

ALGONQUIN POWER INCOME FUND

ANNUAL INFORMATION FORM

May 17, 2002

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.

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ALGONQUIN POWER INCOME 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 Declaration of Trust was amended on December 18, 1998 to provide the Trustees with greater flexibility to borrow monies on behalf of the Fund, which borrowings may be secured by the Fund's assets. The Declaration of Trust was amended 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. The Declaration of Trust was amended 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. Unitholders are being asked to consider making an additional amendment to the Declaration of Trust as set out in the management information circular dated April 8, 2002.

The principal office of the Fund is located at 2845 Bristol Circle, Oakville, Ontario L6H 7H7. The Fund has the following direct or indirect subsidiaries: Algonquin Power Fund (Canada) Inc., a Nova Scotia corporation, Donnacona Holdings Inc., Algonquin Holdco Inc., KMS Peel Inc. and Peel Resources Recovery Operations Inc., Ontario corporations, Lakeport Hydroelectric Corporation, an S Corporation under United States law, Algonquin Power Fund (America) Inc., Algonquin Power Fund (America) Holdco Inc., Algonquin Water Resources of America, Inc., CSI Oswego Corp., KMS America, Inc. and KMS Crossroads, Inc., Delaware corporations, SFR Hydro Corporation, a New Hampshire corporation, Clement Dam Hydroelectric LLC, a New Hampshire limited liability corporation, Worcester Hydro Company, Inc, a Vermont corporation, Court Street Investments, Inc., Oswego Power Company, Inc. and Oswego Energy Corp., Massachusetts corporations, Tug Hill Energy Inc., a New York corporation, Black Mountain Sewer Corporation and Gold Canyon Sewer Company, Arizona corporations, Great Falls Energy, L.L.C., a Maryland limited liability company, and Sanger Power, L.L.C., a California limited liability company.

The Fund also owns, directly or indirectly, interests in the following partnerships: Société Hydro-Donnacona S.E.N.C., a Québec general partnership; 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 Hydroelectric Limited Partnership, New Hampshire limited partnerships, Moretown Hydro Energy Company, a Vermont partnership, HDI Associates I, an Indiana general partnership, Algonquin Power (Mont Laurier) Limited Partnership, a Québec limited partnership; Great Falls Hydroelectric Company Limited Partnership, a Maryland limited partnership, Oswego Hydro Partners, L.P., a Delaware limited partnership and KMS Joliet Power Partners, L.P. and KMS Bakery Power Partners, L.P., Illinois limited partnerships.

The Fund is the sole beneficiary of the 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 Drayton Valley Power Income Fund, 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 owns approximately 86.7% of the outstanding trust units and approximately 47.3% of the outstanding convertible debentures of KMS Power Income Fund, 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. All

of the above-noted entities are wholly-owned, directly or indirectly, by the Fund, with the exception of the KMS entities, which are majority owned, indirectly by the Fund.

All information contained in this Annual Information Form is presented as at May 17, 2002, unless otherwise specified. Reference is made to the glossary attached as Schedule A for the meanings of certain defined terms.

BUSINESS

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 currently holds equity interests, directly and indirectly, in 47 hydroelectric generating facilities located in Ontario (5), Québec (12), Newfoundland (1), Alberta (1), New York State (12), New Hampshire (13), Vermont (2) and New Jersey (1) representing aggregate installed generating capacity of approximately 140 MW. The Fund holds equity interests in one energy from waste facility in Ontario with an installed generating capacity of 10 MW, one bio-gas-fired facility in Illinois with an installed generating capacity of 1.6 MW and three natural gas-fired cogeneration facilities in each of Illinois, New Jersey and California with an installed capacity of 55 MW. In addition, the Fund owns partnership, share and debt interests in three bio-mass fired generating facilities with combined installed capacity of approximately 67 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 and one 150MW natural gas powered combined cycle cogeneration plant located in south-eastern Ontario. In addition to its electricity generating assets, Algonquin owns two wastewater treatment facilities located near Phoenix, Arizona. The facilities are grouped into four business segments: hydroelectric segment, natural gas cogeneration segment, alternative fuel segment and infrastructure segment. 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.

The Fund may, where practical and economic, expand its current operations. The Fund may consider investment opportunities which provide stable cashflow from renewable resource facilities; potential investment candidates could include wind and biomass powered generating stations or facilities within a regulated utility. 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 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.

Algonquin Power Systems Inc., a wholly-owned subsidiary of Algonquin Power, provides operations-related services in respect of the facility interests indirectly owned by the Fund. In addition to operating the hydroelectric generating facilities in which the Fund has an interest, Power Systems is responsible for the operation of 200,000 kilowatts of generating capacity across Canada and the United States and 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 Canada.

In addition to the principals of the Manager, Power Systems' human resources of over 150 individuals is 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.

DEVELOPMENT OF THE BUSINESS

Creation of the Fund and 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 \$15,000 per year plus \$1,000 for each meeting attended in person and \$500 for each meeting attend by telephone per Trustee.

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 one or more additional Trustees to serve until the next annual meeting of Unitholders, but the number of additional Trustees will not at any time exceed one-third of the number of Trustees who held office at the expiration of the immediately preceding 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 instalments, 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 "Development of the Business — Creation of the Fund and 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

The amount of Distributable Cash to be distributed annually per Trust Unit will be equal to a pro rata share of interest, royalty and dividend income, taxable deemed dividends, lease payments or other income from the Leases received by the Fund in the year less: (i) administrative expenses of the Fund; (ii) amounts which may be paid by the Fund in connection with any cash redemptions of Trust Units; (iii) amounts required for the business and operations of the Fund, including amounts required to pay the deferred portion of the purchase price for any assets acquired by the Fund, directly or indirectly; and (iv) capitalized interest with respect to any notes held by the Fund. Any income of the Fund which is applied to any cash redemptions of Trust Units or is otherwise unavailable for cash distribution will be distributed to Unitholders in the form of additional Trust Units. 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, on December 31 of each year, Unitholders will be entitled to receive a distribution of the amount, if any, by which the income of the Fund including any net capital gains for purposes of the Tax Act in respect of the year (calculated without reference to paragraph 82(1)(b) and to subsection 104(6) of the Tax Act) less any deductible non-capital or capital losses of prior years exceeds all amounts otherwise distributed or made payable in respect of the year. Certain adjustments may apply.

The Trustees of the Fund have determined to have the Fund make distributions monthly and not quarterly. The Fund will include in its monthly distributions cash dividends, distributions or returns of capital, if any, received from Fund Businesses. Monthly distributions are due and payable 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, it is anticipated that distributions of Distributable Cash will be greater during the month's 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.

