

The Board of Trustees is comprised of three Trustees who are independent of the Fund. The Trustees establish independence standards in accordance with the requirements of the Toronto Stock Exchange and other provincial securities regulations. At least annually, the independence of each trustee is determined in accordance with these standards.

Trustee Committees, Charters and Evaluation

The trustees have established the audit committee and the corporate governance committee, comprised of all of the trustees. The trustees have approved charters for each committee and at least annually, each charter is reviewed and amended based on recommendations of the corporate governance committee and the chair of the trustees. At least annually, the trustees evaluate and review the performance of the trustees, each of its committees, each of the trustees and the adequacy of the Corporate Governance mandate.

Trustee Meetings

Regular meetings of the Trustees are held at least quarterly to review financial and operational results, and monthly to determine and approve cash distributions to unitholders. At least annually, the Trustees hold meetings at which Fund Managers are not present.

Access to Management and Outside Advisors

The Trustees have unrestricted access to the management and employees of the Fund, its subsidiary entities and the manager and employees of Algonquin Power Systems Inc. whose duties include services to the Fund and Fund entities. At the Fund's expense, the Trustees have the authority to retain external legal counsel, consultants or other advisors to assist them in fulfilling their responsibilities.

Strategic Planning and Business Plans

At least annually, the trustees review and if advisable, approve the Fund's strategic planning process, short and long term strategic plans, and business plans prepared by the Fund Manager in light of emerging trends, the competitive environment, risk issues and significant business practices. Periodic reviews and amendments to plans may occur at any time each year according to changes in the Fund's business climate.

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. A summary of these guidelines is offered below.

Integrity of Financial Information

The trustees, in conjunction with their duties as members of the audit committee, review the integrity of the Fund's financial information and systems, the effectiveness of internal controls and Management's assertions on internal control and disclosure control procedures.

Risk management

At least annually the Trustees review reports provided by the Manager of material risks associated with the businesses and operations of the Fund's subsidiary entities, review the implementation by the Manager of systems to manage these risks and review reports by the Manager relating to the operation of and any material deficiencies in these systems.

Verification of Controls

The trustees verify that internal financial, non-financial and business control and information systems have been established by the Managers and that the Fund is applying appropriate standards of corporate conduct for these controls.

Human Resource Management

The Trustees, with the assistance of the Manager, review the Fund's approach to human resource management and executive compensation, succession plans for the chair of the trustees and the senior management of the fund, and verify the integrity of the Manager and its principals.

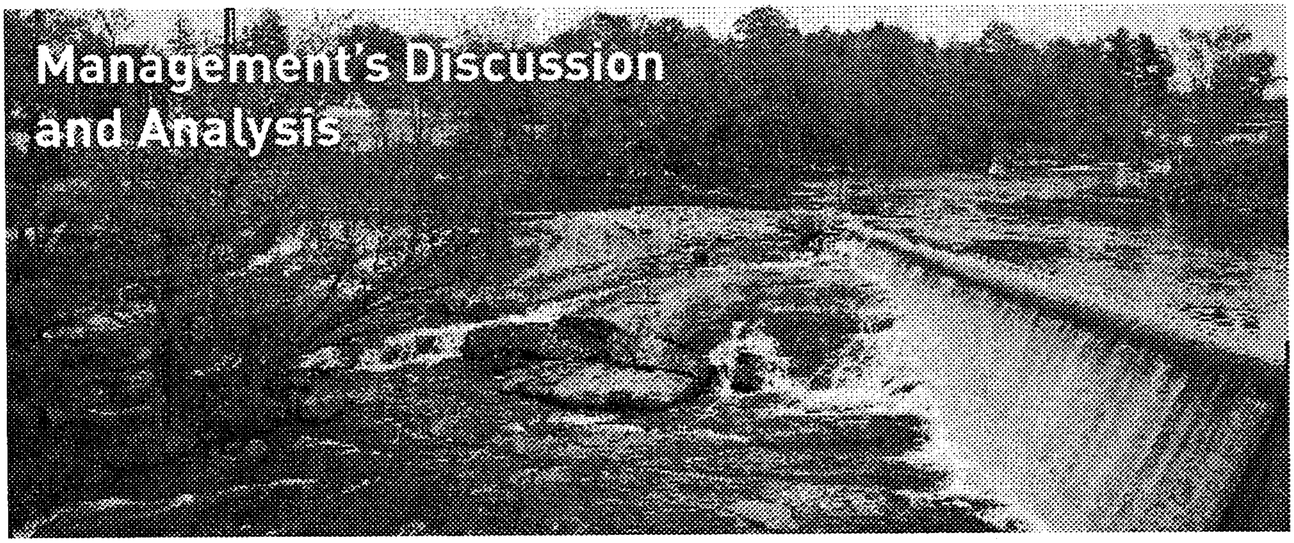
Ethics Reporting

At least annually, the Trustees review reports provided by the Manager relating to compliance with, or material deficiencies of the Fund's code of business conduct and ethics.

Communications and Disclosure

The trustees, in conjunction with the Manager review the Fund's overall communications strategy, including measures for receiving feedback from the fund's unitholders, and management's compliance with the fund's disclosure policies and procedures.

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)

Beaver Falls, New York

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, 2006. This discussion and analysis should be read in conjunction with the Fund's audited consolidated financial statements for the three and twelve months ended December 31, 2006 and 2005 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, 2006 can be found on SEDAR at www.sedar.com.

This management's discussion and analysis is based on information available to management as of March 7, 2007.

Forward-Looking Disclaimer

Certain statements contained in the information herein are forward-looking and reflect the views of the Fund and Algonquin Power Management Inc. (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

Key Financial Information

(C$000)	Three months ended December 31 2006	2005	Year ended December 31 2006	2005	2004
Revenue	**$ 53,738**	$ 50,918	**$ 201,415**	$ 179,324	$ 160,523
Net earnings	**1,796**	8,917	**27,955**	21,788	22,802
Total Assets	**1,048,324**	823,801	**1,048,324**	823,801	824,796
Long Term Debt	**228,021**	157,002	**228,021**	157,002	120,085
Distribution to unitholders	**17,481**	16,016	**66,955**	64,061	63,370
Cash available for distribution*	**17,477**	19,468	**67,491**	64,891	59,887
Per trust unit					
Net earnings	**0.02**	0.13	**0.39**	0.31	0.33
Distribution to unitholders	**0.23**	0.23	**0.92**	0.92	0.92
Cash available for distribution*	**0.23**	0.28	**0.93**	0.93	0.87

*** Non-GAAP measurement, see 'Cash Available for Distribution' in this management's discussion and analysis.**

any forward-looking statements, whether as a result of new information, future developments or otherwise.

For the quarter ended December 31, 2006, the Fund reported total revenue of $53.7 million as compared to $50.9 million during the same period in 2005. Revenue for the fourth quarter of 2006 increased from the same period in the prior year primarily due to the acquisition of the St. Leon Wind Energy facility ("St. Leon"), continued growth in the Infrastructure Division combined with the positive impact of the water distribution and waste-water facilities purchased during 2005. These factors were partially offset by lower revenue from the Fund's operations in the United States ("U.S.") as a result of a stronger Canadian dollar as compared to the same periods in 2005.

For the year ended December 31, 2006, the Fund reported revenue of $201.4 million as compared to $179.3 million during the same period in 2005. Revenue for the year ended December 31, 2006 increased due to increased energy generated as a result of improved hydrology experienced in the Hydroelectric Division, combined with the reasons indicated in the discussion of the fourth quarter results above. A more detailed analysis of these factors is presented within the divisional analysis.

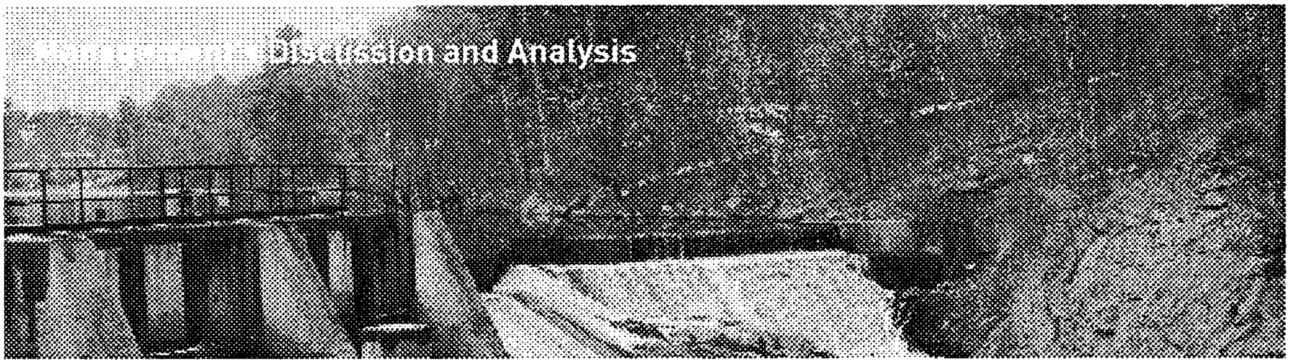
For the quarter and year ended December 31, 2006, the average U.S. exchange rate decreased by approximately 3% and 6%, respectively, as compared to the same period in 2005. As such, any quarterly or annual variance to revenue or expenses, in local currency, at any of the Fund's U.S. entities may be distorted 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.

For the quarter ended December 31, 2006, net earnings were $1.8 million as compared to $8.9 million during the same period in 2005. Net earnings for the fourth quarter of 2006 decreased from the same period in 2005 due to the inclusion of increased interest expense, lower interest and dividend income from the Fund's portfolio investments and the write-down of the Across America note and the deduction of earnings related to non-controlling minority interest. These factors were partially offset by earnings from the St. Leon facility.

Net earnings for the year ended December 31, 2006 were $28.0 million as compared to $21.8 million during the same period in 2005. Net earnings for the year ended December 31, 2006 increased as compared to the same period in 2005 due to increased energy generated as a result of improved hydrology, the addition of earnings from the St. Leon facility, continued growth in the Infrastructure Division and a reduction in expected future income taxes. A more detailed analysis of these factors is presented within the divisional analysis.

Net earnings per trust unit were $0.02 for the quarter ended December 31, 2006 as compared to $0.13 during the same period in 2005. For the year ended December 31, 2006, net earnings per trust unit were $0.39 as compared to $0.31 during 2005.

The Fund generated $0.23 per trust unit of cash available for distribution for the quarter ended December 31, 2006, as compared to $0.28 per trust unit during 2005. During the quarter ended December 31, 2006, the Fund maintained distributions at $0.23 per trust unit, consistent with distributions in 2005. For the year ended December 31, 2006, the Fund generated $0.93 per trust unit of cash available for distribution, consistent with the prior year. The Fund maintained distributions of $0.92 per trust unit, consistent with distributions in 2005.



Mine Falls, New Hampshire

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.

Outlook

Management anticipates that the Fund's four divisions will continue to generate cash available for distribution for 2007 in line with distributions to unitholders. Management also expects that continued growth in the water distribution and waste-water business, 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 the Cogeneration Division, coupled with no unforeseen events will enable the Fund to achieve current levels of cash available for distribution in 2007.

Management continues to identify and implement initiatives aimed at the continual improvement in the performance of the business and seeks opportunities to optimize the overall performance of its portfolio. In addition, the Fund is committed to ensuring that the recently acquired facilities, including the St. Leon facility and the water distribution and the waste-water treatment facilities, are integrated into the Fund's operations.

Management is committed to the growth and development of the Fund's people through various training programs, challenging assignments and learning opportunities. In addition, the Fund ensures continuous health and safety training for its operations and maintenance staff. Such training helps ensure that the Fund's facilities are in compliance in all material respects with local and federal environmental regulations.

Management will continue to invest in information technology to reduce administrative costs and will continue the implementation of supply chain management systems throughout the Fund and integrated billing and customer protocols within the Infrastructure Division.

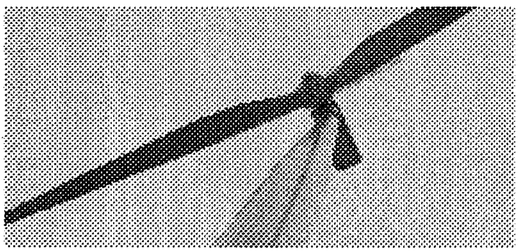
Overall, Algonquin Power Income Fund continues to focus on priorities that enable the Fund to be an innovative, respected and socially responsible participant in the energy, power and utility business sectors, enhancing unitholder value through stable, sustainable cash distributions generated by sound operational and management practices.

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 2006:

1. Acquisition of the Units of AirSource Power Fund I LP

At the end of the second quarter, the Fund completed the acquisition of all of the outstanding partnership units of AirSource Power Fund I LP ("AirSource") and its primary asset, the St. Leon facility. Under the offer, the Fund issued 2,099,255 trust units of the Fund and Algonquin (AirSource) Power LP ("Algonquin AirSource"), a subsidiary of the Fund, issued units which are exchangeable into 3,789,374 trust units of the Fund.



St. Leon, Manitoba

During the third quarter, the Fund exercised its compulsory acquisition rights under the AirSource limited partnership agreement to acquire the remaining partnership units of AirSource. The Fund issued an additional 283,717 trust units of the Fund and Algonquin AirSource issued additional units which are exchangeable into 202,847 trust units of the Fund to acquire the remaining AirSource units.

Total consideration for the acquisition including closing costs is valued at $61.7 million. The total purchase price, including acquisition costs, was $101.7 million. Algonquin AirSource units provide the holder with the distribution privileges equivalent to what they would receive if the units were exchanged for trust units of the Fund, as long as the St. Leon facility generates adequate cash flow. Algonquin AirSource units are exchangeable into trust units of the Fund at the holder's option at the rate of one Algonquin AirSource unit for 0.9808 trust units of the Fund.

During the quarter ended December 31, 2006, Algonquin AirSource units were exchanged for 319,642 trust units of the Fund. Since the purchase of AirSource on June 29, 2006, Algonquin AirSource units were exchanged for 797,770 trust units of the Fund. As at December 31, 2006, Algonquin AirSource units valued at $30.3 million and exchangeable into 3,194,450 trust units of the Fund remained outstanding.

