Trust Units of Algonquin Power Income Fund are not “deposits” within the meaning of the Canada Deposit Insurance Corporation Act (Canada) and are not insured under the provisions of that Act or any other legislation.
ALGONQUIN POWER INCOME FUND

THE FUND

Algonquin Power Income Fund is an unincorporated open ended trust created by a declaration of trust dated September 8, 1997, in accordance with the laws of the Province of Ontario. The head and principal office of the Fund is located at 2845 Bristol Circle, Oakville, Ontario L6H 7H7.

The Declaration of Trust was amended on: (1) December 18, 1998, to provide the Fund with greater flexibility to borrow monies, which borrowings may be secured by the Fund’s assets; (2) on June 1, 2000, to clarify that Fund indebtedness may be secured by some or all of the assets of the Fund, to increase the amount of permitted monthly cash redemptions from $10,000 to $250,000 and to expand the types of permitted investments which the Fund may make to include investments in energy-related assets and such other investments as the Trustees consider reasonable and appropriate; (3) on May 24, 2001, to provide that a quorum at a meeting of Unitholders shall, except in specified circumstances, consist of two or more individuals present in person or represented by proxy; (4) on May 23, 2002, to make clear the ability of the Fund to complete certain transactions in connection with any internal reorganization of the Fund’s assets, without Unitholder approval; (5) on June 26, 2003, to clarify the ability of the Fund to dispose of certain assets of the Fund and provide guarantees of the obligations of the Fund’s related entities, without Unitholder approval, permit fractional Units and to provide for certain other housekeeping amendments; and (6) on May 26, 2004, to authorize the Trustees to appoint up to two (2) additional Trustees between annual meetings of Unitholders. The Declaration of Trust was restated to reflect the foregoing amendments as of May 26, 2004.

Resources of Missouri LLC, a Missouri limited liability company; Algonquin Water Resources of Illinois, LLC, an Illinois limited liability company; Algonquin Power Windsor Locks LLC, a Connecticut limited liability company and Dyna Fibres Inc., a California corporation. In addition, Algonquin Power Acquisition Inc. and Algonquin Energy Services Inc., both Delaware corporations, were incorporated as acquisition vehicles for proposed acquisitions by the Fund in the United States and currently have no assets.

The Fund also has direct or indirect interests in the following partnerships: St. Leon Wind Energy LP and AirSource Power Income Fund, Manitoba limited partnerships; Valley Power LP, an Alberta limited partnership; Société Hydro-Donnacona, S.E.N.C., a Québec general partnership; Société en Commandite Algonquin (Éoliennes), Glenford Partnership and Algonquin Power (Mont-Laurier) Limited Partnership, Québec limited partnerships; Newspring Acquisition Partnership, an Ontario general partnership; Algonquin (AirSource) Power LP and Algonquin Power (Campbellford) Limited Partnership, Ontario limited partnerships; Hollow Dam Power Company and Burt Dam Power Company, New York general partnerships; Hadley Falls Associates, HDI Associates III, Avery Hydroelectric Associates, Gregg Falls Hydroelectric Associates Limited Partnership, Pembroke Hydro Associates Limited Partnership and Mine Falls Limited Partnership, New Hampshire limited partnerships; Moretown Hydro Energy Company, a Vermont partnership; HDI Associates I, an Indiana general partnership; Great Falls Hydroelectric Company Limited Partnership, a Maryland limited partnership; Oswego Hydro Partners, L.P., a Delaware limited partnership; Algonquin Power (Rattle Brook) Partnership, a Newfoundland partnership; and San Bernardino Landfill Gas Partnership LP, a California limited partnership.

The Fund is the sole beneficiary of Algonquin Power Trust, an unincorporated open ended trust created by a declaration of trust dated June 30, 2000 in accordance with the laws of the Province of Ontario. Algonquin Power Trust owns all of the outstanding units of Algonquin Power Operating Trust, an unincorporated open ended trust created by an amended and restated trust indenture effective January 2, 1997, in accordance with the laws of the Province of Alberta. Algonquin Power Trust also owns all of the outstanding trust units of KMS, an unincorporated open ended trust created by a declaration of trust dated February 18, 1997, in accordance with the laws of the Province of Alberta.

The Fund also has an indirect ownership interest in St. Leon Trust, a trust created by a declaration of trust dated June 28, 2005 in accordance with the laws of the Province of Manitoba.

With the exception of (a) Algonquin Power (Campbellford) Limited Partnership, in which the Fund has a 50% indirect ownership interest; (b) Algonquin Power (Rattle Brook) Partnership, in which the Fund has a 45% indirect interest; (c) Valley Power LP, in which the Fund has a 50% indirect interest; (d) Newspring Acquisition Partnership, in which the Fund has a 50% direct interest; (e) Algonquin Power - Cambrian Pacific Genco LLC, in which the Fund has a 98% indirect interest; (f) Across America LFG LLC, in which the Fund has a 0.01% indirect interest; (g) Landfill Power LLC, in which the Fund has a 50% indirect interest; and (h) Algonquin Water Services LLC, in which the Fund has a 50% ownership interest; all of the above-noted entities are wholly-owned, directly or indirectly, by the Fund, subject to the Manager’s Interest.

All information contained in this Annual Information Form is presented as at March 30, 2007, unless otherwise specified. Reference is made to the glossary attached as Schedule A for the meanings of certain defined terms.
DEVELOPMENT OF THE BUSINESS

General

The Fund was created to acquire direct or indirect equity interests in hydroelectric generating facilities located in Canada and the United States. The Fund has since expanded its mandate and will consider investment opportunities which provide stable cash flow from renewable resource facilities. Potential candidates could include wind, biomass or natural gas powered generating stations or facilities within a regulated utility.

The Fund, through its interests in the Fund Businesses, is engaged, indirectly, primarily in the business of generating and marketing electrical energy within the independent power generation industry. As at March 30, 2007, the Fund holds equity interests, directly and indirectly, in 47 hydroelectric generating facilities located in Ontario (4), Québec (12), Newfoundland (1), Alberta (1), New York State (13), New Hampshire (13), Vermont (2) and New Jersey (1) representing aggregate installed generating capacity of approximately 143 MW. In addition, the Fund holds an equity interest in one wind energy generating facility located in Manitoba with installed capacity of approximately 99 MW. The Fund also holds equity interests in one energy from waste facility in Ontario with an installed generating capacity of 10 MW, 10 land-fill gas fired facilities in California, Tennessee, New Jersey, New Hampshire and Minnesota with total installed generating capacity of 36 MW and three natural gas-fired cogeneration facilities in each of Connecticut, New Jersey and California with an installed capacity of approximately 113 MW. In addition, the Fund owns partnership, share and debt interests in three bio-mass fired generating facilities with combined installed capacity of approximately 70 MW located in Alberta, Québec and Nova Scotia. The Fund holds minority term investments in two natural gas/wood waste-fired generating facilities with joint installed capacity of approximately 138 MW located in northern Ontario. In addition to its electricity generating assets, Algonquin owns 17 regulated water distribution and wastewater facilities in Arizona, Illinois, Missouri and Texas. The facilities are grouped into four business segments: hydroelectric segment, natural gas cogeneration segment, alternative fuel segment and infrastructure segment. See “Description of the Business – The Developments”.

The Fund may, where practical and economic, expand its current operations. All investment opportunities must meet established guidelines and are subject to review by the Trustees. Such facilities will only be acquired if the Fund believes that the acquisition will likely result in an increase in distributable cash per Trust Unit, otherwise meet the Fund’s acquisition guidelines and is in accordance with the Fund’s objectives, as set out in the Declaration of Trust. The Trustees believe that the stability and sustainability of cash flows to Unitholders may be enhanced through the diversification of the current asset portfolio. Opportunities providing long term, statistically predictable future cash flows whose risk profile is generally consistent with the existing portfolio of energy and infrastructure assets will be considered. See “Acquisition Guidelines”.

The management of the Manager has extensive experience and contacts in the independent power industry in Canada and the United States and is expected, but is not obligated, to continue presenting appropriate acquisition opportunities to the Fund. Under the terms of the management compensation structure between the Manager and the Fund, the Manager is not paid any acquisition or transaction related fees in respect of acquisitions by the Fund. See “Governance, Management and Operations”.

Acquisition Guidelines

After consultation with and approval by the Trustees of the Fund, who have established certain acquisition guidelines which may change depending on circumstances, the Manager uses an acquisition
strategy which targets energy and/or infrastructure facilities and employs the following guidelines in the review and evaluation of possible acquisitions:

(a) each facility, development or group of developments will only be acquired if the Fund believes that the acquisition will provide a forecast internal rate of return that is greater than 200 basis points above the yield of long-term (20 year) Government of Canada bonds over the expected life of the facility after deducting operating costs, general, administrative and management expenses and incorporating the impact of debt financing, but before income taxes;

(b) each facility, development or group of developments will only be acquired if the Fund believes that the acquisition will likely result in an increase in distributable cash per Trust Unit;

(c) facilities or a group of facilities for which no existing debt financing is in place will be preferred;

(d) facilities where Power Systems or Water Services will become the operator will be preferred;

(e) facilities in respect of which long term power purchase agreements with major electrical utilities exist or facilities within a regulated utility will be preferred and in other cases, commodity price forecasts and exchange rate assumptions used in acquisition evaluations will reflect market expectations;

(f) the acquisition of each facility, or development, will be based on an engineering report confirming the condition of each facility or each of the facilities within the development or group, as applicable, and the technical assumptions utilized in the acquisition evaluation;

(g) for each facility in which an interest with an indefinite term is being acquired, the expected useful life of such facility and associated structures will, with regular maintenance, overhauls and upkeep, be not less than 20 years; and

(h) the acquisition of each facility, or development, will be reviewed and approved by the Trustees.

All acquisitions must be in accordance with the Declaration of Trust.

The Manager and the Operator

The Fund is managed by Algonquin Power Management Inc. Management of the Manager has extensive experience and contacts in the independent power industry in Canada and the United States and may, but is not obligated to, present appropriate acquisition opportunities to the Fund. The Manager is owned by the shareholders of Algonquin Power Corporation Inc. The Manager and its affiliates provide design, financing, construction, management, operation and maintenance of independent hydroelectric power facilities ranging in size from 130 to 18,000 kilowatts. The principals of the Manager together have over 50 years of experience in the industry.

Power Systems, an affiliate of the Manager, provides, on a cost-recovery basis, operations-related services in respect of the facility interests indirectly owned by the Fund. Power Systems is one of the
largest operators of independent hydroelectric generating facilities in Canada. Power Systems supplies both direct operations services to the various facilities and operations supervisory services to Algonquin and its related entities.

Water Services operates, on a cost-recovery basis, the water and wastewater facilities owned by the Fund.

In addition to the principals of the Manager, Power Systems, Water Services and various subsidiaries of the Fund employ over 325 individuals, comprised of engineers, technicians, biologists, professional managers and administrative support staff, including a field team of trained plant operators and field supervisors. The head office of Power Systems, located in Oakville, Ontario, provides technical and management support, regulatory compliance and budget and accounting control for field personnel undertaking plant improvements and repairs. Field staff are organized into regional groups, each with its own trained supervisor. Most of the facilities are outfitted with remote computer controls and systems which allow the plants to be operated remotely in the field or by head office personnel. Power Systems also has data management systems to track the performance of the facilities, with a view to optimizing facility output. See “Governance, Management and Operations”.

Public Offerings Since January 1, 2004

In June 2004, the Fund delivered an aggregate of 1,803,983 Trust Units in connection with the take-over bid by Algonquin Power Trust of the outstanding convertible debentures of KMS Power Income Fund not already owned by Algonquin Power Trust. See “General Development of the Business – Other Developments in Fiscal 2004”.

In July 2004, the Fund completed an offering of $85 million principal amount Series 1 Debentures. The Series 1 Debentures are due July 31, 2011 and bear interest at 6.65% per annum, payable semi-annually in arrears. The Series 1 Debentures are to be repaid in cash or Trust Units and will be convertible at any time up to maturity at the option of the holder into Trust Units of the Fund at a conversion price of $10.65 per Trust Unit. The Series 1 Debentures may not be redeemed by the Fund prior to July 31, 2007. Net proceeds from this offering were used to repay the Fund’s acquisition line of credit and to fund working capital. See “Trust Unit and Loan Capital of the Fund –Fund Debentures”.

In October 2006, the Fund filed a short form prospectus qualifying the distribution of 6,440,000 Trust Units at a price of $10.10 per Trust Unit (plus 644,000 Trust Units issuable on the exercise by the underwriters of an over-allotment option). The offering of Trust Units was conditional upon the closing by the Fund of an offering of 60,000 Series 2 Debentures at a price of $1,000 per Series 2 Debenture, which debentures were qualified for distribution pursuant to a short form prospectus filed by the Fund on November 11, 2006.

As a result of the proposals announced by the Minister of Finance on October 31, 2006 to impose a tax on distributions from certain publicly traded income trusts and partnerships, the Fund, the Manager and the underwriters subsequently agreed, among other things, to defer the closing of the offering of the Series 2 Debentures and to terminate the offering of the Trust Units.

On November 22, 2006, the Fund completed the Series 2 Debenture offering for gross proceeds of $60,000,000. The Series 2 Debentures are due November 30, 2016 and bear interest at 6.20% per annum, payable semi-annually in arrears. The Series 2 Debentures are convertible into Trust Units of the Fund at a conversion price of $11.00 per Trust Unit. The Series 2 Debenture offering was underwritten by a syndicate co-led by BMO Nesbitt Burns Inc. and CIBC World Markets Inc., which also included National Bank Financial Inc., Scotia Capital Inc., RBC Dominion Securities Inc., TD Securities Inc.,
Canaccord Capital Corporation, Dundee Securities Corporation, FirstEnergy Capital Corp., HSBC Securities (Canada) Inc. and Raymond James Ltd. The Fund used the net proceeds from the offering of the Series 2 Debentures to repay bank indebtedness. See “Trust Unit and Loan Capital of the Fund – Fund Debentures”.

In May and August 2006, the Fund delivered an aggregate of 2,382,972 Trust Units in connection with the take-over bid by Algonquin (AirSource) Power LP, an affiliate of the Fund, of all of the outstanding limited partnership units of AirSource. See “General Development of the Business – Other Developments in Fiscal 2006”.

Acquisitions of Facilities in Fiscal 2004

On September 30, 2004, the Fund acquired an interest in 12 landfill gas fired generating stations in California, Tennessee, New Jersey, New Hampshire and Minnesota representing approximately 36 MW of installed capacity. The purchase price for these facilities was $11.7 million (US$9.3 million). The majority of these facilities were commissioned in the late 1990s. The electricity produced is sold to a number of large utilities pursuant to long-term power purchase agreements with an average termination date of 2011. Approximately 66% of the installed capacity of these facilities are located at large landfills which are continuing to accept waste, including three regional landfills permitted for operation for at least 25 years located in the southern California basin. A subsidiary of Algonquin America acquired the corporations which owned the generating assets of these facilities.

The purchase price paid for these facilities, the nature of the acquisition and the date of acquisition are set out in the table below.

<table>
<thead>
<tr>
<th>Facility</th>
<th>Purchase Price (in thousands)</th>
<th>Nature of Acquisition</th>
<th>Date of Acquisition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Landfill gas fired generating facilities</td>
<td>$11,374</td>
<td>Shares</td>
<td>September 30, 2004</td>
</tr>
<tr>
<td>Total</td>
<td>$11,374</td>
<td></td>
<td></td>
</tr>
</tbody>
</table>

Other Developments in Fiscal 2004

Pursuant to an agreement with Confederation Life Insurance Company, in liquidation dated September 5, 2001, Algonquin Power Trust had acquired, among other interests, a 16.9% interest in the senior debt issued by Cardinal Power of Canada L.P. On April 30, 2004, after notice was given by the borrower, the outstanding loan of approximately $18.5 million at March 31, 2004 was repaid plus a prepayment fee of $3.7 million and accrued interest. As a result, the Fund has no further interest in Cardinal.

During the first quarter of 2004, the Fund earned a break fee of $400,000 net of all expenses. The Fund was in negotiations to acquire a facility, but as a result of a right of first refusal between the vendor and another party, the facility was sold to the other party. This fee was recognized by the Fund as other income.

On May 19, 2004, Algonquin Power Trust, the sole unitholder of KMS Power Income Fund, made a take-over bid (the “Take-over Bid”) for all of the outstanding principal amount of convertible
debentures ($15,806,400) of KMS (the “KMS Debentures”) not already owned by Algonquin Power Trust. The Take-over Bid expired on June 25, 2004 and an aggregate of $13,661,500 principal amount of KMS Debentures were tendered to the Take-over Bid. The price offered for the KMS Debentures under the Take-over Bid was 11.4130 Trust Units of the Fund per $100 principal amount of KMS Debentures (inclusive of any accrued and unpaid interest thereon). Algonquin Power Trust took up and paid for all of the KMS Debentures tendered to the Take-over Bid by delivering an aggregate of 1,559,186 Trust Units of the Fund to the tendering debentureholders.

On June 29, 2004, the debentureholders of KMS passed a special resolution to amend the trust indenture governing the KMS Debentures, to provide that, on the maturity date of the KMS Debentures (June 30, 2004), KMS would deliver to debentureholders 11.4130 Trust Units of the Fund per $100 principal amount of KMS Debentures (inclusive of any accrued and unpaid interest thereon). An aggregate of $2,144,900 principal amount of KMS Debentures were not tendered to the Take-over Bid and remained outstanding until maturity. On the maturity date, KMS paid for such KMS Debentures by delivering an aggregate of 244,797 Trust Units of the Fund to the debentureholders who had not tendered their KMS Debentures to the Take-over Bid. KMS ceased to be a reporting issuer effective August 12, 2004.

In October 2004, the Fund provided debt financing in the amount of $8.0 million (US$6.7 million) to Across America LFG LLC, a majority-owned subsidiary of a Fortune 500 company. Across America LFG LLC, through its subsidiaries, owns and manages the landfill gas collection systems which provide landfill gas to the LFG Facilities.

On November 12, 2004, Algonquin Power Operating Trust provided a subordinated acquisition debt facility (the “AirSource Acquisition Debt Facility”) of approximately $4.9 million to AirSource Power Fund I LP (“AirSource”) and a subordinated construction/term debt facility (the “St. Leon GP Construction Facility”) of approximately $64.4 million to St. Leon GP. AirSource subsequently completed an initial public offering of limited partnership units raising gross proceeds of approximately $65 million. AirSource used the net proceeds of the offering and the AirSource Acquisition Debt Facility to acquire the shares of St. Leon GP and the limited partnership interests of St. Leon LP, with the balance being used, in part, to finance construction of the St. Leon Facility near St. Leon, Manitoba. See “General Development of the Business - Other Developments in Fiscal 2005” and “General Development of the Business - Other Developments in Fiscal 2006”.

Acquisitions of Facilities in Fiscal 2005

In January 2005, the Fund, AWRA and certain of its subsidiaries entered into a purchase and sale agreement to acquire all the assets used in the operation of eight water distribution and wastewater facilities from Silverleaf Resorts, Inc. The facilities, which in aggregate serve approximately 5,000 equivalent residential connections, are located in Texas, Missouri and Illinois. The acquisition of the five Texas and Illinois facilities, was completed on March 11, 2005 for a cash consideration of $11.2 million (US$9.4 million). On August 14, 2005, the Fund received approval from the regulator in the state of Missouri and completed the acquisition of the three Missouri facilities for a cash consideration of $4.6 million (US$3.8 million).

On September 21, 2005, the Fund purchased the Beaver Falls Hydro Plant, a 2.5 MW hydro electric generating station located in Beaver Falls, New York, for cash consideration of $1.0 million (US$0.8 million). Electrical energy produced by the facility is sold to National Grid (formerly Niagara Mohawk) under a power purchase agreement which expires in 2019.
On December 13, 2005, the Fund completed the acquisition of all of the issued and outstanding shares of Rio Rico Utilities Inc., which owns the Rio Rico Facility, for $10.2 million (US$8.8 million). The Rio Rico Facility provides water distribution and wastewater services to approximately 5,400 residential water customers and 1,800 residential wastewater customers in the town of Rio Rico, Arizona. The town of Rio Rico serves as a bedroom community for the City of Tucson and the City of Nogales, approximately 20 kilometres north of the Mexico-US border. The town of Rio Rico has been growing at an average annual rate of approximately nine percent (9%) over the past few years and this growth is expected to continue in the coming years.

<table>
<thead>
<tr>
<th>Facility</th>
<th>Purchase Price (in thousands)</th>
<th>Nature of Acquisition</th>
<th>Date of Acquisition</th>
</tr>
</thead>
<tbody>
<tr>
<td>Water and wastewater systems facilities (Texas and Illinois)</td>
<td>$11,200</td>
<td>Assets</td>
<td>March 11, 2005</td>
</tr>
<tr>
<td>Water and wastewater systems facilities (Missouri)</td>
<td>$4,600</td>
<td>Assets</td>
<td>August 14, 2005</td>
</tr>
<tr>
<td>Beaver Falls Facility</td>
<td>$1,000</td>
<td>Assets</td>
<td>September 21, 2005</td>
</tr>
<tr>
<td>Rio Rico Facility</td>
<td>$10,200</td>
<td>Shares</td>
<td>December 13, 2005</td>
</tr>
<tr>
<td><strong>Total</strong></td>
<td><strong>$27,000</strong></td>
<td></td>
<td></td>
</tr>
</tbody>
</table>
option of immediately exchanging their Exchangeable Units and receiving Trust Units for their AirSource Units under the AirSource Offer.

An aggregate of 6,003,910 AirSource Units, representing approximately 92.4% of the outstanding AirSource Units, were deposited in acceptance of the AirSource Offer and were taken up and paid for by AAP LP. A total of 3,863,554 Exchangeable Units and a total of 2,099,255 Trust Units were delivered by AAP LP pursuant to the AirSource Offer. Pursuant to the compulsory acquisition provisions of the AirSource limited partnership agreement, on August 10, 2006, AAP LP acquired the remaining 496,090 AirSource Units not already acquired by AAP LP pursuant to the AirSource Offer.

As of June 17, 2006, the St. Leon Facility achieved commercial operation status under the power purchase agreement with Manitoba Hydro. However, certain issues are still outstanding between St. Leon GP and Vestas-Canadian Wind Technology, Inc. (“Vestas”) pursuant to the turn-key construction contract dated November 12, 2004 (the “Vestas Contract”), including St. Leon GP’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 Vestas 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 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 Vestas Contract and which security, in the opinion of the Fund, will be sufficient to address any amounts proven to be properly due and owing by Vestas to St. Leon GP under the Vestas Contract.

Under the Senior Debt Facility, the conditions precedent to conversion of the construction financing to a term credit facility included Vestas achieving commercial operation of the St. Leon Facility under the Vestas Contract on or before September 30, 2006. As a result of the ongoing issues with Vestas described above, such commercial operation had been delayed and St. Leon Trust received a waiver from such senior lenders deferring such requirement until October 31, 2006. Through further discussions with such senior lenders, St. Leon Trust obtained an amendment to the Senior Debt Facility credit agreement to remove the requirement of achieving commercial operation of the St. Leon Facility as a condition precedent to such conversion, and a deemed conversion of the Senior Debt Facility to a term credit facility has now occurred (“Term Conversion”). Such amendment provides that if resolution of certain outstanding issues under the Vestas Contract is not achieved on or before the first anniversary of the date of the amendments, the lenders of the Senior Debt Facility may require that equity distributions derived from the St. Leon Facility be suspended.

Mr. Vito Ciciretto became Chief Operating Officer for the Fund with effect on July 31, 2006. Mr. Ciciretto is responsible for the overall operations of the Fund’s hydroelectric, cogeneration, alternative fuels and infrastructure divisions.

During the second quarter of 2006, the Fund renewed its revolving credit facility. The credit facility matures on August 28, 2008 and has a total credit limit of $175 million and includes a $20 million operating line. As of December 31, 2006, the Fund has drawn $67 million of the facility primarily to fund the Fund’s commitments to complete the St. Leon Facility.

The Fund announced on November 14, 2006 that it approved plans to retrofit the Sanger Facility with a General Electric LM6000 turbine, which is expected to result in substantial improvement and fuel affiance and facility output. The projected cost of the retrofit program is approximately $26.7 million (US$23 million) and construction is estimated to be completed by the fourth quarter of 2007.
Developments in Fiscal 2007

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 services 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 services and completing the regulatory hearings necessary to approve the transaction was US$950,000.

On March 16, 2007, Algonquin Power Trust commenced a formal take-over bid for all of the outstanding trust units of Clean Power in exchange for Trust Units on a one for 0.6152 basis plus a contingent 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 Clean Power trust unit. In addition, Algonquin Power Trust has made an offer to acquire all of the outstanding 6.75% convertible debentures issued by Clean Power in exchange for convertible debentures of the Fund.
DESCRIPTION OF THE BUSINESS

Notes:
(1) Notes and shares in Long Sault Rapids Facility provide 100% of cash flows up to 2013, 65% up to 2027 and 58% thereafter.
(2) Interest in Trafalgar Class B Note provides 100% of cash flows up to 2010 with a right to 75% of the equity value upon repayment.
(3) Interest in the Glenford Facility provides 100% of cash flows up to approximately 2023 after which the facility is owned by the Fund.
(4) 45% partnership interest in Rattlebrook Facility.
(5) Subject to the Manager's Interest.
(6) The following facilities are not wholly-owned by the Fund: Valley Power, Kirkland, Cochrane, Chapais, Brooklyn, Long Sault Rapids, Trafalgar, Glenford and Rattlebrook.
THE DEVELOPMENTS

As at March 30, 2007, the Fund owns, directly or indirectly, debt, equity and royalty and other interests in 66 power generation facilities including those identified in “Other Interests in Energy Related Developments” and 17 regulated water distribution and wastewater facilities. For the year ended December 31, 2006, the Fund derived approximately 75.3% of its revenues from its interests in power generation facilities (75.9% in 2005), 7.1% of its revenues from waste disposal fees (7.3% in 2005) and 17.6% of its revenues from its interests in regulated water distribution and wastewater facilities (15.8% in 2005).

Power Development

<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2007 Power Purchase Rates(1)</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
<th>Year of Expiry of Lease</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Ontario Developments</strong></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Facility:</strong> Long Sault Rapids Facility (Hydroelectric)</td>
<td>18,000</td>
<td>Abitibi River near Cochrane, Ontario</td>
<td><strong>Electricity Purchaser:</strong> OEFC</td>
<td>119,499</td>
<td>2047</td>
<td>2048</td>
</tr>
<tr>
<td><strong>Owner:</strong> Algonquin Power (Long Sault) Partnership and N-R Power Partnership</td>
<td></td>
<td></td>
<td><strong>Rates:</strong></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>Summer Energy $0.04232/kW-hr</td>
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<td></td>
<td></td>
<td></td>
<td>Summer Capacity $0.06536/kW-hr</td>
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<td></td>
<td>Winter Energy $0.05182/kW-hr</td>
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<td></td>
<td></td>
<td></td>
<td>Winter Capacity $0.08632/kW-hr</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Facility:</strong> Hurdman Dam Facility (Hydroelectric)</td>
<td>570</td>
<td>Mattawa River near Mattawa, Ontario</td>
<td><strong>Electricity Purchaser:</strong> Hydro One Inc.</td>
<td>4,429</td>
<td>2015</td>
<td>2015</td>
</tr>
<tr>
<td><strong>Owner:</strong> Algonquin Canada</td>
<td></td>
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<td><strong>Rates:</strong></td>
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<td></td>
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<td></td>
<td>Paid on Hourly Spot Market Price – blended rate of approximately $0.05/kWhr</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Facility:</strong> Drag Lake Dam Facility(2) (Hydroelectric)</td>
<td>220</td>
<td>Trent River near Haliburton, Ontario</td>
<td><strong>Electricity Purchaser:</strong> OEFC</td>
<td>0</td>
<td>2012</td>
<td>Owned</td>
</tr>
<tr>
<td><strong>Previous Owner:</strong> Algonquin Canada(2)</td>
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<td><strong>Rates:</strong></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>Winter Peak $0.09343/kW-hr</td>
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<td>Winter Off-Peak $0.03797/kW-hr</td>
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<td></td>
<td>Summer Peak $0.07573/kW-hr</td>
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<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/2007 Power Purchase Rates(1)</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
<td>Year of Expiry of Power Purchase Agreement</td>
<td>Year of Expiry of Lease</td>
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</tbody>
</table>
| Facility: Burgess Dam Facility (Hydroelectric) Owner: Algonquin Canada | 140 | Muskoka River near Bala, Ontario | **Electricity Purchaser:** OEFC | **Rates:**  
  Winter Peak $0.0809/kW-hr  
  Winter Off-Peak $0.0319/kW-hr  
  Summer Peak $0.0752/kW-hr  
  Summer Off-Peak $0.0228 kW-hr | 932 | 2009 | Month to Month Lease (3) |
| Facility: Campbellford Facility (Hydroelectric) Owner: Algonquin Power (Campbellford) Limited Partnership(7) | 4,000 | Trent River near Campbellford, Ontario | **Electricity Purchaser:** OEFC | **Rates:**  
  Winter On-Peak $0.0961/kW-hr  
  Winter Off-Peak $0.0373/kW-hr  
  Summer On-Peak $0.0797/kW-hr  
  Summer Off-Peak $0.0326/kW-hr | 27,834 | 2019 | 2019 |

**Québec Developments**

| Facility: Saint-Alban Facility (Hydroelectric) Owner: SLT(8) | 8,200 | Ste-Anne River near the Village of Saint-Alban, Québec | **Electricity Purchaser:** Hydro-Québec | **Rates:**  
  $0.0676/kW-hr (Jan-Nov)  
  $0.0696/kW-hr (Dec) | 37,260 | 2016 | 2016 |
| Facility: Glenford Facility (Hydroelectric) Owner: Glenford Partnership | 4,950 | Ste-Anne River near the Village of Ste-Christine d’Auvergne, Québec | **Electricity Purchaser:** Hydro-Québec | **Rates:**  
  $0.0676/kW-hr (Jan-Nov)  
  $0.0696/kW-hr (Dec) | 24,593 | 2020 | Owned |
<table>
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<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2007 Power Purchase Rates(^{(1)})</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
<th>Year of Expiry of Lease</th>
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</thead>
</table>
| **Facility:** Rawdon Facility (Hydroelectric) | 2,500 | Ouareau River near the Village of Rawdon, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
$0.0676/kW-hr (Jan-Nov)  
$0.0696/kW-hr (Dec) | 13,900 | 2014 | 2014 |
| **Owner:** Algonquin Canada | | | | | | |
| **Facility:** Côte Ste-Catherine Facility (Hydroelectric) | 11,120 | St. Lawrence River near the Town of Ste.-Catherine, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
Phase I  
Energy $0.05298/kW-hr  
Phase II  
Energy $0.057677/kW-hr  
Capacity $141.55/kilowatt (over the average kilowatt output over the period December to March)  
Phase III  
Energy $0.06005/kW-hr  
Capacity $148.42/kilowatt (over the average kilowatt output over the period December to March) | Phase I: 15,507  
Phase II: 35,112  
Phase III: 34,768 | Phase I: 2009  
Phase II: 2018  
Phase III: 2021 | 2009 |
| **Owner:** Algonquin Power (Mont-Laurier) Limited Partnership | | | | | | |
| **Facility:** Ste-Raphaël Facility (Hydroelectric) | 3,500 | Rivière de Sud near Québec City, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
$0.0676/kW-hr (Jan-Nov)  
$0.0696/kW-hr (Dec) | 22,158 | 2014 | 2013 |
| **Owner:** Algonquin Canada | | | | | | |
| **Facility:** Mont Laurier Facility (Hydroelectric) | 2,725 | Rivière-du-Lièvre in the Town of Mont Laurier, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:**  
$0.0676/kW-hr (Jan-Nov)  
$0.06/kW-hr (Dec) | 20,824 | November 2007 | 2023 |
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<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2007 Power Purchase Rates(^{(1)})</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
<th>Year of Expiry of Lease</th>
</tr>
</thead>
</table>
| **Facility:** Rivière-du-Loup Facility (Hydroelectric)  
**Owner:** Algonquin Canada | 2,600 | Rivière-du-Loup near the Town of Rivière-du-Loup, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:** $0.0676/kW-hr (Jan-Nov) $0.0696/kW-hr (Dec) | 16,059 | 2015 | 2015 |
| **Facility:** Hydraska Facility (Hydroelectric)  
**Owner:** Algonquin Power Trust | 2,250 | Yamaska River near the Town of St.-Hyacinthe, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:** Summer Energy $0.05685/kW-hr  
Winter Energy $0.10425/kW-hr | 9,910 | 2014 | 2014 |
| **Facility:** Ste-Brigitte Facility (Hydroelectric)  
**Owner:** Algonquin Canada | 4,200 | Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:** $0.0676/kW-hr (Jan-Nov) $0.0696/kW-hr (Dec) | 12,367 | 2014 | Owned |
| **Facility:** Belleterre Facility (Hydroelectric)  
**Owner:** Algonquin Canada | 2,200 | Winneway River in the Municipality of Laforce, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:** Summer Energy: $0.05635/kW-hr  
Winter Energy: $0.10316/kW-hr  
Capacity: $139.27/kilowatt (over the average kilowatt output over the period December to March) | 14,743 | 2013 | 2011 |
| **Facility:** Donnacona Facility (Hydroelectric)  
**Owner:** | 4,800 | Jacques Cartier River near Donnacona, Québec | **Electricity Purchaser:** Hydro-Québec  
**Rates:** $0.0676/kW-hr (Jan-Nov) $0.0696/kW-hr (Dec) | 20,970 | 2022 | 2017 |
<table>
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<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2007 Power Purchase Rates(^{(1)})</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
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<th>Year of Expiry of Lease</th>
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<tbody>
<tr>
<td>Donnacona Partnership</td>
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<tr>
<td><strong>Facility:</strong> St. Raphaël de Bellechasse Facility (Arthurville) (Hydroelectric) <strong>Owner:</strong> Algonquin Power Trust</td>
<td>650</td>
<td>Riviere du Sud downstream from Ste-Raphaël</td>
<td><strong>Electricity Purchaser:</strong> Hydro-Québec</td>
<td>2,782</td>
<td>2013</td>
<td>Owned</td>
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<tr>
<td><strong>Facility:</strong> Rattle Brook Facility (Hydroelectric) <strong>Owner:</strong> Rattlebrook Partnership</td>
<td>4,000</td>
<td>Rattle Brook near Jackson’s Arm, Newfoundland</td>
<td><strong>Electricity Purchaser:</strong> Newfoundland and Labrador Hydro</td>
<td>17,470</td>
<td>2024</td>
<td>2048</td>
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<tr>
<td><strong>Facility:</strong> Ogdensburg Facility (Hydroelectric) <strong>Owner:</strong> Trafalgar(^{(9)})</td>
<td>3,675</td>
<td>Oswegatchie River near Ogdensburg, New York</td>
<td><strong>Electricity Purchaser:</strong> National Grid</td>
<td>10,596</td>
<td>2007</td>
<td>2038</td>
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<tr>
<td><strong>Facility:</strong> Forestport Facility (Hydroelectric) <strong>Owner:</strong> Trafalgar(^{(9)})</td>
<td>3,300</td>
<td>Black River near Boonville, New York</td>
<td><strong>Electricity Purchaser:</strong> National Grid</td>
<td>10,016</td>
<td>2007</td>
<td>Owned</td>
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<tr>
<td><strong>Facility:</strong> Herkimer Facility (Hydroelectric) <strong>Owner:</strong></td>
<td>1,680</td>
<td>West Canada Creek near Herkimer, New York</td>
<td><strong>Electricity Purchaser:</strong> National Grid</td>
<td>0(^{(6)})</td>
<td>2007</td>
<td>Owned</td>
</tr>
<tr>
<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/ 2007 Power Purchase Rates&lt;sup&gt;(1)&lt;/sup&gt;</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
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<tr>
<td>Trafalgar&lt;sup&gt;(9)&lt;/sup&gt;</td>
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<tr>
<td>Facility: Christine Falls Facility (Hydroelectric)</td>
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<tr>
<td>Owner: Christine Falls Corporation&lt;sup&gt;(9)&lt;/sup&gt;</td>
<td>850 Sacandaga River near Clifton, New York</td>
<td>Electricity Purchaser: National Grid</td>
<td>3,065</td>
<td>2028</td>
<td>Owned</td>
<td></td>
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<tr>
<td>Facility: Cranberry Lake Facility (Hydroelectric)</td>
<td>500 Oswegatchie River near Clifton, New York</td>
<td>Electricity Purchaser: National Grid</td>
<td>2,154</td>
<td>2025</td>
<td>2035</td>
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<tr>
<td>Owner: Trafalgar&lt;sup&gt;(9)&lt;/sup&gt;</td>
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<tr>
<td>Facility: Kayuta Lake Facility (Hydroelectric)</td>
<td>400 Black River near Boonville, New York</td>
<td>Electricity Purchaser: National Grid</td>
<td>0&lt;sup&gt;(6)&lt;/sup&gt;</td>
<td>2028</td>
<td>Owned</td>
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<tr>
<td>Owner: Trafalgar&lt;sup&gt;(9)&lt;/sup&gt;</td>
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<tr>
<td>Facility: Adams Facility (Hydroelectric)</td>
<td>350 Sandy Creek near Adams, New York</td>
<td>Electricity Purchaser: National Grid</td>
<td>0&lt;sup&gt;(6)&lt;/sup&gt;</td>
<td>2028</td>
<td>Owned</td>
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<tr>
<td>Owner: Trafalgar&lt;sup&gt;(9)&lt;/sup&gt;</td>
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<tr>
<td>Facility: Kings Falls Facility (Hydroelectric)</td>
<td>1,750 Deer River near Copenhagen, New York</td>
<td>Electricity Purchaser: National Grid</td>
<td>3,680</td>
<td>2009</td>
<td>Owned</td>
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<tr>
<td>Owner: Tug Hill Energy Inc.&lt;sup&gt;(10)&lt;/sup&gt;</td>
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<tr>
<td>Facility: Otter Creek Facility (Hydroelectric)</td>
<td>530 Otter Creek in Craig, New York</td>
<td>Electricity Purchaser: National Grid</td>
<td>1,944</td>
<td>2009</td>
<td>Owned</td>
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<td>Owner:</td>
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<td>Generating Facility/Owner</td>
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<td>Tug Hill Energy Inc.(^{(10)})</td>
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<tr>
<td>Owner: Oswego Hydro Partners L.P.(^{(10)})</td>
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<td>Owner: Oswego Hydro Partners L.P.(^{(10)})</td>
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<tr>
<td>Owner: Algonquin Power (Beaver Falls) LLC</td>
<td>Owner: Algonquin Power (Beaver Falls) LLC</td>
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<td>Owner: Hollow Dam Partnership</td>
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<tr>
<td>Facility: Gregg’s Falls Facility  (Hydroelectric)</td>
<td>Facility: Gregg’s Falls Facility  (Hydroelectric)</td>
<td>Facility: Gregg’s Falls Facility  (Hydroelectric)</td>
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<td>Generating Facility/Owner</td>
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<td>Annual Average Expected Energy Production (MW-hrs)</td>
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<tr>
<td>Facility: Pembroke Facility (Hydroelectric) Owner: Pembroke Hydro Associates Limited Partnership(^{(11)})</td>
<td>2,600</td>
<td>Suncook River near the Town of Pembroke, New Hampshire</td>
<td>Electricity Purchaser: PSNH Rates: US$ 0.058/kW-hr (est) (^{(5)})</td>
<td>8,272</td>
<td>60 day written notice</td>
<td>Owned</td>
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<tr>
<td>Facility: Clement Facility (Hydroelectric) Owner: Clement Dam Hydroelectric LLC (^{(12)})</td>
<td>2,400</td>
<td>Winnepisauhee River near the Town of Tilton, New Hampshire</td>
<td>Electricity Purchaser: PSNH Rates: US$0.058/kW-hr (est) (^{(5)})</td>
<td>11,288</td>
<td>60 day written notice</td>
<td>2032</td>
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<tr>
<td>Facility: Franklin Facility (Hydroelectric) Owner: Franklin Power LLC (^{(10)})</td>
<td>River Bend 1,600 Steven’s Mill 200</td>
<td>Winnipesaukee River near the Town of Franklin, New Hampshire</td>
<td>Electricity Purchaser: PSNH Rates: River Bend US$0.058/kW-hr (est) (^{(5)}) Steven’s Mill US$0.058/kW-hr (est) (^{(5)})</td>
<td>River Bend 7,550 Steven’s Mill 1,020</td>
<td>60 day written notice – both sites</td>
<td>Owned</td>
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<tr>
<td>Facility: Lochmere Facility (Hydroelectric) Owner: HDI Partnership</td>
<td>1,200</td>
<td>Winnipesaukee River near Lochmere, New Hampshire</td>
<td>Electricity Purchaser: PSNH Rates: US$0.058/kW-hr (est) (^{(5)})</td>
<td>4,083</td>
<td>60 day written notice</td>
<td>2033</td>
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<td>Facility: Lower Robertson Facility (Hydroelectric) Owner: HDI III Partnership</td>
<td>960</td>
<td>Ashuelot River near Hinsdale, New Hampshire</td>
<td>Electricity Purchaser: PSNH Rates: US$0.058/kW-hr (est) (^{(5)})</td>
<td>3,729</td>
<td>60 day written notice</td>
<td>Owned</td>
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<tr>
<td>Facility: Ashuelot Facility (Hydroelectric)</td>
<td>900</td>
<td>Ashuelot River near Hinsdale, New</td>
<td>Electricity Purchaser: PSNH</td>
<td>3,629</td>
<td>60 day written notice</td>
<td>2040</td>
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<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/ 2007 Power Purchase Rates&lt;sup&gt;(4)&lt;/sup&gt;</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
<td>Year of Expiry of Power Purchase Agreement</td>
<td>Year of Expiry of Lease</td>
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<tr>
<td>Owner: HDI III Partnership</td>
<td>Hampshire</td>
<td>Rates: US$ 0.058/kW-hr (est) &lt;sup&gt;(5)&lt;/sup&gt;</td>
<td>2,650</td>
<td>60 day written notice</td>
<td>2032</td>
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<tr>
<td>Facility: Lakeport Facility (Hydroelectric)</td>
<td>600</td>
<td>Winnipesaukee River near Laconia, New Hampshire</td>
<td>Electricity Purchaser: PSNH</td>
<td>Rates: US$ 0.058/kW-hr (est) &lt;sup&gt;(5)&lt;/sup&gt;</td>
<td>1,834</td>
<td>60 day written notice</td>
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<tr>
<td>Owner: Lakeport Corporation&lt;sup&gt;(13)&lt;/sup&gt;</td>
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<tr>
<td>Facility: Avery Facility (Hydroelectric)</td>
<td>260</td>
<td>Winnipesaukee River near Laconia, New Hampshire</td>
<td>Electricity Purchaser: PSNH</td>
<td>Rates: US$ 0.058/kW-hr (est) &lt;sup&gt;(5)&lt;/sup&gt;</td>
<td>1,007</td>
<td>60 day written notice</td>
</tr>
<tr>
<td>Owner: Avery Dam Partnership</td>
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<tr>
<td>Facility: Hadley Falls Facility (Hydroelectric)</td>
<td>250</td>
<td>Piscataquoq River near Goffstown, New Hampshire</td>
<td>Electricity Purchaser: PSNH</td>
<td>Rates: US$ 0.058/kW-hr (est) &lt;sup&gt;(5)&lt;/sup&gt;</td>
<td>920</td>
<td>60 day written notice</td>
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<tr>
<td>Owner: Hadley Falls Partnership</td>
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<tr>
<td>Facility: Hopkinton Facility (Hydroelectric)</td>
<td>250</td>
<td>Contoocook River near Hopkinton, New Hampshire</td>
<td>Electricity Purchaser: PSNH</td>
<td>Rates: US$0.058/kW-hr (est) &lt;sup&gt;(5)&lt;/sup&gt;</td>
<td>6,166</td>
<td>60 day written notice</td>
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<tr>
<td>Owner: HDI Partnership</td>
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<tr>
<td>Facility: Milton Facility (Hydroelectric)</td>
<td>1,335</td>
<td>Salmon River near the Town of Milton, New Hampshire</td>
<td>Electricity Purchaser: PSNH</td>
<td>Rates: US$0.058/kW-hr (est) &lt;sup&gt;(5)&lt;/sup&gt;</td>
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<tr>
<td>Owner: SFR Hydro Corporation&lt;sup&gt;(13)&lt;/sup&gt;</td>
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<sup>(1)</sup> Includes estimates.