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 distribution in specie of an interest in the Fund Assets. No fractional Algonquin Canada Shares, Fund Notes (based on increments of \$100) or other securities, if any, will be distributed and, where the number of Algonquin Canada Shares, Fund 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 “Development of the Business – Creation of the Fund and 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 or as part of an internal reorganization of Algonquin Canada and any one or more of its wholly-owned subsidiaries;

- (c) any issue of shares in the capital of Algonquin Canada or its subsidiaries other than to the Fund or Algonquin Canada, 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 such entity; or
- (e) any amendment to any unanimous shareholders' agreement entered into in respect of Algonquin Canada or its subsidiaries,

without the approval of the Unitholders by Extraordinary Resolution at a meeting of Unitholders called for that purpose.

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.

Foreign Property

The Fund has been registered by the Canada Customs and Revenue Agency (the “CCRA”) as a “registered investment” under the Tax Act and has not been notified by the CCRA that such registration has been revoked. Provided the Fund continues to be so registered, Trust Units of the Fund will not be foreign property for Unitholders who are subject to Part XI of the Tax Act.

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

Administration Agreement

The Manager administers the Fund pursuant to the Administration Agreement entered into between the Fund and the Manager and is responsible for the administration and management of the affairs of the Fund. The Manager is reimbursed for its reasonable out-of-pocket expenses incurred in administering the Fund. The agreement is terminable on 180 days’ notice, or immediately in the event of

termination of the Management Agreement, winding-up of the Fund, the insolvency or receivership of the Manager, a change of control of the Manager (other than a change of control to which the Fund consents) or default of the Manager in the performance of a material obligation which is not remedied within 30 days.

Management Agreement

The Fund and the Manager entered into the Management Agreement on December 23, 1997, as amended, pursuant to which the Manager provides management services (the "Management Services") for certain of the Fund Businesses on behalf of the Fund for the Facilities.

The Management Services provided include, without limitation, 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. Specific functions performed by the Manager include: (i) 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 major 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.

In consideration for providing the Management Services, the Manager received a quarterly fee of \$84,250 during 2001, which fee is adjusted annually for changes in the Canadian Consumer Price Index and a fee based on increases in Distributable Cash equal to the aggregate of 10% of the Distributable Cash per Trust Unit in excess of \$0.97 per Trust Unit and up to \$1.045 per Trust Unit and 25% of the Distributable Cash per Trust Unit in excess of \$1.045 per Trust Unit. The fee related to energy production and the incentive fee related to increases in Distributable Cash are intended to provide the Manager with an incentive to maximize Distributable Cash per Trust Unit. In addition, the Manager is entitled to reimbursement of its reasonable out-of-pocket expenses incurred in connection with its duties under the Management Agreement.

The Management Agreement has an initial ten year term commencing on December 23, 1997 and will be renewed for successive periods of five years each unless the Fund gives notice of non-renewal to the Manager at least 12 months before the end of the relevant term.

The Fund may terminate the Management Agreement earlier if a substantial deterioration of the Fund's business occurs, taken as a whole, which is not caused by an event of force majeure, if, within six months of the deterioration, such termination is approved by a written resolution of Unitholders representing at least $66\frac{2}{3}\%$ of the issued and outstanding Trust Units or at a meeting of Unitholders by a resolution approved by the holders representing at least 50% of all issued and outstanding Trust Units and at least $66\frac{2}{3}\%$ of the Trust Units which are voted at the meeting, in each case excluding Trust Units held by or on behalf of the Manager. In the event of such termination, the Fund will pay the Manager a fee equal to the amount of fees payable to the Manager for the previous year, excluding fees relating to acquisitions and capital expansions. The Fund may also terminate the Management Agreement upon a change of control of the Manager (other than a change of control to which the Fund consents).

The Fund 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 30 days, other than a failure of performance which results from an event of force majeure.

The Manager may terminate the Management Agreement at any time on 12 months' notice.

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

Operations Supervisory Agreement

Algonquin Canada and Power Systems entered into the Operations Supervisory Agreement on December 23, 1997, as amended, pursuant to which Power Systems provides certain operations related services for the Facilities (the "Operations Supervisory 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. Senior officers of Power Systems also act as senior officers of Algonquin Canada. Specific functions include: (i) planning of capital repairs; (ii) compliance monitoring for environmental permits; and (iii) administration of power purchase agreements.

In consideration for providing the Operations Supervisory Services, Power Systems received a quarterly fee of \$77,250 during 2001, which fee is adjusted annually for changes in the Canadian Consumer Price Index.

The Operations Supervisory Agreement contains termination provisions substantially the same as those included in 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 for an aggregate amount totalling approximately \$4.8 million during 2001. In addition, Newspring has entered into agreements with the entity which owns the wastewater treatment facilities to provide similar services for an aggregate amount totalling approximately \$0.4 million during 2001.

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 2001 totalled approximately \$2.0 million which was paid to Power Systems.

Governance Agreement

Pursuant to the Governance Agreement, the Manager is entitled to appoint two directors to Algonquin Canada's board of directors, with the Fund being entitled to appoint one director. The articles

of Algonquin Canada 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 will provide that the Fund will not vote for any amendment to Algonquin Canada's articles, 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. Notwithstanding the foregoing, the Fund will be entitled to remove the Manager's nominees as directors of Algonquin Canada or amend Algonquin Canada's articles if:

(a) Algonquin Canada does not comply with or prevents the implementation of Algonquin Canada's 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;

(f) an offer is made for 100% of the Trust Units and the offeror acquires more than 50% of the Trust Units under that offer; or

(g) the Management Agreement expires or is terminated.

Public Offerings

On October 16, 1997 and December 11, 1997, the Fund filed a preliminary prospectus and a final prospectus, respectively, with the securities regulatory authorities in each of the provinces of Canada with respect to an initial public offering of Trust Units.

On December 23, 1997, the Trust completed the sale of 8,031,775 Trust Units at an issue price of \$10.00 per Trust Unit. Concurrently with the offering, the Fund completed the acquisition of its interests in 14 Facilities, being the Marsh facilities, the Donnacona Facility, the Lochmere Facility, the Hopkinton Facility and the Trafalgar Facilities, and deposited into escrow the purchase price for its interests in the Belleterre Facility, the Ste-Brigitte Facility and the Long Sault Rapids Facility, interests in which Facilities were subsequently acquired on February 4, 1998 and April 17, 1998, respectively.

On May 22, 1998 and June 26, 1998, the Fund filed a preliminary prospectus and a final prospectus, respectively, with the securities regulatory authorities in each of the provinces of Canada with respect to an additional offering of Trust Units.