2. Sanger Repowering

On November 14, 2006, the Fund announced plans to retrofit the Sanger facility with a General Electric LM6000 turbine, estimated for completion during the fourth quarter of 2007. The retrofit is expected to result in improved fuel efficiency, increased facility output, improved ease of maintenance and an extension of the useful life of the facility. The projected cost of the retrofit program is approximately $26.7 million (U.S. $23 million), of which approximately $10.2 million (U.S. $8.8 million) was incurred in the fourth quarter of 2006. The layout of the Sanger facility allows for the installation of the LM6000 turbine concurrently with continued operation of the facility. This is expected to minimize revenue lost during the construction period.

3. Convertible Debenture Offering

On November 22, 2006, the Fund completed an offering of 60,000 convertible unsecured subordinated debentures at a price of $1,000 per debenture for gross proceeds of $60 million. The debentures are due November 30, 2016 and bear interest at 6.20% per annum, payable semi-annually in arrears. The debentures are to be repaid in cash or units and will be convertible at any time up to maturity at the option of the holder into units of the Fund at a conversion price of $11.00 per trust unit. The debentures may not be redeemed by the Fund prior to November 30, 2010. Net proceeds from the debenture offering were used to repay the line of credit and to fund working capital. The Fund has recorded the equity portion of the debentures in the amount of $0.5 million on the balance sheet.

4. Subsequent Event

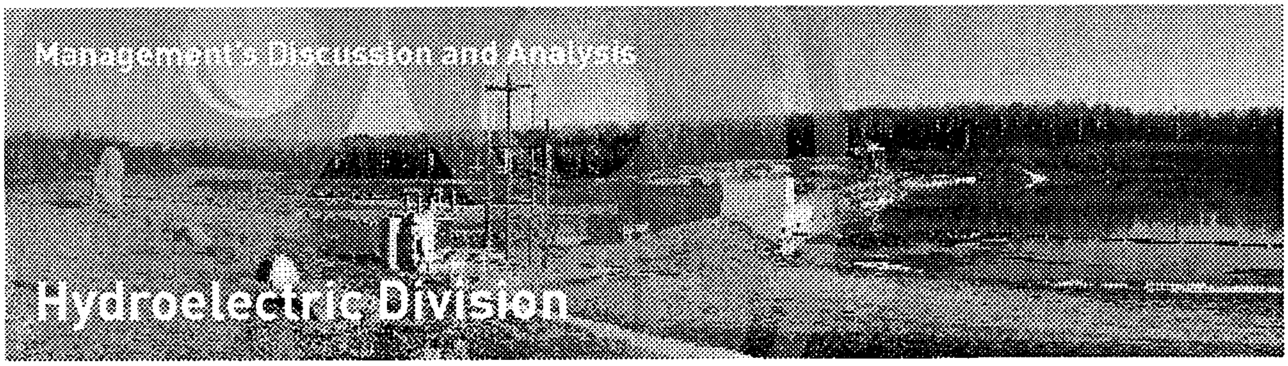
On February 26, 2007, the Fund announced that it had entered into a support agreement with Clean Power Income Fund ("CPIF") pursuant to which an entity of the Fund agreed to make an offer to CPIF unit holders to acquire all of the outstanding CPIF units in exchange for units of the Fund on a one for 0.6152 basis plus a contingency value receipt ("CVR"). Each CVR will entitle the holder thereof, subject to certain conditions, to a payment in cash of an amount up to approximately $0.27 per CPIF unit.

The Fund also announced that a Fund entity will make an offer to acquire all of the outstanding 6.75% convertible debentures issued by CPIF in exchange for the Fund's convertible debentures.

Each of the offers will be made by way of a takeover bid with consideration comprised of additional Fund units and CVRs or convertible debentures of the Fund.

Management's Discussion and Analysis

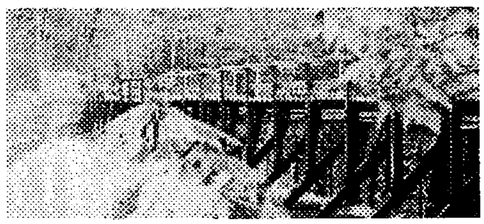
Hydroelectric Division



Long Sault Rapids, Ontario

exceeding expectations

For both the quarter and the year ended December 31, 2006, operating profit was above Management's expectations.



Milton, New Hampshire

For the quarter ended December 31, 2006, revenue in the Hydroelectric Division was $12.5 million as compared to $13.9 million during the same period in During the fourth quarter of 2006, the Hydroelectric Division generated electricity equal to 115% of long term averages as compared to 113% during the same period in 2005. Generated electricity in the Quebec region was higher than the same period in 2005 as a result of improved hydrology experienced in this region during the fourth quarter. The New York region generated greater energy production due to the inclusion of production from the Beaver Falls facility which had not completed its scheduled repairs during the same period in 2005. The decline in revenue was primarily the result of lower average energy rates at the U.S. facilities combined with lower reported revenue from U.S. operations as a result of the stronger Canadian dollar.

For the year ended December 31, 2006, revenue was $45.9 million as compared to $44.1 million during the same period in 2005. During the year ended December 31, 2006, the Hydroelectric Division generated electricity equal to 103% of long term averages as compared to 94% of long term averages in 2005. Generated electricity in the Quebec, Ontario and New York regions was higher than in 2005 as a result of improved hydrology experienced in these regions. Generated electricity in the Western region was lower than in 2005 as a result of a return to long term average hydrology in the region. The increase in revenue was a result of improved energy production offset by lower average energy rates generated at the U.S. facilities and lower reported revenue from U.S. operations as a result of the stronger Canadian dollar.

For the quarter ended December 31, 2006, operating expenses decreased to $4.6 million as compared to $6.0 million during the same period in 2005. The decrease in operating expenses was primarily due to a reduction in repair and maintenance projects initiated in the quarter as compared to the same period

(C$000)	Three months ended December 31		Year ended December 31		Forecast Production
	2006	2005	**2006**	2005	2007
Performance (MW-hrs sold)					
Quebec Region	**88,510**	80,461	**305,656**	267,469	280,951
Ontario Region	**31,370**	32,437	**126,239**	104,216	132,722
New England Region	**22,709**	22,775	**84,595**	83,254	73,896
New York Region	**31,364**	27,698	**95,062**	71,974	91,028
Western Region	**16,437**	19,737	**66,953**	81,521	67,248
Total	**190,390**	183,108	**678,505**	608,434	663,526
Revenue					
Energy sales	**$12,539**	$13,872	**$45,945**	$44,102	
Expenses					
Operating expenses	**$(4,571)**	$(5,964)	**$(16,709)**	$(17,008)	
Other income	**812**	843	**1,833**	1,250	
Division operating profit					
(including other income)	**$8,780**	$8,751	**$31,069**	$28,344	

in 2005 and lower reported expenses from U.S. operations, as a result of a stronger Canadian dollar.

For the year ended December 31, 2006, operating expenses were $16.7 million as compared to $17.0 million in the prior year. The decrease in operating expenses was primarily due to the factors previously noted in the quarterly discussion.

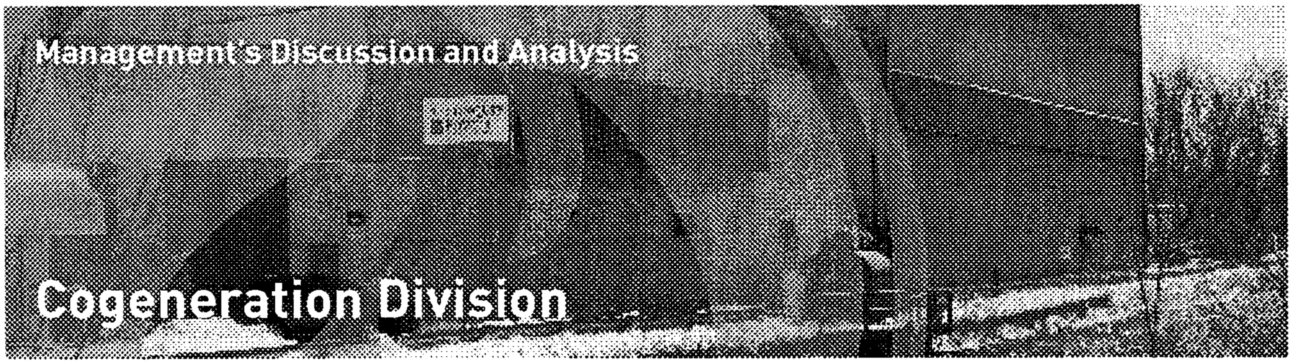
For the quarter ended December 31, 2006, operating profit remained unchanged at $8.8 million as compared to the same period in 2005. For the year ended December 31, 2006, operating profit increased to $31.1 million as compared to $28.3 million in 2005. For both the quarter and the year ended December 31, 2006, operating profit was above Management's expectations.

On September 1, 2005, $4.8 million was repaid on a note related to the Campbellford partnership. On this date, consolidation of the Campbellford investment ceased and equity accounting commenced. The proceeds of $4.8 million were allocated to reduce the existing note receivable and the existing investment in Campbellford. On December 19, 2006, a prepayment fee resulting from the early retirement of the above note in an amount of $1.4 million was received by the Fund. Approximately $0.9 million of this fee was applied against the note principal and the balance was included in income.

Outlook

The Fund's 2007 forecast production is based on the assumption of long term average hydrological conditions. The Hydroelectric Division is expected to perform at or above long term average hydrological conditions in the first quarter of 2007. In addition, the facilities in the New England region are expected to continue to benefit from market rates similar to the rates experienced in 2006.

The Fund will continue to seek accretive hydroelectric acquisitions throughout 2007, with emphasis placed on the acquisition of facilities that provide diversification of regional hydrologic and market conditions. In addition, the Fund is continuing to examine the rationalization of smaller hydroelectric generating facilities that no longer fit the Fund's preferred asset profile.



Management's Discussion and Analysis

Cogeneration Division

Windsor Locks, Connecticut

maximizing opportunities

The retrofit at the Sanger facility is expected to result in improved fuel efficiency, increased facility output, improved ease of maintenance and an extension of the useful life of the facility.

For the quarter ended December 31, 2006, revenue from the Cogeneration Division totaled $19.3 million as compared to $21.4 million during the same period in 2005. For the quarter ended December 31, 2006, the division's performance increased as compared to the same period in 2005, primarily due to increased production at the Sanger facility, where the comparative production figures in 2005 were lower as a result of the planned temporary shutdown of the facility to resell the natural gas normally used in production. Revenue from energy sales decreased as a result of lower energy rates at the Windsor Locks and Crossroads facilities where decreased fuel costs are passed on to the customer in the form of lower energy prices and lower reported revenue from U.S. operations as a result of a stronger Canadian dollar. The decline in revenue was partially offset by increased production at the Sanger facility.

For the year ended December 31, 2006, revenue was $77.8 million as compared to $77.6 million during the same period in 2005. The decrease in energy sales is primarily due to reduced production at the Windsor Locks facility due to the planned overhaul completed in the second quarter of 2006, as well as lower reported revenue from U.S. operations as a result of a stronger Canadian dollar. Other revenue primarily consists of sales of natural gas at the Sanger facility during the last quarter of 2005 and the first half of 2006.

For the quarter ended December 31, 2006, the Fund earned $0.7 million in dividend income from its portfolio investments, as compared to $1.3 million during the same period in 2005. The Fund earned $3.4 million from its portfolio investments for the year ended December 31, 2006 as compared to $3.5 million in 2005.

For the quarter ended December 31, 2006, operating expenses decreased to $13.6 million as compared to $14.5 million during the same period in 2005. Operating expenses decreased as a result of lower gas prices of $0.6 million and lower reported operating expenses from U.S. operations as a result of a stronger Canadian dollar.

For the year ended December 31, 2006, operating expenses increased to $53.4 million as compared to $52.8 million during the same period in 2005, primarily due to higher utility and fuel expenses of $1.3 million. These increases were partially offset by lower reported expenses for U.S. operations as a result of a stronger Canadian dollar.

For the quarter ended December 31, 2006, operating profit decreased to $6.3 million as compared to $8.1 million during the same period in 2005. Operating profit for the year ended December 31, 2006 was $27.8 million as compared to $28.2 million in 2005. Operating profit in the Cogeneration Division

(C$000)	Three months ended December 31		Year ended December 31		Forecast Production
	2006	2005	**2006**	2005	2007
Performance (MW-hrs sold)	**131,567**	113,953	**477,132**	512,972	484,275
Revenue					
Energy sales	**$18,189**	$19,551	**$68,544**	$75,674	
Other revenue	**1,061**	1,884	**9,247**	1,884	
Total Revenue	**$19,250**	$21,435	**$77,791**	$77,558	
Expenses					
Operating expenses	**$(13,639)**	$(14,528)	**$(53,362)**	$(52,822)	
Interest and dividend income	**732**	1,275	**3,382**	3,471	
Division operating profit					
(including interest and dividend income)	**$6,343**	$8,182	**$27,811**	$28,207	

for the quarter and year ended December 31, 2006 met Management's expectations.

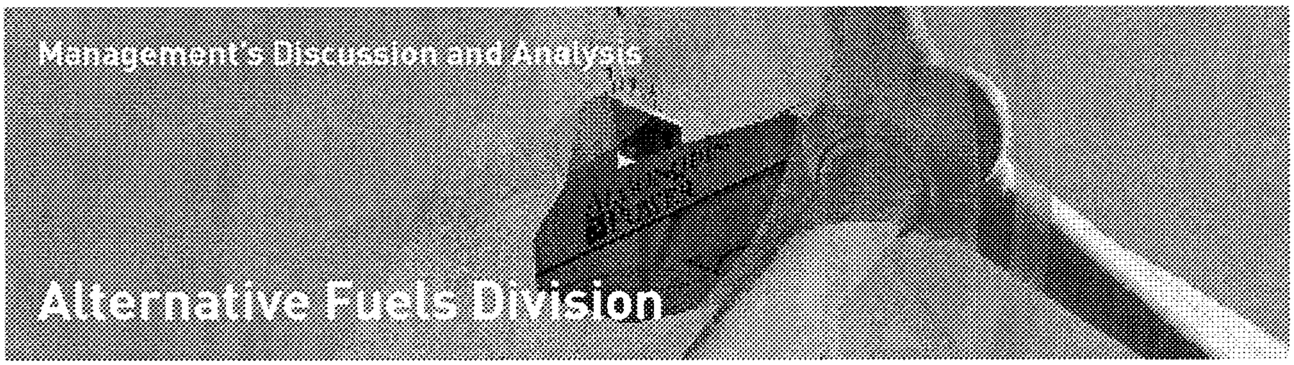
On November 14, 2006, the Fund announced plans to retrofit the Sanger facility with a General Electric LM6000 turbine. The project is continuing to progress on schedule with the tentative outage for commissioning of the new unit targeted for the fourth quarter of 2007. The retrofit is expected to result in improved fuel efficiency, increased facility output, improved ease of maintenance and an extension of the useful life of the facility. The projected cost of the retrofit program is approximately $26.7 million (U.S. $23 million), of which approximately $10.2 million (U.S. $8.8 million) was incurred in the fourth quarter of 2006. The layout of the Sanger facility allows for the installation of the LM6000 turbine concurrently with continued operation of the facility. This is expected to minimize revenue loss during the construction period.