<sup>(2)</sup> Includes securities.

<sup>(3)</sup> Includes options.

<sup>(4)</sup> Includes long-term contracts.

<sup>(5)</sup> Includes short-term contracts.

<sup>(6)</sup> Includes power purchase agreements.

<sup>(7)</sup> Includes leases.

<sup>(8)</sup> Includes power purchase agreements and leases.

<sup>(9)</sup> Includes power purchase agreements and leases.

<sup>(10)</sup> Includes power purchase agreements and leases.

<sup>(11)</sup> Includes power purchase agreements and leases.

<sup>(12)</sup> Includes power purchase agreements and leases.

<sup>(13)</sup> Includes power purchase agreements and leases.

<sup>(14)</sup> Includes power purchase agreements and leases.

<sup>(15)</sup> Includes power purchase agreements and leases.
<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2007 Power Purchase Rates&lt;sup&gt;(1)&lt;/sup&gt;</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
<th>Year of Expiry of Lease</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Facility:</strong> Mine Falls Facility (Hydroelectric) &lt;br&gt; <strong>Owner:</strong> Mine Falls Limited Partnership&lt;sup&gt;(13)&lt;/sup&gt;</td>
<td>3,000</td>
<td>Nashua River near the City of Nashua, New Hampshire</td>
<td><strong>Electricity Purchaser:</strong> PSNH &lt;br&gt; <strong>Rates:</strong> US $ 0.058 / kW-hr (est)&lt;sup&gt;(5)&lt;/sup&gt;</td>
<td>10,717</td>
<td>60 day written notice</td>
<td>2024</td>
</tr>
<tr>
<td><strong>Facility:</strong> Great Falls Facility (Hydroelectric) &lt;br&gt; <strong>Owner:</strong> Great Falls Partnership</td>
<td>10,950</td>
<td>Passaic River near the City of Paterson, New Jersey</td>
<td><strong>Electricity Purchaser:</strong> Public Service Electric and Gas Company &lt;br&gt; <strong>Rates:</strong> US $ 0.052 / kW-hr (est)&lt;sup&gt;(5)&lt;/sup&gt;</td>
<td>19,322</td>
<td>60 day written notice</td>
<td>2021</td>
</tr>
<tr>
<td><strong>Facility:</strong> Worcester Facility (Hydroelectric) &lt;br&gt; <strong>Owner:</strong> Worcester Hydro Company, Inc.&lt;sup&gt;(10)&lt;/sup&gt;</td>
<td>180</td>
<td>Winnooskie River in Worcester, Vermont</td>
<td><strong>Electricity Purchaser:</strong> Vermont Power Exchange, Inc. &lt;br&gt; <strong>Rates:</strong> Winter On-Peak US$0.1573/kW-hr Winter Off-Peak US$0.0864/kW-hr Summer On-Peak US$0.0844/kW-hr Summer Off-Peak US$0.0386 / kW-hr Capacity Adder US$0.0192 / kW-hr</td>
<td>438</td>
<td>2016</td>
<td>Owned</td>
</tr>
<tr>
<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/2007 Power Purchase Rates$^{(1)}$</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
<td>Year of Expiry of Power Purchase Agreement</td>
<td>Year of Expiry of Lease</td>
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<tr>
<td>Facility: Moretown Facility (Hydroelectric)</td>
<td>1,200</td>
<td>Mad River near Moretown, Vermont</td>
<td>Electricity Purchaser: Vermont Power Exchange, Inc. Rates: Winter On-Peak US$0.1078/kW-hr Winter Off-Peak US$0.0682/kW-hr Summer On-Peak US$0.0978/kW-hr Summer Off-Peak US$0.0539/kW-hr Capacity Adder US$0.0243/kW-hr</td>
<td>2,778</td>
<td>2018</td>
<td>Owned</td>
</tr>
</tbody>
</table>

Western Canada Developments

| Facility: Dickson Dam Facility (Hydroelectric) | 15,000 | Innisfail, Alberta | Electricity Purchaser: TransAlta Utilities Corporation Rates: Energy: $0.0619/kW-hr | 67,248 | 2012 | 2030 |

| Facility: Valley Power Facility (Biomass) | 12,000 | Drayton Valley, Alberta | Electricity Purchaser: TransAlta Utilities Corporation Rates: Energy: $0.07093/kW-hr | 87,000 | 2014 | Owned |

Cogeneration Developments

<p>| Facility: Sanger Facility Facility (Cogeneration) | 43,500 | Sanger, California | Electricity Purchaser: Pacific Gas and Electric Company Rates: Winter: Oct - April PG&amp;E Avoided Cost US$ 0.09081/ kW-hr (estimated average)* Summer: May - Sept US$ 0.08663/ kW-hr | 91,000 | 2021 | Owned |</p>
<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2007 Power Purchase Rates(1)</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
<th>Year of Expiry of Lease</th>
</tr>
</thead>
</table>
| Facility: Windsor Locks Facility (Cogeneration) | 56,000 | Windsor Locks, Connecticut | (estimated average)*  
* subject to gas price indexing  
** Capacity Payment  
US$ 190 per kW/year up to 38,000 kW-hrs + bonus of 18%  
(80% earned May – Oct)  
Electricity Purchaser: Connecticut Light and Power Company  
Rates:  
CLP  
onpeak - US$0.09494/kW-hr *  
offpeak - US$0.07894/kW-hr *  
980 Rate – US$0.07215/kW-hr (estimated average)*  
Mill/NGC  
US$0.05838/kW-hr*  
Capacity $180,500**  
Steam - DNM/NGC  
US$8.71/1000lbs*  
Capacity $113,000**  
* Estimated average rate, includes variable component based on natural gas prices  
** Estimated average rate, charges are partially CPI indexed. | 393,000 | 2010 | 2018 |
| Facility: Crossroads Facility (Cogeneration) | 10,000 | Mahwah, New Jersey | Electricity Purchaser: N/A(15)  
Rates: N/A | N/A | N/A | N/A |
<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2007 Power Purchase Rates(1)</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
<th>Year of Expiry of Lease</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Wind Energy Development</strong></td>
<td></td>
<td></td>
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</tr>
<tr>
<td><strong>Facility:</strong> St. Leon Wind Energy (Wind)</td>
<td>99,000</td>
<td>St. Leon, Manitoba</td>
<td><strong>Electricity Purchaser:</strong> Manitoba Hydro-Electric Board</td>
<td>374,000</td>
<td>2025 + one 5 year extension</td>
<td>2043</td>
</tr>
<tr>
<td><strong>Owner:</strong> St. Leon Wind Energy LP</td>
<td></td>
<td></td>
<td><strong>Rates:</strong></td>
<td></td>
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<td></td>
<td>Dependable $ /kW-hr (average estimate)</td>
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<td></td>
<td>Non-dependable $ /kW-hr (average estimate)</td>
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<td></td>
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<td>Rates indexed annually to CPI in May.</td>
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<td></td>
<td>Wind Power Production Incentive $ 0.0100/kW-hr</td>
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<tr>
<td><strong>Thermal Developments</strong></td>
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</tr>
<tr>
<td><strong>Facility:</strong> Prima Deschecha (Landfill Gas)</td>
<td>6,100</td>
<td>San Juan Capistrano, California</td>
<td><strong>Electricity Purchaser:</strong> San Diego Gas &amp; Electric Company</td>
<td>40,000</td>
<td>2026</td>
<td>2027</td>
</tr>
<tr>
<td><strong>Owner:</strong> MM Prima Deschecha Energy LLC</td>
<td></td>
<td></td>
<td><strong>Rates:</strong></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>US$ 0.04894/kW-hr (average estimate)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td><strong>Facility:</strong> Tajiguas (Landfill Gas)</td>
<td>3,050</td>
<td>Goleta, California</td>
<td><strong>Electricity Purchaser:</strong> Southern California Edison</td>
<td>21,500</td>
<td>2027</td>
<td>2018</td>
</tr>
<tr>
<td><strong>Owner:</strong> MMTajiguas Energy LLC</td>
<td></td>
<td></td>
<td><strong>Rates:</strong></td>
<td></td>
<td></td>
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<tr>
<td></td>
<td></td>
<td></td>
<td>US$ 0.0710/kW-hr (average estimate)</td>
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<td></td>
<td></td>
<td></td>
<td>Rate on an annual escalating scale.</td>
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<tr>
<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/ 2007 Power Purchase Rates(1)</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
<td>Year of Expiry of Power Purchase Agreement</td>
<td>Year of Expiry of Lease</td>
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</tr>
<tr>
<td>Facility: Milliken (Landfill Gas)</td>
<td>2,520</td>
<td>Ontario, California</td>
<td>Electricity Purchaser: City of Riverside Municipal Utility</td>
<td>12,000</td>
<td>2008</td>
<td>2008</td>
</tr>
<tr>
<td>Owner: NM Milliken Genco LLC</td>
<td></td>
<td></td>
<td>Rates: US$ 0.05850/kW- hr + California Energy Credits until July 2008 - US$ 0.00675/kWh</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Mid-Valley (Landfill Gas)</td>
<td>2,520</td>
<td>Fontana, California</td>
<td>Electricity Purchaser: City of Riverside Municipal Utility</td>
<td>14,500</td>
<td>2008</td>
<td>2008</td>
</tr>
<tr>
<td>Owner: NM Mid Valley Genco LLC</td>
<td></td>
<td></td>
<td>Rates: US$ 0.05850/kW hr + California Energy Credits until April 2008 - US$ 0.00675/kWh</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Colton (Landfill Gas)</td>
<td>1,250</td>
<td>Colton, California</td>
<td>Electricity Purchaser: City of Colton Municipal Utility</td>
<td>6,500</td>
<td>2008</td>
<td>2008</td>
</tr>
<tr>
<td>Owner: NM Colton Genco</td>
<td></td>
<td></td>
<td>Rates: US$ 0.06210/kW-hr Rate on an annual escalating scale. California Energy Credits until April 2008 - US$ 0.00675/kWh</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Bordeaux (Landfill Gas)</td>
<td>1,900</td>
<td>Nashville, Tennessee</td>
<td>Electricity Purchaser: Metropolitan Government of Nashville &amp; Davidson County</td>
<td>0(6)</td>
<td>2007 + four 4 year extensions</td>
<td>2007 + four 4 year extensions</td>
</tr>
<tr>
<td>Owner: MM Nashville Energy LLC</td>
<td></td>
<td></td>
<td>Rates: US$ 0.03672/kW hr</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Facility: Balefill (Landfill Gas)</td>
<td>3,800</td>
<td>Kearney, New Jersey</td>
<td>Electricity Purchaser: PSE&amp;G Company</td>
<td>25,500</td>
<td>Month to month</td>
<td>2017</td>
</tr>
<tr>
<td>Owner: MM Hackensack Energy LLC</td>
<td></td>
<td></td>
<td>Rates: US$ 0.0580/kW-hr (average estimated market rate)</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Generating Facility/Owner</td>
<td>Generating Capacity (kilowatts)</td>
<td>Location</td>
<td>Electricity Purchaser/2007 Power Purchase Rates(^{(a)})</td>
<td>Annual Average Expected Energy Production (MW-hrs)</td>
<td>Year of Expiry of Power Purchase Agreement</td>
<td>Year of Expiry of Lease</td>
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</tr>
</tbody>
</table>
| **Facility:** Kingsland (Landfill Gas) **Owner:** MM Hackensack Energy LLC | 2,900 | North Arlington, New Jersey | **Electricity Purchaser:** PSE&G Company  
**Rates:** US$ 0.0580/kW-hr (average estimated market rate) | 13,000 | Month to month | 2017 |
| **Facility:** Four Hills (Suncook) (Landfill Gas) **Owner:** Suncook Energy LLC | 3,100 | Nashua, New Hampshire | **Electricity Purchaser:** New England Power  
**Rates:** Onpeak/Mid – US$ 0.04381  
Offpeak – US$ 0.03491  
**Electricity Purchaser:** Public Services of New Hampshire  
**Rates:** – US$ 0.0465 (est)  
Rate on an escalating scale | 17,000 | 2015 | 2024 |
| **Facility:** Burnsville (Landfill Gas) **Owner:** MM Burnsville Energy LLC | 4,210 | Burnsville, Minnesota | **Electricity Purchaser:** Excel Energy (formerly Northern State Power Company)  
**Rates:** US$ 0.0165/kW-hr (est)  
Excel Energy Avoided Cost  
Capacity payment - US$ 37,000 monthly (est) | 19,500 | 2015 | 2014 |
| **Facility:** Flying Cloud (Landfill Gas) **Owner:** Landfill Power LLC | 4,890 | Eden Prarie, Minnesota | **Electricity Purchaser:** Excel Energy  
**Rates:** US$ 0.0165/kW-hr (est)  
Excel Energy Avoided Cost + Capacity payment | 0\(^{(b)}\) | 2021 | 2024 |
<table>
<thead>
<tr>
<th>Generating Facility/Owner</th>
<th>Generating Capacity (kilowatts)</th>
<th>Location</th>
<th>Electricity Purchaser/ 2007 Power Purchase Rates(^1)</th>
<th>Annual Average Expected Energy Production (MW-hrs)</th>
<th>Year of Expiry of Power Purchase Agreement</th>
<th>Year of Expiry of Lease</th>
</tr>
</thead>
<tbody>
<tr>
<td><strong>Facility:</strong> EFW Facility (Energy from Waste)</td>
<td>10,100</td>
<td>Brampton, Ontario</td>
<td>Electricity Purchaser: OEFC</td>
<td>46,000</td>
<td>2012</td>
<td>Owned</td>
</tr>
<tr>
<td><strong>Owner:</strong> Algonquin Power Energy from Waste Inc.</td>
<td></td>
<td></td>
<td><strong>Rates:</strong> Winter Peak – US $0.09687/kW-hr Winter Offpeak – US $0.0373/kW-hr Summer Peak – US $0.08234/kW-hr Summer Offpeak – US $0.0326/kW-hr Tipping - Peel – US $84.84/tonne up to 127,900 tonnes, US $61.43 tonnes thereafter Other - US $145.00/tonne (average rate) Waste rates subject to monthly CPI indexing</td>
<td></td>
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<td></td>
</tr>
</tbody>
</table>

### Wastewater and Distribution Developments

<table>
<thead>
<tr>
<th>Utility</th>
<th>Owner(^{14})</th>
<th>Location</th>
<th>Type of Utility</th>
<th>December 31, 2006 Connections</th>
<th>Rates</th>
</tr>
</thead>
<tbody>
<tr>
<td>Black Mountain</td>
<td>Black Mountain Sewer Corporation</td>
<td>Carefree, Arizona</td>
<td>Wastewater</td>
<td>2,021</td>
<td>Residential US $45.64 (standard rate)</td>
</tr>
<tr>
<td>Gold Canyon</td>
<td>Gold Canyon Sewer Company</td>
<td>Gold Canyon Arizona</td>
<td>Wastewater</td>
<td>5,337</td>
<td>Residential US $35.00 (^{16}) (standard rate)</td>
</tr>
<tr>
<td>Bella Vista</td>
<td>Bella Vista Water Co., Inc.</td>
<td>Sierra Vista, Arizona</td>
<td>Water Distribution</td>
<td>8,009</td>
<td>Residential US $25.05 (Average rate)</td>
</tr>
<tr>
<td>Tall Timbers</td>
<td>Tall Timbers Utility Company, Inc.</td>
<td>Tyler, Texas</td>
<td>Wastewater</td>
<td>1,120</td>
<td>Residential US $40.08 (standard rate)</td>
</tr>
<tr>
<td>Utility</td>
<td>Owner(14)</td>
<td>Location</td>
<td>Type of Utility</td>
<td>December 31, 2006 Connections</td>
<td>Rates</td>
</tr>
<tr>
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</tr>
<tr>
<td>Woodmark</td>
<td>Woodmark Utilities, Inc.</td>
<td>Tyler, Texas</td>
<td>Wastewater</td>
<td>1,310</td>
<td>Residential US $40.00 (standard rate)</td>
</tr>
<tr>
<td>Litchfield Park</td>
<td>Litchfield Park Service Company</td>
<td>Litchfield, Park, Arizona</td>
<td>Wastewater</td>
<td>15,748</td>
<td>Residential US $27.20 Commercial US $46.00 US $21.98 (Average residential rate)</td>
</tr>
<tr>
<td>Fox River</td>
<td>AWRI</td>
<td>Sheridan, Illinois</td>
<td>Wastewater Water Distribution</td>
<td>219</td>
<td>US $240.08</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Wastewater Water Distribution</td>
<td>220</td>
<td>US $141.61</td>
</tr>
<tr>
<td>Timber Creek</td>
<td>AWRM</td>
<td>DeSoto, Missouri</td>
<td>Wastewater Water Distribution</td>
<td>24</td>
<td>US $6.00 min &amp; $7.57/1000 gal. (16) US $3.00 min &amp; US $3.02/1000 gal (16)</td>
</tr>
<tr>
<td>Holliday Hills</td>
<td>AWRM</td>
<td>Branson, Missouri</td>
<td>Water Distribution</td>
<td>478</td>
<td>US $3.00 min. &amp; US $3.02/1000 gal (16)</td>
</tr>
<tr>
<td>Ozark Mountain</td>
<td>AWRM</td>
<td>Kimberling City, Missouri</td>
<td>Wastewater Water Distribution</td>
<td>233</td>
<td>US $6.00 min &amp; $7.57/1000 gal. (16) US $3.00 min. &amp; US $3.02/1000 gal (16)</td>
</tr>
<tr>
<td>Holly Lake Ranch</td>
<td>AWRT</td>
<td>Big Sandy, Texas</td>
<td>Wastewater Water Distribution</td>
<td>151</td>
<td>US $68.39 min &amp; US $5.05/1000 gal. US $21.36 min. &amp; $1.94/1000 gal</td>
</tr>
<tr>
<td>Big Eddy</td>
<td>AWRT</td>
<td>Flint, Texas</td>
<td>Wastewater Water Distribution</td>
<td>345</td>
<td>US $68.39 min &amp; US $5.05/1000 gal. US $21.36 min. &amp; $1.94/1000 gal</td>
</tr>
<tr>
<td>Piney Shores</td>
<td>AWRT</td>
<td>Conroe, Texas</td>
<td>Wastewater Water Distribution</td>
<td>181</td>
<td>US $68.39 min &amp; US $5.05/1000 gal. US $21.36 min. &amp; $1.94/1000 gal</td>
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<tr>
<td>Hill Country</td>
<td>AWRT</td>
<td>New Braunfels, Texas</td>
<td>Wastewater Water Distribution</td>
<td>305</td>
<td>US $68.39 min &amp; US $5.05/1000 gal. US $21.36 min. &amp; $1.94/1000 gal</td>
</tr>
<tr>
<td>Utility</td>
<td>Owner(14)</td>
<td>Location</td>
<td>Type of Utility</td>
<td>December 31, 2006 Connections</td>
<td>Rates</td>
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</tr>
<tr>
<td>Rio Rico</td>
<td>Rio Rico Utilities Inc.</td>
<td>Rio Rico, Arizona</td>
<td>Wastewater, Water</td>
<td>1,997</td>
<td>US $56.36 (residential rates) US $6.45 min &amp; 0-4,000 gal – US $1.44/1,000 gal 4,001-10,000 gal – US $1.70/1,000 gal &gt;10,000 gal – US $1.90/1,000 gal</td>
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<td>Distribution</td>
<td>5,939</td>
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<tr>
<td>Northern Sunrise</td>
<td>Northern Sunrise Water Company Inc.</td>
<td>Sierra Vista, Arizona</td>
<td>Water</td>
<td>354</td>
<td>US $31.00 min &amp; 0-5,000 gal – US $2.00/1,000 gal 5,001-10,000 gal – US $2.75/1,000 gal &gt;10,000 gal – US $3.90/1,000 gal</td>
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<td>Distribution</td>
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<tr>
<td>Southern Sunrise</td>
<td>Southern Sunrise Water Company Inc.</td>
<td>Sierra Vista, Arizona</td>
<td>Water</td>
<td>842</td>
<td>US $31.00 min &amp; 0-5,000 gal – US $2.00/1,000 gal 5,001-10,000 gal – US $2.75/1,000 gal &gt;10,000 gal – US $3.90/1,000 gal</td>
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<td></td>
<td>Distribution</td>
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</tbody>
</table>

**Notes:**

1. 2007 power purchase rates have been rounded to four decimals and are not representative of long term power purchase rates under the applicable power purchase agreements. Long-term rates under different agreements will be both higher and lower than current rates. Seasonal periods and daily periods vary from project to project.
2. The Drag Lake Dam Facility was sold in January 2007 for nominal consideration.
3. No agreement has been obtained for a long-term lease; the current lease is on a month-to-month basis.
4. These rates reflect the estimated Avoided Costs of National Grid.
5. PSNH purchases the energy produced by these generating stations at the ISO-New England, Inc. market rates. These agreements are cancellable on 60 days written notice.
6. Offline for repairs in 2006. No decision has been made as to the timing of repairing this facility.
7. Algonquin Power (Campbellford) Limited Partnership is a limited partnership of which Algonquin Power Trust owns all of the Class B units as a limited partner, representing 50% of the equity of the partnership.
8. See "Material Facilities of the Fund - Hydroelectric - Saint-Alban Facility"
9. Under the Trafalgar Operations Contract, Algonquin Power provides Trafalgar and Christine Falls Corporation with certain operational services in respect of the Trafalgar Facilities.
10. This entity is a subsidiary of Algonquin America.
11. The partners of Pembroke Hydro Associates Limited Partnership are Algonquin America and Algonquin America Holdco.
12. The sole members of Clement Dam Hydroelectric LLC are Algonquin America and Algonquin America Holdco.
13. This entity is a subsidiary of the Fund.
14. Each of these entities are wholly-owned subsidiaries of AWRA.
15. In December, 2006, the Fund exercised the buy-down option of the Power Purchase Agreement at the Crossroads Facility.
16. Authorized rates and tariffs are subject to a rate case adjustment expected in the 2nd quarter of 2007.
The Fund also has notes receivable and equity in companies which own four generating facilities. See “Other Interests in Energy-Related Developments”.

Material Facilities of the Fund

The Fund has a direct or indirect interest in the following facilities, which could be viewed as being material to the Fund, with the cash flow generated from such facilities accounting for 0.75% or more of distributable cash.

Hydroelectric

Long Sault Rapids Facility – Abitibi River, near the Town of Cochrane, Ontario

The Long Sault Rapids Facility is an 18,000 kilowatt hydroelectric generating facility located on the Abitibi River, 19 kilometres north of the Town of Cochrane, in northern Ontario. The facility was commissioned on April 1, 1998.

The facility was developed by a joint venture between Algonquin Power (Long Sault) Partnership and N-R Power Partnership. The facility is owned by the Co-Owners as tenants-in-common and not as joint tenants, with the Co-Owners each having an undivided 50% interest in the facility. The partners in the Algonquin Power (Long Sault) Partnership, Algonquin Power (Long Sault) Corporation Inc. and Energy Acquisition (Long Sault) Ltd., are wholly-owned subsidiaries of Algonquin Power. The partners in the N-R Power Partnership are Nicholls Holdings Inc. and Radtke Holdings Inc., companies controlled by two independent businessmen. There are two non-recourse loans outstanding which are secured against the facility and the Co-Owners’ interest therein (see “Hydroelectric – Long Sault Rapids Facility – Credit Agreements” below).

The facility is a run-of-the-river facility. The powerhouse is an integrated structure, housing four 4,500 kilowatts pit turbine generating units.

Power Purchase Agreement

Pursuant to the terms of the power purchase agreement, the Co-Owners sell power produced by the facility exclusively to OEFC. The power purchase agreement terminates 50 years from the commercial in-service date, April 1, 1998, and may be renewed for a further term upon request by either party on terms and conditions to be mutually agreed. The rates are escalated annually based on an index figure tied to the greater of OEFC’s Total Market Cost index (a minimum of 1% to a maximum of 8%).

The Co-Owners will not receive a monthly capacity payment unless the facility delivers an average of at least 1,800 kilowatts of power to OEFC during at least 85% or more of the On-peak period fifteen minute intervals for that month. Monthly energy in excess of 115% of target generation is subject to an additional payment.

Waterpower Lease

The waterpower lease with the Province of Ontario in respect of the dam site expires in 2048. The lease provides for an annual land rental and an annual water rental charge. The water rental charge will not commence until 2008.
Co-Owners Agreement and Management Agreement

The Co-Owners have entered into an agreement concerning, among other things, their holding of undivided interests in the facility. Upon the occurrence of specified events of default, the non-defaulting Co-Owner may purchase the defaulting Co-Owner’s interest for 90% of the fair market value. The Co-Owners have entered into a management agreement with NR-Algonquin Energy Management Inc. to manage the facility on their behalf for nominal consideration.

Credit Agreements

There is an outstanding senior loan against the facility in the amount of $42.4 million at December 31, 2006. The loan was provided by a syndicate comprised of The Clarica Life Insurance Company ("Clarica"), The Canada Life Assurance Company and The Maritime Life Assurance Company. Clarica acts as agent for the syndicate. The loan has a term of 30 years, maturing in December 2028 and bears interest at an interest rate of 10.16% for the first 15 years and 10.21% thereafter, compounded annually. Blended payments of principal and interest are made monthly. The loan is non-recourse and is secured by the facility and the ownership interests therein.

Under the terms of the credit agreement, a debt reserve is required. At December 31, 2006, the debt reserve was fully funded and contained a balance of $1.3 million.

The LSR Subordinate Note is also an outstanding loan against the facility which the Fund currently owns.

Saint-Alban Facility – Ste-Anne River near the Village of Saint-Alban, Quebec

The Saint-Alban Facility is an 8,200 kilowatt hydroelectric generating facility located on the Ste-Anne River approximately one kilometre from the Village of Saint-Alban, Québec and approximately 200 kilometres east of Montréal. The facility consists of a newly gated spillway and the existing dam and spillway, which were rehabilitated and reconditioned in 1996, two penstocks, a powerhouse structure and a tailrace canal and has been designed as a run-of-the-river facility.

Land and Water Rights

The land upon which the facility is located is currently owned by the Government of Québec. Certain hydraulic rights previously owned by Shawinigan Electric Company, a wholly-owned subsidiary of Hydro-Québec, were acquired during 2006. The Government of Québec entered into a 20 year lease agreement with SLI. The lease agreement will expire in 2016 and will be retroactive to the commissioning date of the facility in 1996.

In addition to contractual lease payments and other amounts payable to the Government of Québec, an annual royalty is payable in respect of the Saint-Alban municipal park.

The Government of Québec has approved the transfer of the leasehold interests from SLI to Algonquin Canada. Acquisition of legal title to this facility is expected to be completed in 2007 once the leasehold interests are properly registered with the Government of Quebec.

Glenford Facility – Ste-Anne River near the Village of Ste-Christine d’Auvergne, Quebec

The Glenford Facility is a 4,950 kilowatt hydroelectric generating facility located on the Ste-Anne River approximately one kilometre from the Village of Ste-Christine d’Auvergne, Québec and
approximately 230 kilometres east of Montréal. The facility consists of the existing dam and spillway, which were rehabilitated and reconditioned in 1995, an intake, powerhouse and tailrace structure and has been designed as a run-of-the-river facility. The Glenford Facility is owned by the Glenford Partnership. The Fund indirectly holds the Glenford Subordinate Note, which is an outstanding loan against the facility.

Land and Water Rights

The Glenford Facility has been constructed on certain lands purchased by the Glenford Partnership. The land owned by the Glenford Partnership includes the bed of the river upon which the existing dam structure is located and certain lands on either side of the river. Accordingly, no lease from the Province of Québec is required.

Credit Agreement

The Glenford Senior Debt is an outstanding senior loan provided to the Glenford Partnership in the amount of $5.2 million at December 31, 2006. The loan was provided by Corpfinance International Limited and has a term of 25 years which commenced in April 1995. The loan is to be repaid in equal monthly payments of $63,591 representing blended interest and principal during its term. The loan is secured solely by the facility and the ownership interests therein.

A hydrology reserve fund with a balance as at December 31, 2006 of $195,000 has been established to provide additional security in respect of the payment of interest and principal on the Glenford Senior Debt. Under the terms of the credit agreement, such reserve is required to be increased at the rate of 9% on an annual basis. A maintenance reserve fund with a balance as at December 31, 2006 of $63,000 has been established in respect of major capital expenditures which may be incurred by the Glenford Partnership.

Rawdon Facility – Ouareau River near the Village of Rawdon, Quebec

The Rawdon Facility is a 2,500 kilowatt hydroelectric generating facility located on the Ouareau River approximately one kilometre from the Village of Rawdon, Québec and approximately 70 kilometres north of Montréal. The facility consists of an existing dam (which was rehabilitated and reconditioned in 1986 by Hydro-Québec), intake, spillway, penstock, powerhouse and tailrace structure and has been designed as a run-of-the-river facility. The Rawdon Facility is owned by Algonquin Canada.

Land and Water Rights

The land upon which the facility is located and the hydraulic rights necessary for the operation of the facility are leased from the Ministry of Natural Resources, Québec pursuant to a 20 year lease agreement. The lease expires in June 2014 and includes a renewal option for an additional 20 year period, exercisable by the lessee upon mutually acceptable terms. The lease may be terminated by the Province of Québec upon, among other events, termination of the power purchase agreement for the facility with Hydro-Québec or transfer of the leasehold interest without approval of the landlord.

Saint-Alban, Glenford and Rawdon Power Purchase Agreements

The term of the power purchase agreements for each of the Rawdon Facility and the Saint-Alban Facility, respectively, is 20 years from the commercial start-up date and is 25 years from the commercial start-up date for the Glenford Facility. The power purchase agreements expire in 2014, 2016 and 2020 for the Rawdon, Saint-Alban and Glenford Facilities, respectively. The agreements may be renewed at
the option of the generator for a period not exceeding the original term upon mutually acceptable terms. See “Saint-Alban, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup, Donnacona and St. Raphaël de Bellechasse Power Purchase Agreements – General” below.

Côte Ste-Catherine Facility – St. Lawrence River near the Town of Ste-Catherine, Quebec

The Côte Ste-Catherine Facility is an 11,120 kilowatt hydroelectric generating facility located at the Côte Ste-Catherine lock of the Lachine section of the St. Lawrence Seaway. The bypass canal upon which the facility is located was constructed as part of the St. Lawrence Seaway in 1958. The facility has a total installed capacity of 11,120 kilowatts. The Côte Ste-Catherine Facility is owned by Algonquin Power (Mont-Laurier) Limited Partnership.