On July 7, 1998, the Fund completed the sale of 6,058,697 Trust Units at an issue price of \$10.65 per Trust Unit. Concurrently with the offering, the Fund completed the acquisition of its interests in 11 Facilities, being the Saint-Alban Facility, the Glenford Facility, the Rawdon Facility, the Lower Robertson Facility, the Ashuelot Facility, the Avery Dam Facility, the Hadley Falls Facility, the Lakeport Facility, the Moretown Facility, the Hollow Dam Facility and the Burt Dam Facility, and set aside the purchase price for its interest in the Rattle Brook Facility, an interest in which Facility was subsequently acquired on December 31, 1998.

On April 6, 1999 and April 27, 1999, the Fund filed a preliminary prospectus and a final prospectus, respectively, with the securities regulatory authorities in each of the provinces of Canada with respect to an additional offering of Trust Units.

On May 4, 1999, the Fund completed the sale of 8,100,000 Trust Units at an issue price of \$10.35 per Trust Unit. Shortly after the completion of the offering, the Fund completed the acquisition of its interests in 7 Facilities, being the Côte Ste-Catherine Facility, the Mont Laurier Facility, the Hydro Snemo Facility, the Hydraska Facility, the Ste-Raphaël Facility, the Clement Dam Facility and the Franklin Facility.

On November 11, 1999 and November 25, 1999, the Fund filed a preliminary prospectus and a final prospectus, respectively, with the securities regulatory authorities in each of the provinces of Canada with respect to an additional offering of Trust Units.

On December 1, 1999, the Fund completed the sale of 1,830,000 Trust Units at an issue price of \$8.75 per Trust Unit. Shortly after the completion of the offering, the Fund completed the acquisition of its interests in the Pembroke Facility and the Gregg Falls Facility.

On August 31, 2000 and September 12, 2000, the Fund filed a preliminary prospectus and a final prospectus, respectively, with the securities regulatory authorities in each of the provinces of Canada with respect to an additional offering of Trust Units.

On September 26, 2000, the Fund completed the sale of 3,000,000 Trust Units at an issue price of \$9.15 per Trust Unit. The Fund used the proceeds to pay off the revolving line of credit and to complete the acquisitions of the Milton Facility, Mine Falls Facility and Great Falls Facility.

On January 11, 2001 and January 19, 2001, the Fund filed a preliminary prospectus and a final prospectus, respectively, with the securities regulatory authorities in each of the provinces of Canada with respect to an additional offering of Trust Units.

On January 25, 2001 and February 15, 2001 the Fund completed the sale of 6,600,000 and 990,000 Trust Units respectively at an issue price of \$9.85 per Trust Unit. The Fund utilized approximately \$27.5 million of the net proceeds to complete the acquisition of an interest in the Campbellford Facility, the Kings Falls Facility, the Otter Creek Facility, the Worcester Facility, the Phoenix Facility, the Arthurville Facility and the Black Mountain wastewater treatment facility.

On July 3, 2001 and July 26, 2001, the Fund completed the sale of 6,500,000 and 975,000 Trust Units respectively at an issue price of 10.05 per Trust Unit. The Fund utilized \$49.4 million to complete the acquisition of interests in the Dickson Dam Facility, the Drayton Valley Facility and the Gold Canyon Facility.

On October 18, 2001 and November 2, 2001 the Fund completed the sale of 7,750,000 and 1,040,300 Trust Units respectively at a price of \$9.70 per Trust Unit. The Fund utilized the proceeds to acquire share and debt interests in six generating facilities.

On March 15, 2002, the Fund issued 6,099,557 Trust Units to Algonquin Power Trust to deliver to unitholders and debentureholders of KMS Power Income Fund to acquire approximately 86.7% of the outstanding trust units and approximately 47.3% of the outstanding convertible debentures of KMS Power Income Fund.

Additional details concerning the terms of the acquisitions of an interest in such Facilities may be found at pages 37 to 46 of the Fund's prospectus dated December 11, 1997 in the section entitled "The Acquisitions", at pages 58 to 64 of the Fund's prospectus dated June 26, 1998 in the section entitled "The Acquisitions", at pages 13 to 15 of the Fund's prospectus dated April 27, 1999 in the section entitled "The Acquisitions" and at pages 7 to 8 of the Fund's prospectus dated November 25, 1999 in the section entitled "Acquisition Process", which sections are incorporated herein by reference. Additional details concerning the acquisition strategy of the Fund may be found in the Fund's prospectus dated January 19, 2001 in the section entitled "Acquisition Process", which section is incorporated herein by reference.

Acquisitions of Facilities in Fiscal 2001

During 2001, the Fund acquired two wastewater treatment facilities, six hydroelectric generating facilities, a note receivable and a 50% interest in a hydroelectric generating facility and 50% ownership of a biomass-fired generating facility for total consideration of approximately \$76,885,000. The acquisitions have been accounted for using the purchase method with earnings from operations included since the date of acquisition. The consideration paid by the Fund has been allocated to net assets acquired as follows:

	(in thousands)
Working capital	\$ 1,379
Capital assets	74,330
Funds held in reserve	2,107
Note receivable	3,680
Future non-current tax asset	802
Future non-current income tax liability	<u>(5,413)</u>
Total cash purchase price paid	<u>\$ 76,885</u>

The purchase price paid for the facilities, the nature of the acquisitions and the dates of acquisition are set out in the table below:

<i>Facility</i>	<i>Purchase Price (in thousands)</i>	<i>Nature of Acquisition</i>	<i>Date of Acquisition</i>
Phoenix, Kings Falls and Otter Creek, New York and Worcester, Vermont	\$ 11,614	Shares	March 21, 2001
Campbellford, Ontario	8,151	Partnership interest and note receivable	March 9, 2001 and April 1, 2001

<i>Facility</i>	<i>Purchase Price (in thousands)</i>	<i>Nature of Acquisition</i>	<i>Date of Acquisition</i>
Arthurville, Québec	905	Shares	April 11, 2001
Black Mountain, Arizona	6,782	Shares	March 16, 2001
Gold Canyon, Arizona	7,315	Shares	July 9, 2001
Dickson Dam and 50% of Drayton Valley, Alberta	42,118	Trust units and partnership units	July 27, 2001
Total	<u>\$ 76,885</u>		