In December, 2006, the Fund received regulatory approval to exercise the buy-down option of the Power Purchase Agreement at the Crossroads facility. The Fund received a net amount of U.S. $0.9 million, after expenses, related to the buy-down of the Power Purchase Agreement. The proceeds were treated as a reduction to fixed assets.

Outlook

Both the Fund's Windsor Locks and Sanger facilities are expected to continue to meet Management's expectations throughout 2007.

Following the buy-down of the Power Purchase Agreement at the Crossroads facility, the Fund is examining its options and plans to have a strategy in place to redeploy or sell the existing equipment at the facility by mid 2007.

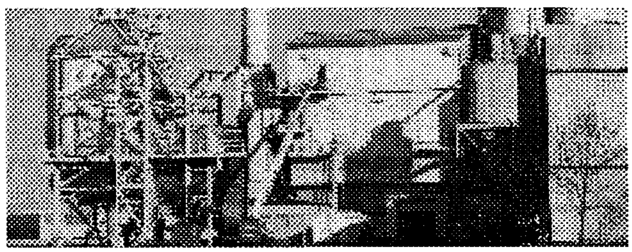


Alternative Fuels Division

St. Leon Wind Energy, Manitoba

continuing growth and progress

For the year ended December 31, 2006, revenue was $42.2 million as compared to $29.3 million during the same period in 2005.

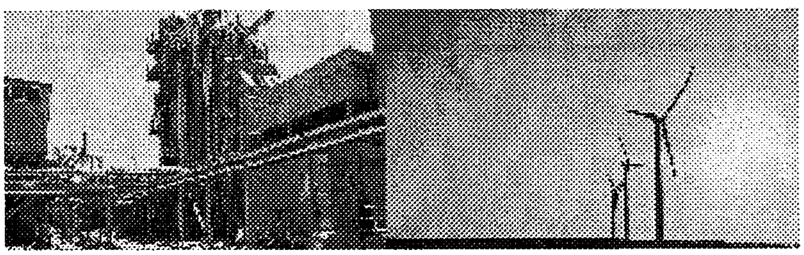


For the quarter ended December 31, 2006, revenue in the Alternative Fuels Division was $13.4 million as compared to $8.1 million during the same period in 2005. During the quarter ended December 31, 2006, the division's performance increased primarily as a result of the inclusion of production from the St. Leon facility, acquired at the end of the second quarter of 2006. Revenue for the quarter ended December 31, 2006 increased due to the inclusion of the St. Leon facility revenue, offset by lower production and reduced average energy prices from the Land-Fill Gas facilities ("LFG") as compared to the same period in 2005. The division reported lower revenue from U.S. operations as a result of a stronger Canadian dollar.

Other revenue consists of liquidated damages earned by the St. Leon facility. Liquidated damages are 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. While all the wind turbines at the facility have been constructed and commissioned, completion of certain aspects of the project under the turnkey construction contract have been delayed and remain to be addressed by the prime contractor, Vestas-Canadian Wind Technology, Inc. ("Vestas"). During the period of time when liquidated damages are received from Vestas, electricity sales received from Manitoba Hydro, after deducting certain costs, are payable to Vestas to the time of commercial operation, as defined in the turnkey construction contract.

For the year ended December 31, 2006, revenue was $42.2 million as compared to $29.3 million during the same period in 2005. During the year ended December 31, 2006, the division's performance increased primarily due to the inclusion of production from the St. Leon facility, and increased energy generated and higher waste processed at the EFW facility in the period as compared to 2005. Revenue for the year ended December 31, 2006 increased due to the inclusion of revenue

(C$000)	Three months ended December 31 2006	2005	Year ended December 31 2006	2005	Forecast Production 2007
Performance (MW-hrs sold)	**162,024**	57,538	**402,565**	213,735	606,839
Performance (tonnes of waste processed)	**39,981**	40,702	**155,479**	145,089	156,933
Revenue					
Energy sales	**$2,917**	$4,414	**$15,492**	$16,262	
Waste disposal sales	**3,562**	3,696	**14,209**	13,031	
Other revenue	**6,872**	-	**12,514**	-	
Total revenue	**$13,351**	$8,110	**$42,215**	$29,293	
Expenses					
Operating expenses	**$(6,657)**	$(6,616)	**$(26,904)**	$(25,014)	
Interest and other income	**552**	2,523	**5,480**	6,494	
Division operating profit					
(including interest and dividend income)	**$7,246**	$4,017	**$20,791**	$10,773	



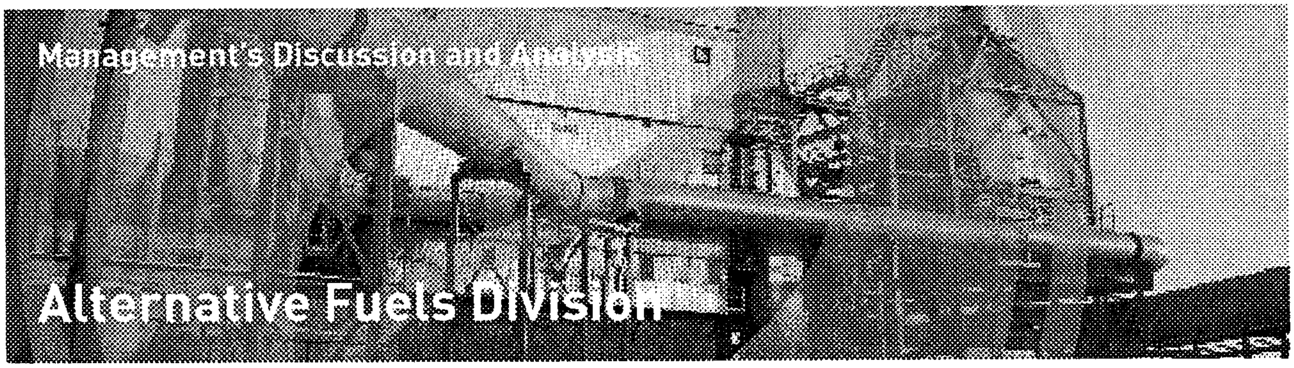
Algonquin Power Energy-from-Waste, Ontario
Sanger, California
St Leon Wind Energy, Manitoba

from the St. Leon facility, increased throughput at the EFW facility, offset partially by lower production and reduced average energy prices from the LFG facilities, as compared to 2005. The division reported lower revenue from U.S. operations as a result of a stronger Canadian dollar.

For the quarter ended December 31, 2006, operating expenses were $6.7 million as compared to $6.6 million during the same period in 2005. Operating expenses for the quarter increased as a result of the inclusion of operating expenses of $0.7 million from the St. Leon facility, offset partially by lower operating expenses at the LFG facilities as compared to the same period in 2005. The division reported lower operating expenses from U.S. operations as a result of a stronger Canadian dollar.

For the year ended December 31, 2006, operating expenses were $26.9 million as compared to $25.0 million during 2005. The increase in operating expenses for the year was primarily the result of the inclusion of operating expenses of $1.1 million from the St. Leon facility, increased fuel related costs of $0.4 million at the Fund's EFW facility and an increase in repair and maintenance costs of $0.7 million for the division as compared to 2005. The division reported lower operating expenses from U.S. operations as a result of a stronger Canadian dollar.

The Fund earned lower interest and other income on its investments within the Alternative Fuels Division during the quarter and year ended December 31, 2006, as compared to the same periods in 2005. Prior to the acquisition of AirSource, the Alternative Fuels Division earned interest income on the AirSource Note, as outlined in note 3 of the Fund's audited consolidated financial statements for the year ended December 31, 2006. Subsequent to the acquisition, the note was eliminated on consolidation of AirSource's assets into the Fund accounts. As a result, the Fund recognized no income from the note in the quarter ended December 31, 2006 as compared to $0.9 million in the same period in 2005. For the year ended December 31, 2006,



Algonquin Power Energy-from-Waste, Ontario

improving performance

For the quarter ended December 31, 2006, operating profit was $7.2 million as compared to $4.0 million during the same period in 2005.

the Fund recognized $3.0 million in income from the note earned up to June 29, 2006, as compared to $3.2 million in 2005.

Also included in other income for the quarter was $0.2 million related to the recognition of a receivable associated with the sale of partnership interests in certain gas collection systems in the quarter and $0.7 million for the year ended December 31, 2006, as compared to $1.2 million in 2005. The partnership is entitled to landfill gas production tax credits (the "Tax Credits") which can be used to reduce U.S. income tax liability. The value of the Tax Credits, which expire in 2007, was negatively impacted by the increase in the average price of crude oil in 2006. The Fund sold approximately 80% of its partnership interest and intends to use its interest in the Tax Credits to reduce its U.S. income tax liability in 2006.

strategic acquisition

On June 29, 2006, the Fund acquired the partnership units of AirSource Power Fund I LP.

Across America, through its subsidiaries, owns and manages the landfill collection systems that provide landfill gas to the Fund's LFG facilities. The Across America Note was primarily financed through the sale of Tax Credits generated by the collection systems it owns. As noted above, the value of the Tax Credits to Across America decreased in 2006, which reduced its ability to service the Note. As a result, in the quarter ended December 31, 2006, the Fund recognized an expense of $3.3 million, representing a write down of the Across America note to net realizable value.

For the quarter ended December 31, 2006, operating profit was $7.2 million as compared to $4.0 million during the same period in 2005. Operating profit for the year ended December 31, 2006 was $20.8 million as compared to $10.8 million in 2005. Improvements continue to be made in the Fund's EFW and LFG facilities but operating profit was still below management's expectations for the quarter and year ended December 31, 2006.

On June 29, 2006, the Fund acquired 92.37% of the outstanding partnership units of AirSource. Its primary asset is the St. Leon facility, comprised of 63 wind turbine generators, each with a capacity of 1.65 MW, totalling approximately 99 MW of installed capacity located near the Town of St. Leon, Manitoba. The facility is the first wind farm in the province of Manitoba, and is currently one of the largest wind turbine farms in Canada. Under the offer, the Fund issued 2.1 million trust units of the Fund and Algonquin AirSource issued units which are exchangeable into 3.8 million trust units of the Fund. During the third quarter, the Fund exercised its compulsory acquisition rights under the AirSource limited partnership agreement to acquire the remaining partnership units of AirSource. Total unit purchase price, including all closing costs, was $61.7 million.

Outlook

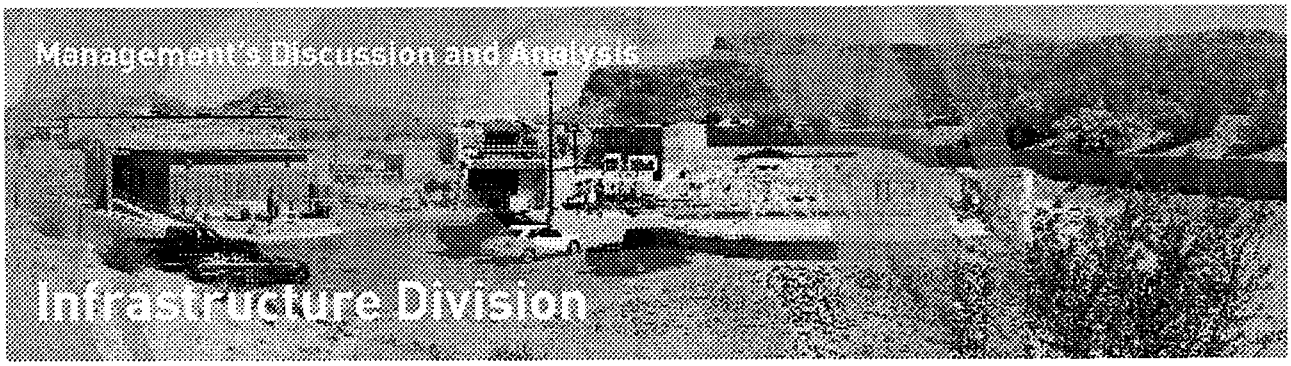
In 2007 the Alternative Fuels Division will continue to focus on operational improvements at the EFW and LFG facilities.

The performance of the St. Leon facility is expected to continue at or above management's expectations throughout 2007. Management continues to work toward resolution of the outstanding items under the turnkey construction contract.

At the EFW facility certain planned improvements began in the fourth quarter of 2006 and will continue throughout the first half of 2007. The improvements are expected to provide increased availability and improved overall plant performance throughout 2007. A steam sales project is planned to move forward during the year and is expected to be completed by the end of the fourth quarter of 2007.

At the Fund's LFG facilities, further improvements in availability are expected following the installation of engine performance enhancement components and an equipment and maintenance and skills audit. The investment in a gas treatment facility late in the fourth quarter of 2006 and additional gas rights in New Jersey will enable the sale of medium BTU gas from the Balefill generating facility. Management also anticipates other revenue from the sale of partnership interests in certain gas collection systems will remain consistent with levels achieved in 2006.

Infrastructure Division



Gold Canyon, Arizona

For the quarter ended December 31, 2006, revenue in the Infrastructure Division increased to $8.6 million as compared to $7.5 million during the same period in 2005. The division's waste-water and water distribution customer base grew by 1% during the quarter ended December 31, 2006. The increase in revenue for the fourth quarter was primarily due to the inclusion of the Rio Rico facility purchased in December 2005, and continued growth at existing facilities during 2006 as compared to 2005. These increases were partially offset by lower reported revenue from operations as a result of a stronger Canadian dollar.

Revenue for the year ended December 31, 2006 increased to $35.5 million from $28.4 million during the same period in 2005. The division's waste-water customer base grew by of 12% while the division's water distribution customer base grew by 7.0% for the year ended December 31, 2006. The increase in revenue for the year ended December 31, 2006 resulted from the inclusion of a full year's revenue from the facilities acquired in 2005, increased revenue of $2.0 million from the Litchfield Park facility and continued customer base growth, as compared to 2005. The facilities acquired in the prior year generated additional revenue of $3.6 million at the Rio Rico facility and $1.2 million at the eight facilities purchased in March and August of 2005, as compared to 2005. These increases were partially offset by lower reported revenue from operations as a result of a stronger Canadian dollar.