Land and Water Rights

The land and water rights necessary for the construction and operation of the Côte Ste-Catherine Facility have been obtained from the St. Lawrence Seaway Authority by way of a lease agreement dated March 1, 1988, as amended. The lease agreement will expire on February 28, 2009. The lease can be extended for an additional period of 21 years upon the lessee giving 6 months notice. Although the facility is located on a federal waterway, the Province of Québec has asserted jurisdiction over the water rights to this facility.

Ste-Raphaël Facility – Rivière de Sud, near Québec City, Quebec

The Ste-Raphaël Facility is a 3,500 kilowatt hydroelectric generating facility located on the Rivière de Sud approximately 60 kilometres east of Québec City, Québec. The Ste-Raphaël Facility is owned by Algonquin Canada.

Land and Water Rights

The land and hydraulic rights necessary for the operation of the facility have been leased from the Ministry of Natural Resources and the Ministry of Environment (Québec) pursuant to a lease agreement dated December 14, 1993. The lease will expire on December 14, 2013 and may be renewed for an additional period of 20 years at the option of the lessee upon terms imposed by the government.

Mont Laurier Facility – Rivière-du-Lièvre near the Town of Mont Laurier, Quebec

The Mont Laurier Facility is a 2,725 kilowatt hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec. The Mont Laurier Facility is owned by MTL Partnership.

Land and Water Rights

The facility is constructed on lands owned by MTL Partnership. Water rights necessary for the operation of the facility have been leased from the Ministry of Natural Resources (Québec) pursuant to a lease agreement dated March 23, 1988 and assigned to the MTL Partnership on October 31, 1994. The term of the lease expires on December 31, 2023.
**Rivière-du-Loup Facility – Town of Rivière-du-Loup, Québec**

The Rivière-du-Loup Facility is located on the Rivière-du-Loup in close proximity to the downtown section of the Town of Rivière-du-Loup, Québec. The total installed capacity of the plant is 2,600 kilowatts. The Rivière-du-Loup Facility is owned by Algonquin Canada.

**Land and Water Rights**

The land and hydraulic rights necessary for the operation of the facility have been leased from the Ministry of Natural Resources and the Ministry of the Environment (Québec) pursuant to a lease agreement dated November 20, 1997. The lease terminates on October 22, 2015. The lease can be extended for an additional period of 20 years at the option of the lessee upon terms imposed by the government.

**Côte Ste-Catherine, Ste-Raphaël, Mont Laurier and Rivière-du-Loup Power Purchase Agreements**

The term of the power purchase agreements for each of the Côte Ste-Catherine – Phase I, Ste-Raphaël, Mont Laurier and Rivière-du-Loup facilities, respectively, is 20 years from the commercial start-up date and is 25 years from the commercial start-up date for the Côte Ste-Catherine – Phase II and Côte Ste-Catherine – Phase III facilities. For the Côte Ste-Catherine Facility Phases I, II and III, the power purchase agreements expire in 2009, 2018 and 2021, respectively. The expiry dates for the power purchase agreements for the Mont Laurier, Ste-Raphaël, and Rivière-du-Loup facilities are 2007, 2014 and 2015, respectively. The agreements may be renewed at the option of the producer for a period not exceeding the original term upon terms imposed by Hydro-Québec. See “Saint-Alban, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup, Donnacona and St. Raphaël de Bellechasse Power Purchase Agreements – General” below.

**Donnacona Facility – Jacques Cartier River near the Town of Donnacona, Quebec**

The Donnacona Facility is a 4,800 kilowatt hydroelectric generating facility located on the lower portion of the Jacques Cartier River, near the Town of Donnacona, Québec. The Jacques Cartier River flows south and empties into the St. Lawrence River approximately 60 kilometres west of Québec City, Québec. The powerhouse houses eight identical 600 kilowatt turbine generators. The Donnacona Facility is owned by the Donnacona Partnership, of which all of the partnership interests are held directly or indirectly by Algonquin Canada.

**Power Purchase Agreement**

The power purchase agreement for the facility has a term of 25 years, expiring in 2022. The agreement may be renewed at the option of the Donnacona Partnership for a period not exceeding the original 25 year term upon terms to be negotiated. Hydro-Québec can veto the renewal, but only if the Donnacona Partnership is in default of a material term of the agreement. See “Saint-Albain, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup, Donnacona and St. Raphaël de Bellechasse Power Purchase Agreements – General” below.

**Land and Water Rights**

The facility is located on property owned by the Donnacona Partnership. In addition to the land, the existing dam structure, the bed of the Jacques Cartier River upstream of the facility and the natural hydraulic forces of that part of the river are owned by the Donnacona Partnership.
The Donnacona Partnership holds certain easements required to allow access to the dam and other structures located near the powerhouse.

The Donnacona Partnership has entered into a lease with the Province of Québec in respect of a section of the bed of the river upstream from the facility and water rights relating to the Jacques Cartier River necessary for the operation of the facility which expires on February 6, 2017. The lease includes a renewal option for an additional 20 year period, exercisable at the request of the Donnacona Partnership upon terms imposed by the Province of Québec.

Rights to all necessary lands have been obtained in order to operate and maintain the transmission line for the facility.

Saint-Alban, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup, and Donnacona Power Purchase Agreements - General

Each of the Saint-Alban, Glenford, Rawdon, Côte Ste-Catherine, Ste-Raphaël, Mont Laurier, Rivière-du-Loup, Donnacona and St. Raphaël de Bellechasse facilities have power purchase agreements with Hydro-Québec under which all power generated by the facilities is sold to Hydro-Québec. The standard Hydro-Québec power purchase agreement stipulates annual minimum energy production requirements in each contract year. Under most Hydro-Québec power purchase agreements, if a facility produces less energy than the minimum, a penalty is payable to Hydro-Québec. The facility can opt to reduce any energy production shortfall over a two year period using energy produced in excess of the minimum requirement, after which, a penalty is payable on any outstanding amounts at the current year prices.

Power purchase rates under the Hydro-Québec agreements (other than for the Mont Laurier and Côte Ste-Catherine (Phase I) Facilities) increase in accordance with the Consumer Price Index for the Montréal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%. The Mont Laurier Facility is subject to a maximum annual escalation of 5.2%. The Côte Ste-Catherine Facility (Phase I) is subject to a maximum annual escalation of 6%.

Dickson Dam Facility – Town of Innisfail, Alberta

The Dickson Dam Facility is located 20 kilometres west of the Town of Innisfail, Alberta. The Dickson Dam Facility is a 15.0 MW hydroelectric generating facility utilizing the infrastructure located at the Dickson Dam and powered by the waterflows of the Red Deer River. The facility consists of three horizontal Francis type turbines and was commissioned into commercial operation on January 16, 1992. The facility is owned by Algonquin Power Operating Trust.

Power Purchase Agreement

The Dickson Dam power purchase agreement was entered into with TransAlta Utilities Corporation (“TransAlta”) on December 7, 1990 and was approved by the Alberta Public Utilities Board on January 16, 1991. It has a term of 20 years ending on January 16, 2012. Under this agreement, TransAlta is obligated to accept delivery of all electricity in amounts up to 115% of the 12.7 MW capacity which is allocated to the facility at rates stipulated by the Small Power Act. The price paid by TransAlta during 2006 was $0.062/kw-hr.
Use of Works Agreement

The Dickson Dam Facility is subject to a Use of Works Agreement with the Government of Alberta under which it has the right to utilize available waterflows for generating power until March 31, 2030. The Use of Works Agreement provides certain rights in favour of the Minister of Environment (Alberta) in connection with the Minister’s water management objectives.

Phoenix Facility – Oswego River near the Town of Phoenix, New York

The Phoenix Facility is located on the Oswego River, in the Town of Phoenix, Onondaga County, New York. The facility is located at an 866 foot long concrete ogee spillway which is owned by New York State Thruway/Canal Corporation (the “NYSTA/CC”). It is a run-of-the-river facility and is rated at 3,500 kilowatts. The facility has two single regulated turbines. This facility is owned by Oswego Hydro Partners L.P., which is indirectly owned by the Fund.

Power Purchase Agreement

The original agreement was dated September 19, 1989, with a term commencing March 28, 1986. The agreement requires maintenance of an adjustment account based on the difference between the specified rate and 90% of the long run Avoided Costs.

Land and Water Rights

Oswego Hydro Partners L.P. holds certain permanent easements on land and buildings used by the facility. The Phoenix Facility is located at the Oswego Canal Lock No. 1 on the Oswego River. The dam, reservoir and navigation lock are owned by the State of New York and are operated and maintained by the NYSTA/CC.

Cogeneration

Sanger Facility – Sanger, California

The Sanger Facility is a 43.5 MW natural gas-fired generating facility located in Sanger, California. The Sanger Facility is a combined cycle generating station comprised of a 32 MW Westinghouse natural gas fired turbine and a 11.5 MW Westinghouse steam turbine, commissioned in 1991. The facility is owned by Algonquin Sanger Power, LLC, a subsidiary of Algonquin America.

On November 1, 2005, the Sanger Facility temporarily ceased delivering energy for a six month period during which the facility was entitled to lower capacity payments. During this period, the Sanger Facility entered into an agreement to resell the natural gas normally consumed by the facility at a more favourable fixed rate. This planned closure of the facility during the first four months of 2006 did not have a negative impact on distributable cash in 2006.
Power Purchase Agreement

Output of the facility is governed by the terms and conditions of a firm capacity and energy power purchase agreement with Pacific Gas and Electric Company ("PG&E"). The agreement has a term of 30 years, expiring in 2022, and calls for delivery of 38,000 kW of firm capacity.

The facility was not eligible to receive a capacity payment of approximately US$1.0 million during the period of the planned closure in 2006.

Fuel Supply

Natural gas for the facility was previously delivered under the terms of a gas supply agreement with Sempra Energy Trading Corp. which expired on July 31, 2006. The agreement provided for a fixed price for all quantities below a base amount. On August 1, 2006, Algonquin Sanger Power L.L.C. entered into an agreement with Constellation NewEnergy for the purchase and sale of all natural gas required for the facility. The expected gas requirement for the subsequent month is bought at the market rates available on the gas nomination date, which is typically the 20th day of each month. Excess gas above the nomination requirement is purchased at spot prices.

Energy Lease

Pursuant to a lease, energy supply and common services agreement with Dyna Fibers Inc., a wholly-owned subsidiary of Algonquin Sanger Power, LLC, Dyna Fibers Inc. leases a portion of the facility site in order to carry on its hydro mulch business and purchases certain energy at a cost equal to a percentage of the fuel costs incurred by the facility, to offset the incremental cost of fuel to supply such energy. The water consumption, exhaust heat and steam consumption by the hydro mulch operations are metered and recorded for FERC qualifying facility calculations that are submitted to PG&E on an annual basis.

Sanger Repowering

In 2006, the Fund approved a retrofit of the Sanger Facility with a General Electric LM6000 turbine. The retrofit is expected to result in substantial improvement and fuel affiance and facility output. The projected cost of the retrofit program is approximately $26.7 million (US$23 million), which includes a project supervision fee to the Manager of US$250,000. The project is continuing on schedule and budget with the retrofit scheduled for the last quarter of 2007 over an eight week period.

The turbine replacement will increase the facility’s capacity to approximately 56 MW. The increase in efficiency of the new unit will reduce the amount of natural gas used to generate electricity at the facility.

Windsor Locks Facility – Windsor Locks, Connecticut

The Windsor Locks Facility is a 56 MW (gross) natural gas-fired generating facility located in Windsor Locks, Connecticut. The Windsor Locks Facility is a combined cycle generating station comprised of a 40 MW General Electric natural gas fired turbine and a 16 MW General Electric steam turbine and was commissioned in 1990. The facility is owned by Algonquin Windsor Locks LLC, a subsidiary of Algonquin America.
Power Purchase Agreement

The majority of the output of the Windsor Locks Facility is governed by the terms and conditions of a power purchase agreement with Connecticut Light and Power Company. The agreement expires in April 2010. The agreement calls for delivery of 38 MW (summer) and 39 MW (winter) firm capacity.

Fuel Supply

Natural gas for the facility is delivered under a gas supply agreement with Yankee Gas Service Company. Gas is supplied by Yankee Gas at a percentage of its weighted average cost of gas for the month. The gas contract contains minimum annual consumption requirements with associated penalties for shortfalls.

Energy Services Agreement and Ground Lease

Pursuant to a ground lease and an energy services agreement with Ahlstrom Windsor Locks, LLC (“Ahlstrom”), Ahlstrom leases to Algonquin Windsor Locks, LLC the facility site and utilizes thermal steam energy and a portion of electrical generation of the Windsor Locks Facility for use at its specialty fibres composites mill located adjacent to the Windsor Locks Facility. Both the ground lease and the energy services agreement expire in January 2018, subject to certain early termination rights in favour of Ahlstrom and rights of renewal in favour of both parties. Payments under the energy services agreement are fully indexed to the cost of natural gas consumed by the facility.

Wind Energy

St. Leon Facility – St. Leon, Manitoba

The St. Leon Facility is a 99 MW wind energy facility located near St. Leon, Manitoba, 150 km southwest of Winnipeg. The facility is indirectly owned by AAP LP following completion of its takeover of AirSource (See “General Development of the Business – Other Developments in Fiscal 2006”).

As of June 17, 2006, the facility achieved commercial operation status under the power purchase agreement with Manitoba Hydro.

Power Purchase Agreement

St. Leon LP and St. Leon GP have entered into a power purchase agreement with Manitoba Hydro dated as of October 28, 2004 under which all electricity produced at the St. Leon Facility is sold to Manitoba Hydro. The term of the power purchase agreement is 20 years, with a price renewal term of up to an additional 5 years. Under the terms of the power purchase agreement, a reserve is required. As at December 31, 2006, the reserve was fully funded and contained a balance of $1.6 million. The facility has been approved to receive a wind power production incentive from the Federal Government of $10.00 per MW-hr.

Credit Facility

A banking syndicate has provided a senior loan to the St. Leon Trust in the amount of $73.3 million at December 31, 2006 to finance construction of the St. Leon Facility. The loan has a term of 5 years which commenced in October 2006. The senior loan bears interest at bankers acceptance rate plus a banking charge of 1%, payable quarterly. St. Leon Trust has entered into an interest rate swap
arrangement to fix the interest on the loan at 4.47%. The loan is secured solely by the facility and the ownership interests therein.

Algonquin Power Venture Fund Inc. ("APVF"), an Ontario labour sponsored venture capital corporation, has provided a subordinated loan to St. Leon GP in the amount of $1.6 million at December 31, 2006. Some of the directors and shareholders of the Manager are also directors, officers and shareholders of the manager of APVF. The loan has a term of 7 years which commenced in November 2004. The subordinated loan bears interest at 11.25% payable monthly. The loan is secured solely by the facility and the ownership interests therein. In January 2007, APVF provided a further $1.4 million in subordinated loans to St. Leon Trust. This subordinated loan bears interest at 9.75% per annum, payable monthly.

Algonquin Power Operating Trust has provided a $69.4 million subordinated debt facility to St. Leon Trust and a $4.9 million subordinated acquisition debt facility to AirSource. As at December 31, 2006, Algonquin Power Operating Trust has funded $35.1 million of the subordinated debt and provided letters of credit in an amount of $14.6 million. The subordinated loan bears interest at 10.739% payable monthly.

Under the terms of the St. Leon Trust Construction Facility, a debt reserve is required. As at December 31, 2006, the reserve was fully funded and contained a balance of $1.0 million.

Energy From Waste

EFW Facility – Brampton, Ontario

The EFW Facility is a 10.0 MW generating station located in Brampton, Ontario which produces electricity from incinerating non-recyclable materials, including municipal solid waste, using steam to drive a turbine generator to produce electricity. It is owned by Algonquin Power Energy from Waste Inc. (formerly KMS Peel Inc.), an Ontario corporation which is wholly-owned by KMS.

Power Purchase Agreement

The EFW Facility has entered into a power purchase agreement with OEFC which requires OEFC to purchase all the electricity produced by the facility. The power purchase agreement expires in 2012.

Fuel Supply

Under a “tip or pay” waste supply agreement with the Regional Municipality of Peel, the Regional Municipality supplies the facility with a minimum of 127,900 tonnes and up to 36,000 tonnes per year of acceptable municipal solid waste, respectively. The agreement expires in 2012. The Regional Municipality has the option to renew the agreement for an additional five-year term. The agreement requires the Regional Municipality to pay a “tipping fee” for each tonne of acceptable waste delivered, plus an additional fee for each tonne of acceptable waste delivered above the base amount. Additional volumes of waste may be supplied by the Regional Municipality at the request of either party, subject to the agreement of the other. The agreement provides that if certain taxes are imposed or revised standards are set for certain environmental or operating matters affecting the facility, the tipping fees paid by the Regional Municipality will be increased to reflect the increased capital or operating costs so imposed by the taxes or revised standards.
The EFW Facility also incinerates waste generated from international flights arriving at the Lester B. Pearson International Airport in Toronto, Ontario on a “tipping fee” basis.

**Landfill Gas Generation**

*Suncook Facility – Nashua, New Hampshire*

The Suncook Facility is a 3.1 MW landfill gas to electricity facility located in Nashua, New Hampshire. The facility uses two Caterpillar engine-generators. The facility was opened in 1997 and is eligible for certain emission tax credits until 2007. The facility also qualifies for Connecticut Renewable Energy Certificates. The facility is owned by Suncook Energy LLC which is indirectly owned by the Fund.

*Power Purchase Agreement*

The facility has power purchase agreements to sell approximately 70% of the energy generated to New England Power (“NEP”) and the remainder to Public Services of New Hampshire and produces 19.2 MW of energy annually. NEP has provided notice that it is exercising its right to terminate the agreement as of April 1, 2007. The Fund does not anticipate that the termination of the power purchase agreement will have a negative impact on distributable cash. The Agreement with Public Services of New Hampshire expires in 2015.

*Location Rights*

The facility is situated on a landfill that remains open and continues to accept waste. The facility’s lease with the City of Nashua, New Hampshire expires in 2024 or earlier, if the City advises that the landfill cannot produce commercially viable quantities of landfill gas.

**Water Distribution and Wastewater Developments**

*Black Mountain Facility – Carefree, Arizona*

The Black Mountain Facility was established in 1971 to support the development of the Boulders Resort and golf course. This resort is located ten miles north of Scottsdale, Arizona, in the town of Carefree, Arizona. The facility currently serves approximately 2,900 customers in the Town of Carefree. The Black Mountain Facility is owned by a wholly-owned subsidiary of AWRA.

The existing plant is located in the residential portion of the Boulders Resort, in the immediate vicinity of residences and the Boulders golf course. The plant owned by the utility treats 120,000 gallons per day and presently runs at capacity every day. The effluent produced by the plant is delivered by pipe to a lake on the Boulders golf course. The facility is an activated sludge plant and produces an effluent which exceeds quality standards for A+ effluent discharge and reuse and which is used for irrigation of the Boulders golf course and surrounding vegetation. Excess wastewater is delivered by pipe to the City of Scottsdale Wastewater Treatment Plant.

The Black Mountain facility completed a rate case in 2006 and received a tariff increase of 20%.

*Gold Canyon Facility – Gold Canyon, Arizona*

The Gold Canyon Facility was established in 1984 to serve a number of residential developments in the City of Gold Canyon area, approximately 25 miles east of downtown Phoenix, Arizona. The
facility currently serves over 5,300 residential customers. During 2005, the facility experienced a 1%
growth rate in the number of connections. The Gold Canyon Facility is owned by a wholly-owned
subsidiary of AWRA.

The treatment process is comprised of an extended aeration facility combined with a sequencing
batch reactor. The expansion of the facility from a capacity of 1.0 million gallons per day to 1.9 million
gallons per day was completed in October 2005. The facility is expected to ultimately serve
approximately 9,000 customers.

The facility is a consumptive re-use facility and sells its reclaimed A+ effluent for use as
irrigation water on five neighbouring golf courses. Excess reclaimed water is recharged, i.e. put back into
the ground to replenish underground water, via three recharge ponds. The treatment facility operates
under Arizona Department on Environmental Quality – Aquifer Protection Permits and Reuse Permits.

The Gold Canyon Facility initiated a rate case in 2006, requesting a tariff increase of
approximately 92%. It is anticipated that this process will be completed by the end of the second quarter
of 2007.

Bella Vista Facility – Town of Sierra Vista, Arizona

The Bella Vista Facility was formed in 1952 to serve a new motel and several small commercial
buildings developed in the Town of Sierra Vista, Arizona. The facility currently serves approximately
8,000 connected water customers and has experienced long term growth at the rate of 3% per year. The
Bella Vista Facility is owned by a wholly-owned subsidiary of AWRA.

All potable water supplied by the facility is obtained from deep well groundwater. There are 29
wells supplying the Bella Vista infrastructure and water from all wells is disinfected at the source prior to
distribution.

The Bella Vista Facility currently has outstanding indebtedness to the Water Infrastructure
Finance Authority evidenced by two 25 year fully amortizing notes. The first note, issued in 1995, bears
interest at the rate of 6.10% and has a remaining balance as at December 31, 2006 of US$127,000. The
other note bears interest at the rate of 6.26% and has an outstanding balance of US$1,729,000 as at
December 31, 2006.

The facility operates under a Certificate of Convenience and Necessity and is regulated by the
Arizona Corporation Commission.

Woodmark Facility – Tyler, Texas

The Woodmark Facility was formed in 1990 to serve a small subdivision under construction near
the City of Tyler, Texas, approximately 90 miles east of Dallas, Texas. The facility currently serves
1,300 connected customers with a capacity of 250,000 gallons/day. The facility experienced growth of
approximately 13% in 2006 and is considering plans to expand its plant capacity in 2008. The
Woodmark Facility is owned by a wholly-owned subsidiary of AWRA.

Litchfield Facility – West Valley of Maricopa County

The Litchfield Facility is a water distribution and wastewater facility located in the West Valley
of Maricopa County, 15 miles west of Phoenix, Arizona whose service area includes sections of the Cities
of Goodyear, Avondale and Litchfield Park, Arizona. According to the 2000 census data, Maricopa
County is the fastest growing county in the United States. The Litchfield Facility is owned by a wholly-owned subsidiary of AWRA.

The facility presently serves approximately 14,700 water and 15,700 wastewater customers with a capacity of 4.1 million gallons/day. During 2006, the facility experienced a 10% growth rate in the number of connections for water customers and an 11% growth rate in the number of connections for wastewater customers to the facility. The facility’s water infrastructure includes a total of nine active wells and a 6.3 million gallon reservoir which provides water to the current customer base through a single pressure zone. In April 2002, the facility completed construction and commissioning of a 4.2 million gallon per day wastewater facility. This facility now operates at 60% capacity and supplies Class “A+” effluent to a number of local golf courses in the area. The facility is considering plans to expand its plant capacity in 2008 with design to begin in 2007.

The Litchfield Facility currently has outstanding indebtedness to the City of Goodyear in the amount of US$13.2 million in respect of which the City of Goodyear has acted as a conduit issuer of a like amount of Industrial Development Authority bonds. The bonds consist of two series, both fully amortizing over a 30 year term. The first series was issued in 1999, has a principal amount as of December 31, 2006 of US$4.9 million bearing interest at the rate of 5.87%. The second series was issued in 2000 with a principal amount as of December 31, 2006 of US$8.3 million and bearing interest at the rate of 6.71%. As partial security for these bonds, the facility is required to hold funds in a restricted, interest bearing, investment account. The balance of this account at December 31, 2006 was US$1.2 million.

**Fox River Facility – LaSalle County, Illinois**

The Fox River Facility is a water distribution and wastewater facility located in LaSalle County, approximately 50 miles south-west of Chicago, Illinois, just outside the town of Sheridan, on the banks of the Fox River. The facility primarily serves the Fox River Resort, a timeshare oriented operation consisting of approximately 220 equivalent water distribution and wastewater connections.

The facility is owned by a wholly-owned subsidiary of AWRA. Currently, only half of the available acreage in the area is developed and the water storage and wastewater treatment plant can accommodate a doubling of demand without the need for major capital expenditure.

**Holly Ranch Facility – Town of Big Sandy, Wood County, Texas**

The Holly Ranch Facility is a water distribution and wastewater facility located in Wood County, approximately 70 miles east of Dallas, Texas, just outside the town of Big Sandy. The facility primarily serves the Holly Lake Resort. The facility has a high component of single family homes (1,580) and approximately 130 condominium and timeshare units with approximately 2,000 equivalent connections.

The facility is owned by a wholly-owned subsidiary of AWRA. The area is situated around a small captive lake and features amenities such as golf courses, trails and pools. It has historically grown at a rate of just over 3.5% annually, with limited marketing efforts.

**Rio Rico Facility – Rio Rico, Arizona**

The Rio Rico Facility is a water distribution and wastewater facility located in Santa Cruz County, Arizona approximately 60 miles south of Tucson, Arizona. The facility serves approximately 5,900 water and 2,000 wastewater connections in the community of Rio Rico, Arizona. The facility is owned by AWRA.
The facility has separate water and wastewater Certificates of Convenience and Necessity and is regulated by the Arizona Corporation Commission.

Other Interests in Energy-Related Developments

The Fund also has notes receivable and equity in companies which own the following four generating facilities.

Kirkland Facility – Kirkland Lake, Ontario

The Kirkland Facility is a 102 MW combined cycle co-generation facility located in Kirkland Lake, Ontario owned by Kirkland Lake Power Corporation ("Kirkland") which burns natural gas and wood waste to generate electricity using three 23 MW gas turbines and two steam turbines. The facility was commissioned in 1991 and is currently operated by Northland Power Inc. ("Northland"). Electricity produced by the facility is sold to OEFC pursuant to a 40 year contract executed in 1989. Electricity in excess of that committed to OEFC under the power purchase agreement may be sold into the deregulated market in Ontario. Natural gas used by the facility is supplied under 20 year supply contracts commencing in 1991. Price increases under such gas supply agreements are generally tied to price increases under the power purchase agreement with OEFC. Wood waste consumed by the facility is supplied by local forest product companies under contracts of varying terms with the longest being 31 years.

Algonquin Power Trust owns 32.4% of the Class B non-voting shares issued by Kirkland. It is Kirkland’s policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Northland has granted Kirkland a put option to sell the Kirkland Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $10 million. Under the management agreement, 90% of operating income of the facility will be paid to Northland after the exercise date and, accordingly, it is anticipated that Kirkland will exercise such put option and the proceeds of such sale will be utilized to repay debt and make distributions to shareholders.

Cochrane Facility – Town of Cochrane, Ontario

The Cochrane Facility is a 35.8 MW combined cycle co-generation facility located in the Town of Cochrane, Ontario. The facility is owned by Cochrane Power Corporation ("Cochrane") which burns natural gas and wood waste to generate power using a 26.5 MW gas turbine and a steam turbine. The facility was commissioned in 1990 and is currently operated by Northland. Electricity produced by the facility is sold to OEFC pursuant to a 25 year contract executed in 1989. Electricity in excess of that committed to OEFC under the power purchase agreement may be sold into the deregulated market in Ontario. The majority (90%) of the natural gas used by the facility is supplied under a supply contract which expires in 2012. Price increases under such gas supply agreements are generally tied to price increases under the power purchase agreement with OEFC. Wood waste consumed by the facility is supplied by local forest product companies under contracts of varying terms with the longest being 30 years.

Algonquin Power Trust owns 25% of the Class B non-voting shares issued by Cochrane. It is Cochrane’s policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income. Northland has granted Cochrane a put option to sell the Cochrane Facility to Northland with an exercise date of February 28, 2011 at an exercise price of $3 million. Under the management agreement, 90% of operating income of the facility will be paid to Northland after the exercise date and, accordingly, it is anticipated that Cochrane will exercise such put option and the proceeds of such sale will be distributed to shareholders.
Chapais Facility – Town of Chapais, Quebec

Chapais Energie, Société en Commandite ("Chapais") owns this wood waste electricity generating facility located in the Town of Chapais, Québec. The Chapais Facility sells electricity to Hydro Québec pursuant to a power purchase agreement expiring December 1, 2015, with a 5 year renewal option. Wood waste is purchased from local sawmills in the area with transportation expense being the principal cost incurred to obtain the wood waste supply. As part of a restructuring which occurred as a result of commissioning delays and difficulties, the original debt incurred by Chapais in the construction of the facility was temporarily exchanged for certain preferred shares which converted to senior secured debt on July 31, 2004.

Algonquin Power Trust owns a 12.1% interest in Tranche A and Tranche B term loan interests issued by Chapais and a 33.9% interest in the Class B non-voting preferred shares of Chapais. The loans bear interest at the rate of 10.789% and 4.91%, respectively. The Fund did not realize a gain or a loss due to this exchange.

Brooklyn Facility – Queen’s County, Nova Scotia

Brooklyn Power Corporation (“Brooklyn”) owns this 28 MW bio-mass-fired electric generating facility located in Queen’s County, Nova Scotia. The Brooklyn Facility consumes the wood waste produced by the facility owned by Bowater Mersey Paper Company Limited (“Bowater”) in addition to certain wood waste purchased from several local sawmill operators in southern Nova Scotia. Brooklyn sells electricity to Nova Scotia Power Inc. (“NSPI”) pursuant to a power purchase contract expiring in 2028, the pricing under which is based on NSPI’s Avoided Costs. Brooklyn delivers steam to Bowater in exchange for a portion of the wood waste fuel.

Algonquin Power Trust owns a 13.6% interest in the senior debt issued by Brooklyn and a 13.6% interest in the outstanding common shares of Brooklyn. The outstanding principal amount of the interest in the senior debt owned by Algonquin Power Trust as at December 31, 2006 was approximately $8.6 million.

DECLARATION OF TRUST

The Fund was created on September 8, 1997 pursuant to the Declaration of Trust with a view to the completion of an initial public offering of its Trust Units and the acquisition of direct or indirect equity interests in certain of the Fund Businesses.

The following is a summary of certain provisions of the Declaration of Trust. For a complete description of the Trust Units and the Declaration of Trust, reference should be made to the Declaration of Trust.

Sole Undertaking

The Declaration of Trust provides that, notwithstanding any other provision thereof, the only undertaking of the Fund is (a) the investing of its funds in property (other than real property or an interest in real property), (b) the acquiring, holding, maintaining, improving, leasing or managing of any real property (or an interest in real property) that is capital property of the Fund, or (c) any combination of the activities in (a) and (b).
**Trustees**

The Trustees are entitled to compensation for services rendered to the Fund in their capacity as Trustees. Compensation has been established at $24,000 per year plus $1,500 for each meeting attended in person and $750 for each meeting attended by telephone per Trustee. As well, the Chairperson of each of the Trustees, the Audit Committee and the Corporate Governance Committee are entitled to receive additional remuneration from the Fund in the amount of $5,000 per year. The Trustees are entitled to be reimbursed for their reasonable out-of-pocket expenses incurred in connection with the conduct of Fund business.

The Declaration of Trust provides that, subject to the terms and conditions of the Declaration of Trust, the Trustees may, in respect of the trust assets and the business and affairs of the Fund, exercise any and all rights, powers and privileges that could be exercised by a legal and beneficial owner thereof. The number of Trustees will be not less than one nor more than seven. The Declaration of Trust prohibits non-residents of Canada (as that term is defined in the **Tax Act**), among others, from being Trustees. The Trustees are responsible for, among other things: (i) acting for, voting on behalf of and representing the Fund as a shareholder of Algonquin Holdco, an indirect shareholder and noteholder of Algonquin Canada, a unitholder of Algonquin Power Trust and a noteholder of Algonquin America; (ii) maintaining records and providing reports to Unitholders; (iii) supervising the activities and managing the investments and affairs of the Fund; and (iv) effecting payments of distributable cash from the Fund to Unitholders.

A Trustee may resign upon written notice to the Fund and may be removed by a majority of the votes cast at a meeting of Unitholders and the vacancy created by such removal may be filled at the same meeting, failing which it may be filled by the Trustees.

A quorum of the Trustees, being one Trustee at any time there is only one Trustee duly appointed or two Trustees at any time there are two or more Trustees duly appointed, may fill a vacancy in the Trustees, except a vacancy resulting from an increase in the number of Trustees or from a failure of the Unitholders to elect the required number of Trustees. In the absence of a quorum of the Trustees, or if the vacancy has arisen from a failure of the Unitholders to elect the minimum number of Trustees, the Trustees will forthwith call a special meeting of Unitholders to fill the vacancy. If the Trustees fail to call such meeting or if there are no Trustees then in office, any Unitholder may call the meeting.

The Trustees may, between annual meetings of Unitholders, appoint up to two additional Trustees to serve until the next annual meeting of Unitholders.

The Declaration of Trust provides that the Trustees will act honestly and in good faith with a view to the best interests of the Fund and in connection therewith will exercise the degree of care, diligence and skill that a reasonably prudent person would exercise in comparable circumstances. The Declaration of Trust provides that the Trustees will be entitled to indemnification from the Fund in respect of the performance of their duties under the Declaration of Trust in the absence of a breach of their duties and standard of care. The Declaration of Trust states that the duties and standard of care of the Trustees provided in the Declaration of Trust are intended to be similar to, and not greater than, those imposed on a director of a corporation governed by the Business Corporations Act.

**Trust Units**

An unlimited number of Trust Units may be issued pursuant to the Declaration of Trust. Each Trust Unit is transferable and represents an equal undivided beneficial interest in any distribution from the Fund, whether of net income, net realized capital gains or other amounts, and in any net assets of the Fund in the event of the termination or winding-up of the Fund. All Trust Units will rank among themselves
equally and rateably without discrimination, preference or priority. Trust Units are not subject to future calls or assessments except that future offerings of Trust Units may be issuable for consideration payable in installments, in which case the Fund may take security over any such Trust Units, and each Trust Unit entitles the holder thereof to one vote for each whole Trust Unit held at all meetings of Unitholders. Except as set out under “Declaration of Trust — Redemption Right” below, the Trust Units have no conversion, retraction, redemption or pre-emptive rights. Additional Trust Units may be issued in the future.

**Issuance of Trust Units**

The Declaration of Trust provides that Trust Units may be issued at the times, to the persons, for the consideration and on the terms and conditions that the Trustees determine. Trust Units may be issued in satisfaction of any non-cash distribution of the Fund to Unitholders on a pro rata basis. The Declaration of Trust also provides that immediately after any pro rata distribution of Trust Units to Unitholders in satisfaction of any non-cash distribution, the number of outstanding Trust Units will be consolidated such that each Unitholder will hold after the consolidation the same number of Trust Units as the Unitholder held before the non-cash distribution. In this case, each certificate representing a number of Trust Units prior to the non-cash distribution is deemed to represent the same number of Trust Units after the non-cash distribution and the consolidation.

**Restrictions on Debt**

The Declaration of Trust precludes the Fund from incurring indebtedness for borrowed money absent the passage of an Extraordinary Resolution, except in connection with the acquisition of additional facilities, provided certain criteria are met, and except for amounts in respect of previous acquisitions of facilities and amounts outstanding up to $1.5 million incurred for capital expenditures and operations related purposes for facilities in which the Fund has an interest.

**Distributions**

See discussion in “Distribution Policy” below.

**Redemption Right**

Trust Units are redeemable at any time at the option of the holders thereof upon delivery to the Fund of the certificate or certificates representing such Trust Units, accompanied by a duly completed and properly executed notice requesting redemption. Upon receipt of the redemption request by the Fund, all rights of the holders with respect to the Trust Units tendered for redemption will cease and the holder thereof will only be entitled to receive a price per Trust Unit (“Cash Redemption Price”) equal to the lesser of: (i) 95% of the “market price” of the Trust Units on the principal market on which the Trust Units are quoted for trading during the ten trading day period commencing immediately after the date on which the Trust Units were tendered to the Fund for redemption (the “Redemption Date”); and (ii) the “closing market price” on the principal market on which the Trust Units are quoted for trading on the Redemption Date.

For the purposes of this calculation, “market price” will be an amount equal to the weighted average trading price of the Trust Units for each of the trading days on which there was a closing price, provided that if the applicable exchange or market cannot provide a weighted average trading price, but only provides the highest and lowest prices of the Trust Units traded on a particular day, the “market price” will be an amount equal to the simple average of the average of the highest and lowest prices for each of the trading days on which there was a trade; and provided further that if there was trading on the
applicable exchange or market for fewer than five of the ten trading days, the “market price” will be the simple average of the following prices established for each of the ten trading days: (i) the average of the last bid and last ask prices of the Trust Units for each day on which there was no trading, (ii) the weighted average trading price of the Trust Units for each day that there was trading if the exchange or market provides a weighted average trading price; and (iii) the average of the highest and lowest prices of the Trust Units for each day that there was trading, if the market provides only the highest and lowest prices of Trust Units traded on a particular day. The “closing market price” will be: (i) an amount equal to the closing price of the Trust Units if there was a trade on the date; (ii) an amount equal to the average of the highest and lowest prices of Trust Units if there was trading and the exchange or other market provides only the highest and lowest prices of Trust Units traded on a particular day; or (iii) the average of the last bid and ask prices of the Trust Units if there was no trading on the date.

The aggregate Cash Redemption Price payable by the Fund in respect of any Trust Units tendered for redemption during any calendar month will be satisfied by way of a cash payment on the last day of the following month, provided that the entitlement of Unitholders to receive such cash payment upon the redemption of their Trust Units is subject to the limitations that: (i) the total amount payable by the Fund in respect of such Trust Units and all other Trust Units tendered for redemption in the same calendar month will not exceed $250,000 (provided that such limitation may be waived at the discretion of the Trustees); (ii) at the time such Trust Units are tendered for redemption, the outstanding Trust Units will be listed for trading on the Toronto Stock Exchange or traded or quoted on any other market which the Trustees consider, in their sole discretion, provides representative fair market value prices for the Trust Units; and (iii) the normal trading of Trust Units is not suspended or halted on any stock exchange on which the Trust Units are listed for trading (or, if not listed on a stock exchange, on any market on which the Trust Units are quoted for trading) on the Redemption Date or for more than five trading days during the ten day trading period commencing immediately after the Redemption Date.