Acquisitions of Facilities in 2002

On March 15, 2002, Algonquin Power Trust, a trust of which the Fund is the sole beneficiary, completed the acquisition of approximately 86.7% of the outstanding trust units of KMS Power Income Fund and approximately 47.3% of the outstanding principal amount of convertible debentures of KMS by delivering 6,099,557 trust units of the Fund to KMS unitholders and debentureholders for total consideration of \$102,147,000. Algonquin Power Trust intends to effect a subsequent acquisition transaction so as to acquire the remaining KMS trust units not tendered to the takeover bid for KMS. KMS owns, directly or indirectly, four generating facilities: an energy-from-waste facility in Ontario; two natural gas-fired co-generation facilities located in New Jersey and Illinois; and a landfill bio-gas-fired generating facility in Illinois. The acquisitions have been accounted for using the purchase method, with earnings from operations included since the date of acquisition. The consideration paid by the Fund has been allocated to net assets acquired as follows:

	(in thousands)
Working capital deficit	\$ (3,776)
Funds held in reserve	1,124
Capital assets	127,736
Long term liabilities assumed	(6,775)
Minority interest	<u>(16,162)</u>
Total purchase price	\$ 102,147
Less: Cash acquired	(544)
Loan advanced in 2001	(35,000)
Trust units issued being non cash consideration	<u>(62,704)</u>
Acquisition cash consideration	<u>\$ 3,899</u>

In May 2002, the Fund indirectly acquired a 43.5 MW natural gas-fired generating station 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 General Electric steam turbine and has demonstrated a successful operating history since its commissioning in 1991. The aggregate purchase price of approximately \$80 million (US\$ 50 million) has been satisfied in part by the assumption of \$30 million (US\$ 19 million) of tax-exempt US\$ denominated bonds and with the balance funded jointly through the use of proceeds of previous Trust Unit offerings of the Fund along with financing provided by the Fund's lending syndicate.

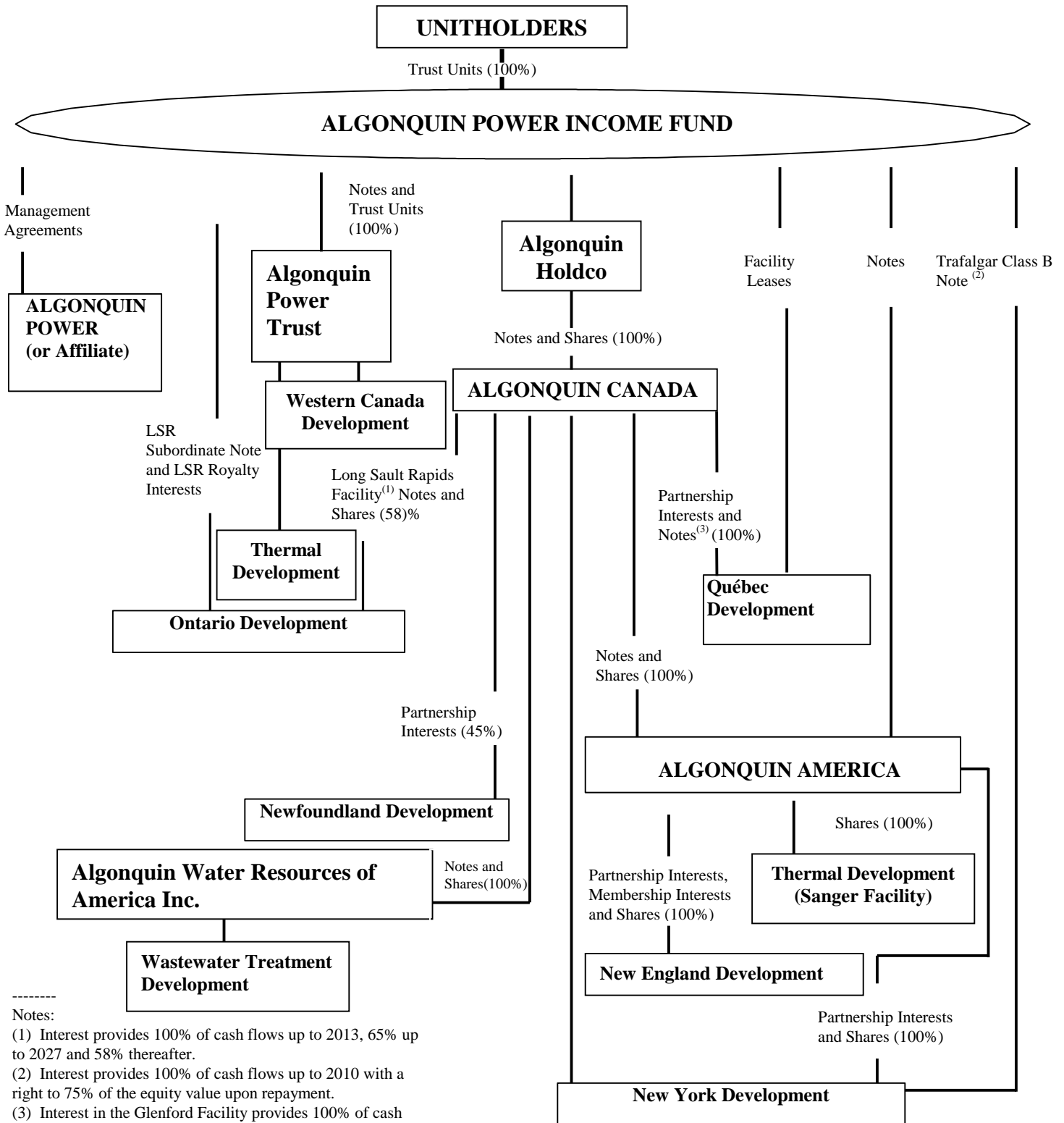
The purchase price allocation has been based on the best information available at the date hereof; however, adjustments to the purchase price and purchase price allocation may be made subsequently as more information is obtained.

Acquisition of Notes Receivable and Other Interests

During the fourth quarter of 2001, the Fund acquired certain notes receivable and equity shares in companies which own six generating facilities for a total of \$74,534,000. These facilities include a biomass-fired facility in each of Alberta, Québec and Nova Scotia and three natural gas-fired cogeneration facilities located in Ontario.

Subsequent to the completion of this transaction the owner of one facility, a biomass-fired facility located in Alberta, repaid the outstanding loan plus a prepayment penalty. The Fund has no further interest in such facility.

Structure of the Fund



Notes:

- (1) Interest provides 100% of cash flows up to 2013, 65% up to 2027 and 58% thereafter.
- (2) Interest 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 and the option to indirectly acquire the facility.

THE DEVELOPMENTS

The Fund acquired with the proceeds of the offerings, directly or indirectly, interests in 60 infrastructure facilities.