In December 2006, the rate case initiated for the Black Mountain facility was approved, resulting in a 20% increase in waste-water rates. In addition, pursuant to the rates and tariff schedule approved in 2004, the Rio Rico facility implemented a 9% waste-water rate increase in November 2006.

For the quarter ended December 31, 2006, operating expenses were $4.1 million as compared to $3.4 million during the same period in 2005. The increase in operating expenses was primarily the result of the inclusion of a full quarter's operating expenses from the facilities acquired in 2005, as compared to the same period in 2005. The division reported lower expenses from operations as a result of a stronger Canadian dollar, which partially offset the increases.

For the year ended December 31, 2006, operating expenses were $15.4 million as compared to $11.8 million during the same period in 2005. The increase in operating expenses was primarily the result of the inclusion of a full year's operating expenses of the facilities acquired in 2005. These facilities generated increased operating costs of $1.8 million at the Rio Rico facility and $0.6 million at the eight facilities purchased in March and August of 2005, as compared to 2005. The division reported lower expenses from its operations as a result of a stronger Canadian dollar, which partially offset the increases.

(C$000)	Three months ended December 31		Year ended December 31		Forecast Total Connections
	2006	2005	**2006**	2005	2007
Number of					
Waste-water customers	**28,911**	25,911	**28,911**	25,911	32,562
Water distribution customers	**32,524**	30,398	**32,524**	30,398	37,182
Revenue					
Waste-water and distribution	**$8,598**	$7,501	**$35,464**	$28,371	
Expenses					
Operating expenses	**$(4,085)**	$(3,410)	**$(15,370)**	$(11,847)	
Other income	**17**	21	**53**	44	
Division operating profit					
(including other income)	**$4,530**	$4,112	**$20,147**	$16,568	

For the quarter ended December 31, 2006, operating profit increased to $4.5 million as compared to $4.1 million during the same period in 2005. Operating profit for the year ended December 31, 2006 increased to $20.1 million from $16.6 million in 2005. Operating profit met management's expectations for the quarter ended December 31, 2006.

Outlook

The Infrastructure Division is expecting strong continued organic growth during 2007 despite a general slowdown in the residential housing market in the United States. Growth is expected to occur primarily in Arizona where the division services one of the fastest growing counties in the United States. Stable, continued growth in the balance of the Infrastructure Division's service areas is expected to contribute to the strong overall performance of the division.

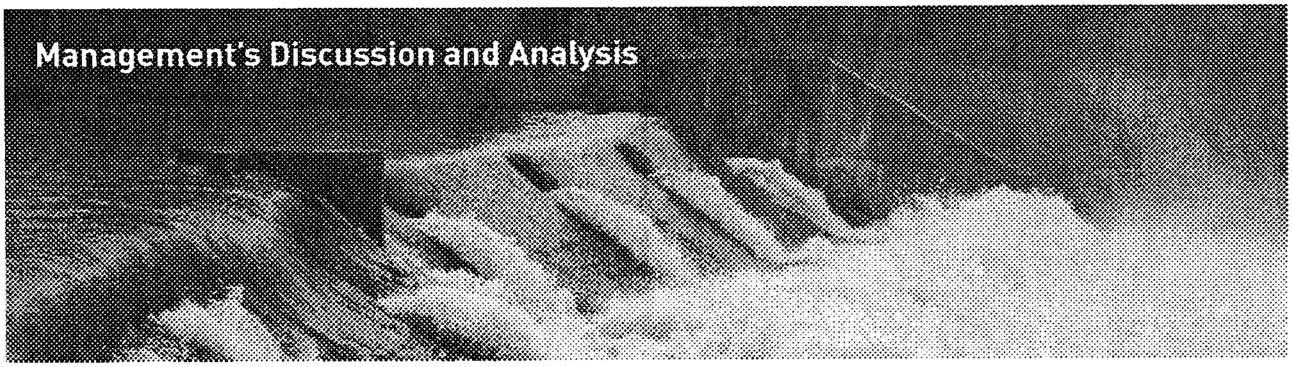
The regulatory review of the rates and tariffs for the Gold Canyon and the three Missouri facilities are expected to be completed in the second quarter of 2007. These rate cases will ensure that the respective facility earns the rate of return on its capital investment as allowed by the regulatory authority under which the facility operates. Management expects that the resolution of these rate cases will 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.

Recent changes in drinking water legislation within the United States have lead to the requirement for new arsenic treatment procedures and systems to be implemented. The first stage was completed in late 2006 at the Litchfield Park Services Company ("LPSCO") facility and second and third phases are scheduled for completion in Q2 of 2007 and Q1 of 2008, respectively. Once implemented, the systems ensure full regulatory compliance for the continued provision of safe drinking water.

Additional significant capital projects planned in the LPSCO service area include the design and construction of a new reservoir and pumping facilities, rehabilitation of existing wells, drilling of new wells, and the design of an additional waste-water treatment plant. These capital projects are being developed to meet the demands of existing customers as well as expected growth in the area and will be considered part of the facility's rate base.

On February 13, 2007, the Fund completed the acquisition of the assets and regulatory licences related to the provision of utility service to approximately 1,500 water distribution customers located near the Town of Sierra Vista, Arizona.

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.



Herkimer, New York

Administrative Expenses

(C$000)	Three months ended December 31 2006	2005	Year ended December 31 2006	2005
Administrative expenses	**$2,060**	$1,661	**$8,014**	$5,681
Management costs	**217**	206	**869**	825
Withholding taxes	**104**	647	**104**	1,177
Loss / (Gain) on foreign exchange	**2,547**	116	**217**	(1,744)
Interest expense	**6,345**	4,377	**22,289**	16,379
Write down of fixed and intangible asset and note receivable	**3,263**	812	**3,263**	3,533
Interest, dividend and other income	**(38)**	(72)	**(113)**	(139)
Loss (Gain) on hedging instruments	**(155)**	-	**497**	-
Income tax expense (recovery)	**(1,485)**	319	**(2,766)**	2,604

During the quarter ended December 31, 2006, administrative expenses increased to $2.1 million from $1.7 million as compared to the same period in 2005. The increase for the quarter was due to the added requirements to administer the Fund, including additional staff. During the year ended December 31, 2006, administrative expenses increased to $8.0 million from $5.7 million. The increase for the year relates to the factors discussed above and the costs associated with several business development opportunities undertaken.

For the quarter ended December 31, 2006, withholding tax expense decreased to $0.1 million as compared to $0.6 million for same period in 2005. For the year ended December 31, 2006, withholding tax expense decreased to $0.1 million as compared to $1.2 million in the prior year. The expense decreased as a result of fewer cross-border notes requiring withholding taxes.

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, 2006 the Fund reported a foreign exchange loss of $2.5 million as compared to $0.1 million during same period in 2005. For the year ended December 31, 2006 the Fund reported a foreign exchange loss of $0.2 million versus a gain of $1.7 million in 2005. At the end of the fourth quarter, the Fund had approximately $34.4 million in U.S. dollar denominated debt.

For the quarter ended December 31, 2006, interest expense increased to $6.3 million as compared to $4.4 million during the same period in 2005. For the year ended December 31, 2006, interest expense increased to $22.3 million as compared to $16.4 million in 2005. The increase was due to increased average levels of debt 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.

Gains or losses on hedging instruments represent increases in the unrealized value of the Fund's interest rate swap and do not impact cash available for distribution. For the year ended December 31, 2006, the unrealized loss on the interest rate swap on the St. Leon project debt totaled $0.5 million.

An income tax recovery of $1.5 million was booked in the fourth quarter of 2006, as compared to $0.3 million during the same period in 2005, primarily due to the inclusion of the results of AirSource. An income tax recovery of $2.8 million was booked in the year ended December 31, 2006 as compared to an expense of $2.6 million in 2005. The recovery was the result of a reduction in expected future income taxes due to a reduction in expected future tax rates and the impact of tax losses generated by certain facilities of the Fund.

Cash Available for Distribution

During the quarter ended December 31, 2006 the Fund generated $17.5 million in cash available for distribution as compared to $19.5 million for the same period in 2005. During the year ended December 31, 2006, the Fund generated $67.5 million in cash available for distribution as compared to $64.9 million in 2005.

The Fund's distribution as a percentage of 'cash available for distribution' ("Payout Ratio") was 100.0% during the fourth quarter of 2006 and 99.2% during the year ended December 31, 2006. The Fund achieved improving annual Payout Ratios of 123.4% in 2002, 106.9% in 2003, 105.8% in 2004 and 98.7% in 2005. The Fund has generated more funds than it distributed for two consecutive years.

In prior years, the shortfalls have been funded primarily by working capital. Should any future shortfall arise, management expects to be able to cover the difference between cash generated and cash distributed through working capital, cash on hand or its credit facility.

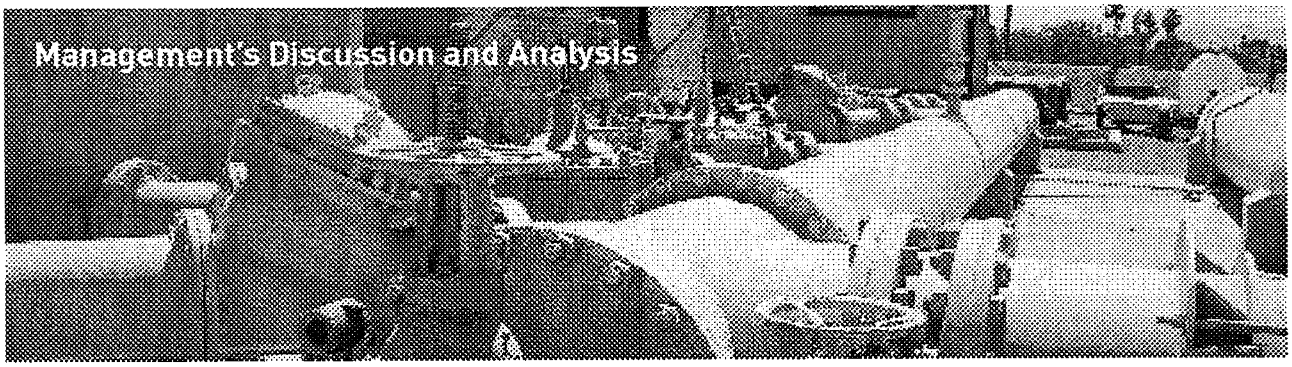
On a per trust unit basis, the Fund generated $0.23 of cash available for distribution during the quarter ended December 31, 2006 as compared to $0.28 during the same period in 2005. The Fund distributed $17.5 million during the quarter ended December 31, 2006 as compared to $16.0 million during the same period in 2005. For the year ended December 31, 2006, on a per trust unit basis, the Fund generated $0.93 of cash available for distribution, consistent with 2005. The Fund distributed $67.0 million during the year ended December 31, 2006 as compared to $64.1 million in 2005.

On a per trust unit basis, the Fund maintained distributions at $0.23 for the quarter ended December 31, 2006, and $0.92 during the year ended December 31, 2006, consistent with 2005.

Under Canadian tax rules, cash distributions consist of a return of capital portion (tax deferred) and a return on capital portion (taxable). For the year ended December 31, 2006, the Fund's return of capital was approximately 52% as compared to 53% for the same period in 2005.

(C$000)	Three months ended December 31		Year ended December 31	
	2006	2005	2006	2005
Cash flow from operating activities	$17,632	$17,498	$68,228	$55,679
Changes in working capital	631	2,140	951	7,932
Operating cash flow before working capital changes	18,263	19,638	69,179	63,611
Receipt of principal on notes receivable	954	804	3,608	4,959
Decrease / (Increase) in restricted cash	-	(17)	-	-
Repayment of long term liabilities	(445)	(469)	(1,254)	(1,380)
Maintenance capital expenditures *	(904)	(589)	(3,209)	(2,167)
Other	(391)	-	(833)	(401)
Cash available for distribution	$17,477	$19,468	$67,491	$64,891
Cash available for distribution per trust unit	$0.23	$0.28	$0.93	$0.93
Distribution to unitholders	$17,481	$16,016	$66,955	$64,061
Distributions to unitholders per trust unit	$0.23	$0.23	$0.92	$0.92

* This includes capital expenditures capitalized in accordance with GAAP, which are of a replacement or regulatory nature or represent a major maintenance cost. The expenditure is 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.



Litchfield Park Service Company, Arizona

Liquidity and Capital Reserves

For the quarter ended December 31, 2006, the Fund had $13.5 million of cash and cash equivalents. As at December 31, 2006, the Fund had negative net working capital of $31.9 million. For purposes of this calculation, working capital excludes cash and cash equivalent, current portion of notes receivable, current portion of long term liabilities and cash distributions payable. The shortfall is primarily the result of construction costs to complete the St. Leon facility, which are now included in accrued liabilities. The Fund has adequate credit capacity to meet these requirements.

During the quarter ended December 31, 2006, the Fund incurred capital expenditures of $13.9 million, as compared to $2.6 million during the comparable period in 2005. During the year ended December 31, 2006, the Fund incurred capital expenditures of $30.9 million, as compared to $15.9 million in 2005. Capital expenditures during the quarter and year ended December 31, 2006 were primarily growth related expenditures in the Infrastructure Division. In addition, capital expenditures of approximately $10.2 million related to the planned re-powering project at the Sanger facility were incurred during the quarter ended December 31, 2006. Capital expenditure requirements are anticipated to be approximately $75 million during fiscal 2007, including approximately $16.6 million related to the completion of the Sanger re-powering project, approximately $44.0 million related to ongoing growth and regulatory requirements in the Infrastructure Division and approximately $9.5 million related to steam generation and transmission assets required for the sale of steam from the EFW facility. 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.

Long term debt increased to $228.0 million at December 31, 2006 as compared to $157.0 million at December 31, 2005. Long term liabilities primarily consist of project level debt of approximately $161.0 million and an amount of $67.0 million drawn on the Fund's revolving credit facility compared to project level debt of $87.7 million and an amount of $69.3 million drawn on the Fund's revolving credit facility at the end of the fourth quarter of 2005. Project debt increased primarily due to the inclusion of senior debt totalling $73.3 million related to the St. Leon 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. At the quarter ended December 31, 2006, the Fund had drawn $67.0 million on its revolving credit facility in addition to letters of credit. During the third quarter, the Fund's lenders converted $30 million of the temporary credit facility to permanent and extended the total credit facility for a one year term to mature August 2008.