If a Unitholder is not entitled to receive cash upon the redemption of Trust Units as a result of the foregoing limitations, then the redemption price for such Trust Units will be the fair market value thereof as determined by the Trustees, taking into account any taxes payable by the Fund arising from such redemption. The redemption price will, subject to any applicable regulatory approvals, be paid and satisfied by way of a pro rata distribution in specie of an interest in Fund Assets. No fractional shares, notes (based on increments of $100) or other securities, if any, will be distributed and, where the number of shares, notes and/or other securities, if any, to be received by a Unitholder includes a fraction, such number will be rounded to the next lowest whole number.

Meetings of Unitholders

The Declaration of Trust provides that Unitholders may pass resolutions that bind the Trustees or the Fund only with respect to: the appointment or removal of Trustees (except filling casual vacancies); the appointment or removal of the auditors of the Fund; the approval of amendments to the Declaration of Trust (except as described under “Declaration of Trust - Amendments to the Declaration of Trust”); the appointment of an inspector; the sale of all or substantially all of the assets of the Fund (other than as part of an internal reorganization); and the termination of the Fund. Such resolutions must be passed by Extraordinary Resolution, except for the appointment or removal of Trustees or auditors of the Fund, which requires the approval of a majority of votes cast at a meeting of Unitholders. Meetings of Unitholders will be called and held annually for the election of Trustees and the appointment of auditors of the Fund.

A special meeting of Unitholders may be called at any time by the Trustees and must be convened if requisitioned by the holders of not less than 10% of the Trust Units then outstanding (not including Units beneficially owned by the Manager) by written requisition. A requisition must state in
reasonable detail the business proposed to be transacted at such meeting.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxyholder need not be a Unitholder. Two individuals present in person or represented by proxy constitute a quorum for the transaction of business at all such meetings.

The Declaration of Trust contains provisions as to the notice required and other procedures with respect to the calling and holding of meetings of Unitholders.

**Exercise of Voting Rights attached to Algonquin Canada Shares**

The Declaration of Trust provides that the Fund will not authorize, either by agreement or by voting the Algonquin Canada Shares:

(a) any amendment to the articles of Algonquin Canada or its subsidiaries to change or remove any restriction on the business of Algonquin Canada or its subsidiaries or change the authorized share capital or change or amend the rights, privileges, restrictions and conditions attaching to any class of shares of Algonquin Canada or its subsidiaries, as applicable;

(b) any sale, lease or other disposition of all or substantially all of the property and assets of Algonquin Canada, except in the ordinary course of business;

(c) any issue of shares in the capital of Algonquin Canada or its subsidiaries other than to the Fund, Algonquin Power Trust or any one or more of their wholly-owned subsidiaries, as applicable;

(d) any amalgamation or other merger of Algonquin Canada or its subsidiaries with any other corporation, except with one or more wholly-owned subsidiaries of the Fund, Algonquin Power Trust or any one or more of their respective wholly-owned subsidiaries; or

(e) any amendment to any unanimous shareholders’ agreement entered into in respect of Algonquin Canada or its subsidiaries, or

except as part of an internal reorganization of the Fund’s assets including, without limitation, Algonquin Power Trust or any one or more wholly-owned subsidiaries of the Fund or Algonquin Power Trust or any one or more trusts of which the Fund is, directly or indirectly, the sole beneficiary.

**Limitation on Non-Resident Ownership**

In order for the Fund to maintain its status as a mutual fund trust under the Tax Act, the Fund must not be established or maintained primarily for the benefit of non-residents of Canada within the meaning of the Tax Act. Accordingly, the Declaration of Trust provides that at no time may non-residents be the beneficial owners of a majority of the Trust Units. If the Trustees or the transfer agent become aware that the beneficial owners of 49% of the Trust Units then outstanding are or may be non-residents or that such a situation is imminent, the Trustees or the transfer agent may make a public announcement thereof and will not accept a subscription for Trust Units from, or issue or register a transfer of Trust Units to, a person unless the person provides a declaration that the beneficial owner is not a non-resident. If, notwithstanding the foregoing, the Trustees or the transfer agent determine that a majority of the Trust Units are held by non-residents, the transfer agent may, or the Trustees may cause the transfer agent to, send a notice to non-resident Unitholders, chosen in inverse order to the order of
acquisition or registration or in such other manner as the Trustees or the transfer agent may consider
 equitable and practicable, requiring them to sell their Trust Units or a portion thereof within a specified
 period of not less than 60 days. If the Unitholders receiving such notice have not sold the specified
 number of Trust Units or provided the transfer agent with satisfactory evidence that the beneficial owners
 are not non-resident within such period, the transfer agent may on behalf of such Unitholder, sell such
 Trust Units and, in the interim, will suspend the voting and distribution rights attached to such Trust
 Units. Upon such sale, the affected holders will cease to be holders of Trust Units and their rights will be
 limited to receiving the net proceeds of sale upon surrender of the certificates representing such Trust
 Units.

Amendments to the Declaration of Trust

The Declaration of Trust may be amended or altered from time to time by Extraordinary
Resolution. The Trustees may, without the approval of Unitholders, authorize certain amendments to the
Declaration of Trust, including amendments:

(a) for the purpose of ensuring continuing compliance with the applicable laws, regulations,
requirements or policies of any governmental authority having jurisdiction over the
Trustees or the Fund;

(b) which, in the opinion of the Trustees, provide additional protection for the Unitholders;

(c) to remove any conflicts or inconsistencies in the Declaration of Trust or to make
corrections that are, in the opinion of the Trustees, necessary or desirable and not
materially prejudicial to the rights of Unitholders; or

(d) which, in the opinion of the Trustees, are necessary or desirable as a result of changes in
or in the administration or interpretation of taxation laws.

Termination of the Fund

The Fund has been established for a term ending 21 years after the date of the death of the last
surviving issue of Her Majesty, Queen Elizabeth II, alive on September 8, 1997. The Declaration of Trust
requires the Trustees to commence to wind-up the affairs of the Fund not more than two years prior to the
end of the term of the Fund. In addition, at any time prior to the expiry of the term of the Fund,
Unitholders may pass an Extraordinary Resolution to terminate the Fund, following which the Trustees
are obligated to commence to wind-up the affairs of the Fund.

Take-over Bids

The Declaration of Trust contains provisions to the effect that if a take-over bid is made for Trust
Units and not less than 90% of the Trust Units (other than Trust Units held at the date of the take-over bid
by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the
offeror, the offeror will be entitled to acquire the Trust Units held by Unitholders who did not accept the
offer on the terms offered by the offeror.
Reporting to Unitholders

The Fund will furnish to the Unitholders such financial statements (including quarterly and annual financial statements) and other reports as are from time to time required by applicable law, including prescribed forms needed for the completion of Unitholders’ tax returns under the Tax Act and equivalent provincial legislation. Each of the Fund Businesses controlled by the Fund has undertaken to provide the Fund with: (i) a report of any material change that occurs in its affairs in form and content that it would file with applicable regulatory authorities if it were a reporting issuer; and (ii) all financial statements that it would be required to file with applicable regulatory authorities if it were a reporting issuer under applicable securities laws. All such reports and statements will be provided to the Fund in a timely manner so as to permit the Fund to comply with the continuous disclosure requirements relating to reports of material changes in its affairs and the delivery of financial statements as required under applicable securities laws.

Prior to each meeting of Unitholders, the Fund will provide Unitholders with information similar to that required to be provided to shareholders of an Ontario public company, along with notice of such meeting.

GOVERNANCE, MANAGEMENT AND OPERATIONS

Management Agreement

Algonquin Canada, Algonquin Holdco and Algonquin Power Trust (collectively, “Algonquin”) and the Manager are parties to the Management Agreement, under which the Manager provides management services (the “Management Services”) for the Fund Businesses. The Management Services provided include advice and consultation concerning business planning, support, guidance and policy making and general management services. Senior officers of the Manager also act as senior officers of the Fund’s related entities. Specific functions performed by the Manager include: (i) managing accounting and financial services; (ii) assisting in the preparation of financial statements; (iii) negotiating and communicating with third parties with respect to contractual and other matters; (iv) arranging external professional and non-professional services; (v) assisting in providing human resources; and (vi) advising on acquisitions and sales of subsidiaries and/or businesses.

In exercising its powers and discharging its duties under the Management Agreement, the Manager is required to exercise the degree of care, diligence and skill that a reasonable, prudent advisor or manager having responsibility for management of a similar business would exercise in comparable circumstances.

The Manager is compensated for its services as follows: (i) the Manager is paid an annual fee of $665,196 per calendar year payable in quarterly instalments of $166,299, adjusted annually for changes in the Canadian consumer price index (the “Annual Fee”); (ii) the Manager is paid incentive fees based on 25% of distributable cash per Trust Unit in excess of $0.92 per annum (the “Incentive Fee”); and (iii) the Manager is reimbursed for its costs and expenses incurred in the performance of the Management Services (together with the Annual Fee and the Incentive Fee, the “Management Fees”). The Manager is not entitled to any acquisition-based incentive fees.

For the fiscal period ended December 31, 2006, the Fund, directly or indirectly, paid to the Manager a total of $0.9 million, including the Annual Fee, benefits expenses and reimbursement of out-of-pocket expenses incurred in connection with its duties under the Management Agreement. No incentive fees were paid to the Manager in 2006.
The Management Agreement’s term expires on December 31, 2012 and on expiry of the initial term, is renewable for rolling five year terms. The Manager may terminate the Management Agreement at any time on twelve (12) months’ notice. Algonquin or the Manager may terminate the Management Agreement immediately in the event of the insolvency or receivership of the other party or in the case of default by the other party in a material obligation under the Management Agreement which is not remedied within thirty (30) days, other than a failure of performance which results from an event of force majeure.

In addition, Algonquin may terminate the Management Agreement on thirty (30) days notice to the Manager if (a) there is a substantial deterioration in the businesses of Algonquin and the Unitholders approve the termination by Extraordinary Resolution (a “Business Deterioration Event”) or there is a change of control of the Manager, other than a change of control to which the Fund consents (a “Change of Control Event”).

In the event the Management Agreement is terminated pursuant to a Business Deterioration Event, the Fund shall pay the Manager, in addition to any other amounts owing to the Manager as the Annual Fee and the Incentive Fee to the effective date of termination, a termination fee in an amount equal to the aggregate amount of the Annual Fee and Incentive Fee that was payable by the Fund to the Manager in respect of the calendar year immediately preceding the year in which such termination is effective.

If the Management Agreement is terminated due to a Change of Control Event, the Fund shall pay the Manager in addition to any other amounts owing to the Manager as Management Fees to the effective date of termination, a termination fee in an amount equal to the aggregate of:

(a) the Annual Fee otherwise payable for the five year period following the effective date of termination, adjusted annually for changes in the Canadian consumer price index; and

(b) an amount equal to the net present value, calculated using a discount rate equal to the rate payable under a ten-year Government of Canada bond on the business day immediately prior to the effective date of termination plus 2.5%, of the projected Incentive Fee payable to the Manager over the five year period commencing on the effective date of termination, based on a five year forecast of distributable cash from the effective date of termination prepared by the Manager, and reported on, in customary form, by the Fund’s auditors, subject to the usual qualifications applicable to financial forecasts.

The Manager holds special voting shares of Algonquin Canada and Algonquin America which confer upon the Manager the right to elect two of the three directors of Algonquin Canada and all of the directors of Algonquin America. These shares carry no other right to vote and no material economic benefit and may be purchased by the Fund, or Algonquin Canada or Algonquin America, as applicable, at their issue price upon termination or expiry of the Management Agreement.

The Management Agreement contains provisions to regulate any conflicts of interest which may arise and provides for indemnification by the Manager of Algonquin in certain circumstances. The Management Agreement may be assigned by the Manager only with the consent of Algonquin.

The head office of the Manager is located at 2845 Bristol Circle, Oakville, Ontario L6H 7H7.
Operations Supervisory Agreement

Algonquin and Power Systems are parties to the Operations Supervisory Agreement, pursuant to which Power Systems provides certain operations-related services which are beyond the scope of the operations and maintenance services agreements which have been entered into between the entities which own the various facilities and Power Systems. Specific functions include: (i) planning of capital repairs; (ii) compliance monitoring for environmental permits; and (iii) administration of power purchase agreements. It contains similar provisions regarding standard of care and conflicts of interest as the Management Agreement.

Power Systems does not receive any payment of fees in connection with its services under the Operations Supervisory Agreement and is now paid on a cost reimbursement basis only.

For the fiscal period ended December 31, 2006, the Fund, directly or indirectly, paid to Power Systems a total of $17.1 million, which amounts relate solely to expenses for which Power Systems was reimbursed pursuant to the amended Operations Supervisory Agreement.

The Operations Supervisory Agreement is coterminous with the Management Agreement.

The head office of Power Systems is located at 2845 Bristol Circle, Oakville, Ontario L6H 7H7.

Administration Agreement

The Manager administers the Fund pursuant to the Administration Agreement entered into between the Fund and the Manager under which it is responsible for the administration and management of the affairs of the Fund. Specific functions include, among other things: (i) preparing all returns, filings and documents; (ii) providing advice with respect to the Fund’s obligations as a reporting issuer; (iii) providing investor relations services; and (iv) providing audit, accounting, engineering, legal, insurance and other professional services.

The Manager is reimbursed for its reasonable out-of-pocket expenses incurred in administering the Fund. These expenses are included in the $0.9 million, including reimbursable expenses, paid to the Manager under the Management Agreement for the fiscal period ended December 31, 2006.

The Administration Agreement is coterminous with the Management Agreement.

Direct Operations Agreements

Direct operations and maintenance services are generally comprised of those services necessary for a facility to continue to operate under typical circumstances. Such services include the provision of direct operating labour, management of available water/fuel resources, monitoring and reporting on facility performance, performance of scheduled maintenance tasks and completion of minor repairs as required. Power Systems has entered into agreements with Fund entities which own generating facilities to provide such services. The Fund, directly or indirectly, paid to Power Systems an aggregate amount of approximately $17.1 million during 2006, which amount was paid on a cost reimbursement basis pursuant to the amended Operations Supervisory Agreement and the direct operations agreements. In addition, the entities which own the water distribution and wastewater treatment facilities to provide similar services paid Water Services an aggregate amount totaling approximately $8.1 million for services during 2006, also on a cost reimbursement basis.
**Contingency Repair and Capital Improvement Projects**

Power Systems also manages the contingency repair and capital improvement projects for the owners of certain generating facilities. The annual repair and maintenance expenditures during 2006 were approximately $11.0 million, which amount was paid to Power Systems on a cost reimbursement basis and is included in the $17.1 million paid to Power Systems under the Operations Supervisory Agreement and the direct operations agreements referred to above.

**Governance Agreement**

Pursuant to the Governance Agreement, the Manager is entitled to appoint two directors to Algonquin Holdco’s and Algonquin Canada’s board of directors, with the Fund being entitled to appoint one director. Although there is currently one trustee of Algonquin Power Trust, the Manager also has the right to increase the number of trustees to three and appoint two of the trustees. The articles of Algonquin Canada and Algonquin Holdco provide that the number of directors is fixed at three.

The Governance Agreement will remain in force for so long as the Management Agreement remains in force and provides that the Fund will not vote for any amendment to Algonquin Canada’s or Algonquin Holdco’s articles or Algonquin Power Trust’s declaration of trust, including an amendment with respect to the number of directors, without the Manager’s approval. The Governance Agreement further provides that the Fund will comply with the Manager’s instructions with respect to the appointment, removal and replacement of the Manager’s nominees to the board of directors of Algonquin Canada and Algonquin Holdco (or trustee of Algonquin Power Trust, if applicable). Notwithstanding the foregoing, the Fund will be entitled to remove the Manager’s nominees as directors of Algonquin Canada and Algonquin Holdco (or trustee of Algonquin Power Trust, if applicable) or amend Algonquin Canada’s or Algonquin Holdco’s articles or Algonquin Power Trust’s declaration of trust, if:

(a) Algonquin Canada, Algonquin Holdco or Algonquin Power Trust does not comply with or prevents the implementation of their distribution policy;

(b) any of the Fund Businesses does not comply with or prevent the implementation of its distribution policy;

(c) any amendment is made to the partnership agreement in respect of any of the Fund Businesses which are partnerships without the consent of the Fund;

(d) there is a change of control of the Manager (other than a change of control to which the Fund consents);

(e) other than in the ordinary course of business and without the prior written consent of the Fund, any of the Fund Businesses undertakes a material change in its business, incurs any material debt or issues any securities other than to another such entity or the Fund; or

(f) the Management Agreement expires or is terminated.

**TRUST UNIT AND LOAN CAPITAL OF THE FUND**

**Trust Unit Capital of the Fund**

The Fund presently has 73,285,772 Trust Units outstanding. See “Declaration of Trust” for a
Pursuant to the AirSource Offer made by AAP LP to acquire all issued and outstanding AirSource Units, the Fund entered into an exchange agreement dated as of April 24, 2006 (the “Exchange Agreement”) pursuant to which a holder of an Exchangeable Unit may exchange such unit for 0.9808 Trust Units of the Fund. As of December 31, 2006, an aggregate of 3,256,984 Exchangeable Units are outstanding. If all outstanding Exchangeable Units in AAP LP are exchanged, an additional 3,194,450 Trust Units will be issued by the Fund pursuant to the Exchange Agreement.

The Fund currently has outstanding $84,980,000 principal amount of Series 1 Debentures and $60,000,000 principal amount of Series 2 Debentures. If all of the principal amount of the Fund Debentures were converted by the holders thereof, an additional 13,433,888 Trust Units will be issued by the Fund pursuant to the terms of the Trust Indenture and Supplemental Trust Indenture.

Loan Capital of the Fund

Line of Credit

The Fund has available a line of credit (the “Credit Line”) provided by a syndicate of Canadian banks in the maximum principal amount of $175.0 million, which was renewed by the Fund in the second quarter of 2006. The Credit Line provides for a general operating facility of $20.0 million, provisions of letters of guarantee of approximately $44.1 million and the balance for acquisition funding purposes.

As of December 31, 2006, the Fund had approximately $67 million outstanding under the Credit Line, all of which had been drawn down for acquisition purposes. In addition, the Fund has used the Credit Line to post (i) a letter of credit in the approximate amount of US$19.5 million in respect of bond liabilities assumed in connection with the acquisition of the Sanger Facility, (ii) a $1 million letter of credit to the Minister of the Environment (Alberta) pursuant to the Use of Works Agreement in respect of the Dickson Dam Facility; (iii) letters of credit for the EFW Facility totalling $4.5 million, (iv) letter of credit to National Grid in respect of the LFG Facilities totalling US$0.9 million, (v) letter of credit to the main contractor in respect of the construction of the St. Leon Facility totalling $14.6 million, and (vi) various other letters of credit required by the Fund entities totalling $0.3 million. As security for repayment of such Credit Line, the Fund has, among other things, provided a fixed and floating charge over all Fund Businesses and pledged the shares of certain Fund entities to the banking syndicate. As a requirement of the Credit Line, the Fund has to maintain certain financial covenants. The Fund is in material compliance with the terms of the agreements governing the Credit Line and no waiver of any breach has occurred thereunder.

Interest

While the Fund maintains a credit rating of triple B (‘BBB’) by Standard & Poors, any amounts outstanding under the Credit Line bears interest at a rate equal to the banker’s acceptance or London Interbank Offered Rate (LIBOR) plus a margin of 1.25% with no additional margins. Interest is payable monthly. The unused portion of the Credit Line attracts an annual standby fee equal to 0.30% payable quarterly. These rates will change should the credit rating of the Fund change. See “Ratings”.

Redemption

The credit agreement in respect of the Credit Line stipulates that the amount outstanding under the Credit Line is due and payable on maturity (August 2008).
**Fund Debentures**

The Fund issued the Fund Debentures under and pursuant to the provisions of the Trust Indenture, as supplemented by the Supplemental Trust Indenture.

The Series 1 Debentures are limited in the aggregate principal amount of $85,000,000 and the Series 2 Debentures are limited in the aggregate principal amount of $60,000,000. The Fund may, however, from time to time, without the consent of the holders of the Fund Debentures, issue additional debentures. For a complete description of the Fund Debentures, reference should be made to the Trust Indenture and the Supplemental Trust Indenture, copies of which are available on www.sedar.com.

**Conversion Privilege**

The Series 1 Debentures are convertible at the holder's option into fully paid, non-assessable and freely-tradeable Trust Units at any time prior to 5:00 p.m. (Toronto time) on the earlier of July 31, 2011 (the "Series 1 Maturity Date") and the business day immediately preceding the date specified by the Fund for redemption of the Series 1 Debentures, at a conversion price of $10.65 per Trust Unit (the "Series 1 Conversion Price") being a ratio of approximately 93.8967 Trust Units per $1,000 principal amount of Series 1 Debentures. The Series 1 Debentures bear interest from the date of issue at 6.65% per annum, which will be payable semi-annually on July 31 and January 31 in each year, which commenced on January 31, 2005 (each, a “Series 1 Interest Payment Date”).

The Series 2 Debentures are convertible at the holder's option into fully paid, non-assessable and freely-tradeable Trust Units at any time prior to 5:00 p.m. (Toronto time) on the earlier of November 30, 2016 (the "Series 2 Maturity Date") and the business day immediately preceding the date specified by the Fund for redemption of the Series 2 Debentures, at a conversion price of $11.00 per Trust Unit (the “Series 2 Conversion Price”) being a ratio of approximately 90.9091 Trust Units per $1,000 principal amount of Series 2 Debentures. The Series 2 Debentures bear interest from the date of issue at 6.20% per annum, which will be payable semi-annually on May 31 and November 30 in each year, commencing on May 31, 2007 (each, a “Series 2 Interest Payment Date”).

Interest will be payable based on a 365-day year. At the option of the Fund, subject to applicable law, the Fund may deliver Trust Units to its agent who shall sell such Trust Units on behalf of the Fund in order to raise funds to satisfy all or any part of the Fund's obligations to pay interest on the Fund Debentures, but in any event, the holders of Fund Debentures shall be entitled to receive cash payments equal to the interest otherwise payable on the Fund Debentures.

No adjustment will be made for distributions on Trust Units issuable upon conversion or for interest accrued on Fund Debentures surrendered for conversion; however, holders converting their Fund Debentures are entitled to receive, in addition to the applicable number of Trust Units, accrued and unpaid interest in respect thereof for the period up to the date of conversion from: (a) the latest Series 1 Interest Payment Date (in the case of the Series 1 Debentures) or (b) the latest Series 2 Interest Payment Date (in the case of the Series 2 Debentures). Notwithstanding the foregoing, (a) no Series 1 Debentures may be converted on any Series 1 Interest Payment Date and during the five business days preceding January 31 and July 31 in each year and (b) no Series 2 Debentures may be converted on any Series 2 Interest Payment Date and during the five business days preceding May 31 and November 30 in each year, as the registers of the Debenture Trustee are closed during such periods.

Subject to the provisions thereof, the Trust Indenture provides for the adjustment of the Series 1 Conversion Price and the Series 2 Conversion Price in certain events including: (a) the subdivision or
consolidation of the outstanding Trust Units; (b) the distribution of Trust Units to holders of Trust Units by way of distribution or otherwise other than an issue of securities to holders of Trust Units who have elected to receive distributions in securities of the Fund in lieu of receiving cash distributions paid in the ordinary course; (c) the issuance of options, rights or warrants to holders of Trust Units entitling them to acquire Trust Units or other securities convertible into Trust Units at less than 95% of the then Current Market Price (as defined below under “Payment upon Redemption or Maturity”) of the Trust Units; and (d) the distribution to all holders of Trust Units of any securities or assets (other than cash distributions and equivalent distributions in securities paid in lieu of cash distributions in the ordinary course). There will be no adjustment of the Series 1 Conversion Price or the Series 2 Conversion Price, in respect of any event described in (b), (c) or (d) above if, subject to prior regulatory approval, the holders of the Fund Debentures are allowed to participate as though they had converted their Fund Debentures prior to the applicable record date or effective date. The Fund will not be required to make adjustments in either the Series 1 Conversion Price or the Series 2 Conversion Price, unless the cumulative effect of such adjustments would change the Series 1 Conversion Price or the Series 2 Conversion Price, as the case may be, by at least 1%.

In the case of any reclassification or change (other than a change resulting only from consolidation or subdivision) of the Trust Units or in case of any amalgamation, consolidation or merger of the Fund with or into any other entity, or in the case of any sale, transfer or other disposition of the properties and assets of the Fund as, or substantially as, an entirety to any other entity, the terms of the conversion privilege shall be adjusted so that each Fund Debenture shall, after such reclassification, change, amalgamation, consolidation, merger or sale, be exercisable for the kind and amount of securities or property of the Fund, or such continuing, successor or purchaser entity, as the case may be, which the holder thereof would have been entitled to receive as a result of such reclassification, change, amalgamation, consolidation, merger or sale if on the effective date thereof it had been the holder of the number of Trust Units into which the Fund Debenture was convertible prior to the effective date of such reclassification, change, amalgamation, consolidation, merger or sale.

No fractional Trust Units will be issued on any conversion of the Fund Debentures, but in lieu thereof, the Fund shall satisfy such fractional interest by a cash payment equal to the Current Market Price of such fractional interest.

Redemption and Purchase

The Series 1 Debentures may not be redeemed by the Fund (except in the case of a change of control) on or before July 31, 2007. Thereafter, but prior to July 31, 2009, the Series 1 Debentures may be redeemed at the option of the Fund, in whole at any time or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted-average trading price of the Trust Units on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given exceeds 125% of the Series 1 Conversion Price.

On or after July 31, 2009 and prior to the Series 1 Maturity Date, the Series 1 Debentures may be redeemed by the Fund, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

The Series 2 Debentures may not be redeemed by the Fund (except in the case of a change of control) on or before November 30, 2010. Thereafter, but prior to November 30, 2012, the Series 2 Debentures may be redeemed at the option of the Fund, in whole at any time or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the weighted-average trading price of the
Trust Units on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given exceeds 125% of the Series 2 Conversion Price.

On or after November 30, 2012 and prior to the Series 2 Maturity Date, the Series 2 Debentures may be redeemed by the Fund, in whole or in part from time to time, on not more than 60 days' and not less than 30 days' prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest.

The Fund will have the right to purchase Fund Debentures in the market, by tender or by private contract subject to regulatory requirements; provided, however, that if an Event of Default (as defined below) has occurred and is continuing, the Fund will not have the right to purchase the Fund Debentures by private contract.

In the case of redemption of less than all of the Fund Debentures, the Fund Debentures to be redeemed will be selected by the Debenture Trustee on a pro rata basis or in such other manner as the Debenture Trustee deems equitable, subject to the consent of the TSX.

Payment upon Redemption or Maturity

On redemption or on the Series 1 Maturity Date or the Series 2 Maturity Date, as applicable, the Fund will repay the indebtedness represented by the Fund Debentures which are to be redeemed or which have matured by paying to the Debenture Trustee in lawful money of Canada an amount equal to the principal amount of the outstanding Fund Debentures, together with accrued and unpaid interest thereon. The Fund may, at its option, on not more than 60 days' and not less than 40 days' prior notice and subject to any required regulatory approvals, unless an Event of Default (as defined below) has occurred and is continuing, elect to satisfy its obligation to repay, in whole or in part, the principal amount of the Fund Debentures which are to be redeemed or which have matured by issuing and delivering freely tradeable Trust Units to the holders of the Fund Debentures. The number of Trust Units to be issued will be determined by dividing the principal amount of the Fund Debentures which are to be redeemed or which have matured by issuing and delivering freely tradeable Trust Units to the holders of the Fund Debentures. The number of Trust Units to be issued will be determined by dividing the principal amount of the Fund Debentures which are to be redeemed by 95% of the Current Market Price of the Trust Units on the date fixed for redemption or the maturity date, as the case may be. No fractional Trust Units will be issued to holders of Fund Debentures but in lieu thereof the Fund shall satisfy such fractional interest by a cash payment equal to the Current Market Price of such fractional interest.

The term “Current Market Price” is defined in the Trust Indenture to mean the weighted average trading price of the Trust Units on the TSX for the 20 consecutive trading days ending on the fifth trading day preceding the date of the applicable event.

Unit Interest Payment Election

Unless an Event of Default (as defined below) has occurred and is continuing, the Fund may elect, from time to time, subject to applicable regulatory approval, to issue and deliver freely-tradeable Trust Units to its agent for sale in order to raise funds to satisfy the Fund's obligations to pay interest on the Fund Debentures in accordance with the Trust Indenture (the “Unit Interest Payment Election”) in which event holders of the Fund Debentures will be entitled to receive a cash payment equal to the interest payable from the proceeds of the sale of such Trust Units by the agent. The Trust Indenture provides that upon such election, the agent shall (i) accept delivery of Trust Units from the Fund, (ii) accept bids with respect to, and consummate sales of, such Trust Units, each as the Fund shall direct in its absolute discretion, (iii) invest the proceeds of such sales in short-term Canadian government obligations which mature prior to the applicable Series 1 Interest Payment Date or Series 2 Interest Payment Date and deliver proceeds to holders of the Fund Debentures sufficient to satisfy the Fund's interest payment obligations; and (iv) perform any other
action necessarily incidental thereto. The amount received by a holder in respect of interest will not be affected by whether or not the Fund elects to utilize the Unit Interest Payment Election.

Neither the Fund's making of the Unit Interest Payment Election nor the consummation of sales of Trust Units pursuant thereto will (a) result in the holders of Fund Debentures not being entitled to receive, on the applicable Series 1 Interest Payment Date or Series 2 Interest Payment Date, cash in an aggregate amount equal to the interest payable on such date, or (b) entitle such holders to receive any Trust Units in satisfaction of the interest payable on the applicable interest payment date.

**Cancellation**

All Fund Debentures converted, redeemed or purchased as aforesaid will be cancelled and may not be reissued or resold.

**Subordination**

The payment of the principal of, and interest on, the Fund Debentures is subordinated in right of payment, in the circumstances referred to below and more particularly as set forth in the Trust Indenture, to the prior payment in full of all Senior Indebtedness of the Fund. “**Senior Indebtedness**” of the Fund is defined in the Trust Indenture as all indebtedness of the Fund, other than the Fund Debentures and any other debentures issued under the Trust Debenture, (whether outstanding as at the date of the Trust Indenture or thereafter created, incurred, assumed or guaranteed), and including, for greater certainty, claims of trade creditors of the Fund, which by the terms of the instrument creating or evidencing the indebtedness, is not expressed to be pari passu with, or subordinate in right of payment to, the Fund Debentures.

The Trust Indenture provides that in the event of any insolvency or bankruptcy proceedings, or any receivership, liquidation or reorganization in connection with or as a result of an insolvency or bankruptcy proceeding or other similar proceedings relative to the Fund, or to its property or assets, or in the event of any proceedings for voluntary liquidation, dissolution or other winding up of the Fund, whether or not involving insolvency or bankruptcy, or any marshalling of the assets and liabilities of the Fund, all creditors under any Senior Indebtedness will receive payment in full before the holders of Fund Debentures will be entitled to receive any payment or distribution of any kind or character, whether in cash, property or securities, which may be payable or deliverable in any such event in respect of any of the Fund Debentures or any unpaid interest accrued thereon.

In addition to the foregoing, pursuant to the terms of the Trust Indenture, neither the Debenture Trustee for, nor the holders of, the Fund Debentures are entitled to demand or otherwise attempt to enforce in any manner, institute proceedings for the collection of, or institute any proceedings against the Fund, including, without limitation, by way of any bankruptcy, insolvency or similar proceedings or any proceeding for the appointment of a receiver, liquidator, trustee or other similar official (it being understood and agreed that the Debenture Trustee and/or the holders of the Fund Debentures are permitted to take any steps necessary to preserve the claims of the holders of the Fund Debentures in any such proceeding and any steps necessary to prevent the extinguishment or other termination of a claim or potential claim as a result of the expiry of a limitation period), or receive any payment or benefit in any manner whatsoever on account of indebtedness represented by the Fund Debentures other than as set forth in the Trust Indenture at any time when (i) an event of default (howsoever designated) has occurred and is continuing under the Credit Line, or (ii) an event of default (howsoever designated) has occurred under any other Senior Indebtedness and is continuing and, in each case, notice of such event of default has been given by or on behalf of the lender or lenders party to such Senior Indebtedness to the Fund or an affiliate thereof that is the borrower pursuant to such Senior Indebtedness (the **“Senior Indebtedness Postponement Provisions”**).
The Fund Debentures are also subordinate to claims of creditors of the Fund.

Priority over Trust Unit Distributions

The Declaration of Trust provides that certain expenses and liabilities of the Fund must be deducted in calculating the amount to be distributed to Unitholders. Accordingly, the funds required to satisfy the interest payable on the Fund Debentures, as well as the amount payable upon redemption or maturity of the Fund Debentures or upon an Event of Default (as defined below), will be deducted and withheld from the amounts that would otherwise be available for payment as distributions to Unitholders.

Put Right upon a Change of Control

Upon the occurrence of a change of control of the Fund involving the acquisition of voting control or direction over 66 2/3% or more of the outstanding Trust Units by any person or group of persons acting jointly or in concert (a “Change of Control”), each holder of Fund Debentures may require the Fund to purchase, on the date which is 30 days following the giving of notice of the Change of Control as set out below (the “Put Date”), the whole or any part of such holder's Fund Debentures at a price equal to 101% of the principal amount thereof (the “Put Price”) plus accrued and unpaid interest to the Put Date.

If 90% or more in the aggregate principal amount of the Fund Debentures outstanding on the date of the giving of notice of the Change of Control have been tendered for purchase on the Put Date, the Fund will have the right to redeem all the remaining Fund Debentures on such date at the Put Price, together with accrued and unpaid interest to such date. Notice of such redemption must be given to the Debenture Trustee prior to the Put Date and as soon as possible thereafter, by the Debenture Trustee to the holders of the Fund Debentures not tendered for purchase. The principal on the Fund Debentures will be payable in lawful money of Canada or, at the option of the Fund and subject to applicable regulatory approval, by payment of Fund Units to satisfy, in whole or in part, its obligation to repay the principal amount of the Fund Debentures.

The Trust Indenture contains notification provisions to the effect that:

(a) the Fund will promptly give written notice to the Debenture Trustee of the occurrence of a Change of Control and the Debenture Trustee will thereafter give to the holders of Fund Debentures a notice of the Change of Control, the repayment right of the holders of Fund Debentures and the right of the Fund to redeem untendered Fund Debentures under certain circumstances; and

(b) a holder of Fund Debentures, to exercise the right to require the Fund to purchase its Fund Debentures, must deliver to the Debenture Trustee, not less than five business days prior to the Put Date, written notice of the holder's exercise of such right, together with a duly endorsed form of transfer.

The Fund will comply with the requirements of Canadian securities laws and regulations to the extent such laws and regulations are applicable in connection with the repurchase of the Fund Debentures in the event of a Change of Control.

Modification

The rights of the holders of the Fund Debentures as well as any other series of debentures that may be issued under the Trust Indenture may be modified in accordance with the terms of the Trust Indenture. For that purpose, among others, the Trust Indenture contains certain provisions which will make binding on
all holders of Fund Debentures resolutions passed at meetings of the holders of Fund Debentures by votes cast thereat by holders of not less than 66 2/3% of the principal amount of the then outstanding Fund Debentures present at the meeting or represented by proxy, or rendered by instruments in writing signed by the holders of not less than 66 2/3% of the principal amount of the then outstanding Fund Debentures. In certain cases, the modification will, instead of or in addition to, require assent by the holders of the required percentage of Fund Debentures of each particularly affected series. Under the Trust Indenture, the Debenture Trustee has the right to make certain amendments to the Trust Indenture in its discretion, without the consent of the holders of Fund Debentures.

Events of Default

The Trust Indenture provides that an event of default ("Event of Default") in respect of the Fund Debentures will occur if certain events described in the Trust Indenture occur, including if any one or more of the following described events has occurred and is continuing with respect to the Fund Debentures: (i) failure for 15 days to pay interest on the Fund Debentures when due; (ii) failure to pay principal or premium, if any, on the Fund Debentures, whether at maturity, upon redemption, by declaration or otherwise; or (iii) certain events of bankruptcy, insolvency or reorganization of the Fund under bankruptcy or insolvency laws. Subject to the Senior Indebtedness Postponement Provisions, if an Event of Default has occurred and is continuing, the Debenture Trustee may, in its discretion, and shall, upon the request of holders of not less than 25% in principal amount of the then outstanding Fund Debentures, declare the principal of (and premium, if any) and interest on all outstanding Fund Debentures to be immediately due and payable.

Offers for Debentures

The Trust Indenture contains provisions to the effect that if an offer is made for the Fund Debentures which is a take-over bid for Fund Debentures within the meaning of the Securities Act (Ontario) and not less than 90% of the Fund Debentures (other than Fund Debentures held at the date of the take-over bid by or on behalf of the offeror or associates or affiliates of the offeror) are taken up and paid for by the offeror, the offeror will be entitled to acquire the Fund Debentures held by holders of Fund Debentures who did not accept the offer on the terms offered by the offeror.