Hydroelectric Generating Facility	Generating Capacity (kilowatts)	Location	2002 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Ontario Development						
Long Sault Rapids Facility	18,000	Abitibi River near Cochrane, Ontario	Summer Energy \$0.0370/kW-hr Summer Capacity \$0.0572/kW-hr Winter Energy \$0.0453/kW-hr Winter Capacity \$0.0755/kW-hr	119,584	2047	2001 ⁽²⁾
Hurdman Dam Facility	570	Mattawa River near Mattawa, Ontario	Winter Peak \$0.0878 /kW-hr Winter Off-Peak \$0.0347 /kW-hr Summer Peak \$0.0814 kW-hr Summer Off-Peak \$0.0249 /kW-hr	4,429	2005	2004
Drag Lake Dam Facility	225	Trent River near Haliburton, Ontario	Winter Peak \$0.0934 /kW-hr Winter Off-Peak \$0.0380 /kW-hr Summer Peak \$0.0757 /kW-hr Summer Off-Peak \$0.0338 /kW-hr	1,219	2012	Owned
Burgess Dam Facility	130	Muskoka River near Bala, Ontario	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	1998 ⁽³⁾
Campbellford Facility	4,000	Trent River near Campbellford, Ontario	Winter On-Peak \$0.6310 / 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 Development						
Côte Ste-Catherine Facility	11,120	St. Lawrence River near the Town of Ste.-Catherine, Québec	Phase I Energy \$0.0472/kW-hr Phase II Energy \$0.04966/kW-hr Capacity \$121.90/kW-hr (the average kilowatts) Phase III Energy \$0.05171/kW-hr Capacity \$127.81/kW-hr (the average kilowatts)	Phase I 16,616 Phase II 37,625 Phase III 37,247	Phase I 2009 Phase II 2018 Phase III 2021	2009

Hydroelectric Generating Facility	Generating Capacity (kilowatts)	Location	2002 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
Saint-Alban Facility	8,200	Ste-Anne River near the Village of Saint-Alban, Québec	\$0.05821 /kW-hr .	37,260	2016	1998 ⁽⁶⁾
Glenford Facility	4,950	Ste-Anne River near the Village of Ste-Christine d'Auvergne, Québec	\$0.05821 / kW-hr	24,593	2020	Owned
Donnacona Facility	4,800	Jacques Cartier River near Donnacona, Québec	\$0.05821/kW-hr	20,970	2022	2017
Ste-Brigitte Facility	4,200	Nicolet River in the Municipality of Ste-Brigitte-des-Saults, Québec	\$0.05821 /kW-hr	13,741	2014	Owned
Ste-Raphaël Facility	3,500	Rivière de Sud near Québec City, Québec	\$0.05821/kW-hr	25,035	2014	2013
Mont Laurier Facility	2,725	Rivière-du-Lièvre in the Town of Mont Laurier, Québec	\$0.06193/kW-hr	20,824	2007	2023
Hydro Snemo Facility	2,600	Rivière-du-Loup near the Town of Rivière-du-Loup, Québec	\$0.05821/kW-hr	17,455	2015	2015
Rawdon Facility	2,500	Ouareau River near the Village of Rawdon, Québec	\$0.05821 /kW-hr .	13,900	2014	2014
Hydraska Facility	2,250	Yamaska River near the Town of St-Hyacinthe, Québec	Summer Energy \$0.04894/kW-hr Winter Energy \$0.08977/kW-hr	10,825	2014	2014
Belleterre Facility	2,200	Winneway River in the Municipality of Laforce, Québec	\$0.04853 /kW-hr \$119.93 /kW (over the average kilowatt output over the period December to March)	15,703	2013	2011
Arthurville Facility	650	Riviere du Sud downstream from Ste-Raphaël	Flat Rate Annually of \$0.05821 / kW-hr	2,782	2013	Owned
Newfoundland Development						
Rattle Brook Facility	4,000	Rattle Brook near Jackson's Arm, Newfoundland	Summer Energy \$0.04167 /kW-hr Summer Capacity \$0.02237 /kW-hr Winter Energy \$0.04167 /kW-hr Winter Capacity \$0.04782 /kW-hr	17,470	2024	2048

Hydroelectric Generating Facility	Generating Capacity (kilowatts)	Location	2002 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
New York Development						
Ogdensburg Facility ⁽⁴⁾	3,675	Oswegatchie River near Ogdensburg, New York	US\$0.0400 /kW-hr	10,596	2007	2038
Forestport Facility ⁽⁴⁾	3,300	Black River near Boonville, New York	US\$0.0400 /kW-hr	10,016	2007	Owned
Herkimer Facility ⁽⁴⁾	1,680	West Canada Creek near Herkimer, New York	US\$0.0400 /kW-hr	5,114	2007	Owned
Hollow Dam Facility ⁽⁴⁾	900	Oswegatchie River near Gouverneur, New York	US\$0.0400 /kW-hr	4,400	2000 ⁽⁵⁾	2026
Christine Falls Facility	850	Sacandaga River near Clifton, New York	US\$0.23002 /kW-hr	3,065	2028	Owned
Burt Dam ⁽⁴⁾	600	18 Mile Creek near Newfane, New York	US\$0.0400 /kW-hr	2,300	2000 ⁽⁵⁾	2036
Cranberry Lake Facility	500	Oswegatchie River near Clifton, New York	US\$0.0400 /kW-hr	2,154	2025	2035
Kayuta Lake Facility	400	Black River near Boonville, New York	US\$0.0839822 /kW-hr	2,089	2028	Owned
Adams Facility	350	Sandy Creek near Adams, New York	US\$0.09670 /kW-hr	648	2028	Owned
Kings Falls Facility	1,750	Deer River near Copenhagen, New York	Flat Rate Annually of US\$0.03670 / kW-hr	3,680	2003	Owned
Otter Creek Facility	530	Otter Creek in Craig, New York	Flat Rate Annually of US\$0.04 / kW-hr	1,944	2001	Owned
Phoenix Facility	3,500	Oswego River in Phoenix, New York	Flat Rate Annually of US\$0.092050 / kW-hr	11,760	2026	Owned
New England Development						
Gregg Falls Facility	3,500	Piscataquog River near the Town of Goffstown, New Hampshire	Energy Block 1 US\$0.1332/kW-hr Block 2 US\$0.1169/kW-hr Block 3 US\$0.1005/kW-hr Block 4 US\$0.0830/kW-hr Block 5 US\$0.0666/kW-hr	10,083	2020	2031
Pembroke Facility	2,600	Suncook River near the Town of Pembroke, New Hampshire	Energy Block 1 US\$0.1332/kW-hr Block 2 US\$0.1169/kW-hr Block 3 US\$0.1005/kW-hr Block 4 US\$0.0830/kW-hr Block 5 US\$0.0666/kW-hr	9,311	2020	Owned
Clement Dam Facility	2,400	Winnipisauhee River near the Town of Tilton, New	US\$0.09000/kW-hr	11,288	2004	2032