On March 9, 2007, Standard & Poor's announced that it was lowering the long-term corporate credit rating on the Fund from 'BBB+' to 'BBB' and removed the Fund from credit watch. Standard & Poor's commented that increased financial and merchant risk was generally responsible for such downgrade decision. As a result, the margin charged on any amounts outstanding under the Credit Line increases by 0.125% with no other changes to the credit facility.

During the quarter ended December 31, 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 the convertible debenture offering to reduce the balance outstanding on its credit facility. In addition, the Fund drew $16.0 million on its credit facility to fund capital requirements, including approximately $10.2 million related to the Sanger re-powering project. Subsequent to the end of the quarter, the Fund drew an additional $5.0 million on its credit facility to fund capital requirements. Since the Fund utilizes the revolving credit facility for growth capital expenditures including acquisitions, the revolving credit has been reduced in the past by the issuance of units and/or debentures to the public.

For the quarter ended December 31, 2006 the Fund maintained a long term debt-to-equity ratio (including long term liabilities, other long term liabilities, and convertible debentures) of 80.4%. 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, 2006 would be reduced to 38.4%.

Contractual Obligations

Information concerning contractual obligations as of February 27, 2007 is shown below:

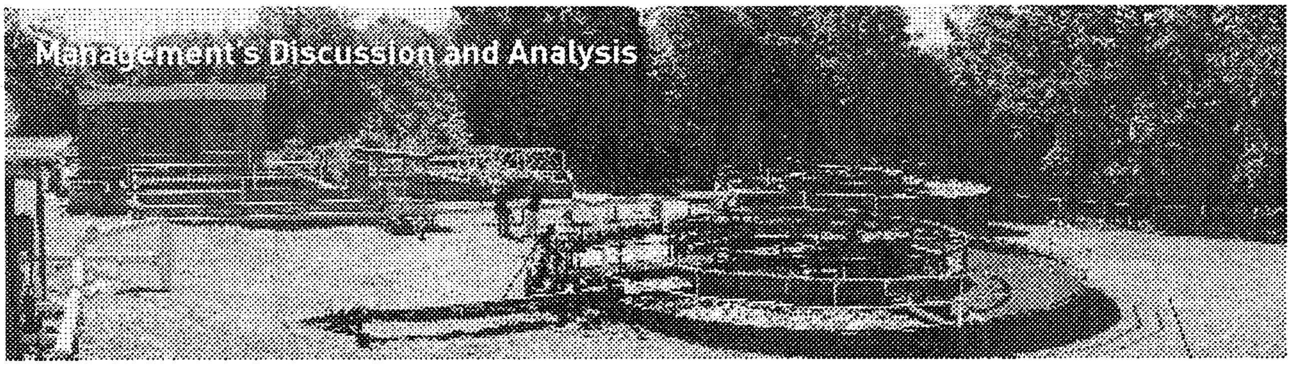
	Total	Due less than 1 year	Due 2 to 3 years	Due 4 to 5 years	Due after 5 years
Long term debt obligations	$229,515	$1,494	$72,901	$8,313	$146,807
Other obligations	42,417	21,766	6,238	1,015	13,398
Total obligations	$271,932	$ 23,260	$79,139	$9,328	$160,205

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, 2007 of $9.5 million regarding the installation of the additional steam generation and transmission assets required for the sale of steam from the EFW facility and $16.6 million related to the completion of the Sanger re-powering project.

Unitholders' Equity and Convertible Debentures

As at December 31, 2006, the Fund had 72,874,211 issued and outstanding trust units with a total of 76,068,620 trust units issued and outstanding on a fully diluted basis.

Pursuant to the takeover bid of AirSource, on June 29, 2006, 2,099,255 trust units of the Fund were issued. In addition, Algonquin AirSource issued trust units, which are exchangeable into 3,789,374 trust units of the Fund at the holder's option (the "Exchangeable Units"). As the Exchangeable Units provide the holder with distribution privileges equivalent to what they would receive if the trust units converted into trust units of the Fund, the Fund effectively issued, on a fully diluted basis, 5,888,629 trust units on June 29, 2006. During the third quarter, a further 283,717 trust units of the Fund and Exchangeable Units which are convertible into 202,847 trust units of the Fund were issued to acquire the remaining untendered AirSource units, in conjunction with the takeover bid.



Tall Timbers, Texas

Unitholders' Equity and Convertible Debentures Cont'd

For the quarter ended December 31, 2006, 319,642 Trust units of the Fund were issued pursuant to the conversion of Exchangeable Units. For the year ended December 31, 2006, 797,770 trust units of the Fund were issued pursuant to the conversion of Exchangeable Units and 1,877 trust units of the Fund were issued pursuant to the conversion of convertible debentures. As at December 31, 2006, there were 3,194,450 trust units of the Fund remaining to be issued pursuant to the conversion of Exchangeable Units. Subsequent to December 31, 2006 and prior to February 27, 2007, a further 366,819 trust units of the Fund were issued pursuant to the conversion of Exchangeable Units.

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. As at December 31, 2006, there were 84,980 convertible debentures outstanding as a result of the conversion of certain debentures into units.

In the quarter ended December 31, 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.

Dealings with Algonquin Power Group

The following related party transactions occurred during the year ended December 31, 2006:

Algonquin Power Management Inc. ("APMI") provides management services including advice and consultation concerning business planning, support, guidance and policy making and general management services. In 2006 and 2005, APMI was paid on a cost recovery basis for all costs incurred and charged $869 (2005-$825). 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 2006 and 2005 no incentive fees were earned by APMI.

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 2006 were $296 (2005 - $296) and additional rent representing operating costs was $89 (2005 - $198).

When appropriate for use in its operations the Fund utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. The Fund entered into an agreement and remitted $1.3 million to the affiliate as an advance against expense reimbursement (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.

AirSource entered into a construction services agreement (the "Construction Services Agreement") dated October 28, 2004 with Greenwing Algonquin Power Development Inc. ("GWAP"). The Construction Services Agreement has a term ending on the commercial operation date of the Facility in accordance with the terms of the Turn-key Construction Contract. GWAP may terminate the Construction Services Agreement in its sole discretion upon 30 days' prior notice. The services to be provided by GWAP under the Construction Services Agreement include, among other things, assisting with the supervision of the construction of the Facility and assisting with the administration of the Turn-key Construction Contract. As consideration for its services, GWAP will be paid a fee equal to 1.0% of the Turn-key Construction Contract price, not including goods and services taxes, which will generally be payable as to 50% at the time of approval of invoices by St. Leon GP to Vestas under the Turn-key Construction Contract and as to 50% based on the percentage of completion of each phase of the Facility.

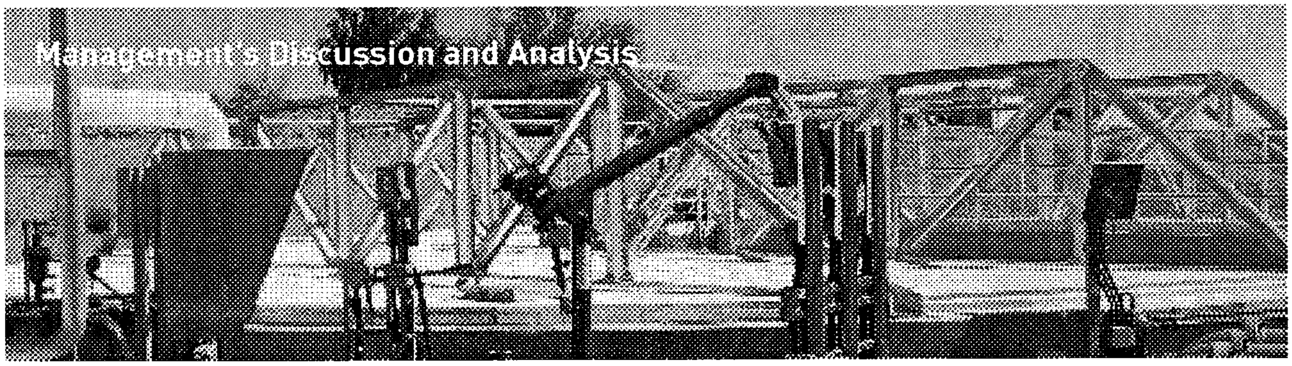
AirSource has agreed to reimburse AirSource Power Fund GP Inc (the "General Partner") of the AirSource Power Fund I LP for reasonable costs incurred by it in acting as registrar and transfer agent and in attending to the administration of the Partnership, as required in the Partnership Agreement. The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

The Fund has entered into an agreement to sell steam from the EFW facility to an industrial customer located in close proximity to the 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 $9,550. The Fund has incurred amounts totaling $2,873 (2005 -$2,418) included in assets under construction. An entity owned by APMI is entitled to 50% of the cash flow above 15% return on investment due to its management role on the project.

Risk Management

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. A more comprehensive assessment of the Fund's business risks is set out in the 2006 Annual Information Form.

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.



Gold Canyon, Arizona

Risk Management Cont'd

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.

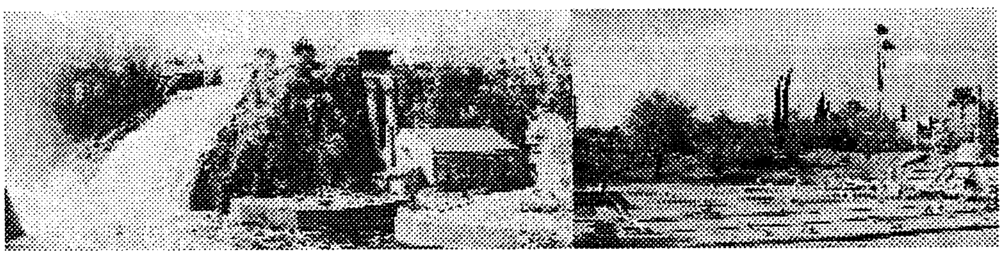
The hydroelectric operations of the Fund are impacted by seasonal fluctuations. These assets are primarily "run-of-river" and as such fluctuate with the natural water flows. During the winter and summer periods, flows are generally lower while during the spring and fall periods flows are generally higher. 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.

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.

There remain certain completion risks associated with the St. Leon facility. Although the wind turbines are operational, there are certain deficiencies as defined in the turn-key contract that must be completed in order to finalize the project. Management is working with Vestas to resolve these deficiencies.

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, 2006, the Fund had effectively hedged 74% of its expected 2007 U.S. dollar cash flow at $1.379 and 53% of its expected U.S. dollar cash flow at 1.308. The Fund has total forward contracts to sell U.S. dollars for fiscal 2007 to fiscal 2010 totalling U.S. $ 65.7 million carrying an average rate of $1.32. Subsequent to December 31, 2006, the Fund entered into U.S. $ 17.1 million of additional forward contracts. This increased the Fund's effective hedge of its 2007 and 2008 expected U.S. dollar cash flow to 95% and 77% respectively and increased its total forward contracts to U.S. $82.9 million carrying an average rate of $1.29. The Fund discontinued hedge accounting in the quarter ended December 31, 2006. As a result, the Fund recorded an unrealized gain on hedging instruments of $11.2 million to reflect the market value of these transactions. The Fund's policy is not to utilize derivative financial instruments for trading or speculative purposes.

The Fund has a credit facility and project specific debt of approximately $228.0 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, 2006, the mark to market loss on the interest rate swap was $0.5 million.

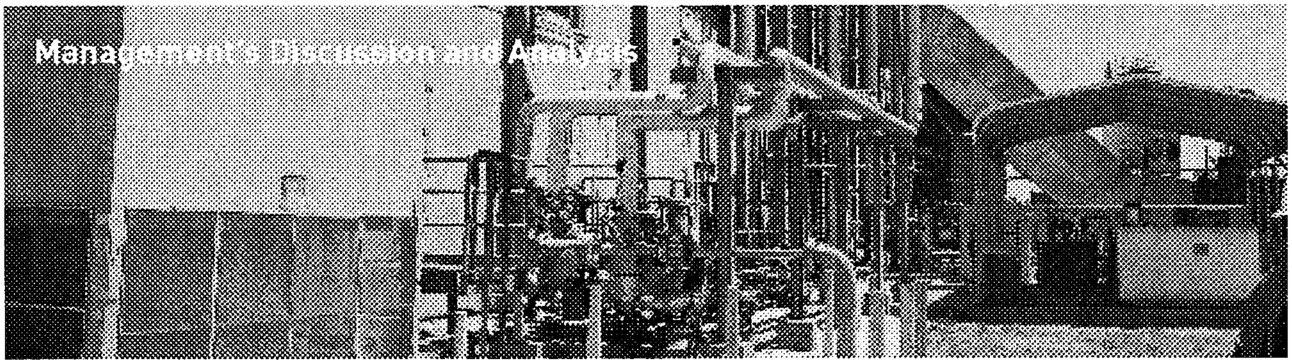


Riviere-du-Loup, Quebec
Black Mountain, Arizona

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 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 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 December 21, 2006, the Minister of Finance introduced draft legislation to impose a tax on distributions from certain publicly traded income trusts and partnerships (the "SIFT Proposals"). The SIFT Proposals will apply to "specified investment flow-throughs" ("SIFT") which will include trusts resident in Canada whose units are listed on a stock exchange or other public market if the trust holds one or more "non-portfolio properties". Based on the SIFT Proposals, the Fund is a specified investment flow through entity. As a SIFT, 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. 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.



Sanger, California

Risk Management Cont'd

Starting with the 2011 taxation year, a SIFT 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. Any non-portfolio earnings distributed by a SIFT 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 under the draft legislation released by the Minister of Finance on October 16, 2006.

No assurance can be given as to the precise form that the SIFT Proposals will take if and when enacted. If the SIFT Proposals apply to the Fund in 2011 and, provided the corporate rate reductions and the enhanced dividend and tax credit proposals are enacted as proposed, 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 Proposals were not enacted. However, no assurance can be given in this regard. Non-resident Unitholders and Canadian resident Unitholders which are exempt from tax would be negatively affected by the application of the SIFT Proposals if enacted as proposed 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.

The Fund's water distribution and waste-water utilities may be located within areas of the United States experiencing high 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.

The Fund has fixed the price of its natural gas exposure at the EFW facility until 2007. The 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.

The Fund maintains adequate insurance on all of its facilities. This includes property and casualty, boiler and machinery, and liability insurance.