Limitation on Non-Resident Ownership

At no time may non-residents of Canada be the beneficial owners of a majority of the outstanding Trust Units (on a fully-diluted basis). The Fund may require declarations as to the jurisdictions in which beneficial owners of Fund Debentures are resident. If the Fund becomes aware that the beneficial owners of 49% of the Trust Units then outstanding (on a fully-diluted basis) are, or may be, non-residents, or that such a situation is imminent, the Fund may make a public announcement thereof and shall cause the Debenture Trustee or the transfer agent and registrar of the Trust Units (the “Transfer Agent”) not to register a transfer of Fund Debentures or Trust Units to a person unless the person provides a declaration that the person is not a non-resident. If, notwithstanding the foregoing, the Fund determines that a majority of the outstanding Trust Units (on a fully-diluted basis) are held by non-residents, the Fund may send a notice to non-resident holders of Fund Debentures or Trust Units, chosen in inverse order to the order of acquisition or registration of the Fund Debentures and Trust Units or in such manner as the Fund may consider equitable and practicable, requiring them to sell their Fund Debentures or Trust Units to a person unless the person provides a declaration that the person is not a non-resident. If, notwithstanding the foregoing, the Fund determines that a majority of the outstanding Trust Units (on a fully-diluted basis) are held by non-residents, the Fund may send a notice to non-resident holders of Fund Debentures or Trust Units, chosen in inverse order to the order of acquisition or registration of the Fund Debentures and Trust Units or in such manner as the Fund may consider equitable and practicable, requiring them to sell their Fund Debentures or Trust Units to a person unless the person provides a declaration that the person is not a non-resident. If, notwithstanding the foregoing, the Fund determines that a majority of the outstanding Trust Units (on a fully-diluted basis) are held by non-residents, the Fund may send a notice to non-resident holders of Fund Debentures or Trust Units, chosen in inverse order to the order of acquisition or registration of the Fund Debentures and Trust Units or in such manner as the Fund may consider equitable and practicable, requiring them to sell their Fund Debentures or Trust Units to a person unless the person provides a declaration that the person is not a non-resident.
Trust Units. Upon such sale, the affected holders shall cease to be holders of Fund Debentures or Trust Units, as the case may be, and their rights shall be limited to receiving the net proceeds of sale upon surrender of such Fund Debentures or Trust Units.

Priority of Debt

The Fund Debentures will be direct obligations of the Fund and will not be secured by any mortgage, pledge, hypothec or other charge and will be subordinated to other liabilities of the Fund. The Trust Indenture does not restrict the Fund from incurring additional indebtedness for borrowed money or from mortgaging, pledging or charging its assets to secure any indebtedness.

THE INDEPENDENT POWER GENERATION INDUSTRY

As mentioned above, the Fund is primarily engaged indirectly in the business of generating and marketing electrical energy within the independent power generation industry.

General

Hydroelectric

A hydroelectric generating facility consists of a number of components, including a dam, headrace canal or penstock, intake structure, electromechanical equipment consisting of a turbine(s), a generator(s), draft tube and tailrace canal. In addition, there are electrical switchgear and controls equipment which are necessary to interconnect the facility with the receiving electrical grid system.

A dam structure is required to create or increase the natural elevation difference between the upstream reservoir and the downstream tailrace (referred to as “head”), as well as to provide sufficient depth within the reservoir for an intake. Dam structures are also used to create an upstream reservoir which allows water to be stored within a headpond.

Water flows are conveyed from the upstream reservoir to the generating equipment via a penstock or headrace canal. A penstock is a pipeline capable of operating under pressure, and is normally constructed of steel or other suitable materials. A headrace canal is a channel which conveys water from the reservoir to the intake in a hydraulically efficient manner. The intake structure is a water intake located at the entrance to a penstock or at the end of a headrace canal. The purpose of the intake structure is to collect water from the upstream reservoir. Turbine(s) and generator(s) transform the hydraulic energy into electrical energy.

The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse. A transmission line is often required to interconnect a facility with the grid. The majority of hydroelectric generating facilities are also equipped with remote monitoring equipment, which allows the facility to be monitored and operated from a remote location.

Energy from Municipal Waste

In North America and elsewhere, the combination of increasing population and stricter environmental regulations has imposed increasing limitations upon the development of new municipal landfills and on the expansion of existing landfills. To reduce the total tonnage of municipal waste being directed to landfills and to extend the useful life of existing landfills, considerable effort is being directed toward the establishment of energy from waste facilities. The establishment of energy from waste
facilities is now a licenced process in certain states of the United States and Canadian provinces.

**Biomass**

Biomass is a combustion process that converts organic material into electricity through combustion. The combustion process generates hot flue gases that in turn produce steam in the heat exchange sections of boilers. The steam is used to generate electricity in the turbine/generator. Electricity production from biomass is expected to continue to be used as base load power. Most wood and wood products industries obtain electricity and thermal energy from biomass.

**Cogeneration**

Cogeneration is the simultaneous production of electricity and thermal energy such as hot water or steam from a single fuel source. Often natural gas is used to produce both electricity and steam. The steam produced is normally required by an associated or nearby commercial facility, while the electricity generated is sold to a utility or used within the facility. Cogeneration provides facilities with greater efficiency, greater reliability and increased process flexibility than conventional generation methods. Examples of industries using cogeneration facilities include food processing, pulp and paper and chemical plants.

Where both electrical and thermal energy are generated separately, typically one third to one half of the fuel’s energy content is converted into useful energy output such as steam or electricity. The remainder is wasted energy which escapes as unused heat. By producing electricity and steam simultaneously, cogeneration uses a higher proportion of the fuel’s energy content. Depending on the degree of steam and/or useful heat utilization, 55% to 80% of the fuel’s energy content is converted into useful energy output, which produces significant fuel savings over conventional arrangements.

Cogeneration compared to conventional processes also has environmental benefits as it results in burning less fuel and producing less carbon dioxide. Furthermore, in cogeneration facilities which use fuels such as natural gas or oil, sulphur dioxide and nitrous oxide emissions are greatly reduced compared to other technologies and fuels.

**Landfill Gas Generation**

Landfill sites produce methane gas from the decomposition of organic materials which can be burned to produce energy. Typically, landfill gas is collected by drilling gas wells into the landfill at predetermined locations. The wells are connected by an underground pipe system that deliver the gas to the processing and conversion stations where it is piped off to engines or turbines to be burned to generate electricity.

**Wind Power Generation**

The energy of the wind can be harnessed for the production of electricity through the use of wind turbines. A wind energy system transforms the kinetic energy of wind into electrical energy that can be delivered to the electricity distribution system for use by energy consumers. When the wind blows, large rotor blades on the wind turbines are rotated, generating energy that is converted to electricity. Most modern wind turbines consist of a rotor mounted on a shaft connected to a speed increasing gear box and high speed generator. Monitoring systems control the angle of and power output from the rotor blades to ensure that the rotor blades are turned to face the wind direction, and generally to monitor the wind turbines installed at a facility.
Canada

In Canada, the provinces have legislative authority over the supply of energy. The majority of the electrical supply within the Canadian provinces is provided by large Crown corporations such as Ontario Power Generation Inc. and Hydro-Québec or smaller, investor-owned utilities. These large utilities have been primarily responsible for the generation, transmission and distribution of electricity. In the late 1980’s and early 1990’s, British Columbia, Alberta, Ontario, Québec, Nova Scotia and Newfoundland (and later Saskatchewan and Manitoba) established programs to actively seek independently produced power. By the late 1990’s, many of the large utilities started the process of restructuring the energy market. To date, British Columbia, Alberta, and Ontario have made progress on restructuring and introducing competition into the energy market.

In February 2005, the Minister of Finance delivered a budget containing a number of new measures for green energy developers, subject to approval. The government has set aside $1 billion over the next five years for an “innovative Clean Fund” to purchase emission reductions from Canadians and Canadian industry through a competitive process. Eligible projects could include new green power sources. The budget also extended the Wind Power Production Incentive with a goal of stimulating 4,000 MW of new wind energy. The incentive payment of $10 per MW-Hr of production for the first ten years of operations remains the same, but will be available to eligible projects commissioned before April 1, 2010. Furthermore, a new Renewable Power Production Incentive ("RPPI") intended to stimulate up to 1,500 MW of other renewable energy was created. The RPPI provides for an incentive of $10 per MW-Hr of production for the first ten years of operations for eligible projects commissioned after March 31, 2006 and before April 1, 2011. Eligible technologies could include waterpower, advanced, innovative and highly efficient biomass, combustion technologies using biogas, and other renewable technologies.

Alberta

Electrical power generators in Alberta are regulated by the Electric Utilities Act (the "EU Act"). The EU Act permits the development of a competitive marketplace for electricity in Alberta. The EU Act also created the Alberta Power Pool through which all electrical power must be traded in Alberta.

The EU Act was amended to separate generation, transmission and distribution of electrical power in Alberta for regulatory purposes. The amendments to the EU Act and corresponding regulations in 2000 created the Alberta Balancing Pool. The amended legislation provides that the relevant utility is to purchase power at the prices set out in the power purchase agreement entered into pursuant to the Small Power Act and sell the power into the Power Pool. All revenues associated with the sale of such power into the Power Pool are to be paid into the Balancing Pool and all costs associated with such power purchase agreements are to be paid out of the Balancing Pool. The effect of the amendments is to render a utility that is a party to such a power purchase agreement a flow through for the rights and obligations under the power purchase agreement.

The government of Alberta proclaimed in force on June 1, 2003, a new Electric Utilities Act (2003) (the “New EU Act”) and the Independent Power and Small Power Regulation (the “New EU Act Regulations”). The New EU Act effected alterations to the governance of institutional entities such as the Power Pool and the New EU Act Regulations addressed payments to be made to and by the Balancing Pool, but neither served to alter the Small Power Act-related arrangements described above.
Ontario

In 1987, the provincial utility and the provincial government developed policies and programs to encourage the addition of new generation by independent power generators. Over 90 of these independent generators or non-utility generators entered into long-term power purchase agreements with Ontario Hydro. These projects represent over 1,225 megawatts of energy from a variety of fuels, such as water, natural gas and wood wastes.

The regulatory framework for wholesale and retail competition has been developed by the Ontario government through the Ontario Energy Board (the “OEB”). While transitional issues such as pricing and metering continue to be considered by the OEB, full competition in the wholesale and retail electricity market commenced on May 1, 2002.

On August 23, 2004, at the request of the Minister of Energy, the OEB launched a consultation process to develop a new electricity price plan that would provide stable and predictable electricity pricing, encourage conservation and ensure that the price consumers pay for electricity better reflected the price paid to generators. Under the new price plan which was announced on March 11, 2005 and came into effect on April 1, 2005, eligible consumers paid 5.0 cents per kilowatt hour for the first 750 kW-hr they used each month, and 5.8 cents per kW-hr for electricity used per month over this amount.

In June 2005, the Ontario government announced that the Province will (a) increase the percentage of clean, renewable energy in Ontario’s supply mix by 5% (1,350 MW) by 2007 and 10% (2,700 MW) by 2010, (b) help Ontarians reduce their electricity use by 5% by 2007, (c) reduce electricity consumption of government operations by 10% by 2007 and (d) eliminate the Province’s coal-fired electricity generation by 2009.

Starting November 1, 2005, the price threshold – the amount of electricity that is charged at the lower price – changes twice a year for residential consumers. The price threshold will be 1,000 kW-hr per month in the winter (November 1st to April 30th) and 600 kW-hr per month in the summer (May 1st to October 31st). Current prices are in effect until April 30, 2006. After that, if needed, prices may change every six months based on an updated OEB forecast and any accumulated differences between the amount that consumers paid for electricity and the amount paid to generators in the previous price-setting period.

The restructuring of Ontario Hydro and the Ontario energy market and the current decisions of the Ontario Government has not had a material impact on the long term purchase agreement for each generating facility located in Ontario in which the Fund has an interest. OEFC now holds all rights, obligations and liabilities under such power purchase contracts. This Ontario government agency will continue to purchase the energy generated by the Ontario facilities in which the Fund has an interest pursuant to the existing contracts. The Fund has also received a licence to generate from the OEB as required by the Energy Act.

The Ontario government indicated that it will achieve its commitments by increasing by 10% the amount of electricity being generated from renewable resources by the year 2010.

Manitoba

Prior to Manitoba Hydro negotiating the power purchase agreement with St. Leon LP and St. Leon GP in respect of the wind energy project constructed near St. Leon, Manitoba, Manitoba did not have independent wind power generation facilities in service. In the past, Manitoba Hydro had been exclusively responsible for the production of electricity in the Province. Manitoba Hydro is a net exporter
of electricity, mainly to Ontario and certain states of the United States. To date, the Province has been able to utilize its large hydro resources to satisfy internal and export requirements.

In 2002, the Manitoba government developed a strategy on climate change to meet or exceed targets established under the Kyoto Protocol to the United Nations Framework Convention on Climate Change. The Manitoba strategy is based on recommendations from the Climate Change Task Force through the Climate Change Action Plan. The plan supports numerous clean energy programs within the provincial government and municipalities as well as within business, outside agencies, academic institutions and the public.

The Manitoba government and Manitoba Hydro have independently undertaken studies to determine the potential of wind power generation in Manitoba. As a result of such studies, Manitoba Hydro has advised it plans to have approximately 1000 MW of wind power capacity (inclusive of the generating capacity represented by the St. Leon Facility), to be constructed, using in part, independent power producers by 2010. Manitoba has announced a Request for Proposal process for 300 MW of new wind power to be released later in 2007.

**Newfoundland**

In anticipation of an increase in electricity demand in the Province of Newfoundland, Newfoundland and Labrador Hydro began seeking generating capacity from independent power producers in 1990. In April 1990, a new policy was developed stating that Newfoundland and Labrador Hydro was prepared to relinquish its franchise rights to private developers on any hydroelectric project up to ten megawatts or greater under certain conditions.

In December 1993, Newfoundland and Labrador Hydro announced that it would issue power purchase agreements to four small hydroelectric projects located on the island of Newfoundland totaling 38 megawatts. The utility also announced that it would purchase electricity from these facilities commencing on October 1, 1998.

In 1998, the provincial government announced a moratorium on the development of small hydroelectric projects in Newfoundland. The government announced a review of environmental issues associated with such development and a review of the need for additional generation capacity. The government cancelled two of the four facilities that were proceeding to construction. The Rattle Brook facility was completed and commissioned in 1998.

**Québec**

Between 1991 and 1993, Hydro-Québec negotiated and signed agreements with private producers for the purchase of a total of 474 megawatts from hydroelectric generating facilities, wind powered facilities and cogeneration plants fuelled by biomass and natural gas.

In April 2002, the Québec government adopted the Dam Safety Act and corresponding regulations. The Dam Safety Act imposes a series of safety measures governing the construction, alteration and operation of high-capacity dams. It requires dam owners to maintain their facilities in good repair and monitor their hydraulic works.

On November 2002, the Québec government announced that there would be no new dams built for small hydroelectric projects.

In May 2006, the Québec government unveiled its energy strategy following a broadly-based
consultation process that began in November 2004. The Quebec government announced that it would strengthen its energy supply security by giving priority to hydroelectricity, wind energy potential, hydrocarbon reserves and the diversification of natural gas supplies.

**United States**

The power generation industry in the United States is regulated by FERC under the PURPA legislation. FERC, pursuant to the PURPA legislation, mandates the development of policies by state utility commissions and utilities themselves that enable private producers to build power facilities. The key policy issue was the development of long term power purchase agreements with fixed, long-term power purchase rates. The long-term rates were based on projections of the utilities’ Avoided Costs. Today, due to market forces and economic changes, many of these long-term agreements are priced far above current market rates. While these higher costs are burdensome to the utilities, most have recognized these costs as Stranded Costs.

On February 2, 2006, PURPA issued revised rules, *Revised Regulations Governing Small Power Production and Cogeneration Facilities*, Order No. 671, 114 FERC 61,102 (2006). Further regulations were also issued to clarify the regulations and became effective on April 20, 2006. In order to comply with the new regulations, in June of 2006, the Fund filed with FERC a notification of holding company status for each direct and indirect subsidiary company of the Fund. Based on an initial review of the regulations, Algonquin Canada may be impacted by the revised rules. The Fund is investigating the option of filing an exemption or waiver with FERC for Algonquin Canada.

Currently, the Fund, as well as many industry stakeholders, is evaluating the affect of the revisions to the industry. Based on an initial review of the revised rules, the key regulations that could impact the Fund are:

(a) Any type of Qualifying Facility that exists but has never filed a self-certification (or obtained an order certifying it as a Qualifying Facility) must file a self-certification (or petition for an order) within 60 days of Order No. 671. This filing requirement was added to Section 292.207 and now forms part of the general requirements that must be met in order to be eligible to be classified as a Qualifying Facility.

(b) Any cogeneration Qualifying Facility, any small power production Qualifying Facility less than 30 megawatts, and any geothermal small power production Qualifying Facility, is now subject to rate regulation under Section 205 and 206 of the Federal Power Act. However, sales of energy or capacity made by Qualifying Facilities 20 megawatts or smaller, or made pursuant to a contract executed on or before March 4, 2006, or made pursuant to a state regulatory authority's implementation of PURPA are exempt from scrutiny under sections 205 and 206. If this exception does not apply, then these Qualifying Facilities must make a rate filing under section 205 of the Federal Power Act in order to be eligible to sell electricity. Rate filings were required to be made on or before the effective date of Order 671, which was March 4, 2006.

**California**

The California Legislature passed Assembly Bill 1890 (“*AB 1890*”) in 1996 to restructure the electricity industry. The State restructuring law dramatically changed the market system that was in place for more than eighty years. The intent of the restructuring was to ensure a transition to a more competitive electricity market by creating a new market that provided competitive low-cost and reliable electric service. While municipal utilities were not required to participate in the restructured market, customers of investor-owned electric utilities were free to choose their electricity provider. The market was controlled by the Power Exchange, which was to provide market services and control, and the
Independent System Operator, which was given control over the transmission grid.

The restructured electricity industry took form in early 1998 and the new market appeared to be off to a good start. Initially, as expected, electricity prices tracked closely the marginal cost of power production. Ultimately, however, many implementation problems developed, which eventually elevated to an “energy crisis” in 2000. Problems that began to appear were extremely high costs of electricity, decreased reliability, very high profits by generators and large debts incurred by utilities.

Customers of the investor-owned utilities had their rates frozen as part of the overall legislative design and did not see the high wholesale costs reflected in their utility bills. Because of the rate freeze, utilities could not pass these expenses on to their customers, leaving utilities, such as Pacific Gas and Electric Company, with negative balances in their revenue accounts. Pacific Gas and Electric Company ultimately declared bankruptcy on April 6, 2001.

The California Legislature addressed the crisis by implementing a number of changes to restructure the electricity market. A key component of the changes was to ensure that there was and is an adequate supply of electricity to meet market demands. In September 2002, Pacific Gas and Electric Company filed a Plan of Reorganization which the company stated would allow it to emerge from Chapter 11 protection. On June 19, 2003, federal bankruptcy court announced the settlement agreement between PG&E and the California Public Utility Commission’s staff. In December 2003, the California Public Utility Commission approved the settlement agreement and the bankruptcy court confirmed the Plan of Reorganization.

**Connecticut**

Connecticut Light and Power Company is part of the North East Utilities System which is located in the New England Power Pool (“NEPOOL”). ISO New England Inc. was established as a not-for-profit, private corporation on July 1, 1997 following its approval by FERC. The organization immediately assumed responsibility for managing the New England region’s electric bulk power generation and transmission systems and administering the region’s open access transmission tariff.

Since May 1, 1999, ISO New England Inc. has also administered the wholesale electricity marketplace for the region. Six electricity products are bought and sold by market participants on an Internet-based market system.

**Minnesota**

During the Minnesota legislature’s 2001 session, the Minnesota Renewable Energy Objectives was enacted as a statute. The Objectives require each electric utility to “make a good faith effort to generate or procure electricity generated by an eligible energy technology” so that: (1) commencing in 2005, at least one percent of the electric utility's total retail electric sales is generated by eligible energy technologies; (2) the amount provided under clause (1) is increased by one percent of the utility's total retail electric sales each year until 2015; and (3) ten percent of the electric energy provided to retail customers in Minnesota is generated by eligible energy technologies.

**New Hampshire**

New Hampshire has one large, investor-owned utility, Public Service Company of New Hampshire, which is a subsidiary of Northeast Utilities, as well as a number of smaller regional utilities. With the passing of PURPA in 1978, the New Hampshire legislature passed the Limited Electrical Energy Producers Act which directed the NHPUC to encourage the State’s utilities to purchase independently
produced power from a variety of sources. The State legislature also granted the NHPUC authority to set long term rates for renewable energy sources and beginning in 1984, the PSNH issued power purchase agreements with long term fixed power purchase rates that helped stimulate the development of small hydroelectric generating facilities. While these rates were based on PSNH’s own projected energy costs at that time, the contracted rates are now well above today’s market rates for electricity. The NHPUC also issued rate orders to utilities such as PSNH to purchase electricity from certain power producers at stipulated power purchase rates.

In March 2002, PSNH approached all the existing holders of power purchase agreements and rate orders with an offer to buy down or buy out the existing contracts that contained over market power purchase rates. By the end of the year, PSNH either bought out or bought down twelve contracts or rate orders.

**New Jersey**

In the early 1990s, as a result of the new bulk energy market, the New Jersey Board of Public Utilities challenged in court the validity of the long-term contracts with independent power producers. The intention was to necessitate the buy-out of uneconomical independent power producer contracts. However, in 1995, the legal dispute was overruled by the United States Court of Appeals for the Third Circuit. The basis of the decision was that the New Jersey Board of Public Utilities disobeyed the FERC and PURPA regulations.

Further changes to the New Jersey energy marketplace have taken place over the last few years. In February 1999, the State of New Jersey enacted the Electric Discount and Energy Competition Act. This regulation encourages competition in the energy markets, including electricity generation, in New Jersey. On August 1, 1999, New Jersey finally deregulated the electric and gas utility business throughout the State.

**New York State**

Following the implementation of PURPA in 1978, New York State aggressively pursued the development of independent power production. There are currently over 300 independent power facilities now in operation in New York State and independent power producers have added more than 6,000 megawatts of new electric generating capacity.

**Tennessee**

While some states have advanced toward deregulation of electricity, Tennessee’s unique relationship with the Tennessee Valley Authority (“TVA”) prevents most similar actions. TVA’s status as a federal utility means that Congress must act before substantial further changes in the provision of electric power can occur in Tennessee. While the electric utility industry in Tennessee developed almost exclusively around the Tennessee Valley Authority, the electric industry outside of Tennessee developed a vertically integrated structure in which each utility owned its own generation, transmission and distribution facilities. In anticipation of increased customer demands, these electric utilities invested in additional generating capacity.

In April 1996, FERC issued Order 888 requiring all public distribution utilities that own, operate or control interstate transmission services to file tariffs offering to others the same services that they provide to themselves. It also sets conditions under which a utility may seek recovery of stranded costs. Although Order 888 does not require corporate unbundling or divestiture, it does require the structural separation of utilities’ transmission services from their power marketing functions. Because TVA is not
currently under FERC jurisdiction, it is not required to adhere to FERC mandates, such as Order 888, except on a voluntary basis.

While Tennessee has continually monitored the issue of electricity deregulation, it was one of the last states to officially consider it. Passage of Public Chapter 531 in 1997 marked the first official step toward electricity deregulation in Tennessee. This legislation established a Special Joint Committee to study the issues of electricity deregulation and its impact on Tennessee.

**Vermont**

Following the implementation of PURPA in 1978, the State of Vermont agreed to encourage the development of independent power production. The electrical distribution system of the State is comprised of approximately 26 small, local utilities and for efficiency it was determined that one purchaser, the Vermont Electrical Exchange, Inc., should act as purchasing agent for all State utilities. Consequently, Vermont Electrical Exchange, Inc. has entered into a number of contracts with private producers under which it purchases power from these independent power producers and, in turn, delivers such power to member utilities.

**Competition and Green Power Pricing**

Unlike electricity generated by fossil fuels such as natural gas and coal which are subject to potentially dramatic and unexpected price swings due to disruptions in supply or abnormal changes in demand, the supply of hydroelectric power is not subject to commodity fuel price volatility or risk. In addition, the generation of hydroelectric power does not involve significant ongoing capital and operating costs to ensure strict compliance with environmental regulations, which is a significant advantage over power generated by burning waste or utilizing landfill gases.

Deregulation has increased demand for privately generated power from a variety of sources including fossil fuels, waste, wind and water. Taking into account capital costs, wind power is generally more expensive than traditional forms of generated power. Fossil fuels are harmful to the environment; and waste burning power generation requires producers to abide by stringent and costly environmental regulations.

With deregulation and opening of competition in the electricity marketplace, there will be an increase in the opportunity for the energy customer to choose the type of generation producing the electricity.

“Green Power” is electricity generated from renewable energy sources that do not contribute to greenhouse gas emissions. Green Power includes technologies such as small hydroelectric (generally defined as facilities of less than 20 megawatts in capacity), bioenergy, landfill gas, wind and photovoltaic. The US Department of Energy has suggested that in a competitive marketplace, utilities and energy marketers will utilize Green Power pricing to strengthen their image with their customers and build customer loyalty. Further, the Department has found that most utility customers want their utilities to pursue environmentally benign options for generating electricity and some customers are willing to pay extra to receive power generated by renewable resources. The Department believes that as deregulation and open competition evolve, the Green Power approach will help offset the relatively higher costs of renewable power compared to less costly gas-fired generation.

In April 1997, Natural Resources Canada announced that, as part of the federal Green Power Procurement program, the federal government entered into an agreement to purchase up to 13,100 megawatt hours per year of Green Power from a utility to supply electricity to buildings owned by
Natural Resources Canada and Environment Canada. Further, at that time, the Minister of the Environment announced that Environment Canada would be greening up to 20 per cent of its nation-wide electrical consumption before 2010 to assist the growth of the Green Power sector while reducing the greenhouse gas emissions caused by the Department’s use of electricity.

Recently, international environmental agreements such as the Kyoto Protocol on Climate Change have set targets for the reduction of greenhouse gas emissions. The Canadian government has announced its intention to implement the Kyoto Protocol with some changes. The United States, at both the federal and state government levels, has announced various programs and targets to reduce greenhouse gas emissions. Though programs and policies are evolving at all government levels, the trading of greenhouse gas credits created by renewable energy projects is seen as part of the eventual solution.

WATER SERVICES INDUSTRY

The Global Water Services Market

The global market for water supply and treatment equipment and services has been growing rapidly over the last decade and currently constitutes over a third of the global market for environmental products and services. The trend to market pricing for water services, combined with the growing private sector participation in water and wastewater utilities, has generated an opportunity for private capital to participate in water services markets. The opportunity is enhanced by increasingly stringent potable water quality standards, decreasing supplies of naturally clean water in populated areas and enforcement of environmental regulations.

The United States, Western Europe and Japan represent over 80 percent of the total market for water services and equipment. These markets are generally mature with an average growth of approximately 3 to 4 percent consistent with the growth in population. The largest participants in serving the global water and wastewater industry are based in the United States, France, Britain, Japan and Germany.

United States Water Services Industry

The ownership of water assets and the provision of water and wastewater services around the world, including the United States, remain primarily concentrated in the public sector, typically at the municipal or community level. Rates charged by such utilities are determined in the discretion of the municipality on the premise that such services are provided at cost.

Notwithstanding the foregoing, approximately 55 million Americans living in smaller communities are served by approximately 60,000 privately owned water utilities and 5,500 privately owned wastewater utilities. Rates charged by these utilities are determined in conjunction with state or county regulators with such rates set so as to provide the utilities with sufficient revenues to generate after-tax equity returns of approximately 10 to 12%.

In the continental United States, water supplies and resources for approximately one-third of the landmass are considered endangered. The southwest United States is particularly susceptible to the effects of groundwater and surface-water withdrawals, precipitation lost through evaporation, lack of industrial water recycling and extremes of temperatures.

The connection between the water delivery and wastewater collection and reclamation industries is becoming intertwined with the advent of stronger re-use requirements and continuing evolution in
water rights. The industry and regulators appear now to agree that high quality reclaimed water from wastewater treatment and potable groundwater are integrally connected. In many jurisdictions in the United States, reclaimed water is being used in place of potable or virgin groundwater for commercial and irrigation applications and recharged into ground aquifers for future withdrawal and re-introduction into the potable water systems by water delivery utilities. The wastewater treatment utilities are awarded credits for such recharge and the water delivery utilities utilize such credits to gain access to additional groundwater resources for pumping and delivering water to new customers.

The global market for water and wastewater services and equipment is large and growing. There are a large number of private water and wastewater companies in the United States and a large concentration of these utilities is located in the high growth areas of the arid southern States.

It is estimated that investment of between US$25 billion and US$40 billion will be required in the industry over the next 20 years for capital improvements, replacement of aging infrastructure and improvements to meet higher drinking water standards. Under the regulations governing private investor owned utilities, rates will be established to ensure investors of such capital earn the target market return.

Generally, investor-owned water and sewer providers in the United States operate as geographic monopolies within the areas in which they serve. A water or sewer company is provided a service territory defined by a Certificate of Convenience and Necessity which imposes an exclusive right and duty to serve in the service territory. A Certificate of Convenience and Necessity is typically granted by a state agency, which also serves as an economic and service quality regulator for these water or sewer service providers. Such agencies are charged with ensuring that water and sewer services are provided at reasonable rates to the company's customers. The agency must balance the interests of the rate payers as well as companies and their shareholders. Rates are approved by the agency to provide the water or sewer company the opportunity, but not the guarantee, to earn a reasonable return on its investment after recovering its prudently incurred operating expenses.

**Arizona**

While the majority of water and sewer customers are served by large municipalities, there are numerous investor-owned providers. The Arizona Corporation Commission is the regulatory authority with jurisdiction over these water and sewer companies as well as all other types of investor-owned utilities. Municipal water and sewer systems and water improvement districts are kept accountable through the electoral process and hence do not fall under the jurisdiction of the Arizona Corporation Commission.

Environmental regulation and compliance is provided by the Arizona Department of Environmental Quality and various County agencies.

**Illinois**

The Illinois Commerce Commission currently regulates 33 water, 5 sewer, and 14 combination water and sewer investor-owned utilities serving a population of nearly 1.15 million people. Environmental regulatory authority is provided by the Illinois Environmental Protection Agency.

**Missouri**

The Missouri Public Service Commission is the state agency responsible for the regulation of private and investor-owned utilities. The Missouri Public Service Commission regulates approximately 67 water and 56 sewer companies. Environmental regulation is provided by the Missouri Department of
Natural Resources and certain County authorities.

Texas

The Texas Commission on Environmental Quality provides regulatory oversight of investor-owned water and sewer utilities. The Texas Commission on Environmental Quality also has the responsibility of implementing, monitoring, and enforcing environmental regulations, such as those stemming from the Clean Water Act and the Safe Drinking Water Act, for all water and sewer service providers, including those owned and operated by municipalities.

OTHER CONSIDERATIONS

Competition

The Fund competes for infrastructure project acquisitions with individuals, corporations and institutions (both Canadian and foreign) which are seeking or may seek infrastructure project investments similar to those desired by the Fund. Availability of investment funds and an increase in interest in infrastructure project investments may increase competition for infrastructure investments, thereby increasing purchase prices. Many of these investors have greater financial resources than those of the Fund or operate according to more flexible conditions.

The Fund will access public markets to finance infrastructure project acquisitions if funds are not immediately available. In addition, the Fund believes that the Manager, in its role as administrator and manager, provides the Fund with a competitive advantage with its experience in identifying strategic investment opportunities.

Significant deregulation and opening of competition is occurring in the electricity marketplace. The Fund is in a strong competitive position since, for new generation, small hydroelectric is the lowest cost producer, after industrial co-generation, in relation to total costs, and is the lowest cost producer with respect to variable production costs. See “The Independent Power Generation Industry - Competition and Green Power Pricing”.

Environmental Matters

The Facilities encompass operations which require adherence to environmental standards imposed by regulatory bodies through licences, permits, policies and legislation. Failure to operate the Facilities in strict compliance with these regulatory standards may expose the Facilities to claims, clean-up costs and loss of operating licences and permits.

The Manager has an environmental management program including environmental policies and procedures that involve long-term environmental monitoring programs, reporting, government liaison and the development and implementation of emergency action plans as related to environmental matters.

Environmental protection requirements did not have a significant financial or operational effect on the Fund’s capital expenditures, earnings and competitive position for the twelve months ended December 31, 2006. Further, such requirements are not expected to have a significant impact in future years, although, management of the Fund expects that more stringent environmental standards will continue to be implemented by various governmental agencies.
Employees

Algonquin Canada currently has 18 employees who are involved in the operation of the hydroelectric facilities in Quebec. Power Systems currently has 53 employees who are involved in the operation of the hydroelectric facilities, 25 employees who provide technical, environmental and safety services to the Fund, and an additional 56 employees through its subsidiaries are involved in the operations of the cogeneration, wind and landfill gas facilities. Algonquin Power Trust (including its subsidiaries) currently has 31 employees who are involved in the management of the Fund and a further 60 employees involved in the operations of the EFW Facility. In addition, the Manager and Water Services currently have approximately 85 employees. Labour relations have been stable to date and there has not been any disruption in operations as a result of labour disputes with employees. With the exception of 45 employees at the EFW Facility, these employees are non-unionized.

Foreign Operations

For 2006, 67.6% of the gross revenue of the Fund was generated in the United States. As at March 30, 2007, the Fund has interests in 58 facilities located in the United States, including 17 water distribution and wastewater treatment facilities.

Currency fluctuations may affect the cash flow which the Fund will realize from its operations, as certain of the Fund Businesses sell electricity in the United States and receive proceeds from such sales in US dollars. Such Fund Businesses also incur costs in US dollars.

Intellectual Property

The “Algonquin” name and trademark and related marks and designs are licenced to the Fund by Algonquin Power under a non-exclusive, royalty-free trademark licence agreement dated December 23, 1997 between Algonquin Power and the Fund. Subject to the terms of the licence agreement, this licence will remain in effect for as long as the Management Agreement is in effect. The Fund, by using the “Algonquin” name, has the benefit of the goodwill and recognition associated with Algonquin Power and its affiliates’ use of the “Algonquin” name in the energy sector for the past ten years.

Seasonality

Based on the type of power purchase agreements in place at all of the facilities in which the Fund has an interest, the revenue generated by the facilities is proportional to the amount of electrical energy generated. In addition, the amount of energy generated at the hydroelectric facilities is dependent upon available water flows. Accordingly, the Fund’s revenues are affected by low and high water flow caused by seasonal rains and melts, with the result that revenues are higher in the spring and fall and are lower in the summer and winter. Engineering studies have been undertaken to assess the amount of energy which can be expected to be generated from each facility on an average annual basis. Furthermore, the majority of the facilities have significant operating histories with which to compare the theoretical estimates in the engineering studies. Due to geographic diversity of the facilities, the variability of total revenues is 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 St. Leon 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 St. Leon Facility may be different and distributable cash could be impacted.
Customers

The Fund Businesses derive their revenues principally from the sale of electricity to large utilities. For the twelve months ended December 31, 2006, the Fund Businesses’ revenues were derived as follows: Connecticut Light and Power – approximately 22.1%; OEFC - approximately 8.5%; Hydro Québec - approximately 15.8%; Pacific Gas and Electric 10.8%; regulated water distribution and reclamation facilities – 17.6%; and others - approximately 25.2%.

Economic Dependence

The largest customer on a percentage basis is Connecticut Light and Power Company which totalled 22.1% in revenues in the year ended December 31, 2006; however, this customer's contribution to distributable cash was a significantly lower percentage of total distributable cash (9.4%) for the year ended December 31, 2006. Otherwise, the Fund does not believe it is substantially dependant on any single contractual agreement or set of related agreements either for the sale of a major part of its products and services or for the purchase of a major part of its requirements for goods, services or raw materials or any franchise or licence or other agreement to use a patent formula, trade secret, process or trade-name upon which its business depends.

Social or Environmental Policies

The Fund has safety and environmental compliance policies in place. These policies have been communicated with staff, and have been incorporated into the Fund’s Safety Mission Statement and Employee manual. The Fund’s Safety Mission Statement is to:

1. uphold Public Safety at all facilities under Algonquin management.
2. uphold Employee Safety in the work-place.
3. uphold Environmental Compliance.
4. uphold Regulatory Compliance.
5. maintain Employee Job Satisfaction.
6. foster Open Communication To Achieve Company Guidelines.
7. ensure Long Term Integrity of Client’s Assets.
8. maximize Client Revenue on facilities under Algonquin management.