Hydroelectric Generating Facility	Generating Capacity (kilowatts)	Location	2002 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
		Hampshire				
Franklin Facility	River Bend 1,600 Steven's Mill 200	Winnepesaukee River near the Town of Franklin, New Hampshire	On Peak US\$0.1282/kW-hr Off Peak US\$0.9690/KW-hr Capacity US\$90.34/ Average kW Energy US\$0.11040/kW-hr Capacity US\$90.34/ Average kW	River Bend 7,550 Steven's Mill 1,020	2006	Owned
Moretown Facility	1,200	Mad River near Moretown, Vermont	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	3,592	2018	Owned
Lochmere Facility	1,200	Winnepesaukee River near Lochmere, New Hampshire	US\$0.09/kW-hr	4,652	2006	2033
Lower Robertson Facility	960	Ashuelot River near Hinsdale, New Hampshire	On-Peak US\$0.1678/kW-hr Off-Peak US\$0.1248/kW-hr Capacity US\$106.58/Average kW	3,729	2015	Owned
Ashuelot Facility	900	Ashuelot River near Hinsdale, New Hampshire	On-Peak US\$0.1678/kW-hr Off-Peak US\$0.1248/kW-hr Capacity US\$106.58/Average kW	3,629	2015	2040
Lakeport Facility	600	Winnepesaukee River near Laconia, New Hampshire	On-Peak US\$0.1283/kW-hr Off-Peak US\$0.0970/kW-hr Capacity US\$90.35 /Average kW	2,650	2005	2032
Avery Dam Facility	260	Winnepesaukee River near Laconia, New Hampshire	On-Peak US\$0.1678/kW-hr Off-Peak US\$0.1248/kW-hr Capacity US\$106.58/Average kW	1,834	2015	2035
Hadley Falls Facility	250	Piscataquoq River near Goffstown, New Hampshire	On-Peak US\$0.1035/kW-hr Off-Peak US\$0.0761/kW-hr Capacity US\$96.40/Average kW	1,007	2006	2016
Hopkinton Facility	250	Contoocook River near Hopkinton, New Hampshire	US\$0.0900/kW-hr	920	2006	2023
Milton Facility	1,335	Salmon River near the Town of Milton, New Hampshire	Block I US\$0.0778 / kW-hr Block II US\$0.0771 / kW-hr	6,166	2012	Owned
Mine Falls Facility	3,000	Nashua River near the City of Nashua, New Hampshire	US \$ 0.0900 / kW-hr	10,700	2005	2024
Great Falls Facility	10,950	Passaic River near the	US \$ 0.04 / kW-hr	25,500	2002	2021

Hydroelectric Generating Facility	Generating Capacity (kilowatts)	Location	2002 Power Purchase Rates ⁽¹⁾	Annual Average Expected Energy Production (MW-hrs)	Year of Expiry of Power Purchase Agreement	Year of Expiry of Lease
		City of Paterson, New Jersey				
Worcester Facility	180	Winooskie River in Worcester, Vermont	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	430	2016	Owned

Western Canada Development						
Drayton Valley Biomass-Fired Facility	12,000	Drayton Valley, Alberta	\$0.0633/kW-hr	87,600	2014	Owned
Dickson Dam Hydroelectric Generating Facility	15,000	Innisfail, Alberta	\$0.0633/kW-hr	67,310	2012	2030
Thermal Development						
CDT (KMS Joliet) Landfill Gas Management Facility	3,200	Joliet, Illinois	Municipal Average Rate \$0.0615/kW-hr	12,878	Perpetual Renewals	2007
KMS Crossroads Cogeneration Facility	10,000	Mahwah, New Jersey	Energy Rate Fixed \$0.09362/kW-hr Onpeak - \$0.0995/kW-hr Midpeak - \$0.077/ kW-hr Offpeak - \$0.0270/kW-hr	OR 34,012 CDA 17,609	2008 – OEFC 2017 – Industrial	2016
Entenmann's (KMS Bakery) Cogeneration Facility	1,600	Near Chicago, Illinois	Electrical \$0.12827/kW-hr Thermal \$0.24904/kW-hr 3% increase every August 1 st .	5,283	2004	2002
Peel Facility	10,100	Brampton, Ontario	Winter Peak - \$0.0969/kW-hr Winter Offpeak - \$0.0373/kW-hr Summer Peak - \$0.0823/kW-hr Summer Offpeak - \$0.0326/kW-hr All rates subject to CPI Increases	61,345	2012	Owned
Sanger Cogeneration Facility	43,500	Sanger, California	\$0.0537/ kW-hr Capacity Payment- \$190 per kW/year	367,920	2022	Owned

Notes:

- (1) 2001 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) Interim lease to be replaced by a long term lease of 50 years less a day.

- (3) Lease has been extended on a month-to-month basis during negotiations for the renewal of the lease. Long term lease to be entered into will be for twenty years.
- (4) These rates changed to the avoided costs of Niagara Mohawk effective January 1, 2001.
- (5) Agreement has been extended on a month-to-month basis during negotiations for the renewal of the agreement.
- (6) A long term lease is currently being finalized.
- (7) The Fund also has notes receivable and equity shares in companies which own five generating facilities.
- (8) The Fund also owns two wastewater treatment facilities, the Black Mountain Facility and the Gold Canyon Facility.

Ontario Development - Long Sault Rapids, Hurdman Dam, Drag Lake Dam, Burgess Dam and Campbellford Facilities

Long Sault Rapids Facility

The Long Sault Rapids Facility is an 18,000 kilowatt hydroelectric generating facility located on the Abitibi River, 19 kilometers 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 "Credit Agreements" below).

The facility includes a 125 meter long rock filled dam that crosses the Abitibi River. The dam has created a narrow headpond approximately ten kilometres in length. The facility is a run-of-the-river facility and the headpond will not be utilized for storage and peaking purposes. The powerhouse is an integrated structure, housing four pit turbine generating units each rated at 4,500 kilowatts of generating capacity which were manufactured by Sulzer Canada Inc.

Electricity produced by the facility is sold directly to Ontario Electricity Financial Corporation for distribution to its customers by means of a 23.5 kilometre 115 kV transmission line, which crosses both private property and provincially owned land pursuant to easements, rights of way and land use permits. Rights to all necessary lands have been obtained in order to construct, operate and maintain the transmission line.