Critical Accounting Estimates

The Fund recognizes revenue derived from energy sales at the time energy is delivered. Water reclamation and distribution revenue is recognized when 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 books deferred credits 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 for a term of 10 years. 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 records the deferred credits based on its expected repayments as determined by historical experience and industry practice.

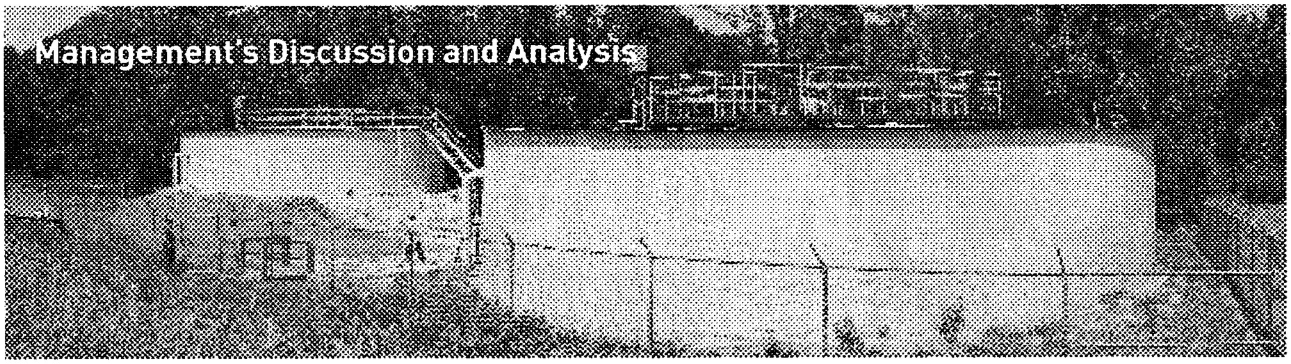
The Fund records at cost capital assets such as land, facilities and equipment. Improvements that increase or prolong the service life or capacity of an asset are also capitalized at cost. Intangible assets such as power purchase contracts acquired, licensing costs and customer relationship costs are recorded at cost. The Fund reviews capital and intangible assets for permanent impairment whenever events or changes in circumstances indicate the carrying amounts may not be recoverable.

The Fund enters into forward contracts to hedge against its exposure to the U.S. dollar. Gains and losses from these activities are reported as adjustments to the related revenue or expense account as they are settled.

Controls and Procedures

Disclosure Control and Procedures

In accordance with the requirements of the Securities Act (Ontario) and other provincial securities legislation, the Chief Executive Officer ("CEO") and Chief Financial Officer ("CFO") of the Fund will be required to certify annually 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. As of the end of the period covered by the annual filings, an evaluation was carried out, under the supervision and with the participation of management, including the CEO and CFO, of the effectiveness of the design and operation of the Fund's disclosure controls and procedures. Based on that evaluation, the CEO and CFO concluded that disclosure controls and procedures were effective.



Big Eddy, Texas

Controls and Procedures Cont'd

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. The Fund believes the internal controls over its financial reporting were suitably designed to achieve this objective as of December 31, 2006.

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.

During the 2006 fiscal year, the CEO and CFO of the Fund engaged third parties to assist them in reviewing the Fund's internal controls over financial reporting. As part of that process certain improvements in internal controls were completed. In particular, formal documentation of the internal control procedures performed was completed, the review procedures to be undertaken in the financial reporting and tax processes were formalized and control environment controls were strengthened by updating the code of conduct and whistleblower policy. No changes were 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.

[illegible]	1st Qtr 2006	2nd Qtr 2006	3rd Qtr 2006	4th Qtr 2006	Total
Revenue	$49.5	$47.1	$51.1	53.7	201.4
Net earnings	7.3	13.8	5.0	1.8	28.0
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	228.0	228.0
Distribution per trust unit	0.23	0.23	0.23	0.23	0.92

[illegible]	1st Qtr 2005	2nd Qtr 2005	3rd Qtr 2005	4th Qtr 2005	Total
Revenue	40.6	45.0	42.8	50.9	179.3
Net earnings	1.8	1.6	9.5	8.9	21.8
Net earnings per trust unit	0.03	0.02	0.14	0.13	0.31
Total Assets	813.1	822.1	838.2	823.8	823.8
Long term debt	235.6	261.8	286.8	271.5	271.5
Distribution per trust unit	0.23	0.23	0.23	0.23	0.92

Quarterly Financial Information

The above is a summary of unaudited quarterly financial information for the two years ended December 31, 2006.

The quarterly results are impacted by various factors including seasonal fluctuations and acquisitions of facilities as noted in this management's discussion and analysis.

Recently Issued Canadian Accounting Standards

Financial Instruments

In January 2005, the CICA issued the following Handbook sections: Section 3855 – "Financial Instruments – Recognition and Measurement", Section 1530 – "Comprehensive Income" and Section 3865 – "Hedges". These new standards will be effective for interim and annual financial statements commencing in 2007. The new standards will require presentation of a separate statement of comprehensive income. Foreign exchange gains and losses on the translation of the financial statements of self-sustaining subsidiaries previously recorded in a separate section of shareholders' equity will be presented in comprehensive income. Derivative financial instruments will be recorded in the balance sheet at fair value and the changes in fair value of derivatives designated as cash flow hedges will be reported in comprehensive income. The existing principals of Accounting Guideline 13 will be substantially unchanged for hedge documentation. The Fund is assessing the impact of the new standards.

Auditors' Report

To the Unitholders of Algonquin Power Income Fund

We have audited the consolidated balance sheets of Algonquin Power Income Fund as at December 31, 2006 and 2005 and the consolidated statements of earnings and deficit 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, 2006 and 2005 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

Chartered Accountants

KPMG LLP

Toronto, Canada
February 27, 2007 (except as to note 21, which is as of March 9, 2007)

Consolidated Balance Sheets

December 31, 2006 and December 31, 2005 (thousands of Canadian dollars)

	2006	2005
Assets		
Current assets		
Cash and cash equivalents	$ 13,465	$ 11,363
Accounts receivable	41,291	29,206
Prepaid expenses	2,777	1,918
Current portion of notes receivable (Note 3)	2,337	2,791
	59,870	45,278
Long term investments (Note 3)	29,976	57,489
Future non-current income tax asset (Note 12)	7,639	7,719
Capital assets (net of accumulated amortization) (Note 4)	810,474	627,652
Intangible assets (net of accumulated amortization) (Note 5)	111,978	76,848
Restricted cash (Note 1)	6,753	3,458
Deferred costs		
(net of accumulated amortization of $3,919, (2005 - $2,425))	8,246	5,357
Other assets (Note 6)	13,388	-
	$ 1,048,324	$ 823,801
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 75,011	$ 28,585
Due to Algonquin Power Group (Note 13)	-	62
Cash distribution payable	11,659	10,677
Current portion of long-term liabilities (Notes 8 and 10)	1,876	1,445
Current income tax liability	141	435
Future income tax liability (Note 12)	848	1,143
	89,535	42,347
Long-term liabilities (Note 7 and 8)	228,021	157,002
Convertible debentures (Note 9)	144,501	85,000
Other long-term obligations (Note 10)	10,711	10,435
Deferred credits (Note 6)	27,780	19,102
Future non-current income tax liability (Note 12)	71,257	56,917
Non controlling interest (Note 2)	31,804	-
Unitholders' equity		
Trust units (Note 11)	684,414	654,176
Equity component of convertible debentures	479	-
Deficit	(240,178)	(201,178)
	444,715	452,998
Commitments and contingencies (Notes 2, 4, 13 and 14)		
Subsequent events (Note 21)	$ 1,048,324	$ 823,801

See accompanying notes to
the consolidated financial statements

Approved by the Trustees

Consolidated Statements of Earnings and Deficit

For the years ended December 31, 2006 and December 31, 2005 (thousands of Canadian dollars)

	2006	2005
Revenue		
Energy sales	$ 129,981	$ 136,038
Waste disposal fees	14,209	13,031
Water reclamation and distribution	35,464	28,371
Other revenue (Note 19)	21,761	1,884
	201,415	179,324
Expenses		
Operating	112,345	106,691
Amortization of capital assets	31,996	27,325
Amortization of intangible assets	6,035	6,463
Management costs (Note 13)	869	825
Administrative expenses	8,014	5,681
Withholding taxes	104	1,177
(Gain) / loss on foreign exchange	217	(1,744)
	159,580	146,418
Earnings before undernoted	41,835	32,906
Interest expense	(22,289)	(16,379)
Interest, dividend and other income (Note 18)	10,861	11,398
Write down of fixed assets, intangible assets and notes receivable (notes 3, 4 and 5)	(3,263)	(3,533)
Loss on hedging instruments (Note 6)	(497)	-
Earnings before income taxes and minority interest	26,647	24,392
Current income taxes (Note 12)	861	854
Future income taxes (Note 12)	(3,627)	1,750
	(2,766)	2,604
Minority interest (note 2)	1,458	-
Net earnings	27,955	21,788
Deficit, beginning of the year	(201,178)	(158,905)
Cash distributions	(66,955)	(64,061)
Deficit, end of the year	(240,178)	(201,178)
Basic and Diluted earnings per trust unit (Note 17)	$ 0.39	$ 0.31

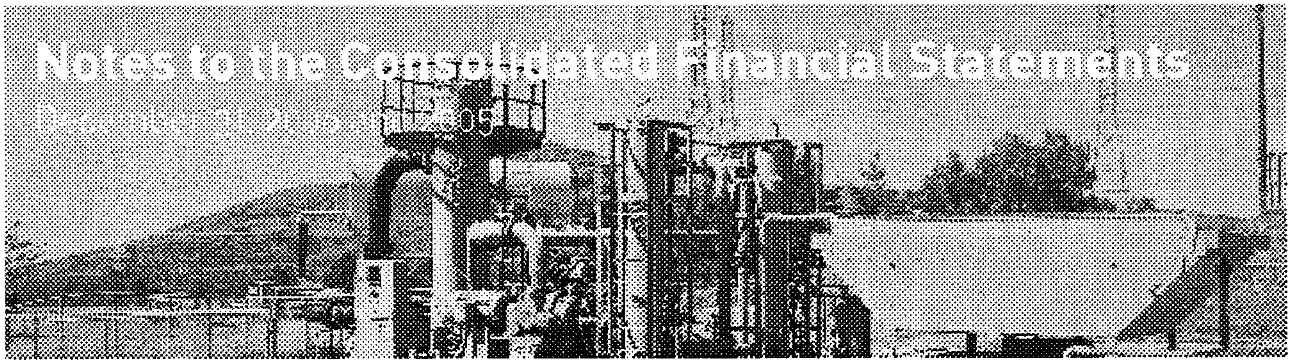
See accompanying notes to the consolidated financial statements

Consolidated Statements of Cash Flows

For the years ended December 31, 2006 and December 31, 2005 (Thousands of Canadian dollars)

	2006	2005
Operating Activities		
Net earnings	$ 27,955	$ 21,788
Items not affecting cash		
Amortization of capital assets	31,996	27,325
Amortization of intangible assets	6,035	6,463
Other amortization	1,669	1,339
Equity income, net of distributions received	(143)	208
Future income taxes	(3,627)	1,750
Loss on hedging instruments	497	-
Write down of fixed asset, intangible asset and note receivable (Notes 3, 4 and 5)	3,263	3,533
Minority interest (Note 2)	1,458	-
AirSource commitment fee	-	3,228
Unrealized (gain) / loss on foreign exchange	76	(2,023)
	69,179	63,611
Changes in non-cash operating working capital	(951)	(7,932)
	68,228	55,679
Financing Activities		
Cash distributions trust units	(64,890)	(64,061)
Cash distributions non controlling interest	(1,083)	-
Convertible debenture issue (Note 9)	60,000	-
Expenses of convertible debenture issue (Note 9)	(2,900)	205
Deferred financing costs	(358)	(816)
Increase in long-term liabilities	-	93,080
Decrease in long-term liabilities	(3,718)	(55,310)
Other	281	317
Deferred credits	94	(290)
	(12,574)	(26,875)
Investing Activities		
Decrease / (increase) in restricted cash	(3,281)	270
Deferred charges	(1,114)	(338)
Receipt of principal on notes receivable	4,552	9,697
Additions to capital assets	(30,934)	(15,912)
Increase in notes receivable	(322)	(16,241)
Proceeds received from sale of power purchase agreement	1,021	-
Acquisitions of operating entities net of cash acquired	(23,431)	(28,952)
	(53,509)	(51,476)
Effect of exchange rate differences on cash and cash equivalents	(43)	(313)
Increase / (decrease) in cash and cash equivalents	2,102	(22,985)
Cash and cash equivalents, beginning of the year	11,363	34,348
Cash and cash equivalents, end of the year	$ 13,465	$ 11,363
Supplemental disclosure of cash flow information		
Cash paid during the period for interest expense	$ 20,702	$ 15,753
Cash paid during the period for income taxes	$ 1,060	$ 871

See accompanying notes to the consolidated financial statements



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

Prima Deschecha, California

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.

The Trustees declare on a monthly basis, distributions to its Unitholders. Currently such distributions are $0.92 per unit on an annualized basis.

The Fund is managed by Algonquin Power Management Inc. ("APMI"), a company wholly owned by the shareholders of Algonquin Power Corporation Inc. ("APC"). APC is the general partner of Algonquin Airlink Limited Partnership which owns an aircraft that the Fund charters. APC is the general partner of Algonquin Property LP which leases the corporate office to the Fund. GWAP, an entity majority owned by APMI, is the promoter of AirSource Power Fund I LP. 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. The Fund consolidates its proportionate share in the Valley Power Limited Partnership.

In accordance with Accounting Guideline 15, "Consolidation of Variable Interest Entities" ("AcG -15"), the Fund consolidates certain entities that are subject to control on a basis of control other than ownership of voting interests.

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, being 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.

No interest was capitalized to capital assets in 2006 and 2005.

(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) Notes receivable

Notes receivable are carried at cost. A provision for credit losses on notes receivable is charged to the consolidated statement of earnings and deficit to cover any losses of principal and accrued interest.

(h) Deferred costs

Deferred costs, which include the costs of arranging the credit facility, costs associated with the issuance of convertible debentures and periodic customer rate reviews with the utility governing bodies for the water reclamation and distribution facilities, are amortized on a straight-line basis over the term of the expected benefit, being 2 to 10 years.

(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, distributions of earnings and additional investments.