The Fund has an Environmental, Health and Safety Group that reports independently to the Executive Director - Environmental Compliance and Safety (this position reports to the Trustees). This group is responsible for developing environmental and safety policies, developing and delivering environmental and safety training, conducting internal audits of environmental and safety performance, and arranging for third party environmental and safety audits.
SELECTED FINANCIAL INFORMATION

The following sets out certain selected financial information for the Fund:

<table>
<thead>
<tr>
<th></th>
<th>Three months ended March 31, 2004</th>
<th>Three months ended June 30, 2004</th>
<th>Three months ended September 30, 2004</th>
<th>Three months ended December 31, 2004</th>
<th>Year ended December 31, 2004</th>
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<tr>
<td>Operating Revenue</td>
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<td>41.9</td>
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<td>Total Expenses</td>
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<td>26.7</td>
<td>35.6</td>
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<tr>
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<td>2.3</td>
</tr>
<tr>
<td>Net Earnings/(Loss)</td>
<td>3.3</td>
<td>8.1</td>
<td>11.5</td>
<td>(0.1)</td>
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<td>Net Earnings/(Loss) per Trust Unit</td>
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<td>0.23</td>
<td>0.23</td>
<td>0.92</td>
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(see page 75 for the next table)

<table>
<thead>
<tr>
<th></th>
<th>Three months ended March 31, 2005</th>
<th>Three months ended June 30, 2005</th>
<th>Three months ended September 30, 2005</th>
<th>Three months ended December 31, 2005</th>
<th>Year ended December 31, 2005</th>
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<td>2.6</td>
</tr>
<tr>
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<tr>
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<td>Distributions per Trust Unit</td>
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<td>0.23</td>
<td>0.23</td>
<td>0.23</td>
<td>0.92</td>
</tr>
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(see page 75 for the next table)

<table>
<thead>
<tr>
<th></th>
<th>Three months ended March 31, 2006</th>
<th>Three months ended June 30, 2006</th>
<th>Three months ended September 30, 2006</th>
<th>Three months ended December 31, 2006</th>
<th>Year ended December 31, 2006</th>
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<tbody>
<tr>
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<td>51.1</td>
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<td>34.6</td>
<td>40.2</td>
<td>44.7</td>
<td>159.6</td>
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DISTRIBUTION POLICY

The following outlines the distribution policy of the Fund as contained in the Declaration of Trust, including any restrictions on the ability to make distributions.

The amount of distributable cash to be distributed annually per Trust Unit will be equal to a pro rata share of all cash amounts which are received by the Fund including, without limitation, interest, dividends, royalties, lease payments, distributions from trusts, proceeds from the disposition of securities including any proceeds of redemption of shares or trust units, return of capital and repayment of indebtedness and all cash amounts received by the Fund in respect of any prior year to the extent not previously distributed (excluding all amounts required to satisfy the redemption of Units and which have become payable in cash by the Fund in respect of the year, and the amount (if any) by which Net Income for the year is negative), less any amount or amounts which the Trustees may reasonably consider to be necessary to provide for the payment of any costs, expenses or obligations which have been incurred in the course of the activities and operations of the Fund (including, for greater certainty, administrative expenses of the Fund and amounts required for the business and operation of the Fund and, in particular, amounts required to pay the deferred portion of the purchase price for any assets acquired by the Fund, directly or indirectly) and to provide for the payment of any tax liability of the Fund or its subsidiary entities. Where the Trustees determine that the Fund does not have available cash in an amount sufficient to make payment of the full amount of any distribution which has been declared to be payable on the due date for such payment, the payment may, at the option of the Trustees, include the pro rata issuance of additional Units, or fractions of Units, if necessary, having a value equal to the difference between the amount of such distribution and the amount of cash which has been determined by the Trustees to be available for the payment of such distribution. Such additional Trust Units will be issued pursuant to exemptions under applicable securities laws, discretionary exemptions granted by applicable securities regulatory authorities or a prospectus or similar filing. In addition, the Trustees may declare to be payable and make distributions to the Unitholders, from time to time, out of Net Income of the Fund, Net Realized Capital Gains of the Fund, the capital of the Fund or otherwise, in any year, in such amount or amounts, and on such dates as the Trustees may determine. Having regard to the present intention of the Trustees to allocate, distribute and make payable to Unitholders all of the Net Income of the Fund, Net Realized Capital Gains of the Fund and any other applicable amounts for each taxation year so that the Fund will not have any liability for tax under Part I of the Income Tax Act in any such year, the amount, if any, by which the Net Income of the Fund and Net Realized Capital Gains of the Fund for each taxation year exceed the aggregate of: (i) such part of the taxable capital gains of the Fund for the year required to be retained by the Fund to maximize its capital gains refund for such year, but only if the Trustees have passed a resolution that this is to apply to the Fund for that year by the end of the year; and (ii) any

<table>
<thead>
<tr>
<th></th>
<th>Three months ended March 31, 2005</th>
<th>Three months ended June 30, 2005</th>
<th>Three months ended September 30, 2005</th>
<th>Three months ended December 31, 2005</th>
<th>Year ended December 31, 2005</th>
</tr>
</thead>
<tbody>
<tr>
<td>Interest Expense</td>
<td>4.6</td>
<td>5.1</td>
<td>6.3</td>
<td>6.3</td>
<td>22.3</td>
</tr>
<tr>
<td>Income Taxes</td>
<td>0.2</td>
<td>(2.4)</td>
<td>0.9</td>
<td>(1.5)</td>
<td>(2.8)</td>
</tr>
<tr>
<td>Net Earnings/(Loss)</td>
<td>7.3</td>
<td>13.8</td>
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<td>1.8</td>
<td>28.0</td>
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<td>Net Earnings/(Loss) per Trust Unit</td>
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<td>1,048.3</td>
<td>1,048.3</td>
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<tr>
<td>Total Long Term Debt</td>
<td>185.3</td>
<td>265.8</td>
<td>268.4</td>
<td>228.0</td>
<td>228.0</td>
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<tr>
<td>Distributions per Trust Unit</td>
<td>0.23</td>
<td>0.23</td>
<td>0.23</td>
<td>0.23</td>
<td>0.23</td>
</tr>
</tbody>
</table>
amount that became payable by the Fund during the year to Unitholders on the Trust Units (other than amounts that became payable to Unitholders on the redemption of their Trust Units), shall without any further actions on the part of the Trustees, be due and payable at the end of the year to Unitholders of record as at that time.

The Fund includes in its monthly distributions cash dividends, distributions or returns of capital, if any, received from Fund Businesses. Monthly distributions are made to Unitholders of record on the last day of each month and are expected to be paid on or before 45 days thereafter without interest or penalty. Revenues from the hydroelectric facilities operated by the Fund Businesses are higher in the spring due to the spring run-off and in the fall due to higher levels of rainfall and, as a result, distributable cash is typically greater during the months ending in the spring and the fall. In an effort to assist in the equalization of distributions throughout the year, funds have been set aside to be used at the discretion of the Trustees to help compensate for seasonal fluctuations in waterflows. The Trustees declared and made distributions totaling $67 million during 2006. Distributions of $63.4 million and $64.1 million were made in 2004 and 2005, respectively. The amount of distributions is dependent on a number of factors. See “Risk Factors” below. The Fund does not currently anticipate any change to its distribution policy.

**MANAGEMENT’S DISCUSSION AND ANALYSIS**


**CANADIAN FEDERAL INCOME TAX CONSIDERATIONS**

In the opinion of Blake, Cassels & Graydon LLP, counsel to the Fund, the following summary describes the principal Canadian federal income tax considerations pursuant to the Tax Act and the regulations thereunder generally applicable to a Unitholder who acquires Trust Units and who, for purposes of the Tax Act, is resident in Canada, holds the Trust Units as capital property and deals at arm’s length with the Fund, Algonquin Power and the Manager and is not affiliated with the Fund, Algonquin Power or the Manager. Generally, Trust Units will be considered to be capital property to a Unitholder provided the Unitholder does not hold the Trust Units in the course of carrying on a business and has not acquired them in one or more transactions considered to be an adventure in the nature of trade. Certain Unitholders who might not otherwise be considered to hold their Trust Units as capital property may, in certain circumstances, be entitled to have them treated as capital property by making the election permitted by subsection 39(4) of the Tax Act. This summary is not applicable to a Unitholder that is a “financial institution” for purposes of the mark-to-market rules, to a Unitholder an interest in which is a “tax shelter investment” or to any such Unitholder that is a “specified financial institution”, all within the meaning of the Tax Act. Any such Unitholder should consult its own tax advisor with respect to an investment in Trust Units.

This summary is based upon the provisions of the Tax Act and the Income Tax Regulations (the “Regulations”) in force as of the date hereof, all specific proposals to amend the Tax Act or the Regulations that have been publicly announced by the Minister of Finance prior to the date hereof, including the 2006 Proposed Changes (as defined below) (the “Proposed Amendments”), certificates of the Fund and Algonquin Power as to certain factual matters and Counsel’s understanding of the administrative policies and assessing practices of the Canada Revenue Agency (“CRA”) made publicly available prior to the date hereof. This summary is also based on the assumption that the Fund will at all times comply with the Declaration of Trust. On October 31, 2003, The Department of Finance (“Finance”) released, for public consultation, draft proposed amendments (the “October 31 Proposals”)
to the Tax Act that would require, for taxation years commencing after 2004, that there be a reasonable expectation of profit from a business or property for a taxpayer to realize a loss from such business or property, and that makes it clear that a profit for this purpose does not include capital gains. This summary does not take into account the effect of the October 31 Proposals on a Unitholder or the Fund. On February 23, 2005, the Minister of Finance announced that the Department of Finance has developed an alternative to the October 31 Proposals which will be released for comment in the near future. Such alternative proposal has not yet been released.

This summary is not exhaustive of all possible Canadian federal income tax consequences and, except for the Proposed Amendments, does not take into account or anticipate any changes in the law or in the administrative policies or assessing practices of CRA, whether by legislative, governmental or judicial action, nor does it take into account provincial, territorial or foreign tax considerations, which may differ significantly from those discussed herein. No assurance can be given that the Proposed Amendments will be enacted as currently proposed or at all.

This summary is of a general nature only and is not intended to be legal or tax advice to any prospective purchaser of Trust Units or any Unitholder. Consequently, prospective purchasers and Unitholders should consult their own tax advisors with respect to their particular circumstances.

This summary is based on the assumption that each of Clean Power and the Fund would have been “SIFT trusts” on October 31, 2006 as defined in Bill C-52, tabled in the House of Commons on March 29, 2007, had such legislation been in force and applied at that date. If this were not the case the discussion below would be materially adversely different.

Status of the Fund

This summary assumes that the Fund qualifies and will continue to qualify as a “mutual fund trust” as defined in the Tax Act. In order to so qualify, Trust Units representing at least 95% of the fair market value of all Trust Units of the Fund must have conditions attached thereto that include conditions requiring the Fund to accept, at the demand of the holder thereof and at prices determined and payable in accordance with the conditions, the surrender of the Trust Units, or fractions or parts thereof, that are fully paid. In addition, there must at all times be at least 150 Unitholders of the Fund each of whom owns not less than one “block” of Trust Units having a fair market value of not less than $500. A “block” of Trust Units means 100 Trust Units if the fair market value of one Trust Unit is less than $25. Further, the undertaking of the Fund must be restricted to the investing of its funds in property (other than real property or an interest in real property), the acquiring, holding, maintaining, improving, leasing or managing of any real property (or an interest in real property) that is capital property of the Fund, or a combination of these activities. The Fund will be deemed not to be a mutual fund trust if it can reasonably be considered that the Fund, having regard to all the circumstances, was established or is maintained primarily for the benefit of non-resident persons. On September 16, 2004, the Minister of Finance released certain proposals such that a trust such as the Fund would lose its status as a mutual fund trust under the Tax Act if, at any time, the aggregate fair market value of all of its issued and outstanding units held by one or more non-resident persons and/or by partnerships which are not Canadian partnerships under the Tax Act, is more than 50% of the aggregate fair market value of all issued and outstanding units of the trust, unless no more than 10% (based on fair market value) of the trust’s property at any time is taxable Canadian property and certain other types of specified property. These proposals did not provide any means of rectifying the loss of mutual fund trust status. On December 6, 2004, the Minister of Finance suspended implementation of these proposals pending further consultation with the private sector.
While Counsel cannot provide an opinion on matters of fact such as the foregoing, Counsel understands that the Fund intends, and this summary assumes, that at all relevant times these and other applicable requirements will be satisfied and that the Fund is not established nor will it be maintained primarily for the benefit of non-resident persons and that more than 50% of the Units will not at any time be owned by non-residents of Canada or partnerships (other than partnerships all of the partners of which are residents of Canada (for purposes of the Tax Act)), so that the Fund qualifies and will continue to qualify as a mutual fund trust at all relevant times. In the event the Fund does not qualify as a mutual fund trust, the income tax considerations would in some respects be materially different from those described below. The Fund has been registered by CRA as a registered investment for purposes of the Tax Act.

2006 Proposed Changes

On October 31, 2006, Finance announced a Tax Fairness Plan which, in part, proposed changes to the manner in which certain flow-through entities and the distributions from such entities are taxed. On March 29, 2007, the Minister of Finance tabled Bill C-52 in the House of Commons to implement some of those changes. The summary below is based strictly on the general information found in the background paper issued by Finance at the time of the October 31, 2006 announcement (which is not legislation), the Guidelines (as defined below) issued by Finance on December 15, 2006, and Bill C-52 (together, the “2006 Proposed Changes”). No assurance can be given that the final legislation implementing the 2006 Proposed Changes will be consistent with the foregoing or that Canadian federal income tax law respecting income trusts and other flow-through entities will not be further changed in a manner which adversely affects the Fund and its Unitholders. To the extent that changes, including the 2006 Proposed Changes, are implemented, such changes could result in the income tax considerations described below being materially different in certain respects. The 2006 Proposed Changes, if enacted, would apply a tax on certain income earned and distributed by a SIFT trust, as well as taxing the taxable distributions received by investors from such entities as dividends.

Pursuant to the 2006 Proposed Changes, the Fund will constitute a SIFT trust and, as a result, the Fund and its Unitholders will be subject to the 2006 Proposed Changes. It is assumed for the purposes of this summary that the Fund will be characterized as a SIFT trust.

For income trusts that would have been SIFT trusts on October 31, 2006, as defined in Bill C-52, had such legislation been in force and applied at that date, the 2006 Proposed Changes will not apply to the trust for a taxation year of the trust that ends before the earlier of 2011 and the first day after December 15, 2006 on which the trust exceeds normal growth as determined by the Guidelines (as defined below) as amended from time to time, unless the excess arose as the result of a prescribed transaction. On December 15, 2006, Finance issued a press release that provided guidelines with respect to the meaning of “undue expansion” and “normal growth” (the “Guidelines”). The Guidelines indicate that no change will be recommended to the 2011 date in respect of any “SIFT” whose equity capital grows as a result of issuances of new equity (which includes Trust Units, debt that is convertible into Trust Units, and potentially other substitutes for such equity), before 2011, by an amount that does not exceed the greater of $50 million and an objective “safe harbour” amount based on a percentage of the SIFT's market capitalization as of the end of trading on October 31, 2006 (measured in terms of the value of a SIFT's issued and outstanding publicly-traded units, not including debt, options or other interests that were convertible into units of the SIFT). For the period from November 1, 2006 to the end of 2007, the Guidelines provide that a SIFT's safe harbour will be 40% of the October 31, 2006 benchmark.

On March 16, 2007, Algonquin Power Trust commenced a formal take-over bid (the “Clean Power Offering”) for all of the outstanding trust units and convertible debentures of Clean Power in consideration for Trust Units plus contingent value receipts, and convertible debentures of the Fund,
respectively. Even if the Fund were to issue such Trust Units and convertible debentures, it is not anticipated that it would exceed the 40% safe harbour amount under the Guidelines taking into account certain exceptions provided in the Guidelines. No assurances can be given by counsel that the 2006 Proposed Changes will be enacted as proposed and that the Fund might not become subject to the 2006 Proposals prior to 2011.

Taxation of the Fund

Subject to the 2006 Proposed Changes, the Fund is subject to taxation in each taxation year on its taxable income for the year, including net realized taxable capital gains, less the portion thereof that is paid or payable in the year to Unitholders and which is deducted by the Fund in computing its income for purposes of the Tax Act. An amount will be considered to be payable to a Unitholder in a taxation year if it is paid in the year by the Fund or the Unitholder is entitled in that year to enforce payment of the amount. The taxation year of the Fund is the calendar year.

The Fund will generally be entitled to deduct its expenses incurred to earn such income provided such expenses are reasonable and otherwise deductible, and it will be entitled to claim capital cost allowance with respect to its undepreciated capital cost in any facility equipment held by the Fund, subject to the provisions of the Tax Act in that regard. The Fund will be limited to claiming as a deduction in respect of capital cost allowance relating to “leasing property” and “specified energy property”, within the meaning of the Tax Act, an amount equal to the Fund’s income from such property. The Fund may deduct in computing its income for a year a portion of the reasonable expenses of the issue of Trust Units paid by the Fund from the proceeds of the public offerings of its Units. Such portion of issue expenses deductible by the Fund in a taxation year is determined pursuant to the Tax Act and is generally equal to that portion of 20% of the total issue expenses that the number of days in the Fund’s taxation year is of 365 days, to the extent that the issue expenses were not otherwise deductible in a preceding year.

Under the Declaration of Trust, an amount equal to all of the income of the Fund for each year (determined without reference to paragraph 82(1)(b) and subsection 104(6) of the Tax Act), together with the taxable and non-taxable portion of any capital gains realized by the Fund in the year, (excluding income and capital gains which may be realized by the Fund upon a distribution in specie of the Fund Assets in connection with a redemption of a Trust Unit) net of the Fund’s deductions and expenses, will be payable in the year to the holders of the Trust Units by way of cash distributions, subject to the exceptions described below.

Under the Declaration of Trust, cash of the Fund may be used to finance cash redemptions of Trust Units and accordingly such cash so utilized will not be payable to holders of the Trust Units by way of cash distributions but rather may be payable in the form of additional Trust Units (“Reinvested Trust Units”).

A distribution by the Fund to a Unitholder of a portion of the assets of the Fund upon a redemption of Trust Units will be treated as a disposition thereof by the Fund for proceeds equal to their fair market value (determined, in the case of an interest in the debt obligations held by the Fund, without taking into account any accrued interest) and will give rise to income (or loss) and/or a capital gain (or a capital loss) to the Fund to the extent that the fair market value of the Fund Assets so distributed (less any accrued interest) exceeds (or is exceeded by) the cost amount to the Fund of the respective portion of the Fund Assets immediately prior to the distribution. In addition, the Fund will be required to include in its income any interest that had accrued on any of the Fund Notes and other accrued but unpaid income, if any, in respect of the Fund Assets so disposed of up to the date of distribution to the extent not otherwise included in its income for the year of disposition or a previous year. On a redemption of Trust Units,
income and capital gains arising in the Fund attributable to an in specie distribution of Fund Assets and certain income of the Fund will be payable to the redeeming Unitholder, with the result that the taxable portion of such gains and such income should generally be taxable to the redeeming Unitholder and not the Fund. Nevertheless, the Declaration of Trust provides that cash of the Fund which is required to satisfy any tax liabilities on the part of the Fund will not be payable to the Unitholders.

For purposes of the Tax Act, the Fund generally intends to deduct in computing its income such amount as will be sufficient to ensure that the Fund will not be liable for income tax under Part I of the Tax Act except to the extent that the Fund expects to receive a “capital gains refund” determined under the Tax Act based on redemptions of Trust Units during the year. Counsel has been advised by the Fund that the Fund does not expect that it will be liable for any material amount of tax under Part I of the Tax Act and that the Fund does not expect to be adversely affected by the October 31 Proposals. However, Counsel can provide no opinion in this regard.

Under the 2006 Proposed Changes, on the basis that the Fund is a SIFT trust, once it becomes subject to the 2006 Proposed Changes, the Fund will no longer be able to deduct any part of the amounts payable to Unitholders in respect of non-portfolio earnings, which are defined as: (i) income from businesses it carries on in Canada or from its non-portfolio properties other than income that is a taxable dividend received by the trust (exceeding any losses for the taxation year from businesses or non-portfolio properties), and (ii) taxable capital gains from its dispositions of non-portfolio properties (exceeding its allowable capital losses from the disposition of such properties). Such amount is referred to as the non-deductible distributions amount. "Non-portfolio properties" include: (i) Canadian real, immovable and resource properties, as defined, if at any time the total fair market value of such properties is greater than 50% of the equity value of the SIFT trust itself, (ii) a property that the SIFT trust (or a non-arm's length person or partnership) uses in the course of carrying on a business in Canada, and (iii) investments in a subject entity that have a fair market value greater than 10% of the subject entity's equity value or a subject entity where the SIFT trust holds securities of it or its affiliates that have a total fair market value greater than 50% of the equity value of the SIFT trust. A subject entity includes corporations resident in Canada, trusts resident in Canada, and Canadian resident partnerships. It is expected that the investments by the Fund in Algonquin Power Trust and Algonquin Holdco will be investments in a subject entity for this purpose. Income which a SIFT trust is unable to deduct will be taxed in the SIFT trust at rates of tax similar to the combined federal and provincial corporate tax rate. For 2011, the 2006 Proposed Changes state that the combined rate would be 31.5%. At the time of their original release on October 31, 2006, the release stated that the 2006 Proposed Changes do not change the tax treatment of distributions that are paid as returns of capital and it is understood that that is intended to be the case.

**Taxation of the Unitholders**

Subject to the 2006 Proposed Changes, a Unitholder will generally be required to include in computing income for a particular taxation year the Unitholder’s portion of the income of the Fund for that taxation year, including net realized taxable capital gains, that is paid or payable to the Unitholder in that particular year, notwithstanding that any such amount may be payable in Reinvested Trust Units.

Provided that appropriate designations are made by the Fund, such portions of its net taxable capital gains, taxable dividends from taxable Canadian corporations and foreign source income as are paid or payable to a Unitholder will effectively retain their character and be treated as such in the hands of the Unitholder for the purposes of the Tax Act. Accordingly, such amounts will generally be taken into account in determining the Unitholder’s foreign tax credits and, in the case of a Unitholder that is an individual, the Unitholder’s entitlement to the dividend tax credit. An enhanced gross-up and dividend tax credit is available for eligible dividends received from a corporation resident in Canada which are so designated by the corporation. Such amounts will also be taken into account in determining the
Unitholder’s liability, if any, for alternative minimum tax under the Tax Act.

Pursuant to the 2006 Proposed Changes, once the Fund becomes subject to the 2006 Proposed Changes, the portion of the taxable distributions received from the Fund by a Unitholder that is in respect of a non-deductible distribution amount of the Fund in a taxation year will be received by the Unitholder as a taxable dividend from a taxable Canadian corporation and an eligible dividend for purposes of the enhanced dividend gross-up and tax credit.

Any amount in excess of the income of the Fund that is paid or payable by the Fund to a Unitholder in a year should not generally be included in the Unitholder’s income for the year. However, where such an amount is paid or becomes payable to a Unitholder, other than as proceeds of disposition or deemed disposition of Trust Units or any part thereof, the amount will generally reduce the adjusted cost base of the Trust Units held by such Unitholder, except to the extent that the amount represents the Unitholder’s share of the non-taxable portion of the net realized capital gains of the Fund for the year, the taxable portion of which was designated by the Fund in respect of the Unitholder. To the extent that the adjusted cost base of a Trust Unit would otherwise be less than zero in any taxation year of a Unitholder, the negative amount will be deemed to be a capital gain realized by the Unitholder in such taxation year from the disposition of the Trust Unit and the amount of such capital gain will be added to the adjusted cost base of the Trust Unit.

The adjusted cost base of a Trust Unit to a Unitholder will include all amounts paid or payable by the Unitholder for the Trust Unit, with certain adjustments. Trust Units issued to a Unitholder in lieu of a cash distribution of income (including net capital gains) will have a cost equal to the amount of such income and this cost will be averaged with the adjusted cost base of all other Trust Units held as capital property in accordance with the detailed provisions of the Tax Act in that regard.

Upon the disposition or deemed disposition by a Unitholder of a Trust Unit, whether on redemption or otherwise, the Unitholder will generally realize a capital gain (or a capital loss) equal to the amount by which the proceeds of disposition (excluding any amount payable by the Fund which represents an amount that must otherwise be included in the Unitholder’s income as described above) are greater (or less) than the aggregate of the Unitholder’s adjusted cost base of the Trust Unit and any reasonable costs of disposition. Where Trust Units are redeemed and any Fund Assets are distributed in specie to the Unitholder, the proceeds of disposition to the Unitholder of the Trust Units will be equal to the fair market value of the Fund Assets so distributed (excluding any income or gain realized by the Fund on the disposition of such Fund Assets to the Unitholder).

One-half of any capital gain realized by a Unitholder on the disposition of a Trust Unit and the amount of any net taxable capital gains designated by the Fund in respect of a Unitholder will be included in the Unitholder’s income under the Tax Act in the taxation year in which the disposition occurs or in respect of which a net taxable capital gains designation is made by the Fund. Subject to certain specific rules in the Tax Act, one-half of any capital loss realized on the disposition of a Trust Unit may be deducted against one-half of any capital gains realized by the Unitholder in the year of disposition, in the three preceding taxation years or in any subsequent taxation years. Capital losses realized on a disposition of Trust Units by a Unitholder that is a corporation may be reduced by the amount of taxable dividends designated to the Unitholder in accordance with the detailed rules in the Tax Act in that regard.
The cost amount to a Unitholder, immediately after a redemption of Trust Units of the Unitholder, of any Fund Assets distributed to the Unitholder by the Fund upon such redemption or upon the termination of the Fund, will be equal to the fair market value of such Fund Assets at the time of the distribution. The redeeming Unitholder will be required to include in income interest on any Fund Note acquired (including interest that had accrued prior to the date of the acquisition of the interest in the Fund Note by the Unitholder) in accordance with the provisions of the Tax Act. To the extent that the Unitholder is required to include in income any interest that had accrued prior to the date of the acquisition of the Fund Notes by the Unitholder, an offsetting deduction may be available and to the extent of such deduction the adjusted cost base of the Fund Notes will be reduced.

Taxable capital gains realized by a Unitholder that is an individual may give rise to alternative minimum tax, depending on the Unitholder’s circumstances.

Holders are advised to consult their own tax advisors prior to exercising their redemption rights.

**Tax Exempt Unitholders**

The Trust Units will generally be qualified investments for trusts (“Plans”) governed by registered retirement savings plans (“RRSPs”), registered retirement income funds (“RRIFs”), deferred profit sharing plans (“DPSPs”) and registered education savings plans (“RESPs”) under the Tax Act, subject however to the specific provisions of any particular Plan and the Fund maintaining its status as a mutual fund trust or continuing to be a registered investment under the Tax Act. The Trust Units will not be prohibited investments for registered pension plans, subject to the qualifications set out under the heading “Eligibility For Investment”. The Plans will generally not be liable for tax in respect of any distributions received from the Fund or any capital gains realized on the disposition of any Trust Units. Where a Plan receives Fund Assets as a result of a redemption of Trust Units, such Fund Assets will likely not be qualified investments under the Tax Act for the Plans and could give rise to adverse consequences to the Plans (and, in the case of RRSPs or RRIFs, to the annuitants thereunder) including, in the case of RESPs, revocation of such Plans. Accordingly, Plans that own Trust Units should consult their own tax advisors before deciding to exercise the redemption rights thereunder.

If the Fund ceases to qualify as a mutual fund trust and the Fund’s registration as a registered investment under the Tax Act is revoked, the Trust Units will cease to be qualified investments under the Tax Act for Plans which could give rise to adverse consequences to the Plans (and in the case of RRSPs and RRIFs to the annuitants thereunder) including, in the case of RESPs, revocation of the registration of such Plans.

**ELIGIBILITY FOR INVESTMENT**

In the opinion of Blake, Cassels & Graydon LLP, as at the date hereof, eligibility of the Trust Units for investment by purchasers to whom the following statutes apply is, in certain cases, governed by criteria which such purchasers are required to establish as policies or guidelines pursuant to the applicable statute (and, where applicable, the regulations thereunder) and is subject to compliance with the prudent investment standards and general investment provisions provided therein:

- *Insurance Companies Act* (Canada)
- *Trust and Loan Companies Act* (Canada)
- *Pension Benefits Standards Act, 1985* (Canada)
- *an Act respecting insurance* (Québec) (in respect of insurers other than guarantee fund corporations, mutual associations and professional corporations)
an Act respecting trust companies and savings companies (Québec) (for a trust company investing its own funds and deposits it receives and a savings company (as defined therein) investing its funds)
Supplemental Pension Plans Act (Québec)
Pension Benefits Act (Ontario)
Loan and Trust Corporations Act (Ontario)
Alberta Heritage Savings Trust Act (Alberta)
Loan and Trust Corporations Act (Alberta)
Employment Pension Plans Act (Alberta)
Insurance Act (Alberta)
Financial Institutions Act (British Columbia)
Pension Benefit Standards Act (British Columbia)
Pension Benefits Act (New Brunswick)
Pension Benefits Act, 1992 (Saskatchewan)
The Pension Benefits Act (Manitoba)

Subject to the assumptions, limitations and restrictions described under “Canadian Federal Income Tax Considerations” being met, and to the provisions of any particular plan, in the opinion of such Counsel, as at the date hereof, the Trust Units will also be qualified investments for trusts governed by RRSPs, RRIFs, DPSPs and RESPs.

RATINGS

The Fund currently maintains a triple B long-term corporate credit rating (BBB) and an SR-2/Negative stability rating. The Fund also carries a triple B (BBB) credit rating on its secured bank loan facility. The long-term corporate credit rating and the stability rating changed from a prior rating of triple B plus (BBB+) and SR-2/Stable, respectively.

On November 3, 2006, Standard & Poor’s (“S&P”) placed the Fund’s triple B plus (BBB+) long-term corporate credit rating and the Fund’s SR-2 Canadian stability rating on credit watch with negative implications (SR-2/StabilityWatchNeg) following the announcement by the Fund that it had postponed the Trust Unit offering planned by the Fund in October 2006 and the Series 2 Debenture offering which was eventually completed by the Fund on November 22, 2006. The credit watch designation on the Fund’s SR-2 Canadian stability rating was removed by Standard & Poors on December 8, 2006, based on its conclusion that the fundamental cash generation characteristics of the Fund will be generally unchanged in the near term, despite the Canadian federal government’s recently announced proposal to tax existing non-REIT income trusts starting in 2011.

On March 9, 2007, Standard & Poor’s announced that it was lowering the Fund’s long-term corporate credit rating from BBB+ to BBB and removed the rating from its credit watch designation. Standard & Poor’s commented that increased financial and merchant risk was generally responsible for the downgrade decision.

The income fund stability and sustainability rating system managed by S&P is intended to rank the stability of an income fund’s cash distribution stream on the basis of volatility and sustainability. The scale utilized by S&P runs from SR-1 (Highest) to SR-7 (Very Low). A rating of 'SR-1' signifies the highest level of expected sustainability and the lowest level of expected variability in a fund's distribution stream relative to other rated Canadian income funds. Conversely, a rating of 'SR-7' indicates the highest degree of expected variability and the lowest degree of expected sustainability in distributions. Funds
rated 'SR-2' are considered by S&P to have a very high level of cash distribution stability relative to other rated Canadian income funds.

S&P’s issue credit rating is a current opinion of the creditworthiness of an obligor with respect to a specific financial obligation, a specific class of financial obligations, or a specific financial program (such as medium-term note programs and commercial paper programs). The rating takes into consideration the creditworthiness of guarantors, insurers, or other forms of credit enhancement on the obligation, as well as the currency in which the obligation is denominated. Long-term credit ratings are divided into several categories ranging from ‘AAA’, reflecting the strongest credit quality, to ‘D’, reflecting the lowest. Long-term ratings from ‘AA’ to ‘CCC’ may be modified by the addition of a plus or minus sign to show relative standing within the major rating categories.

According to S&P, an obligation rated ‘BBB’ exhibits adequate protection parameters. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitment on the obligation. The addition of the plus reflects the relative standing of the Fund within the ‘BBB’ rating category.

Investors should be advised that the ratings provided by S&P are not recommendations to buy, sell or hold Trust Units and are subject to revision or withdrawal at any time by S&P.

MARKET FOR SECURITIES

Trading Price and Volume

Trust Units

The Trust Units have been listed and posted for trading on the Toronto Stock Exchange (“TSX”) since December 23, 1997 under the symbol “APF.UN”. The following table sets forth the high and low closing prices and the aggregate volume of trading of the Trust Units on the periods indicated (as quoted by the TSX):

<table>
<thead>
<tr>
<th>Period</th>
<th>High ($)</th>
<th>Low ($)</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>January</td>
<td>10.80</td>
<td>10.21</td>
<td>120,942</td>
</tr>
<tr>
<td>February</td>
<td>11.30</td>
<td>10.33</td>
<td>264,709</td>
</tr>
<tr>
<td>March</td>
<td>11.24</td>
<td>10.22</td>
<td>146,856</td>
</tr>
<tr>
<td>April</td>
<td>10.52</td>
<td>9.05</td>
<td>174,171</td>
</tr>
<tr>
<td>May</td>
<td>9.50</td>
<td>9.01</td>
<td>120,278</td>
</tr>
<tr>
<td>June</td>
<td>9.60</td>
<td>9.01</td>
<td>111,794</td>
</tr>
<tr>
<td>July</td>
<td>9.58</td>
<td>9.13</td>
<td>99,701</td>
</tr>
<tr>
<td>August</td>
<td>9.49</td>
<td>9.10</td>
<td>117,549</td>
</tr>
<tr>
<td>September</td>
<td>9.89</td>
<td>9.25</td>
<td>146,385</td>
</tr>
<tr>
<td>October</td>
<td>10.43</td>
<td>9.60</td>
<td>175,113</td>
</tr>
<tr>
<td>November</td>
<td>10.34</td>
<td>9.70</td>
<td>167,273</td>
</tr>
<tr>
<td>December</td>
<td>10.75</td>
<td>10.14</td>
<td>86,601</td>
</tr>
</tbody>
</table>
### Trading of Trust Units on the Toronto Stock Exchange

<table>
<thead>
<tr>
<th>Period</th>
<th>High ($)</th>
<th>Low ($)</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>January</td>
<td>10.68</td>
<td>10.32</td>
<td>138,735</td>
</tr>
<tr>
<td>February</td>
<td>10.69</td>
<td>20.26</td>
<td>199,435</td>
</tr>
<tr>
<td>March</td>
<td>10.33</td>
<td>9.07</td>
<td>193,435</td>
</tr>
<tr>
<td>April</td>
<td>10.04</td>
<td>9.30</td>
<td>121,795</td>
</tr>
<tr>
<td>May</td>
<td>10.20</td>
<td>9.55</td>
<td>124,295</td>
</tr>
<tr>
<td>June</td>
<td>10.52</td>
<td>9.95</td>
<td>117,204</td>
</tr>
<tr>
<td>July</td>
<td>10.78</td>
<td>10.25</td>
<td>152,670</td>
</tr>
<tr>
<td>August</td>
<td>10.61</td>
<td>9.86</td>
<td>126,095</td>
</tr>
<tr>
<td>September</td>
<td>10.42</td>
<td>9.76</td>
<td>150,652</td>
</tr>
<tr>
<td>October</td>
<td>10.10</td>
<td>9.15</td>
<td>177,425</td>
</tr>
<tr>
<td>November</td>
<td>10.46</td>
<td>9.20</td>
<td>169,363</td>
</tr>
<tr>
<td>December</td>
<td>10.62</td>
<td>10.12</td>
<td>153,375</td>
</tr>
<tr>
<td>2006</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>January</td>
<td>11.07</td>
<td>10.20</td>
<td>164,709</td>
</tr>
<tr>
<td>February</td>
<td>11.05</td>
<td>10.12</td>
<td>185,225</td>
</tr>
<tr>
<td>March</td>
<td>10.95</td>
<td>9.75</td>
<td>138,952</td>
</tr>
<tr>
<td>April</td>
<td>10.60</td>
<td>10.05</td>
<td>64,489</td>
</tr>
<tr>
<td>May</td>
<td>10.32</td>
<td>9.50</td>
<td>112,781</td>
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<tr>
<td>June</td>
<td>10.20</td>
<td>9.28</td>
<td>97,113</td>
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<tr>
<td>July</td>
<td>10.30</td>
<td>9.17</td>
<td>162,420</td>
</tr>
<tr>
<td>August</td>
<td>10.25</td>
<td>9.85</td>
<td>106,395</td>
</tr>
<tr>
<td>September</td>
<td>10.48</td>
<td>9.93</td>
<td>205,160</td>
</tr>
<tr>
<td>October</td>
<td>10.39</td>
<td>10.05</td>
<td>219,561</td>
</tr>
<tr>
<td>November</td>
<td>10.09</td>
<td>8.49</td>
<td>341,009</td>
</tr>
<tr>
<td>December</td>
<td>9.95</td>
<td>9.15</td>
<td>224,273</td>
</tr>
</tbody>
</table>

### Series 1 Debentures

The Series 1 Debentures have been listed and posted for trading on the Toronto Stock Exchange ("TSX") since July 20, 2004 under the symbol “APF.DB”. The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 1 Debentures on the periods indicated (as quoted by the TSX):

<table>
<thead>
<tr>
<th>Period</th>
<th>High ($)</th>
<th>Low ($)</th>
<th>Volume $100</th>
</tr>
</thead>
<tbody>
<tr>
<td>2004</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>July 20 – July 31</td>
<td>100.45</td>
<td>99.00</td>
<td>108,210</td>
</tr>
<tr>
<td>August</td>
<td>102.75</td>
<td>100.00</td>
<td>66,010</td>
</tr>
<tr>
<td>September</td>
<td>108.00</td>
<td>101.60</td>
<td>29,320</td>
</tr>
<tr>
<td>October</td>
<td>106.00</td>
<td>102.60</td>
<td>17,290</td>
</tr>
<tr>
<td>November</td>
<td>107.99</td>
<td>102.60</td>
<td>17,190</td>
</tr>
<tr>
<td>December</td>
<td>107.00</td>
<td>103.35</td>
<td>14,110</td>
</tr>
</tbody>
</table>
## Trading of Series 1 Debentures on the Toronto Stock Exchange

<table>
<thead>
<tr>
<th>Period</th>
<th>High</th>
<th>Low</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>107.00</td>
<td>104.50</td>
<td>8,720</td>
</tr>
<tr>
<td>February</td>
<td>107.00</td>
<td>103.53</td>
<td>25,670</td>
</tr>
<tr>
<td>March</td>
<td>104.50</td>
<td>100.25</td>
<td>31,330</td>
</tr>
<tr>
<td>April</td>
<td>105.00</td>
<td>102.00</td>
<td>20,840</td>
</tr>
<tr>
<td>May</td>
<td>104.50</td>
<td>102.10</td>
<td>15,250</td>
</tr>
<tr>
<td>June</td>
<td>106.53</td>
<td>103.10</td>
<td>6,750</td>
</tr>
<tr>
<td>July</td>
<td>106.00</td>
<td>103.51</td>
<td>8,050</td>
</tr>
<tr>
<td>August</td>
<td>108.00</td>
<td>103.75</td>
<td>5,260</td>
</tr>
<tr>
<td>September</td>
<td>109.53</td>
<td>105.50</td>
<td>10,130</td>
</tr>
<tr>
<td>October</td>
<td>108.00</td>
<td>100.53</td>
<td>12,080</td>
</tr>
<tr>
<td>November</td>
<td>106.50</td>
<td>102.00</td>
<td>16,160</td>
</tr>
<tr>
<td>December</td>
<td>106.53</td>
<td>103.00</td>
<td>8,320</td>
</tr>
</tbody>
</table>

2005

<table>
<thead>
<tr>
<th>Period</th>
<th>High</th>
<th>Low</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>January</td>
<td>106.53</td>
<td>103.75</td>
<td>8,210</td>
</tr>
<tr>
<td>February</td>
<td>106.53</td>
<td>103.00</td>
<td>6,820</td>
</tr>
<tr>
<td>March</td>
<td>105.50</td>
<td>103.25</td>
<td>13,940</td>
</tr>
<tr>
<td>April</td>
<td>104.75</td>
<td>100.70</td>
<td>13,840</td>
</tr>
<tr>
<td>May</td>
<td>104.49</td>
<td>100.53</td>
<td>12,780</td>
</tr>
<tr>
<td>June</td>
<td>104.00</td>
<td>101.00</td>
<td>10,300</td>
</tr>
<tr>
<td>July</td>
<td>104.10</td>
<td>101.00</td>
<td>12,100</td>
</tr>
<tr>
<td>August</td>
<td>104.95</td>
<td>101.31</td>
<td>4,830</td>
</tr>
<tr>
<td>September</td>
<td>105.26</td>
<td>103.11</td>
<td>6,360</td>
</tr>
<tr>
<td>October</td>
<td>106.53</td>
<td>102.00</td>
<td>7,520</td>
</tr>
<tr>
<td>November</td>
<td>105.49</td>
<td>100.53</td>
<td>13,820</td>
</tr>
<tr>
<td>December</td>
<td>104.00</td>
<td>100.98</td>
<td>9,850</td>
</tr>
</tbody>
</table>

2006

<table>
<thead>
<tr>
<th>Period</th>
<th>High</th>
<th>Low</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>November 22 – November 30</td>
<td>97.68</td>
<td>96.14</td>
<td>48,150</td>
</tr>
<tr>
<td>December</td>
<td>102.00</td>
<td>98.00</td>
<td>81,190</td>
</tr>
</tbody>
</table>

### Series 2 Debentures

The Series 2 Debentures have been listed and posted for trading on the Toronto Stock Exchange since November 22, 2006 under the symbol “APF.DB.A”. The following table sets forth the high and low closing prices and the aggregate volume of trading of the Series 2 Debentures on the periods indicated (as quoted by the TSX):

## Trading of Series 2 Debentures on the Toronto Stock Exchange

<table>
<thead>
<tr>
<th>Period</th>
<th>High</th>
<th>Low</th>
<th>Volume</th>
</tr>
</thead>
<tbody>
<tr>
<td>November 22 – November 30</td>
<td>97.68</td>
<td>96.14</td>
<td>48,150</td>
</tr>
<tr>
<td>December</td>
<td>102.00</td>
<td>98.00</td>
<td>81,190</td>
</tr>
</tbody>
</table>
TRUSTEES AND OFFICER OF THE FUND

The following table sets forth certain information with respect to the Trustees and the sole officer of the Fund.