Power Purchase Agreement

Pursuant to the terms of the power purchase agreement, the Co-Owners sell power produced by the facility exclusively to Ontario Electricity Financial Corporation and Ontario Electricity Financial Corporation purchases all power delivered at the delivery point, approximately 23.5 kilometres from the facility site. 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. Ontario Electricity Financial Corporation has the option to terminate the agreement upon 60 days' written notice if the Co-Owners fail to deliver power to Ontario Electricity Financial Corporation for 24 consecutive months and, in Ontario Electricity Financial Corporation's opinion, the Co-Owners are not taking appropriate steps to remedy the situation. In addition, Ontario

Electricity Financial Corporation has the right to discontinue the receipt of power, by written notice, should the Co-Owners fail to perform any obligation under the agreement or under an operations agreement between Ontario Electricity Financial Corporation and the Co-Owners outlining operating procedures for the facility, until the obligation is fulfilled.

The agreement provides that the payment made by Ontario Electricity Financial Corporation for power produced by the facility is calculated as the sum of the monthly capacity payment and the monthly energy payment. The monthly capacity payment is calculated as the product of the number of On-peak hours for the month and the sum of the applicable energy and capacity rates. The monthly energy payment is the product of Off-peak hours and the applicable energy rate. The rates are escalated annually based on an index figure tied to the greater of Ontario Electricity Financial Corporation's all customer rate or direct customer rate. The agreement provides that the rates will not decrease based on this index.

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 Ontario Electricity Financial Corporation during at least 85% or more of the On-peak period fifteen minute intervals for that month. The monthly payment from Ontario Electricity Financial Corporation will not include an amount for any monthly capacity power delivered in excess of target generation specified in the agreement and will not include an amount for any monthly energy in excess of 115% of target generation specified in the agreement.

Waterpower Lease

The Co-Owners have entered into an interim waterpower lease with the Province of Ontario in respect of the dam site for a term expiring on June 30, 2001. The interim lease provides that the parties will enter into a long term waterpower lease upon certain matters being completed, including approval of the long term lease by the Lieutenant Governor in Council. The long term lease will be for a term of 50 years less a day, comprised of an initial term of 20 years, a 10 year extension on the same terms and conditions and two additional 10 year extensions on terms and conditions to be approved by the Province. The long term waterpower lease will provide for an annual land rental and an annual energy charge. The energy rate does not commence until 10 years after the long term lease comes into effect; however, the energy rate will be subject to annual review by the Province and may be adjusted at the discretion of the Province.

Partnership Agreements

There are partnership agreements governing the affairs of both Co-Owners. The provisions of each partnership agreement are virtually identical. The partnerships were formed for the purpose of carrying on the business of financing, holding and operating undivided interests in the facility.

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 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 \$44,397,000 at December 31, 2001. 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 commencing upon completion of construction and conversion of the loan to long-term financing (which conversion occurred effective January 31, 1999) and an identical amortization period with 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.

The credit agreement contains certain events of default, including: (i) the sale of assets and property covered by the lenders' security without the lenders' consent; (ii) certain changes in ownership; (iii) any amendment, waiver, termination, renewal or extension or breach continuing for 30 days after written notice of any of the material facility agreements, without the prior written consent of a majority of the lenders; or (iv) if there is a change in the manager or operator from Power Systems.

Under the terms of the credit agreement, a debt reserve is required. At December 31, 2001, 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.

Hurdman Dam, Drag Lake Dam and Burgess Dam Facilities

The Drag Lake Dam facility, with a generating capacity of 225 kilowatts is located on the Trent River at the Drag Lake Dam, in Haliburton, Ontario. The Burgess Dam facility, with a generating capacity of 130 kilowatts, is located at the outlet of Lake Muskoka River at Moon River, in Bala, Ontario.

The Hurdman Dam facility, with a generating capacity of 570 kilowatts, is located on the Mattawa River, two kilometres upstream from the Town of Mattawa, Ontario. These three facilities are owned by Algonquin Canada.

Power Purchase Agreements

Pursuant to the terms of the power purchase agreements, each facility will sell all power produced at such facility exclusively to Ontario Electricity Financial Corporation and Ontario Electricity Financial Corporation agrees to purchase all such power. The initial term of the agreement for the Hurdman Dam facility is 20 years commencing January 1, 1985, for the Drag Lake Dam facility is 20 years from the commencement of commercial operations, which occurred on March 9, 1992 and for the Burgess Dam facility is 20 years from the commencement of commercial operations, which occurred on August 14, 1989.

The agreements contain typical non-utility generator obligations to Ontario Electricity Financial Corporation. There are no minimum contractual delivery quantities. The power purchase rates applicable to the facilities are currently based on On-peak versus Off-peak hours and summer (April 1 to September 30) versus winter.

Land and Water Rights

For the Hurdman Dam facility, a waterpower renewal lease agreement was entered into with the Province of Ontario in respect of the facility site dated January 1, 1994. The agreement provides for both waterpower and land usage rights. The term of the agreement is for 10 years, with a right to three further 10 year renewal terms upon the request of the lessee. The annual rent is: (i) an amount determined in accordance with a formula based on energy produced multiplied by the increase in the consumer price index; (ii) \$15,000; and (iii) 9% of gross revenues generated by the facility. The Province may terminate the lease if amounts owing under the lease remain unpaid for 90 days or if taxes or other assessments remain unpaid. Upon expiry or termination of the lease, improvements on the site become the property of the Province upon payment of the value of such improvements. Water levels must be maintained as specified in the lease. The lease is subject to termination if the power purchase agreement with Ontario Electricity Financial Corporation is terminated.

With respect to the Drag Lake Dam facility, the land on which the powerhouse and penstock are located is owned by Algonquin Canada. The dam site is licenced from the Trent-Severn Waterway.

The Burgess Dam facility has a lease for the facility site with The Corporation of the Township of Muskoka Lakes (the "Township") that commenced on May 1, 1988 for an initial term of ten years. The lease has four 10 year renewal terms on terms to be mutually agreed. The lease expired on April 30, 1998 and the Manager is currently negotiating a renewal with the Township. The Township has agreed to extend the lease on a month-to-month basis during the negotiations. The lease may be terminated for non-payment of rent, failure to maintain the site, vacancy for 20 or more days or other breaches on the part of the lessee, upon notice and after an opportunity to cure has expired. The lease includes the water rights owned by the Township and under the direction of the Ontario Ministry of Natural Resources.