(j) Deferred credits

Certain of the water companies receive advances from developers for water and sewage main extensions. The amounts advanced are generally repayable over a period of 10 years based on 10% of the revenues generated by the housing/development in the area developed. Generally, advances not refunded within the specified period are not required to be repaid. The estimate of non-refundable amounts is credited against capital assets. The Fund also receives contributions in aid of construction with no repayment requirements in which the full amount is immediately treated as a capital grant and netted against capital assets.

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.

(k) 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 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.

(l) Foreign currency translation

The Fund's United States subsidiaries and partnership interests are considered to be functionally integrated with the Canadian operations. All monetary assets and liabilities denominated in United States dollars are translated into Canadian dollars at year-end exchange rates, whereas non-monetary assets and liabilities are translated at the rate in effect at the transaction date. The revenues and expenses of these integrated operations are translated at the average rate of exchange in effect during the period. The foreign currency translation adjustment is reflected in the consolidated statement of earnings and deficit. Amortization of assets translated at historical exchange rates are translated at the same exchange rate as the assets to which they relate.

(m) Derivatives contracts

Derivative instruments are utilized by the Fund in the management of its foreign exchange and interest rate exposure. The Fund's policy is not to utilize derivative financial instruments for trading or speculative purposes.

The Fund formally documents all relationships between hedging instruments and hedged items, as well as its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. The Fund also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair values or cash flows of hedged items.

All derivative instruments that do not qualify for hedge accounting or are not designated as a hedge, are recorded as either an asset or a liability with changes in fair value recognized in earnings. The Fund ceased designating its forward selling of US funds as hedges at December 31, 2006. Consequently, as at December 31, 2006, the Fund recorded an increase in Other Assets and an increase in Deferred Credits of $11,167 to record the fair value of the outstanding forward currency sales.

The Fund has not designated its interest swap arrangements as a hedge. Consequently, as at December 31, 2006, the Fund recorded a decrease in other assets and an increase in loss on hedging instruments of $479 (2005 – nil)

(n) 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 obligation has been recorded in 2006 and 2005.

(o) Income taxes

As the Fund is an unincorporated trust, it is entitled to deduct distributions to unitholders to the extent of its taxable income and consequently, it is expected that the Fund will not be directly liable for any material income tax as this will be the responsibility of the individual unitholder. Any provision for income taxes will relate solely to the income taxes of the Fund's wholly owned subsidiaries that are corporations.

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. No future tax assets or liabilities are recorded on temporary differences in the flow through entities.

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

(p) 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.

(q) Future accounting and reporting changes

The CICA has issued three new accounting standards: CICA Handbook Section 3855, Financial Instruments – Recognition and Measurement; Section 3865, Hedges; and Section 1530, Comprehensive Income. These standards are effective for the Fund beginning January 1, 2007. The principal impacts of the standards are as follows:

Financial Instruments – Recognition and Measurement Financial assets will be classified as available for sale, held to maturity, trading, or loans and receivables. Financial liabilities will be classified as trading or other. Initially, all financial assets and financial liabilities must be recorded on the balance sheet at fair value. Subsequent measurement is to be determined by the classification of each financial asset and financial liability. Realized and unrealized gains and losses on financial assets and liabilities that are held for trading will continue to be recorded in the consolidated statement of income. Unrealized gains and losses on financial assets that are held as available for sale will be recorded in other comprehensive income until realized, when they will be recorded in the consolidated statement of income. All derivatives, including embedded derivatives that must be separately accounted for, will be recorded at fair value in the consolidated balance sheet.

Hedges In a cash flow hedge, the change in fair value of the derivative, to the extent effective, will be recorded in other comprehensive income until the asset or liability being hedged affects the consolidated statement of income, at which time the related change in fair value of the derivative will also be recorded in the consolidated statement of income. Any hedge ineffectiveness will be recorded in the consolidated statement of income.

Comprehensive Income Changes in the fair value of cash flow hedging instruments will be recorded in a statement of other comprehensive income will form part of unitholders equity.

Transitional Impact The transitional impact of these new standards is still being evaluated by management. As explained in 1(m) the Fund mark to market its foreign exchange forwards and interest rate swap and will record future changes in income.

2. Acquisitions

a) 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, 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 $60.6 million. Total purchase price, including acquisition costs, was $101.7 million.

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. At December 31, 2006, there were 3,256,984 exchangeable units outstanding for a value of $30.3 million. From the date of the acquisition to December 31 2006, 813,388 Algonquin AirSource Units were exchanged for 797,770 Trust Units. The exchange agreement will continue until there are no outstanding Exchangeable Units.

The Exchangeable Units are classified on the Fund's balance sheet as 'Non controlling interest'.

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:

	Total
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 other non tangible assets. These assets will be amortized over their expected useful lives being 10 and 25 years.

During 2006, the Fund provided $19.5 million of financing to AirSource. As of June 29, 2006, the Fund had advanced $40.0 million to AirSource as well as providing letters of credit of $15.4 million, for a total of $55.4 million.

b) 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, these payments continue until 2008, for Woodmark until 2009, and for Rio Rico until 2008. As of December 31, 2006 the fund accrued $2,802 (2005 - $2,698) as a growth premium, and increased intangible assets by a similar amount including an amount calculated for future income taxes of $1,166 (2005 - $1,627).

	2006	2005
Litchfield Park	$ 1,855	$ 2,584
Woodmark	131	114
Rio Rico	816	-
	$ 2,802	$ 2,698
In US$	$ 2,460	$ 2,300

3. Long-term investments

	2006	2005
Debt and equity interests, ranging in ownership between 12.1% to 32.4%, in four generating facilities.	$ 24,704	$ 27,346
A 45% partnership interest in the Algonquin Power (Rattle Brook) Partnership	3,699	3,719
A 50% partnership interest in Campbellford Limited Partnership	555	392
	28,958	31,457
Across America Note Note bearing interest of 12.00% repayable in quarterly installments (principal and interest) of U.S. $400, maturing January 31, 2008.	1,948	6,185
AirSource Note Note bearing interest of 11.189% maturing September 30, 2014. Interest decreases to 10.739% after conversion. No principal payments until January 1, 2009. During 2006, the Fund completed the acquisition of AirSource and the outstanding balance eliminates on consolidation.	-	20,481
Airlink Advance (note 13) Advance for expense reimbursement for business use of aircraft	1,076	1,212
Other	331	945
	3,355	28,823
	32,313	60,280
Less: current portion	(2,337)	(2,791)
	$ 29,976	$ 57,489

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

3. Long-term investments continued

In 2005, the principal on the Campbellford Note of $4,738 was repaid and the consolidation of the Campbellford investment ceased and equity accounting commenced. The proceeds of $4,738 were allocated to reduce the existing note receivable and the existing investment in Campbellford.

In 2006, the Fund wrote down the value of the Across America Note to its estimated fair value.

4. Capital assets

	2006		
	Cost	Accumulated amortization	Net book value
Land	**$ 11,504**	**$ -**	**$ 11,504**
Facilities	**917,424**	**131,905**	**785,519**
Equipment	**24,823**	**11,372**	**13,451**
	$ 953,751	**$143,277**	**$810,474**

Facilities include cost of $94,606 (2005 - $94,587) and accumulated amortization of $17,817 (2005 - $6,711) under capital lease and $22,431 (2005 - $8,433) of construction in process. Amortization expense of facilities under capital lease was $2,536 (2005 - $2,536). In addition $2,010 (2005 - $11,329) of contributions received in aid of construction have been credited to facilities cost. Equipment includes cost of $3,556 (2005 - $3,341) and accumulated amortization of $1,139 (2005 - $921) of equipment under capital lease

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 $9,550. The Fund has incurred amounts totaling $2,873 (2005 -$2,418) included in assets under construction. APC is entitled to 50% of the cash flow above 15% return on investment pursuant to its project management contract.

The Fund has committed to contractual arrangements to complete the Sanger re-powering project totaling approximately $16,596. The project is expected to be completed in the forth quarter of 2007. Included in the cost to complete the project, APMI will be paid a development supervision fee of $250.

	2005		
	Cost	Accumulated amortization	Net book value
Land	$ 11,504	$ -	$ 11,504
Facilities	709,504	103,729	605,775
Equipment	17,925	7,552	10,373
	$738,933	$ 111,281	$ 627,652

In 2005, the Fund wrote down the cost of both the capital asset and intangible asset related to the Crossroads facility located in New Jersey to its estimated fair value.

5. Intangible assets

	2006		
	Cost	Accumulated amortization	Net book value
Power purchase contracts	$120,892	$ 30,992	$ 89,900
Customer relationships	23,348	1,385	21,963
Licenses and agreements	696	581	115
	$144,936	$ 32,958	$ 111,978

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

	2005		
	Cost	Accumulated amortization	Net book value
Power purchase contracts	$ 73,966	$ 25,234	$ 48,732
Customer relationships	29,109	1,167	27,942
Licenses and agreements	696	522	174
	$ 103,771	$ 26,923	$ 76,848

6. Other Assets

On November 1, 2005, AirSource entered into a fixed for floating interest rate swap until September 2015 in the notional amount of $73.3 million 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 $497 for 2006 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 million which has been included in the purchase price allocation. The Fund has not designated the swap as a hedge for accounting purposes.

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, 2006 amounted to U.S. $65,749 until 2010 at a weighted average exchange rate of $1.32. The fair value of the outstanding futures contracts is $11,167 at December 31, 2006 (2005 – $17,053) which has been recorded as a deferred credit.

7. Revolving credit facility

During 2006, the Fund reached an agreement with the Fund's senior lenders to increase its revolving credit facility by $30.0 million to bring the total available credit to $175.0 million including a $20.0 million operating line. In July 2006, the credit facility was extended for another one year term to mature in July 2008. At December 31, 2006, $67,000 (2005 - $69,300) (Note 8) 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 $44,122 (2005 - $43,883) 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.

8. Long-term liabilities

	2006	2005
Senior Debt Long Sault Rapids Interest at rates varying from 10.16% to 10.21% repayable in monthly blended installments of $402, maturing December, 2027.	**$ 42,379**	$ 42,868
Senior Debt Chute Ford Interest rate of 11.55% repayable in monthly blended installments of $64, maturing April, 2020.	**5,180**	5,335
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 2006 is 3.47%. (2005 – 2.50%).	**22,374**	22,385
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, 2006 was U.S. $1,729 and U.S. $127 respectively (2005 – U.S. $1,802 and U.S. $134).	**2,162**	2,257
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, 2006 was U.S. $4,908 and U.S. $8,255, respectively, (2005 – U.S. $5,086 and U.S. $8,339).	**15,340**	15,653
Revolving credit facility (Note 7) Revolving line of credit interest rate is equal to bankers acceptance or LIBOR plus 1.125 %. The effective rate of interest for 2006 was 5.36% (2005 – 4.16%).	**67,000**	69,300
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 2006 was 5.41%.	**73,300**	-
AirSource Development Debt Financing from Algonquin Power Venture Fund 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**	-
Other	**180**	209
	$229,515	$ 158,007
Less: current portion	**(1,494)**	(1,005)
	$228,021	$ 157,002

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.

Under the AirSource credit agreement, the conditions precedent to conversion of the construction financing to a term credit facility included Vestas-Canadian Wind Technologies, Inc. ("Vestas") achieving commercial operation of the St. Leon facility under the Turn-key Contract on or before September 30, 2006. As a result of the ongoing issues with Vestas, such commercial operation was delayed and AirSource received a waiver from such senior lenders deferring such requirement until October 31, 2006. AirSource amended the credit agreement with its lenders to remove the requirement of achieving commercial operation of the St. Leon facility as a condition precedent to such conversion. Conversion to a term credit facility occurred on October 31, 2006. The amendment further provides that if resolution of certain outstanding issues under the Turn-key Contract is not achieved on or before the first anniversary of the date of the amendment, the lenders of the senior debt may require that equity distributions derived from AirSource be suspended until commercial operation is achieved.

Interest paid on the long-term liabilities was $14,270 (2005 - $9,588).

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

2007	$ 1,494
2008	69,844
2009	3,057
2010	3,279
2011	5,034
Thereafter	146,807
	$ 229,515

9. 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 debenture issue costs of $2,900 are deferred and amortized over the term of the convertible debentures. 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. 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 and Deficit.

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 debenture issue costs of $3,895 were deferred and amortized over the term of the convertible debentures. 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. 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 2006, 20 (2005 – nil) of 2004 convertible debentures were converted into 1,877 (2005 – nil) units which resulted in an increase in units of $20 (2005 – nil) and a decrease in convertible debentures by a similar amount.

Total interest on the convertible debentures in 2006 was $6,049 (2005 - $5,653).

10. Other long-term liabilities

	2006	2005
Bonds Payable		
Obligation to the City of Sanger due October 1, 2011 at interest rates varying from 5.15% to 5.55%. U.S. $1,030 (2005 – U.S.$1,205).	**$ 1,200**	$ 1,405
Customer Deposits		
Each facility in the Infrastructure Division is obligated 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.	**3,248**	3,061
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.	**2,351**	2,360
Other	**4,294**	4,049
	11,093	10,875
Less: current portion	**(382)**	(440)
	$ 10,711	$ 10,435

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

2007	$ 382
2008	438
2009	239
2010	242
2011	258
Thereafter	9,534
	$ 11,093

Interest paid on other long-term liabilities was $424 (2005 – $315).

11. 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, 2004 and 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

12. Income taxes

The provision for income taxes in the consolidated statements of earnings represents an effective tax rate different than the Canadian enacted statutory rate of 32.31% (2005 – 33.61%). The differences are as follows:

	2006	2005
Earnings before income tax and minority interest	$ 26,645	$ 24,392
Less: income taxed directly in hands of unitholders, not the Fund	(37,235)	(35,163)
Losses of taxable entities	(10,590)	(10,771)
Computed income tax expense (recovery) at Canadian statutory rate	(3,421)	(3,620)
Increase (decrease) resulting from:		
Change in substantively enacted tax rate	(1,674)	1,259
Operating in countries with different income tax rates	229	223
Valuation allowances	(239)	9,191
Manufacturing and processing deduction	-	121
Unrealized foreign exchange rate difference	-	(680)
Other	2,339	(3,890)
Income tax expense	$ (2,766)	$ 2,604

The tax effect of temporary differences of Fund's subsidiaries that give rise to significant portions of the future tax assets and future tax liabilities at December 31, 2006 and 2005 are presented below:

	2006	2005
Future tax assets:		
Non-capital loss, debt restructuring charges and currently non-deductible interest carryforwards	$ 20,241	$ 15,079
Unrealized foreign exchange differences on US entity debt	17,403	17,330
Customer advances in aid of construction – difference between net book value and tax value	5,007	4,572
Total future tax assets	42,651	36,981
Less: Valuation allowance	(32,955)	(33,193)
	9,696	3,788
Future tax liabilities:		
Capital assets – differences between net book value and undepreciated capital cost	(57,112)	(39,690)
Intangible assets – difference between net book value and cumulative eligible capital	(16,589)	(12,759)
Other	(461)	(1,680)
Total future tax liabilities	(74,162)	(54,129)
Net future tax liability	$(64,466)	$ (50,341)
Classified in the financial statements as:		
Future current income tax asset	$ -	$ -
Future non-current income tax asset	7,639	7,719
Future current income tax liability	(848)	(1,143)
Future non-current income tax liability	(71,257)	(56,917)
	$(64,466)	$ (50,341)

12. Income taxes continued

On December 21, 2006 the Minister of Finance (Canada) released draft legislation ("the Proposals") relating to the federal income taxation of publicly-traded trusts and partnerships. Under transitional relief the Proposals are contemplated to apply to a publicly-traded trust 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.