<table>
<thead>
<tr>
<th>Name and Municipality of Residence</th>
<th>Principal Occupation</th>
<th>Served as Trustee or Officer from</th>
<th>Number of Units Beneficially Owned (Dollar Value as of December 31, 2006)</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHRISTOPHER J. BALL Toronto, Ontario, Canada Age: 55</td>
<td>Christopher J. Ball is currently the Executive Vice President of Corpfinance International Limited, an investment banking boutique firm. From 1982 to 1988, Mr. Ball was Vice President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held various managerial positions with the Canadian Imperial Bank of Commerce. He is also a Director of the Independent Power Association of British Columbia.</td>
<td>Trustee since October 22, 2002</td>
<td>2,000 ($19,860)</td>
</tr>
<tr>
<td>KENNETH MOORE Toronto, Ontario, Canada Age: 48</td>
<td>Kenneth Moore is currently the Managing Partner of NewPoint Capital Partners Inc., an investment banking firm. From 1993 to 1997, Mr. Moore was a senior partner at Crosbie &amp; Co., another Toronto mid-market investment banking firm. Prior to investment banking, he was a Vice-President at Barclays Bank where he was responsible for a number of leveraged acquisitions and restructurings. Mr. Moore holds a Chartered Financial Analyst designation.</td>
<td>Trustee since December 18, 1998</td>
<td>6,000 ($59,580)</td>
</tr>
<tr>
<td>GEORGE L. STEEVES Aurora, Ontario, Canada Age: 56</td>
<td>Mr. Steeves is the Principal of True North Energy (1169417 Ontario Inc.), an energy consulting firm. From January 2001 to April 2002, Mr. Steeves was a division manager of Earthtech Canada Inc. Prior to January 2001, he was the president of Cumming Cockburn Limited, an engineering firm, and has extensive financial expertise in acting as a Chairman, director and/or audit committee member of public and private companies, including the Fund, Borealis Hydroelectric Holdings Inc. and KMS Power Income Fund. Mr. Steeves has completed the Chartered Director program of the Directors College</td>
<td>Trustee since September 8, 1997</td>
<td>5,718 ($56,779)</td>
</tr>
</tbody>
</table>

(1) Value as of December 31, 2006.

(2) Value as of December 31, 2007.
| Name and Municipality of Residence | Principal Occupation | Served as Trustee or Officer from | Number of Units Beneficially Owned (Dollar Value as of December 31, 2006)
---|---|---|---
PETER KAMPIAN Cambridge, Ontario, Canada Age: 48
500 ($4,965)
VITO CICIRETTI Newmarket, Ontario, Canada Age: 43
Mr. Ciciretti is the Chief Operating Officer of Algonquin Power Trust and Algonquin Power Income Fund Officer since August 2006
Nil

Notes:

(1) The closing price of the Trust Units on December 29, 2006, the last day of trading in 2006, was $9.93.

(2) Mr. Steeves’ directly owns 2,804 Units and Mr. Steeves’ spouse owns 2,914 Units. Mr. Steeves exercises control and direction over the Units owned by his spouse.

(3) Prior to becoming an officer of Algonquin Power Trust and Algonquin Power Income Fund in January 2002, Mr. Kampian had been Chief Financial Officer of the Manager since July 1999.

(4) Prior to becoming an officer of Algonquin Power Trust and Algonquin Power Income Fund in August 2006, Mr. Ciciretti held various positions, including General Manager and Executive Program Director, with Honeywell Aerospace from 1990 to July 2006.

Each of the Trustees will serve as a Trustee of the Fund until the next annual meeting of Unitholders or until his successor is elected in accordance with the Declaration of Trust.

Each of the Trustees has held their principal occupations for more than five years, other than Mr. Steeves who was from January 2001 to April 2002 a division manager of Earthtech Canada Inc. (engineering firm).

The Fund does not have an executive committee of the Trustees.
AUDIT COMMITTEE

Audit Committee Charter

Attached as Schedule “B” to the Annual Information Form is the charter for the Fund’s audit committee (the “Audit Committee”).

Composition of the Audit Committee

Members of the Audit Committee are Christopher J. Ball, Kenneth Moore and George L. Steeves. Each member of the Audit Committee is independent and financially literate.

Relevant Education and Experience

The following is a description of the education and experience, apart from their roles as Trustees of the Fund, of each member of the Audit Committee that is relevant to the performance of his responsibilities as a member of the Audit Committee.

Mr. Ball has extensive financial experience, with over 30 years of domestic and international lending experience. He is Executive Vice-President of Corpfinance International Limited, a privately owned long-term debt and securitization financier. Mr. Ball was formerly a Vice-President at Standard Chartered Bank of Canada with responsibilities for the Canadian branch operation. Prior to that, Mr. Ball held numerous positions with Canadian Imperial Bank of Commerce, including credit function responsibilities. Mr. Ball is the Chair of the Audit Committee.

Mr. Moore also has extensive financial experience. He is the Managing Partner of NewPoint Capital Partners Inc., a boutique financial advisory firm focused on mergers and acquisitions. He was formerly a Vice-President at a Canadian Chartered Bank. Mr. Moore holds a Chartered Financial Analyst designation.

Mr. Steeves received a Bachelor and Masters of Engineering from Carleton University. Mr. Steeves is the former president of Cumming Cockburn Limited and has extensive financial experience in acting as a Chairman, director and/or audit committee member of public and private companies, including the Fund, Borealis Hydroelectric Holdings Inc. and KMS. Mr. Steeves has completed the Chartered Director program of the Directors College (McMaster University and the Conference Board) and has the certification of Ch. Dir. (Chartered Director). He received a Bachelor and Masters of Engineering from Carlton University and holds the Professional Engineering designation in Ontario and British Columbia.

Pre-Approval Policies and Procedures

All non-audit services proposed to be provided by the Fund’s auditors must be approved by the Trustees prior to the auditors providing such services.
External Auditor Service Fees

For the financial year ended December 31, 2006 and December 31, 2005, KPMG LLP charged the following fees to the Fund:

<table>
<thead>
<tr>
<th>Services</th>
<th>2006 Fees ($)</th>
<th>2005 Fees ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Audit</td>
<td>330,000</td>
<td>350,000</td>
</tr>
<tr>
<td>Audit-Related(1)</td>
<td>443,894</td>
<td>191,540</td>
</tr>
<tr>
<td>Tax Fees(2)</td>
<td>247,800</td>
<td>281,600</td>
</tr>
<tr>
<td>All Other Fees</td>
<td>Nil</td>
<td>Nil</td>
</tr>
</tbody>
</table>

Notes:

(1) For assurance and related services that are reasonably related to the performance of the audit or review of the Fund’s financial statements and not reported under Audit Fees, including prospectus advice, accounting advice, French translation services and audits of Algonquin Sanger Power LLC, Litchfield Park Service Company and the Long Sault Partnership.

(2) For tax compliance, advice and planning services.

DIRECTORS AND EXECUTIVE OFFICERS OF THE MANAGER AND POWER SYSTEMS

The following sets out certain information with respect to the directors and executive officers of the Manager and Power Systems. Unless otherwise indicated, the directors and officers have been in their principal occupations for more than five years.

<table>
<thead>
<tr>
<th>Name and Municipality of Residence</th>
<th>Office</th>
<th>Principal Occupation</th>
</tr>
</thead>
<tbody>
<tr>
<td>CHRISTOPHER K. JARRATT Oakville, Ontario</td>
<td>Chief Executive Officer and Director of the Manager and Director of Power Systems</td>
<td>Principal of Algonquin Power</td>
</tr>
<tr>
<td>IAN E. ROBERTSON Oakville, Ontario</td>
<td>Vice-President and Director of the Manager and Director of Power Systems</td>
<td>Principal of Algonquin Power</td>
</tr>
<tr>
<td>DAVID C. KERR Toronto, Ontario</td>
<td>Vice-President, Secretary and Director of the Manager and Secretary and Director of Power Systems</td>
<td>Principal of Algonquin Power</td>
</tr>
</tbody>
</table>
Name and Municipality of Residence  Office  Principal Occupation

PETER KAMPIAN  Chief Financial Officer of the Manager and of Power Systems  Chief Financial Officer of Algonquin Power Income Fund

Cambridge, Ontario

Approximately 76,725 of the Trust Units are beneficially owned, directly or indirectly, by the directors and senior officers of the Manager, as a group.

LEGAL PROCEEDINGS

Except as otherwise described elsewhere in this annual information form and as described below, there are no legal proceedings to which the Fund is a party or to which its property is subject.

Campbellford Litigation

Algonquin Power Trust and certain of its subsidiaries are engaged in proceedings with 740769 Ontario Inc. in connection with a prepayment under the term loan owned by Algonquin Power Trust relating to the Campbellford Facility. It is too early in these proceedings to determine the potential exposure to the Fund.

Trafalgar Class B Note

In August 1999, the Fund and Algonquin Canada declared the Trafalgar Class B Note in default, accelerated the indebtedness represented thereby and initiated foreclosure proceedings. The outstanding balance of the Trafalgar Class B Note as at December 31, 2006 was approximately $US23.9 million.

Trafalgar, one of the co-issuers of the Trafalgar Class B Note, subsequently commenced an action in New York District Court against the Fund, Algonquin Canada, Algonquin Power and Aetna Life Insurance Company (“Aetna”) in connection with the sale of the Trafalgar Class B Note by Aetna to the Fund and Algonquin Canada and the Fund’s foreclosure on the security for the Trafalgar Class B Note. The Manager believes that this case is without merit. By a decision entered on December 19, 2006, the New York District Court held that the sale of the Trafalgar Class B Note to the Fund and Algonquin Canada was lawfully undertaken. The other claims made by Trafalgar are still in litigation. The decision may ultimately be appealed by Trafalgar. In a separate action, Trafalgar obtained a judgment against a third party and received an award of approximately US$10 million. The Fund has made a claim against this award. The Fund’s claim against this award is the subject of litigation in Trafalgar’s bankruptcy proceeding as described below.

On August 27, 2001, Trafalgar and Marina Development, Inc. (the sole shareholder of the Trafalgar Companies) filed for bankruptcy protection. As a result of the bankruptcy proceedings, all revenue generated by the Trafalgar Facilities is being held as part of the estate of Trafalgar, together with the amount of the US$10 million judgment award. All operating expenses are being paid from these amounts. US$2.75 million of these funds are to be paid to the Fund upon the conclusion of the Trafalgar dispute, irrespective of outcome.

Although the Manager paid one half of the external legal fees incurred up to July 1, 2002 with respect to this dispute, the Fund is funding the litigation. In the event of a recovery by the Fund of all or part of the funds, the Fund and the Manager will divide such amounts in proportion to the amount of legal fees funded, after reimbursement of expenses.
REGULATORY ACTIONS

Except as disclosed elsewhere in this annual information form, during the financial year ended December 31, 2006, there have been:

(a) no penalties or sanctions imposed against the Fund by a court relating to securities legislation or by a securities regulatory authority;

(b) no other penalties or sanctions imposed by a court or regulatory body against the Fund that would likely be considered important to a reasonable investor in making an investment decision; or

(c) no settlement agreements that the Fund has entered into with a court relating to securities legislation or with a securities regulatory authority.

INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as disclosed elsewhere in this annual information form, the Manager has no material interest, direct or indirect, in any transaction occurring within the three most recently completed financial or during the current financial year that has materially affected or will materially affect the Fund.

TRANSFER AGENTS AND REGISTRARS

The transfer agent and registrar for the Trust Units is CIBC Mellon Trust Company, at its offices in Toronto, Montréal, Vancouver, Calgary, Halifax and Winnipeg.

MATERIAL CONTRACTS

Except as disclosed elsewhere in this annual information form or as filed by the Fund on the System for Electronic Document Analysis and Retrieval (SEDAR), no contracts which could reasonably be regarded as material to the Fund have been entered into within the most recently completed financial year.

LEGAL MATTERS

Certain legal matters in connection with the preparation of this annual information form have been passed upon on behalf of the Fund and the Manager by Blake, Cassels & Graydon LLP. As of the date hereof, the partners and associates of Blake, Cassels & Graydon LLP own less than 1% of the issued and outstanding Trust Units of the Funds.

RISK FACTORS

The following are certain additional risk factors relating to the business of the Fund. The following information is a summary only of certain risk factors and is qualified in its entirety by reference to, and must be read in conjunction with, the detailed information appearing elsewhere in this annual information form and the documents incorporated by reference herein.
Regulatory Climate and Permits

Profitability of the Fund Businesses will be in part dependent upon the continuation of a favourable regulatory climate with respect to the continuing operations and the future growth and development of the independent power production industry as a whole and, in particular, with respect to the hydroelectric power segment of the industry. Should the regulatory regime be modified in a manner which adversely affects the treatment of such facilities, including increases in taxes and permit fees, distributable cash to Unitholders may be adversely affected.

The operation of infrastructure facilities is highly regulated. For example, in the case of hydroelectric generating facilities, water rights are generally owned by government and government agencies reserve the right to control water levels. The failure to obtain all necessary licences or permits, including renewals thereof or modifications thereto, may adversely affect distributable cash available for distribution to Unitholders.

In the United States, FERC issues licences for the construction, operation and maintenance of generating facilities. Facilities are required to be licenced or have valid exemptions from FERC. Failure to maintain such licences, including amendments or modifications thereto, may result in the owner being unable to operate the licenced facility and could adversely affect distributable cash available for distribution to Unitholders.

The US facilities obtain certain benefits and exemptions because of their Qualifying Facility status (“QF Status”) under PURPA. If any facility were to lose its QF Status, the facility would no longer be entitled to the exemptions and benefits thereof. Loss of QF Status may also require the facility to cease selling electricity at the rates set forth in the existing power purchase agreements to the extent they exceed current short run Avoided Costs. Under certain circumstances, loss of QF Status on a retroactive basis could lead to, among other things, claims by the utility customers for a refund of payments previously made.

The Fund’s water and wastewater facilities are subject to rate setting by State regulatory authorities. Rates charged by the Fund’s facilities may be reviewed and altered by the State regulatory authorities from time to time. These facilities are also subject to State and Federal permits, discharge parameters and other environmental requirements. Discharge and treatment requirements may change from time to time.

Dependence upon Fund Businesses

The Fund is entirely dependent upon the operations and assets of the Fund Businesses. Accordingly, distributions to Unitholders are dependent upon the ability of each of the Fund Businesses to pay principal and interest on the notes issued by it and to declare and pay dividends or distributions. The profitability of the Fund Businesses may be affected by expiry of the present long-term power purchase agreements to which certain of the Fund Businesses are a party.

Credit Line

The Fund has available the Credit Line provided by a syndicate of Canadian banks in the maximum principal amount of $175 million. The facility is to be utilized in respect of the acquisition of generating or infrastructure facilities by the Fund which meet the Fund's acquisition guidelines, letters of credit required in respect of acquired facilities and working capital requirements. As security for repayment of such line of credit, the Fund has, among other things, pledged the shares of certain Fund entities. As of December 31, 2006, the Fund had approximately $67 million outstanding under the Credit
Line. In addition, the Fund has posted certain letters of credit totaling $44.1 million as security for obligations of the Fund Businesses. The terms of the Credit Line require the Fund to pay a standby charge of 0.3% on the unused portion of the revolving credit facility and maintain certain financial covenants. The facility is secured by, among other things, a fixed and floating charge over all the entities owned by the Fund. If the Credit Line goes into default, or is not renewed or refinanced when due, there is a risk that the lenders could exercise their security. If the Credit Line is not renewed or refinanced on reasonable terms, distributions to Unitholders may be impaired.

**Loan Defaults**

The cash flows from several of the facilities are subordinated to senior debt. There is a risk that any particular loan may go into default if there is a breach in complying with such covenants and obligations resulting in the lender realizing on its security and, indirectly, causing the Fund to lose its investment in such facility.

**Tax Related Risks**

It is expected that the 2006 Proposed Changes, if enacted in their currently proposed form, will subject the Fund to trust level taxation beginning on January 1, 2011 (and potentially sooner), which will materially reduce the amount of cash available for distributions to Unitholders. A reduction in the value of the Trust Units would be expected to increase the cost to the Fund of raising capital in the public capital markets. There can be no assurance that the Fund will be able to reorganize its legal and tax structure to reduce the expected impact of the 2006 Proposed Changes. In addition, there can be no assurance that the Fund will be able to maintain its grandfathered status under the 2006 Proposed Changes until 2011. If the Fund is deemed to have undergone "undue expansion" during the transitional period from October 31, 2006 to December 31, 2010, the 2006 Proposed Changes would become effective on a date earlier than January 1, 2011. Loss of grandfathered status could have a material and adverse effect on the value of the Trust Units. See “Canadian Federal Income Tax Considerations”.

Even if the Fund were to issue Trust Units and convertible debentures in connection with the Clean Power Offering, it is not anticipated that the Fund would exceed the 40% safe harbour amount under the Guidelines taking into account certain exceptions provided under the Guidelines. See “Canadian Federal Income Tax Considerations”.

No assurance can be given as to the final provisions of any legislation that may be enacted to implement the 2006 Proposed Changes. The terms of such provisions may differ from those of the 2006 Proposed Changes described herein, possibly in ways that would be materially adverse to the Fund and the Unitholders.

There can be no assurance that income tax laws and the tax treatment of mutual fund trusts will not be changed in a manner which adversely affects Unitholders. In addition, adverse tax consequences may arise to Unitholders and to the Fund in the event that the Fund ceases to qualify as a “mutual fund trust” under the Tax Act, including potential liability for Part XII.2 taxes under the Tax Act. On September 16, 2004, the Minister of Finance released certain proposals that a trust, such as the Fund, would lose its status as a mutual fund trust under the Tax Act if, at any time, the aggregate fair market value of all of its issued and outstanding units held by one or more non-resident persons and/or by partnerships which are not Canadian partnerships under the Tax Act, is more than 50% of the aggregate fair market value of all issued and outstanding units of the trust, unless no more than 10% (based on fair market value) of the trust’s property at any time is taxable Canadian property and certain other types of specified property. These proposals did not provide any means of rectifying the loss of mutual fund trust status. On December 6, 2004, the Minister of Finance suspended implementation of these proposals.
pending further consultation with the private sector. 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 will agree. If CRA successfully
challenges the deductibility of such expenses or the correctness of such cost amounts, the return to
Unitholders may be adversely affected. The October 31 Proposals could offset the Fund’s ability to
deduct its expenses, although the Fund does not expect to be adversely affected by the October 31
Proposals (see also “Canadian Federal Income Tax Considerations”).

Growth Capital Requirements

The Fund’s water and wastewater 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. Accordingly, the Fund may have an obligation to expand its infrastructure and
facilities to accommodate this growth. The Fund may have a requirement to access capital to undertake
this construction obligation.

Environmental and Safety Considerations

The facilities encompass operations which require adherence to environmental and safety
standards imposed by regulatory bodies. Failure to operate the facilities in strict compliance with these
regulatory standards may expose the facilities to claims and clean-up costs.

Exchange Rates

Currency fluctuations may affect the cash flow which the Fund will realize from its operations, as
certain of the Fund Businesses sell electricity in the United States and receive proceeds from such sales in
US dollars. Such Fund Businesses also incur costs in US dollars.

Labour Relations

While labour relations have been stable to date and there have not been any disruptions in
operations as a result of labour disputes with employees, the maintenance of a productive and efficient
labour environment cannot be assured. With the exception of the EFW Facility, employees of the Fund
Businesses and their material subcontractors are non-unionized. The EFW Facility is unionized and a
new collective bargaining agreement was finalized in 2005. In the event of a strike or lock-out, the ability
of Fund Businesses to generate distributable cash available for distribution to Unitholders may be
impaired.

Dependence Upon Key Customers

The customers that currently purchase power from the facilities are large utilities. If, for any
reason, such customers were unable to fulfill their contractual obligations under the power purchase
agreements, distributable cash available to Unitholders would decline.

Reliance on the Manager and Power Systems and Potential Conflicts of Interest

Unitholders will be dependent upon the Manager for the administration of the Fund and upon the
Manager and Power Systems for the management and operation of the facilities.

There may be situations in which conflicts of interest may arise between the Manager, Power
Systems and their respective officers and directors in relation to the interests of the Fund. The Manager
and its affiliated entities may engage in activities similar to the activities of the Fund. The Manager or affiliated entities may acquire, own, manage and administer other facilities in the independent power production industry and, in particular, in the hydroelectric power segment of the industry. Provisions in business corporations act legislation provides certain procedures to be followed by directors and officers and remedies available against them where such procedures are not followed in the event of conflicts of interest. In addition, the Management Agreement provides that, to the extent there is a conflict of interest which is not required to be dealt with by a board of directors or trustees, the resolution of the conflict by the Manager shall be fair and reasonable to the Fund Businesses.

Climate

Based on the type of power purchase agreements in place at all of the facilities in which the Fund has an interest, the revenue generated by the facilities is proportional to the amount of electrical energy generated. In addition, the amount of energy generated at the hydroelectric generating facilities is dependent upon available water flows. Accordingly, revenues will be significantly affected by low and high water flows within the watercourses on which the facilities are located. Engineering studies have been undertaken to assess the amount of energy which can be expected to be generated from each facility on an average annual basis. Furthermore, the majority of the facilities have significant operating histories with which to compare the theoretical estimates determined in the engineering studies. However, there can be no assurance that the historical water availability will remain unchanged or that no material hydrologic event will impact the hydrologic conditions which exist 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 St. Leon 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 St. Leon Facility may be different and distributable cash available to Unitholders could be impacted.

Severe flooding may damage the hydroelectric generating facilities. Insurance may partially reduce this risk.

Equipment Failure

There is a risk of equipment failure due to wear and tear, design error or operator error, among other things, which could adversely affect revenues and distributable cash. Regular maintenance programs, insurance and maintenance funds partially mitigate this risk.

Commodity Prices

Distributable cash available to Unitholders will, in part, depend upon prices to be paid for energy purchased by customers. Such commodity pricing will vary over time. Over the long term, unexpected fluctuations in such pricing may impact upon distributable cash available to Unitholders. The facilities which are primarily impacted by changes in the price of natural gas are the Cogeneration Developments. However, most of the power purchase agreements at these facilities include variable components based on the market price of natural gas, reducing the impact of an increase in the price of natural gas on the distributable cash available to Unitholders generated by the facility.
Investment Eligibility

If the Fund ceases to qualify as a mutual fund trust and its registration as a registered investment under the Tax Act is revoked, the Trust Units will cease to be qualified investments for Plans and RESPs. It is also possible that the Fund may distribute Fund Assets on a redemption of Trust Units and that such Fund Assets are not qualified Investments or Plans (See also “Canadian Federal Income Tax Considerations”). Where, at the end of any month, a Plan or RESP holds Trust Units or Fund Assets that are not qualified investments, the Plan or RESP may become liable to pay a penalty tax in respect of that month equal to 1% of the fair market value of the Trust Units or Fund Assets, as the case may be, at the time such property was acquired by the Plan. Certain other adverse tax consequences could also arise for a Plan or RESP or an annuitant or subscriber thereunder if the Plan or RESP acquires or holds Trust Units or Fund Assets and such property is not a qualified investment. One of the ways in which the Fund could cease to qualify as a mutual fund trust would be if non-residents of Canada (“non-residents”) within the meaning of the Tax Act were to become the beneficial owners of a majority of the Trust Units.

Delays in Distributions

Payments by Algonquin Canada and Algonquin Power Trust to the Fund may be delayed by restrictions imposed by lenders, disruptions in service, recovery by the Manager of its expenses or the establishment of reserves for expenses.

Nature of Trust Units

The Trust Units are dissimilar to conventional debt instruments in that there is no principal amount owing directly to Unitholders. The Trust Units do not represent a traditional investment and should not be viewed by investors as shares of Algonquin Canada or its subsidiaries or trust units of Algonquin Power Trust. Each Trust Unit represents an equal undivided beneficial interest in the Fund. The Fund’s sole assets will be the Fund Assets and other permitted investments.

Potential Dilution

The Declaration of Trust authorizes the Fund to issue an unlimited number of Trust Units at the times, to the persons, for the consideration and on the terms and conditions that the Trustees determine. Additional Trust Units will be issued by the Fund upon the exchange of the Exchangeable Units or conversion of the Fund Debentures. As well, there is a possibility that the Fund will issue additional Trust Units in the future as the Trustees deem necessary to meet the Fund’s requirements.

Inapplicability of Certain Corporate Law Rights and Remedies

Unitholder rights and responsibilities, although similar, are not necessarily the same as those of shareholders. Unlike a shareholder in a corporation, a unitholder in an income trust does not have the right to bring “oppressive or derivative actions” against the trustees or the management company. This type of action is used by minority equity shareholders to argue against actions by management that may be against the interests of minority shareholders. While the courts can intercede to remedy the situation on behalf of a shareholder, they would not have the same ability in the case of a trust.

In addition, while income trusts resemble corporate entities in several ways, they fall under a different code of law with different requirements for corporate governance.
As well, unlike directors and officers of a corporation who have a duty to act in the best interests of the shareholders, trustees may be individually indemnified by the income trust in respect to the discharge of their duties, or they may delegate many of their responsibilities to management to avoid potential liability. The Declaration of Trust imposes duties on the Trustees similar to those applicable to directors of a corporation.

**Inapplicability of Insolvency and Restructuring Legislation**

The principal Canadian statutes that have traditionally been used for purposes of financial restructuring are the *Bankruptcy and Insolvency Act* (the “BIA”), and the *Companies’ Creditors Arrangement Act* (the “CCAA”). Under the BIA, a trust cannot be a “debtor” or an “insolvent person” as a trust is not a “person” as defined in the BIA. Similarly, a trust is not a “company” or a “body corporate” and thus cannot be a “debtor company” within the meaning of the CCAA.

The question arises as to how a financially distressed income trust would achieve financial restructuring, given the existing state of Canadian insolvency legislation. Because of the legal status of an income trust, existing bankruptcy and insolvency law would not apply.

**Negative Impacts on Cash Distributions**

The structure of an income trust is designed to maximize the cash distributions from a set of revenue-generating assets, with these distributions made on a periodic basis either monthly or quarterly. Cash distributions are maximized because income trusts distribute all available earnings to investors, whereas corporations distribute dividends on a discretionary basis.

One of the defining features of an income trust structure is for the trust to hold a significant amount of unsecured, subordinated debt. The Fund currently holds approximately $161 million in project-specific debt. The maximization of cash distributions can be negatively impacted if this debt is replaced by new debt that has less favourable terms.

In addition, cash distributions may be restricted if the Fund fails to maintain certain covenants under the Credit Line. If the Fund fails to meet its obligations under the Credit Line, creditors may have the power to suspend cash distributions to Unitholders of the Fund.

**Uncertain Trust Unit Market**

The Fund cannot predict at what price the Trust Units will continue to trade and there can be no assurance that an active trading market in the Trust Units will be sustained.

Units of a publicly traded income fund will not necessarily trade at values determined solely by reference to the underlying value of its assets.

One of the factors that may influence the market price of the Trust Units is the annual distribution on the Trust Units. An increase in market interest rates may lead purchasers of Trust Units to demand a higher annual distribution and this could adversely affect the market price of the Trust Units. In addition, the market price for the Trust Units may be affected by changes in general market conditions, fluctuations in the market for equity or debt securities and numerous other factors beyond the control of the Fund.

There can be no assurance that the Fund will be in a position to redeem Trust Units when requested to do so.
Completion of Acquisitions

In any additional offerings, the Manager intends to utilize the net proceeds from the additional offering to complete the acquisitions detailed in the prospectus, promptly following the closing of an additional offering. While Fund Businesses generally enter into agreements governing the purchase and sale of potential facility interests to be acquired, there can be no assurances that the vendors of such facility interests will close the transactions of purchase and sale. In the event the Manager is unsuccessful in completing any particular acquisition within 30 days from closing of an additional offering, the Manager intends to utilize the portion of the net proceeds plus accrued interest thereon (i) firstly, to retire any indebtedness of the Fund or its Facilities then outstanding and (ii) secondly, the balance thereof shall be distributed pro-rata to Unitholders as a return of capital.

Liability of Unitholders

The Declaration of Trust provides that no Unitholder will be subject to any liability in connection with the Fund or its obligations and affairs. The Declaration of Trust also provides that the Trustees and the Fund will make all reasonable efforts to include as a specific term of any obligations or liabilities being incurred by the Fund or by the Trustees on behalf of the Fund a contractual provision to the effect that neither the Unitholders nor the Trustees have any personal liability or obligations in respect thereof. Personal liability may arise in respect of claims against the Fund that do not arise under contracts, including claims in tort, claims for taxes and possibly certain other statutory liabilities. The Manager believes that the possibility of any personal liability of this nature arising is unlikely.

In addition, the Ontario government passed legislation to provide certainty to unitholders of publicly traded trusts that their exposure to claims against the trust will be limited to their investment. Bill 106, the Budget Measures Act, 2004 (No. 2) (“Bill 106”), which proposed the enactment of the Trust Beneficiaries’ Liability Act, 2004 (the “TBLA”), received Royal Assent on December 16, 2004. Bill 106 was deemed to come in force as of January 1, 2004. The TBLA came into force on December 16, 2004, the date that Bill 106 received Royal Assent.

The TBLA applies to unitholders of any trust that is a “reporting issuer” under the Securities Act (Ontario) if its declaration of trust selects Ontario as its governing law. The Fund satisfies such requirements. The TBLA provides that investors in a publicly traded trust are not liable, as beneficiaries of the trust, for any act, default, obligation or liability of the trust or any of its trustees.

ADDITIONAL INFORMATION

Additional information, including Trustees’ remuneration and indebtedness, principal holders of Trust Units, options to purchase securities of the Fund and interests of insiders in material transactions, as applicable, is contained in the Fund’s information circular dated March 23, 2007 for the annual meeting of Unitholders to be held on April 26, 2007. Additional financial information is provided in the Fund’s financial statements for the year ended December 31, 2006. A copy of such documents may be obtained upon request from the Fund.

The Fund will also provide to any person upon request to the Fund:
(a) when Trust Units are in the course of a distribution pursuant to a short form prospectus or when a preliminary short form prospectus has been filed in respect of a distribution of Trust Units,

(i) one copy of the Fund’s Annual Information Form, together with one copy of any document, or the pertinent pages of any document, incorporated by reference in the Annual Information Form;

(ii) one copy of the comparative financial statements of the Fund for its most recently completed financial year together with the accompanying report of the auditors and one copy of any interim financial statements of the Fund subsequent to the financial statements for its most recently completed financial year;

(iii) one copy of the Fund’s information circular in respect of its most recent annual meeting of Unitholders that involved the election of Trustees or one copy of any annual filing prepared in lieu of that information circular, as appropriate; and

(iv) one copy of any other documents that are incorporated by reference into the preliminary short form prospectus or the short form prospectus and are not required to be provided under (i) to (iii) above; or

(b) at any other time, one copy of any other documents referred to in (a)(i), (ii) and (iii) above, provided the Fund may require the payment of a reasonable charge if the request is made by a person who is not a Unitholder.
“AAP LP” means Algonquin (AirSource) Power LP, an Ontario limited partnership;

“Administration Agreement” means the amended and restated administration agreement between the Manager and the Fund dated as of January 1, 2006, pursuant to which the Manager provides administrative services to the Fund;

“affiliate” means an affiliate within the meaning of the Securities Act (Ontario);

“AirSource” means AirSource Power Income Fund I LP, a limited partnership formed under the laws of the province of Manitoba;

“AirSource Acquisition Debt Facility” means the amended and restated $4.9 million subordinated acquisition debt facility provided by Algonquin Power Operating Trust to AirSource;

“Algonquin” means, collectively, Algonquin Canada, Algonquin Holdco and Algonquin Power Trust;

“Algonquin America” means Algonquin Power Fund (America) Inc., a Delaware corporation wholly-owned by Algonquin Canada;

“Algonquin America Holdco” means Algonquin Power Fund (America) Holdco Inc., a Delaware corporation wholly-owned by Algonquin America;

“Algonquin Canada” means Algonquin Power Fund (Canada) Inc., a Nova Scotia corporation wholly-owned by Algonquin Holdco;

“Algonquin Canada Shares” means common shares of Algonquin Canada;

“Algonquin Holdco” means Algonquin Holdco Inc., an Ontario corporation wholly-owned by the Fund;


“Algonquin Power” means Algonquin Power Corporation Inc., an Ontario corporation;

“Algonquin Power (Long Sault) Partnership” means the partnership formed between the Algonquin LSR Companies, which partnership owns a 50% undivided interest in the Long Sault Rapids Facility;

“Algonquin Power Operating Trust” means Algonquin Power Operating Trust (formerly Drayton Valley Power Income Fund), an unincorporated open-ended trust established under the laws of the Province of Alberta, the sole unitholder of which is Algonquin Power Trust;

“Algonquin Power Trust” means the Algonquin Power Trust, an unincorporated open-ended trust established under the laws of Ontario and of which the Fund is the sole beneficiary;

“Ashuelot Facility” means the 900 kilowatt hydroelectric generating facility located on the Ashuelot River approximately 0.2 kilometres upstream of the highway bridge at Hinsdale, New Hampshire and which is owned by the HDI III Partnership;
“associate” means an associate within the meaning of the Securities Act (Ontario);

“Avery Dam Facility” means the 260 kilowatt hydroelectric generating facility located on the Winnipesaukee River near the City of Laconia, New Hampshire and which is owned by the Avery Dam Partnership;

“Avery Dam Partnership” means Avery Hydroelectric Associates, a New Hampshire limited partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Avery Dam Facility;

“Avoided Costs” means costs a utility does not incur to add new generating capacity to the system by purchasing electricity from an independent or parallel generator;

“AWRA” means Algonquin Water Resources of America Inc., a Delaware corporation wholly-owned by Algonquin Canada;

“AWRI” means Algonquin Water Resources of Illinois, LLC, a wholly-owned subsidiary of AWRA;

“AWRM” means Algonquin Water Resources of Missouri LLC, a wholly-owned subsidiary of AWRA;

“AWRT” means Algonquin Water Resources of Texas LLC, a wholly-owned subsidiary of AWRA;

“Beaver Falls Facility” means the 2,500 kilowatt hydroelectric generating facility located on the Beaver River near the City of Watertown, New York and which is owned by Algonquin Power (Beaver Falls) LLC;

“Bella Vista Facility” means the wastewater treatment facility located in the Town of Sierra Vista Arizona, and which is owned by Bella Vista Water Company, Inc., an Arizona corporation wholly-owned by AWRA;

“Black Mountain Facility” means the wastewater treatment facility located in the residential portion of the Boulders Resort, located 10 miles north of Scottsdale, Arizona, in the Town of Carefree, Arizona and which is owned by Black Mountain Sewer Corporation, an Arizona corporation wholly-owned by AWRA;

“Brooklyn Facility” means a 23.8 MW biomass-fired electric generating facility located in Queen’s County, Nova Scotia;

“BTU” means the quantity of heat required at sea level to heat 454.3 grams of water from 60°F to 61°F Fahrenheit at a constant measure of one atmosphere;

“Burt Dam Facility” means the 600 kilowatt hydroelectric generating facility located on the Eighteen Mile Creek in the Town of Newfane, New York and which is owned by the Burt Dam Partnership;

“Burt Dam Partnership” means Burt Dam Power Company, a New York general partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Burt Dam Facility;

“Business Corporations Act” means the Business Corporations Act (Ontario);
“Campbellford Facility” means a 4,000 kilowatt hydroelectric generating facility located at Lock No. 14 on the Trent-Severn Waterway approximately four kilometres north of Campbellford, Ontario and which is owned by Algonquin Power (Campbellford) Limited Partnership.