Under the Proposals, certain distributions attributable to a SIFT will not be deductible in computing the SIFT's taxable income, and the SIFT will be subject to tax on such distributions 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 the proposed tax on an Existing Trust may commence before 2011.

The Fund is a SIFT as defined in the Proposals. If enacted, the Fund would be subject to taxes on certain income earned from investments in its subsidiaries. The tax payable by the Fund on those distributions will result in a corresponding decrease to the cash flow available to be distributed to the unitholders. The Fund would also be required to recognize 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. It is anticipated that the recognition of these future income tax assets and liabilities will result in an increase in the net future tax liability of the Fund with a corresponding decrease in the net Unitholder's Equity.

At December 31, 2006, the Fund itself has undeducted financing expenses and underwriters' fees of $5,049 (2005 - $4,665) which will be deductible by the Fund and which will reduce the ultimate amount taxable to the unitholders over the next four years. This will be offset by additions to the unitholders' taxable income since the Fund's capital assets have an accounting basis which exceeds their tax basis by $10,113 (2005 - $8,111). In addition, two trusts wholly owned by the Fund have capital assets with an accounting basis which exceeds their tax basis by $59,739 (2005 - $1,706).

13. Algonquin Power Group

In addition to the transactions described in note 4 with APC and 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 2006 and 2005, APMI was paid on a cost recovery basis for all costs incurred and charged $869 (2005-$825). 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 2006 and 2005 no incentive fees were earned by APMI.

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 2006 were $296 (2005 - $296) and additional rent representing operating costs was $89 (2005 - $198).

When appropriate for use in its operations the Fund utilizes chartered aircraft, including the use of an aircraft owned by an affiliate of APMI. 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.

AirSource entered into a construction services agreement (the "Construction Services Agreement") dated October 28, 2004 with GWAP. The Construction Services Agreement has a term ending on the commercial operation date of the Facility in accordance with the terms of the Turn-key Construction Contract. GWAP may terminate the Construction Services Agreement in its sole discretion upon 30 days' prior notice. The services to be provided by GWAP under the Construction Services Agreement include, among other things, assisting with the supervision of the construction of the Facility and assisting with the administration of the Turn-key

Construction Contract. As consideration for its services, GWAP will be paid a fee equal to 1.0% of the Turn-key Construction Contract price, not including goods and services taxes, which will generally be payable as to 50% at the time of approval of invoices by St. Leon GP to Vestas under the Turn-key Construction Contract and as to 50% based on the percentage of completion of each phase of the Facility. As at December 31, 2006, $141 had been paid in fees being owed to GWAP and capitalized into capital assets. As of December 31, 2006 $1.0 million is included in accounts payable and accrued liabilities as the remaining fees owed to GWAP. GWAP will also be reimbursed for any out-of-pocket expenses incurred in providing such services, including the cost of third party subcontractors and other service suppliers. GWAP was reimbursed $517 during the year ended December 31, 2006, which was capitalized into capital assets.

AirSource has agreed to reimburse AirSource Power Fund GP Inc., the general partner (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 $65 during the year ended December 31, 2006.

14. Commitments and Contingencies

(a) Land and Water Leases

Certain of the operating entities including AirSource in 2006 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 $2,702 during 2006 (2005 - $2,394) 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.

(c) Commitments

AirSource has entered into a Turn-key Construction Contract (the "Contract") with Vestas for the construction of the Facility. The Contract price is $176.1 million, including approved change orders, and is payable on the achievement of specified milestones. At the date of acquisition, $148.7 million has been paid to Vestas and $27.4 million was accrued. The performance of Vestas under the Contract is secured by a standby letter of credit in favour of St. Leon Wind Energy GP Inc (the owner of the Facility) totalling $13.8 million. Certain obligations of the Facility are secured by a stand by letter of credit in favour of Vestas, totalling $14.6 million.

As of June 17, 2006, the 99 MW St. Leon wind energy generating facility achieved commercial operation status under the power purchase agreement with The Manitoba Hydro-Electric Board. However, certain issues are still outstanding between an AirSource affiliate, St. Leon Wind Energy GP Inc ("St. Leon GP") and Vestas pursuant to the Turn-key Contract, including St. Leon's assertion that certain contractual milestones have not been achieved. As a result, St. Leon GP believes it is entitled to payment of ongoing liquidated damages under the Turn-key Contract until such milestones are met and is recognizing such amounts in its financial statements.

Vestas has advised St. Leon GP that it disputes the continuing payment of such amounts and, commencing July 11, 2006, Vestas has discontinued further liquidated damage payments. Notwithstanding this, Vestas is continuing its efforts to complete the aspects of the construction work required to satisfy the outstanding milestones. St. Leon GP continues to hold substantial security posted by Vestas in respect of Vestas' obligations under the Turn-key Contract and which security, in the opinion of St. Leon GP, will be sufficient to address any amounts proven to be properly due and owing by Vestas to St. Leon GP under the Turn-key Contract. As of December 31, 2006 Vestas has paid $8.8 million in liquidated damages. Vestas is entitled to substantially all revenue received from Manitoba Hydro-Electric Board ("Manitoba Hydro") during this time period. For 2006, AirSource has billed and recorded in other revenue $19.1 million of liquidated damages, of which $10.3 million is included in accounts receivable. AirSource also recorded $13.4 million in energy sales receipts from Manitoba Hydro for 2006 in accounts payable and accrued liabilities as it is owed to Vestas.

14. Commitments and Contingencies continued

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.

The Contract price includes a two year warranty period for the wind turbines and one year warranty period for the balance of plant after the facility is deemed to be in commercial operation as defined by the contract.

15. 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 $231,697 (2005 - $160,284). The book value of these long-term liabilities is $229,515 (2005 - $158,007). The fair value of other long-term liabilities approximates their carrying value, with the exception of the Joliet subsidy which is not readily available.

Deferred credits include payments made by developers to the infrastructure division of which a portion based on revenue for the development in question needs to be paid back over time. These amounts 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.

16. 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 2006 was $0.0766 per trust unit for each month for a total of $0.92 for 2006, the same as 2005.

17. Basic and diluted net earnings per trust unit

Net earnings per trust unit has been calculated using the weighted average number of units outstanding during the year. The weighted average number of units outstanding for 2006 was 71,085,930 (2005 - 69,691,592). The net earnings per trust unit for 2006 was $0.39 (2005 - $0.31). The effect of the conversion of the convertible debentures and exchangeable units into trust units was not included in the computation of fully diluted net earnings per trust unit as the effect of conversions would be anti-dilutive.

18. Interest, dividend and other income

Other income includes the following items:

	2006	2005
Interest income	$ 4,184	$ 4,884
Dividend income	3,382	3,470
Sale of gas collection partnership interest	630	1,204
Equity income	538	333
Other	2,127	1,507
	$ 10,861	$ 11,398

19. Other revenue

Other revenue includes the following items:

	2006	2005
Liquidated damages (Note 14 (c))	$ 11,039	$ -
Wind Production Incentive	1,475	-
Natural gas sales	6,275	1,884
Hydro mulch sales	2,972	-
	$ 21,761	$ 1,884

20. Segmented information

	2006	2005
Revenue		
Canada	$ 65,209	$ 48,679
United States	136,206	130,645
	$201,415	$ 179,324
Capital assets		
Canada	$490,969	$309,669
United States	319,505	317,983
	$810,474	$ 627,652
Intangible assets		
Canada	$ 60,711	$ 25,260
United States	51,267	51,588
	$ 111,978	$ 76,848
Other assets		
Canada	$ 13,388	$ -
United States	-	-
	$ 13,388	$ -

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

20. Segmented Information continued

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 outlined on the following page:

Year ended December 31, 2006	Hydro	Cogen-eration	Alternative Fuels	Infra-structure	Admin	Total
Revenue						
Energy sales	45,945	68,544	15,492	-	-	129,981
Waste disposal fees	-	-	14,209	-	-	14,209
Water reclamation and distribution	-	-	-	35,464	-	35,464
Other revenue	-	9,247	12,514	-	-	21,761
Total revenue	45,945	77,791	42,215	35,464	-	201,415
Operating expenses	16,709	53,362	26,904	15,370	-	112,345
	29,236	24,429	15,311	20,094	-	89,070
Other administration costs	(473)	-	10	(167)	(8,574)	(9,204)
Interest expense	(5,029)	(1,121)	(2,565)	(1,014)	(12,560)	(22,289)
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)	(9,290)	(6,553)	-	(31,996)
Amortization of intangible assets	(1)	(2,195)	(3,013)	(826)	-	(6,035)
Earnings before income taxes and minority interest	15,818	18,090	2,173	11,587	(21,021)	26,647
Capital assets	278,918	85,114	274,682	171,760	-	810,474
Intangible assets	18	19,078	61,643	31,239	-	111,978
Capital expenditures	1,703	13,992	3,481	11,542	216	30,934
Acquisition of operating entities	-	-	20,628	2,803	-	23,431
Total assets	297,257	133,146	379,220	211,664	27,037	1,048,324

Year ended December 31, 2005	Hydro	Cogen-eration	Alternative Fuels	Infra-structure	Admin	Total
Revenue						
Energy sales	44,102	75,674	16,262	-	-	136,038
Waste disposal fees	-	-	13,031	-	-	13,031
Water reclamation and distribution	-	-	-	28,371	-	28,371
Other revenue	-	1,884	-	-	-	1,884
Total revenue	44,102	77,558	29,293	28,371	-	179,324
Operating expenses	17,008	52,822	25,014	11,847	-	106,691
	27,094	24,736	4,279	16,524	-	72,633
Other administration costs	(99)	-	(130)	(106)	(5,604)	(5,939)
Interest expense	(5,068)	(987)	(385)	(1,140)	(8,799)	(16,379)
Interest, dividend and other income	1,250	3,471	6,494	44	139	11,398
Write down of capital asset and intangible asset	-	(3,533)	-	-	-	(3,533)
Amortization of capital assets	(9,672)	(6,714)	(5,155)	(5,784)	-	(27,325)
Amortization of intangible assets	(1)	(3,429)	(2,336)	(697)	-	(6,463)
Earnings before income taxes and minority interest	13,504	13,544	2,767	8,841	(14,264)	24,392
Capital assets	276,850	91,591	93,072	166,139	-	627,652
Intangible assets	20	22,295	26,438	28,095	-	76,848
Capital expenditures	436	(120)	5,234	10,127	235	15,912
Acquisition of operating entities	1,140	-	-	27,812	-	28,952
Total assets	295,834	146,158	162,431	206,900	12,478	823,801

All energy sales are earned from contracts with large public utilities. The following utilities contributed more than 10% of these total revenues in either 2006 or 2005: Hydro Québec 16% (2005-13%), Pacific Gas and Electric 11% (2005-12%), and Connecticut Light and Power 22% (2005-25%). The Fund has mitigated its credit risk to the extent possible by selling energy to these large utilities in various North American locations.

The infrastructure division is subject to rate regulation. The regulators in the states of Arizona, Texas and Missouri, where the Fund has regulated infrastructure operations, set the rates and tariffs that each facility can charge its customers. Generally, the allowed rates and tariffs are reviewed on a periodic basis when the facility elects or is requested to apply for a rate change. Rate regulation has not impacted the Fund's accounting for the assets and liabilities.

21. Subsequent events

Subsequent to the end of the year a further 366,819 Fund trust units were issued pursuant to the conversion of exchangeable units. In addition the Fund entered into U.S. $17.1 million of additional forward contracts, increasing its total forward contracts to U.S. $82.9 million carrying an average rate of $1.29.

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 utility service to approximately 1,500 water distribution customers located near the Town of Sierra Vista, Arizona. The aggregate cost for completing the acquisition of the assets related to such service and completing the regulatory hearings necessary to approve the transaction was approximately U.S. $1.0 million of which all but $0.2 million have been included in the 2006 financial statements.

On February 26, 2007, the Fund announced that it had entered into a support agreement with Clean Power Income Fund ("CPIF") pursuant to which an entity of the Fund agreed to make an offer to CPIF unit holders to acquire all of the outstanding CPIF units in exchange for units of the Fund on a one for 0.6152 basis plus a contingency value receipt ("CVR"). Each CVR will entitle the holder thereof, subject to certain conditions, to a payment in cash of an amount up to approximately $0.27 per CPIF unit. The Fund also announced that a Fund entity will make an offer to acquire all of the outstanding 6.75% convertible debentures issued by CPIF in exchange for the Fund's convertible debentures. Each of the offers will be made by way of a takeover bid with consideration comprised of additional Fund units and CVRs or convertible debentures of the Fund.

On March 9, 2007, Standard & Poor's announced that it was lowering the long-term corporate credit rating on the Fund from 'BBB+' to 'BBB' and removed the Fund from credit watch. Standard & Poor's commented that increased financial and merchant risk was generally responsible for such downgrade decision. As a result, the margin charged on any amounts outstanding under the Credit Line increases to 1.25% with no change to the interest rate charged.

Corporate Information

Trustees

Kenneth Moore, Chairman – Managing Partner, NewPoint Capital Partners Inc.

Christopher J. Ball – Executive Vice-President, Corpfinance International Limited

George Steeves – Principal, True North Energy

The Management Group

Algonquin Power Management Inc.

Chris K. Jarratt, Chief Executive Officer and Director

David C. Kerr, Director

Ian E. Robertson, Director

Algonquin Power Income Fund

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Annual General Meeting

April 26, 2007, 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

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Income Fund