“CDA” means Crossroads Developers Associates L.L.C., a New Jersey limited liability company;

“Chapais Facility” means an electricity generating facility which burns woodwaste and which is located in the Town of Chapais, Québec;

“Clean Power” means Clean Power Income Fund, an open-ended trust established under the laws of the Province of Ontario;

“Cochrane Facility” means the 35.8 MW combined cycle co-generation facility located in the Town of Cochrane, Ontario;

“Cogeneration Developments” means the Fund’s indirect interests in the Sanger Facility, Windsor Locks Facility and Crossroads Facility;

“Co-Owners” means Algonquin Power (Long Sault) Partnership, an Ontario partnership, and N-R Power Partnership, an Ontario partnership, the co-owners of the Long Sault Rapids Facility;

“Côte Ste-Catherine Facility” means the 11.1 MW hydroelectric generating facility located at the Côte Ste-Catherine lock of the Lachine section of the St. Lawrence Seaway, and which is owned by Algonquin Power (Mont-Laurier) Limited Partnership;

“Crossroads Facility” means the 10 MW cogeneration facility located in Mahwah, New Jersey and which is owned by KMS Crossroads Inc., a Delaware corporation, which is wholly-owned, indirectly, by KMS;

“Debenture Trustee” means CIBC Mellon Trust Company;

“Declaration of Trust” means the declaration of trust dated as of September 8, 1997, as amended, as the same may be further amended, supplemented or restated from time to time, pursuant to which the Fund was created;

“Dickson Dam Facility” means the 15 MW hydroelectric generating facility located on the Red Deer River at Dickson Dam, 20 kilometres west of the Town of Innisfail, Alberta and which is owned by Algonquin Power Operating Trust;

“Donnacona Facility” means the 4,800 kilowatt hydroelectric generating facility located on the lower portion of the Jacques Cartier River, near the Town of Donnacona, Québec and which facility is owned by the Donnacona Partnership;

“Donnacona Holdco” means Donnacona Holdings Inc., an Ontario corporation wholly-owned by Algonquin Canada, and which owns a 0.01% interest in the Donnacona Partnership;

“Donnacona Partnership” means Société Hydro-Donnacona S.E.N.C., a Québec general partnership comprised of Algonquin Canada holding a 99.99% interest and its wholly-owned subsidiary, Donnacona Holdco, holding a 0.01% interest;
“EFW Facility” means the 10 MW energy from waste generating facility located in the Regional Municipality of Peel, Ontario and which is owned by Algonquin Power Energy from Waste Inc., a wholly-owned subsidiary of KMS;

“Exchangeable Units” means the exchangeable limited partnership units of AAP LP which are exchangeable by the holder, at any time, into Trust Units;

“Extraordinary Resolution” means a resolution passed by a majority of not less than 66 2/3% of the votes cast, either in person or by proxy, at a meeting of Unitholders called for the purpose of approving such resolution, or approved in writing by the holders of not less than 66 2/3% of the Trust Units entitled to be voted on such resolution;

“Facilities” means infrastructure facilities in which the Fund has an interest, directly or indirectly;

“FERC” means the United States Federal Energy Regulatory Commission;

“Fox River Facility” means the wastewater treatment facility located in Sheridan, Illinois and which is owned by AWRT, a Texas limited liability corporation which is wholly-owned by AWRA;

“Fund” means the Algonquin Power Income Fund, an unincorporated open-ended trust established under the laws of Ontario;

“Fund Assets” means the shares of Algonquin Holdco, units of the Algonquin Power Trust, the Fund Notes, the LSR Royalty Interests and any other securities or assets held directly or indirectly by the Fund from time to time;

Inc., Algonquin Energy Services Inc., Société en Commandite Algonquin (Éoliennes), Algonquin Water Services LLC and any other business a subsidiary of the Fund may acquire or any other business carried on by a corporation, partnership or other entity, the shares, partnership interests or other equity interest, as the case may be, of which the Fund acquires;

“Fund Debentures” means the Series 1 Debentures and the Series 2 Debentures;

“Fund Notes” means any notes issued by Algonquin Power Trust, Algonquin Canada, Algonquin Holdco and Algonquin America to the Fund, the LSR Subordinate Note and the Trafalgar Class B Note;

“gigawatts” or “GW” means 1,000 megawatts of electrical power;

“Glenford Facility” means the 4,950 kilowatt hydroelectric generating facility located on the Ste-Anne River near the Village of Ste-Christine d’Auvergne, Québec and which is owned by the Glenford Partnership;

“Glenford Minority Inc.” means an Ontario corporation which is currently wholly-owned by Algonquin Power and which holds a 0.01% limited partnership interest in the cash distributions and income allocations from the Glenford Partnership;

“Glenford Subordinate Note” means the 8.5% secured subordinated note of Algonquin Power due by July 1, 2023 in the principal amount of approximately $5.0 million issued to Algonquin Canada on July 7, 1998;

“Glenford Partnership” means Société en Commandite Chute Ford, a limited partnership formed under the laws of Québec comprised of Algonquin Power and Glenford Minority Inc.;

“Glenford Senior Debt” means financing in the outstanding principal amount of approximately $5.5 million provided by Corpfinance International Limited to the Glenford Partnership;

“Gold Canyon Facility” means the wastewater treatment facility located in an industrial area of the Town of Gold Canyon, Arizona and which is owned by Gold Canyon Sewer Company, an Arizona corporation wholly-owned by AWRA;

“Governance Agreement” means the amended and restated governance agreement dated as of January 1, 2006 between the Fund, the Manager and Algonquin dealing with the composition of the boards of directors of Algonquin Holdco and Algonquin Canada and other matters;

“Great Falls Facility” means a 10,950 kilowatt hydroelectric generating facility located on the Passaic River near the City of Paterson, New Jersey and which is owned by the Great Falls Partnership;

“Great Falls Partnership” means Great Falls Hydroelectric Company Limited Partnership, a Maryland limited partnership which owns the Great Falls Facility of which Algonquin America and Great Falls Energy, L.L.C. are the partners;

“Hadley Falls Facility” means the 250 kilowatt hydroelectric generating facility located at the Hadley Falls Dam near the Town of Goffstown, New Hampshire and which is owned by the Hadley Falls Partnership;
“Hadley Falls Partnership” means Hadley Falls Associates, a New Hampshire limited partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Hadley Falls Facility;

“HDI Partnership” means HDI Associates I, an Indiana general partnership comprised of Algonquin America and Algonquin America Holdco, which owns the Lochmere Facility and the Hopkinton Facility;

“HDI III Partnership” means HDI Associates III, a New Hampshire limited partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Lower Robertson Facility and the Ashuelot Facility;

“Hollow Dam Facility” means the 900 kilowatt hydroelectric generating facility located on the West Branch of the Oswegatchie River in the Town of Fowler, New York and which is owned by the Hollow Dam Partnership;

“Hollow Dam Partnership” means Hollow Dam Power Company, a New York general partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Hollow Dam Facility;

“Hopkinton Facility” means the 250 kilowatt hydroelectric generating facility located on the Contoocook River in the Village of Contoocook, New Hampshire and which generating facility is owned by the HDI Partnership;

“Joliet Facility” means the 3.2 MW landfill gas-fuel generating facility located in Joliet, Illinois and which is owned by KMS Joliet Power Partners, L.P., an Illinois limited partnership, and which was permanently closed on May 10, 2005;

“kilowatt hour” or “kW-hr” means an hour during which one kilowatt of electrical energy has been continuously produced;

“kilowatts” or “kW” means 1,000 watts of electrical power;

“Kirkland Facility” means a 102 MW combined cycle power co-generation facility located in Kirkland Lake, Ontario;

“KMS” means KMS Power Income Fund, an unincorporated open-ended trust established under the laws of Alberta;

“KMS America” means KMS America Inc., a Delaware corporation which is wholly-owned by Algonquin Power Energy from Waste Inc.;

“Lakeport Corporation” means Lakeport Hydroelectric Corp., a New Hampshire corporation whose sole shareholder is Algonquin America, and which owns the Lakeport Facility;

“Lakeport Facility” means the 600 kilowatt hydroelectric generating facility located on the Winnipesaukee River near the Town of Lakeport, New Hampshire and which is owned by the Lakeport Corporation;

“LFG Facilities” means the 12 landfill gas powered generating stations in California, Tennessee, New Jersey, New Hampshire and Minnesota representing approximately 36 MW of installed capacity and which are owned by the Fund;
“Litchfield Facility” means the wastewater treatment facility located in Litchfield Park, Arizona and which is owned by Litchfield Park Service Company, an Arizona corporation which is wholly-owned by AWRA;

“Long Sault Rapids Facility” means the 18,000 kilowatt hydroelectric generating facility located on the Abitibi River, near the Town of Cochrane, Ontario and which facility is owned by the Co-Owners;

“Lower Robertson Facility” means the 960 kilowatt hydroelectric generating facility located on the Ashuelot River approximately one kilometre upstream of the Highway bridge at Hinsdale, New Hampshire and which is owned by the HDI III Partnership;

“LSR Royalty Interests” means the LSR Brace Royalty Interest, the LSR McKenzie Royalty Interest and the LSR Richardson Royalty Interest, all acquired by the Fund on April 17, 1998;

“LSR Subordinate Note” means the 14.14% secured, subordinated note in the principal amount of $2,000,000 issued jointly and severally by Algonquin Power (Long Sault) Corporation Inc., Energy Acquisition (Long Sault) Ltd., Nicholls Holdings Inc. and Radtke Holdings Inc. and acquired by the Fund on April 17, 1998;

“Management Agreement” means the amended and restated management agreement dated as of January 1, 2006 between the Manager and Algonquin pursuant to which the Manager or its delegate provides management services to the subsidiary entities of the Fund;

“Manager” means Algonquin Power Management Inc., an Ontario corporation wholly-owned by the shareholders of Algonquin Power;

“Manager’s Interest” means the special voting shares of Algonquin Canada and Algonquin America owned by the Manager entitling it to elect two of the three directors of Algonquin Canada and all of the directors of Algonquin America;

“megawatt” or “MW” means 1,000,000 watts of electrical power;

“megawatt hour” or “MW-hr” means 1,000 kilowatt hours of electrical energy;

“MMBTU” means one million BTU’s;

“Mont Laurier Facility” means the 2,725 kilowatt hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec and which is owned by the MTL Partnership;

“Moretown Facility” means the 1,200 kilowatt hydroelectric generating facility located on the Mad River near the Town of Moretown, Vermont and which is owned by the Moretown Partnership;

“Moretown Partnership” means Moretown Hydro Energy Company, a Vermont partnership comprised of Algonquin America and Algonquin America Holdco, and which owns the Moretown Facility;

“MTL Partnership” means Algonquin Power (Mont-Laurier) Limited Partnership, a Québec limited partnership between Algonquin Canada and Algonquin Power Trust;

“National Grid” means National Grid plc, a company registered in England and Wales;
“Net Income of the Fund” or “Net Income” means for any taxation year of the Fund the net income of the Fund for the year computed in accordance with the provisions of the Tax Act, less the amounts of any non-capital losses of the Fund for prior years that are deductible in computing the Fund’s taxable income for the year in accordance with the Tax Act; provided, however, that capital gains and capital losses shall be excluded and provided further that: (i) the portion of the Fund’s income comprised of taxable dividends received from corporations resident in Canada shall be calculated on the basis that the amount included in the Fund’s income is the actual amount of the dividend received, excluding the gross-up adjustment provided in paragraph 82(1)(b) of the Tax Act; and (ii) no amount shall be deductible in respect of amounts paid or payable to Unitholders. Net Income of the Fund shall not include any income or capital gains, which are realized by the Fund, in accordance with the Tax Act, on a distribution of Fund Assets to a Unitholder pursuant to an in specie redemption of the Unitholder’s Units;

“Net Realized Capital Gains” means for any year of the Fund the amount determined as the amount, if any, by which the aggregate of the capital gains of the Fund in the year exceeds the aggregate of the capital losses of the Fund in the year and the product of two (or the reciprocal of any proportion other than one-half that may be provided under section 38 of the Tax Act in respect of the relevant year) and the amount of any net capital losses from prior years which the Fund is permitted by the Tax Act to deduct in computing the taxable income of the Fund for the year. Net Realized Capital Gains shall not include any income or capital gains, which are realized by the Fund, in accordance with the Tax Act, on a distribution of Fund Assets to a Unitholder pursuant to an in specie redemption of the Unitholder’s Units;

“NHPUC” means the New Hampshire Public Utilities Commission;

“Niagara Mohawk” means Niagara Mohawk Power Corporation;

“Nicholls LSR Companies” means Nicholls Holdings Inc., an Ontario corporation, and Radtke Holdings Inc., an Ontario corporation;

“N-R Power Partnership” means the partnership formed between the Nicholls LSR Companies, which partnership owns a 50% undivided interest in the Long Sault Rapids Facility;

“OEFC” means Ontario Electricity Financial Corporation;

“Off-peak” means hours other than On-peak hours;

“On-peak” means hours between 7:00 a.m. and 11:00 p.m., local time, Monday to Friday, inclusive, but excluding public holidays;

“Operations Supervisory Agreement” means the amended and restated operations supervisory agreement between Algonquin and Power Systems dated as of January 1, 2006 pursuant to which Power Systems provides operations and supervisory services to certain of the subsidiary entities of the Fund;

“Phoenix Facility” means the 3,500 kilowatt hydroelectric generating facility located on the Oswego River, in the Town of Phoenix, Onondaga County, New York and which is owned by Oswego Hydro Partners L.P.;

“Power Systems” means Algonquin Power Systems Inc., an Ontario corporation wholly-owned by Algonquin Power;

“PSNH” means Public Service Company of New Hampshire, a large, investor-owned utility;
“PURPA” means U.S. Public Utilities Regulatory Policies Act;

“Rattle Brook Partnership” means the Algonquin Power (Rattle Brook) Partnership, a Newfoundland partnership currently comprised of Algonquin Power Corporation (Rattle Brook) Inc., wholly-owned by the shareholders of Algonquin Power and Algonquin Canada;

“Rawdon Facility” means the 2,500 kilowatt hydroelectric generating facility located on the Ouareau River approximately one kilometre from the Village of Rawdon, Québec and which is owned by Algonquin Canada;

“Rio Rico Facility” means the wastewater and water distribution facility located in Rio Rico, Arizona and which is owned by Rio Rico Utilities Inc., an Arizona company which is wholly-owned by AWRA;

“Rivière-du-Loup Facility” means the 2,600 kilowatt hydroelectric generating facility located on the Rivière-du-Loup near the Town of Rivière-du-Loup, Québec, formerly known as the Hydro Senmo Facility, and which is owned by Algonquin Canada;

“run-of-the-river” means a mode of operation of a hydroelectric generating facility where there is a continuous discharge of water from the facility with no storage and release of water;

“Saint-Alban Facility” means the 8,200 kilowatt hydroelectric generating facility located on the Ste-Anne River approximately one kilometre from the Village of Saint-Alban, Québec and which is owned by SLI;

“Sanger Facility” means a 43.5 MW natural gas-fired generating facility located in the City of Sanger, California and which is owned by Algonquin Sanger Power, L.L.C.;

“Senior Debt Facility” means the $73.3 million senior debt facility provided by a syndicate of banks to St. Leon Trust;

“Series 1 Debentures” means the 6.65% convertible unsecured subordinated debentures of the Fund due July 31, 2011 at a price of $1,000 per debenture;

“Series 2 Debentures” means the 6.20% convertible unsecured subordinated debentures of the Fund due November 30, 2016 at a price of $1,000 per debenture;

“SLI” means SNC-Lavalin Inc., a Canadian corporation which owns the Saint-Alban Facility;

“Small Power Act” means the Small Power Research and Development Act (Alberta);

“St. Leon Facility” means the 99 MW wind energy generating facility near St. Leon, Manitoba which is owned by St. Leon LP;

“St. Leon GP” means St. Leon Wind Energy GP Inc., a corporation incorporated under the laws of Canada;

“St. Leon LP” means St. Leon Wind Energy LP, a limited partnership formed under the laws of the province of Manitoba;

“St. Leon Trust” means St. Leon Wind Energy Trust, a trust established under the laws of the province of Manitoba;
“St. Leon Trust Construction Facility” means the $69.4 million subordinated construction/term debt facility provided by Algonquin Power Operating Trust to St. Leon Trust;

“Ste-Raphaël Facility” means the 3,500 kilowatt hydroelectric generating facility located on the Rivière de Sud near Québec City and which is owned by Algonquin Canada;

“Stranded Costs” means costs incurred by a utility during the normal course of business prior to deregulation that can no longer be paid by the rate base due to changes to various factors, including price, the economy, system requirements, government policies and technology;

“Suncook Facility” means the 3.1 MW landfill gas to electricity facility located in Nashua, New Hampshire, which is owned by Suncook Energy LLC;

“Supplemental Trust Indenture” means the supplemental trust indenture dated as of November 10, 2006 between the Fund and the Debenture Trustee;

“Tax Act” means the Income Tax Act (Canada);

“Trafalgar” means Trafalgar Power, Inc., a Delaware corporation;

“Trafalgar Class B Note” means the 6.10% secured, subordinated note due December 31, 2010 jointly and severally of the Trafalgar Companies;

“Trafalgar Companies” means Trafalgar and Christine Falls Corporation, a New York corporation;

“Trafalgar Facilities” means the following hydroelectric generating facilities: Ogdensburg, Forestport, Herkimer, Christine Falls, Cranberry Lake, Kayuta Lake and Adams, which are owned by the Trafalgar Companies;

“Trafalgar Operations Contract” means the agreement dated January 15, 1996 between Algonquin Power and the Trafalgar Companies, pursuant to which Algonquin Power provides operations and management services for the Trafalgar Facilities;

“Trust Indenture” means the trust indenture dated as of July 20, 2004 between the Fund and the Debenture Trustee, as supplemented by the Supplemental Trust Indenture;

“Trust Units” or “Units” means units of the Fund, each unit representing an equal undivided beneficial interest in the Fund;

“Trustee” means a trustee of the Fund from time to time;

“TSX” means the Toronto Stock Exchange;

“Unitholders” means the holders of Trust Units from time to time;

“Vestas” means Vestas-Canadian Wind Technology, Inc.;

“Vestas Contract” means the turn-key construction contract dated November 12, 2004 between St. Leon GP and Vestas;
“Water Services” means Algonquin Water Services LLC, formerly Newspring Water LLC, an Arizona limited liability company owned equally by Algonquin Power and Newspring Acquisition Partnership (a partnership between Algonquin Power and the Fund) to manage and operate water distribution and wastewater treatment facilities in Arizona and Texas;

“Windsor Locks Facility” means the 56 MW (gross) combined cycle, gas-fired co-generation facility located at Windsor Locks, Connecticut and which is owned by Algonquin Windsor Locks LLC, a Connecticut limited liability company, wholly-owned by Algonquin America;

“Woodmark Facility” means the wastewater treatment facility located in Tyler, Texas and which is owned by Woodmark Utility Company, Inc., a Texas corporation which is wholly-owned by AWRA; and

Words importing the singular number only include the plural and vice versa and words importing any gender include all genders.

All dollar amounts are in Canadian dollars unless otherwise stated.

For the purposes of this annual information form, any reference to any direct or indirect subsidiary, associate or affiliate of the Fund or any entity in which the Fund holds, directly or indirectly, a majority of the equity interests, the word “control”, the word “wholly-owned” and similar expressions, shall be construed without reference to any holdings by the Manager of special voting shares entitling the Manager to elect directors of Algonquin Canada or Algonquin America.
SCHEDULE B
ALGONQUIN POWER INCOME FUND
AUDIT COMMITTEE CHARTER

By appropriate resolution of the Trustees of Algonquin Power Income Fund (the “Trustees”), the Audit Committee (the “Committee”) has been established as a standing committee of the Trustees with the terms of reference set forth below. At the time of its establishment, the Committee is comprised of all the Trustees. Unless the context requires otherwise, the term “Fund” refers to Algonquin Power Income Fund and its subsidiaries.

1. PURPOSE

1.1 The Committee’s purpose is to:

(a) assist the Trustees’ oversight of:

   (i) the integrity of the Fund’s financial statements, Management’s Discussion and Analysis of Operating Performance (“MD&A”) and other financial reporting;

   (ii) the Fund’s compliance with legal and regulatory requirements;

   (iii) the external auditor’s qualifications, independence and performance;

   (iv) the performance of the Fund’s internal audit function and internal auditor;

   (v) the communication among Algonquin Power Management Inc. (the “Manager”), management of the Fund’s subsidiary entities and the Fund’s Chief Financial Officer (collectively, “Management”), the external auditor, the internal auditor and the Trustees;

   (vi) the review and approval of any related party transactions; and

   (vii) any other matters as defined by the Trustees;

(b) prepare and/or approve any report that is required by law or regulation to be included in any of the Fund’s public disclosure documents relating to the Committee.

2. COMMITTEE MEMBERSHIP

2.1 Number of Members – The Committee shall consist of not fewer than three members.

2.2 Independence of Members – Each member of the Committee shall:

   (a) be a Trustee of the Fund;

   (b) not be an officer or employee of any of the Fund’s subsidiary entities or the Manager or any of their respective affiliates;

   (c) be an unrelated director for the purposes of the Toronto Stock Exchange (the “TSX”) Corporate Governance Policy; and
2.3 Financial Literacy – Each member of the Committee shall satisfy the financial literacy requirements applicable to members of audit committees under the TSX Corporate Governance Policy, MI 52-110 and other applicable laws and regulations.

2.4 Accounting or Related Financial Experience – At least one member of the Committee shall satisfy the financial expertise and experience requirements under the TSX Corporate Governance Policy and be an audit committee financial expert within the meaning of MI 52-110 and other applicable laws and regulations.

2.5 Annual Appointment of Members - The Committee and its Chair shall be appointed annually by the Trustees and each member of the Committee shall serve at the pleasure of the Trustees until he or she resigns, is removed or ceases to be a Trustee.

3. COMMITTEE MEETINGS

3.1 Time and Place of Meetings - The time and place of the meetings of the Committee and the calling of meetings and the procedure in all things at such meetings shall be determined by the Committee; provided, however, that the Committee shall meet at least quarterly, a majority of the members of the Committee shall constitute a quorum and the Committee shall maintain minutes or other records of its meetings and activities.

3.2 In Camera Meetings - As part of each meeting of the Committee at which it approves, or if applicable, recommends that the Trustees approve, the annual audited financial statements of the Fund or at which the Committee reviews the interim financial statements of the Fund, and at such other times as the Committee deems appropriate, the Committee shall meet separately with each of the persons set forth below to discuss and review specific issues as appropriate:

   (a) representatives of Management;
   (b) the external auditor; and
   (c) the internal audit personnel.

4. COMMITTEE AUTHORITY AND RESOURCES

4.1 Direct Channels of Communication - The Committee shall have direct channels of communication with the Fund’s internal and external auditors to discuss and review specific issues as appropriate.

4.2 Retaining and Compensating Advisors – The Committee, or any member of the Committee with the approval of the Committee, may retain at the expense of the Fund such independent legal, accounting (other than the external auditor) or other advisors on such terms as the Committee may consider appropriate and shall not be required to obtain any other approval in order to retain or compensate any such advisors.
4.3 **Funding** – The Fund shall provide for appropriate funding, as determined by the Committee, for payment of compensation of the external auditor and any advisor retained by the Committee under Section 4.2 of this Charter.

4.4 **Investigations** – The Committee shall have unrestricted access to the Fund’s Chief Financial Officer and personnel of the Manager and the Fund’s subsidiary entities and documents and shall be provided with the resources necessary to carry out its responsibilities.

5. **RENUMERATION OF COMMITTEE MEMBERS**

5.1 **Director Fees Only** - No member of the Committee may accept, directly or indirectly, fees from the Fund or any of its subsidiary entities other than remuneration for acting as a Trustee or member of the Committee or any other committee of the Trustees.

5.2 **Other Payments** - For greater certainty, no member of the Committee shall accept any consulting, advisory or other compensatory fee from the Fund. For purposes of Section 5.1, the indirect acceptance by a member of the Committee of any fee includes acceptance of a fee by an immediate family member or a partner, member or executive officer of, or a person who occupies a similar position with, an entity that provides accounting, consulting, legal, investment banking or financial advisory services to the Fund or any of its subsidiaries, other than limited partners, non-managing members and those occupying similar positions who, in each case, have no active role in providing services to the entity.

6. **DUTIES AND RESPONSIBILITIES OF THE COMMITTEE**

6.1 **Overview** - The Committee’s principal responsibility is one of oversight. Management is responsible for preparing the Fund’s financial statements and the external auditor is responsible for auditing those financial statements.

The Committee’s specific duties and responsibilities are as follows:

(a) **Financial and Related Information** -

(i) **Annual Financial Statements** - The Committee shall review and discuss with Management and the external auditor the Fund’s annual financial statements and related MD&A and if applicable, report thereon to the Trustees as a whole before they approve such statements and MD&A.

(ii) **Interim Financial Statements** – The Committee shall review and discuss with Management and the external auditor the Fund’s interim financial statements and related MD&A and if applicable, report thereon to the Trustees as a whole before they approve such statements and MD&A.

(iii) **Prospectuses and Other Documents** - The Committee shall review and discuss with Management and the external auditor the financial information, financial statements and related MD&A appearing in any prospectus, annual report, annual information form, management information circular or any other public disclosure document prior to its public release or filing and if applicable, report thereon to the Trustees as a whole.
Accounting Treatment – Prior to the completion of the annual external audit, and at any other time deemed advisable by the Committee, the Committee shall review and discuss with Management and the external auditor (and shall arrange for the documentation of such discussions in a manner it deems appropriate) the quality and not just the acceptability of the Fund’s accounting principles and financial statement presentation, including, without limitation, the following:

(A) all critical accounting policies and practices to be used, including, without limitation, the reasons why certain estimates or policies are or are not considered critical and how current and anticipated future events impact those determinations and an assessment of Management’s disclosures along with any significant proposed modifications by the auditors that were not included;

(B) all alternative treatments within generally accepted accounting principles for policies and practices related to material items that have been discussed with Management, including, without limitation, ramification of the use of such alternative disclosure and treatments, and the treatment preferred by the external auditor, which discussion should address recognition, measurement and disclosure consideration related to the accounting for specific transactions as well as general accounting policies. Communications regarding specific transactions should identify the underlying facts, financial statement accounts impacted and applicability of existing corporate accounting policies to the transaction. Communications regarding general accounting policies should focus on the initial selection of, and changes in, significant accounting policies, the impact of the Management’s judgments and accounting estimates and the external auditor’s judgments about the quality of the Fund’s accounting principles. Communications regarding specific transactions and general accounting policies should include the range of alternatives available under generally accepted accounting principles discussed by Management and the auditors and the reasons for selecting the chosen treatment or policy. If the external auditor’s preferred accounting treatment or accounting policy is not selected, the reasons therefore should also be reported to the Committee;

(C) other material written communications between the external auditor and Management, such as any management letter, schedule of unadjusted differences, listing of adjustments and reclassifications not recorded, management representation letter, report on observations and recommendations on internal controls, engagement letter and independence letter;

(D) major issues regarding financial statement presentations;

(E) any significant changes in the Fund’s selection or application of accounting principles;

(F) the effect of regulatory and accounting initiatives, as well as off-balance sheet structures, on the financial statements of the Fund; and
(G) the adequacy of the Fund’s internal controls and any special audit steps adopted in light of control deficiencies.

(v) Disclosure of Other Financial Information - The Committee shall:

(A) review, and discuss generally with Management, the type and presentation of information to be included in, all public disclosure by the Fund containing audited, unaudited or forward-looking financial information in advance of its public release by the Fund, including, without limitation, earnings guidance and financial information based on unreleased financial statements;

(B) discuss generally with Management the type and presentation of information to be included in earnings and any other financial information given to analysts and rating agencies, if any; and

(C) satisfy itself that adequate procedures are in place for the review of the Fund’s disclosure of financial information extracted or derived from the Fund’s financial statements, other than the Fund’s financial statements, MD&A and earnings press releases, and shall periodically assess the adequacy of those procedures.

(b) External Auditor -

(i) Authority with Respect to External Auditor - As representative of the Fund’s unitholders and as a committee of the Trustees, the Committee shall be directly responsible for the appointment, compensation, retention, termination and oversight of the work of the external auditor (including, without limitation, resolution of disagreements between Management and the auditor regarding financial reporting) for the purpose of preparing or issuing an audit report or performing other audit, review or attest services for the Fund. In this capacity, the Committee shall have sole authority for recommending the person to be proposed to the Fund’s unitholders for appointment as external auditor, whether at any time the incumbent external auditor should be removed from office, and the compensation of the external auditor. The Committee shall require the external auditor to confirm in an engagement letter to the Committee each year that the external auditor is accountable to the Trustees and the Committee as representatives of unitholders and that it will report directly to the Committee.

(ii) Approval of Audit Plan - The Committee shall approve, prior to the external auditor’s audit, the external auditor’s audit plan (including, without limitation, staffing), the scope of the external auditor’s review and all related fees.

(iii) Independence - The Committee shall satisfy itself as to the independence of the external auditor. As part of this process:

(A) The Committee shall require the external auditor to submit on a periodic basis to the Committee a formal written statement confirming its independence under applicable laws and regulations and delineating all relationships between the auditor and the Fund and the Committee shall actively engage in a dialogue with the external auditor with respect to
any disclosed relationships or services that may impact the objectivity and independence of the external auditor and take, or, if applicable, recommend that the Trustees take, any action the Committee considers appropriate in response to such report to satisfy itself of the external auditor’s independence.

(B) In accordance with applicable laws and regulations, the Committee shall pre-approve any non-audit services (including, without limitation, fees therefore) provided to the Fund or its subsidiaries by the external auditor or any auditor of any such subsidiary and shall consider whether these services are compatible with the external auditor’s independence, including, without limitation, the nature and scope of the specific non-audit services to be performed and whether the audit process would require the external auditor to review any advice rendered by the external auditor in connection with the provision of non-audit services. The Chair may approve additional non-audit services that arise between Committee meetings, provided that the Chair reports any such approvals to the Committee at the next scheduled meeting.

(C) The Committee shall establish a policy setting out the restrictions on the Fund’s subsidiary entities hiring employees and former employees of the Fund’s external auditor or former external auditor.

(iv) Rotating of Auditor Partner - The Committee shall evaluate the performance of the external auditor and whether it is appropriate to adopt a policy of rotating lead or responsible partners of the external auditors.

(v) Review of Audit Problems and Internal Audit - The Committee shall review with the external auditor:

(A) any problems or difficulties the external auditor may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any disagreements with Management and any management letter provided by the auditor and the Fund’s response to that letter;

(B) any changes required in the planned scope of the internal audit; and

(C) the internal audit department’s responsibilities, budget and staffing.

(vi) Review of Proposed Audit and Accounting Changes – The Committee shall review major changes to the Fund’s auditing and accounting principles and practices suggested by the external auditor.

(vii) Regulatory Matters - The Committee shall discuss with the external auditor the matters required to be discussed by Section 5741 of the CICA Handbook - Assurance relating to the conduct of the audit.

(c) Internal Audit Function - Controls –
(i) **Regular Reporting** - Internal audit personnel shall report regularly to the Committee.

(ii) **Oversight of Internal Controls** - The Committee shall oversee Management’s design and implementation of and reporting on the Fund’s internal controls and review the adequacy and effectiveness of Management’s financial information systems and internal controls. The Committee shall periodically review and approve the mandate, plan, budget and staffing of internal audit personnel. The Committee shall direct Management to make any changes it deems advisable in respect of the internal audit function.

(iii) **Review of Audit Problems** - The Committee shall review with the internal audit personnel: any problem or difficulties the internal audit personnel may have encountered, including, without limitation, any restrictions on the scope of activities or access to required information, and any significant reports to Management prepared by the internal audit personnel and Management’s responses thereto.

(iv) **Review of Internal Audit Personnel** - The Committee shall review the appointment, performance and replacement of the senior internal auditing personnel and the activities, organization structure and qualifications of the persons responsible for the internal audit function.

(d) **Risk Assessment and Risk Management** -

(i) **Risk Exposure** - The Committee shall discuss with the external auditor, internal audit personnel and Management periodically the Fund’s major financial risk exposures and the steps Management has taken to monitor and control such exposures.

(ii) **Investment Practices** - The Committee shall review Management’s plans and strategies around investment practices, banking performance and treasury risk management.

(iii) **Compliance with Covenants** - The Committee shall review Management’s procedures to ensure compliance by the Fund with its loan covenants and restrictions, if any.

(e) **Legal Compliance** -

(i) On at least a quarterly basis, the Committee shall review with the Fund’s legal counsel, external auditor and Management any legal matters (including, without limitation, litigation, regulatory investigations and inquiries, changes to applicable laws and regulations, complaints or published reports) that could have a significant impact on the Fund’s financial position, operating results or financial statements and the Fund’s compliance with applicable laws and regulations.

(ii) The Committee shall review and, if applicable, advise the Trustees with respect to the Fund’s policies and procedures regarding compliance with applicable laws and regulations and shall notify Management and, if applicable, the Trustees,
promptly after becoming aware of any material non-compliance by the Fund with applicable laws and regulations.

(f) Whistle Blowing - The Committee shall establish procedures for:

(i) the receipt, retention and treatment of complaints received by the Fund regarding accounting, internal accounting controls or auditing matters; and

(ii) the confidential, anonymous submission by employees of the Fund’s subsidiary entities of concerns regarding questionable accounting or auditing matters.

(g) Related Party Transactions – The Committee shall review and approve any transaction between the Fund and a related party and any transaction involving the Fund and another party in which the parties’ relationship could enable the negotiation of terms on other than an independent, arms’ length basis.

(h) Review of the Management’s Certifications and Reports – The Committee shall review and discuss with Management all certifications of financial information, management reports on internal controls and all other management certifications and reports relating to the Fund’s financial position or operations required to be filed or released under applicable laws and regulations prior to the filing or release of such certifications or reports.

(i) Liaison – The Committee shall review and ensure that appropriate liaison and co-operation exist between the external auditor and internal audit personnel and provide a direct channel of communication between external and internal auditors and the Committee.

(j) Public Reports - The Committee shall prepare and/or approve any report that is required by law or regulation to be included in any of the Fund’s public disclosure documents relating to the Committee.

(k) Other Matters – The Committee may, in addition to the foregoing, perform such other functions as may be necessary or appropriate for the performance of its oversight function.

7. REPORTING TO THE TRUSTEES

7.1 Regular Reporting – If applicable, the Committee shall report to the Trustees following each meeting of the Committee and at such other times as the Committee may determine to be appropriate.

8. EVALUATION OF COMMITTEE PERFORMANCE

8.1 Performance Review - The Committee shall periodically assess its performance.

8.2 Amendments to Charter –

(a) Review by Committee - On at least an annual basis, the Committee shall review and discuss the adequacy of this Charter and if applicable, recommend any proposed changes to the Trustees.
(b) **Review by Trustees** – The Trustees will review and reassess the adequacy of the Charter on an annual basis and at such other times, as it considers appropriate.

9. **LEGISLATIVE AND REGULATORY CHANGES**

9.1 **Compliance** – It is the Trustees’ intention that this mandate shall reflect at all times all legislative and regulatory requirements applicable to the Committee. Accordingly, this Charter shall be deemed to have been updated to reflect any amendments to such legislative and regulatory requirements and shall be formally amended at least annually to reflect such amendments.

9.2 **Rules Not Yet in Force** – As of the date of this Charter, MI 52-110 and certain guidelines of the TSX applicable to audit committees were not yet in force. The Committee shall comply with such draft instruments as if they were in force.

10. **CURRENCY OF CHARTER**

10.1 **Currency of Charter** – This Charter was approved by the Trustees on May 11, 2004.