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

Campbellford Facility

The Campbellford Facility is a 4,000 kilowatt hydroelectric generating facility located at Lock No. 14 on the Trent-Severn Waterway approximately four kilometers north of Campbellford, Ontario. This facility was an expansion project by the Town of Campbellford and Algonquin Power to the existing 2,100 kilowatt generating station owned by the town. The expansion was completed in late 1993 and commissioned in January 1994.

The facility is a run-of-the-river facility that consists of a shared 240 meter power canal leading to a concrete powerhouse housing two S-Kaplan double regulated turbines.

Land and Water Rights

The Town of Campbellford has a lease from the Government of Canada which gives the municipality the rights to all the available water in excess of that required for navigation at Lock No. 14 on the Trent-Severn Waterway. In addition to the water, the Town of Campbellford also has a lease for the land adjacent to Lock No.14 where the Campbellford Facility was developed.

In 1991, the Town of Campbellford entered into an arrangement with an Algonquin Power entity to develop the under-utilized water resources at the Lock No.14 site on the Trent-Severn Waterway. The Town of Campbellford subleased the necessary lands and water rights to the Algonquin Power entity to

allow it to build the Campbellford Facility. The arrangement is for 25 years from the commencement of the agreement, being March 8, 1994. At the conclusion of the term, the plant and equipment will be turned over to the Town of Campbellford.

On November 15, 1994, the Campbellford Facility was granted by Environment Canada – Parks Services, under the Dominion Water Act, a licence to operate a low head hydro power facility at Lock No. 14 on the Trent River. The term of the approval is 30 years, commencing July 1, 1994 and ending June 30, 2024.

Power Purchase Agreement

The agreement has a term of 25 years commencing March 10, 1994. The specified settlement rates set out in the agreement will be paid to the producer.

Québec Development — Côte Ste-Catherine, Saint-Alban, Glenford, Donnacona, Ste-Brigitte, Mont Laurier, Hydro Snemo, Rawdon, Hydraska, Ste-Raphaël, Belleterre and Arthurville Facilities

Côte Ste-Catherine Facility

The Côte Ste-Catherine Facility is 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 and was constructed in three separate phases, each phase having a total installed capacity of 2,120 kilowatts, 4,500 kilowatts and 4,500 kilowatts, respectively, and each phase was commissioned in 1989, 1993 and 1996, respectively. Due to the year round, high volume water flows of the St. Lawrence River, the Manager expects there to be sufficient water to operate the Côte Ste-Catherine Facility at full capacity throughout the year. The Côte Ste-Catherine Facility uses approximately 2% of the river flow at any given time.

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. The facility is located on a federal waterway. However, the Province of Québec has asserted jurisdiction over the water rights to this facility.

Credit Agreement

There is an outstanding senior loan against the facility in the amount of \$22,189,000 at December 31, 2000. The loan was provided by a syndicate comprised of Clarica, The Standard Life Assurance Company (“Standard Life”) and the Caisse de Dépôt et Placement du Québec (the “Caisse”). Clarica acts as agent for the syndicate. The loan has a term of 23.25 years commencing on October 31, 1994 and the loan bears interest varying from 9.91% to 11.05% during the term, compounded monthly. Blended payments of principal and interest are made monthly. Recourse on the loan is limited to the assets which comprise the Côte Ste-Catherine Facility and the Mont Laurier Facility (up to \$4.0 million). The sale of assets and property covered by the lenders’ security without the lenders’ consent is prohibited. Certain changes in ownership also constitute an event of default under this loan. An event of

default also occurs if there is any amendment, waiver, termination, renewal or extension or breach continuing for 30 days after written notice of any of the material project agreements, without the prior written consent of a majority of the lenders.

Algonquin Power Trust purchased the senior loan in May 2001 for a purchase price of \$22,493,953. This resulted in the Fund eliminating all external debt on the facility. To complete the repayment of the loan to third parties, Algonquin Power Trust paid a prepayment fee of \$6,751,000. The amount owing to Algonquin Power Trust as at December 31, 2001 was \$21,715,073, bears interest at the rate of 9% per annum and was due March 9, 2002.

Saint-Alban Facility

The 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 is located at the site of a decommissioned hydroelectric generating facility previously owned by Hydro-Québec. 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 Shawinigan Electric Company, a wholly-owned subsidiary of Hydro-Québec. SLI has entered into a temporary lease agreement with Shawinigan Electric Company for use of the land and hydraulic forces required to operate the facility. The temporary lease expired on December 1, 1998, however, Hydro-Québec has confirmed to SLI that it has extended the term of this lease until the land and water rights have been transferred to the Ministry of Natural Resources, Québec. Approval from Shawinigan Electric Company has been sought to allow the granting of a security interest in the temporary lease. It is contemplated that all land and hydraulic rights associated with the Saint-Alban Facility owned by Shawinigan Electric Company will be transferred to the Ministry of Natural Resources, Québec and that SLI will enter into a 20 year lease agreement with the Ministry of Natural Resources, Québec. SLI is presently negotiating the final terms of the lease with the Ministry.

In addition to contractual lease payments and amounts payable to the Ministry of Natural Resources, Québec, an agreement exists for the payment of an annual royalty of approximately \$10,500 in 2001 (increasing by \$500 per year) in respect of the Saint-Alban municipal park.

The lease agreement entered into between Ministry of Natural Resources, Québec and SLI prohibits transfer of the leasehold interest held by SLI until May 2001. Approval from the Government of Québec to the transfer of the leasehold interest to Algonquin Canada upon the Saint-Alban Transfer Date has been sought. Acquisition of legal title to this facility interest will be completed following the Saint-Alban Transfer Date.

Glenford Facility

The 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 is located at the site of a decommissioned hydroelectric generating facility previously owned by Hydro-Québec. 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.

Land and Water Rights

The Glenford Facility has been constructed on certain lands purchased by the Glenford Partnership and which lands include the existing structures associated with the historic generating facility. In addition, certain easements were granted to the former owner in respect of flooding rights and the access road. 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 \$5.8 million at December 31, 2001. 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.

The credit agreement contains certain events of default, including: (i) the sale of assets and property covered by the lender's security without the lender's consent; (ii) certain changes in ownership; (iii) any amendment, waiver, termination, renewal or extension or breach continuing for 15 days after written notice of any of the material facility agreements, without the prior written consent of the lender; or (iv) if there is a change in the manager or operator from Power Systems.

A hydrology reserve fund with a balance as at December 31, 2001 of \$127,735 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, 2001 of \$140,903 has been established in respect of major capital expenditures which may be incurred by the Glenford Partnership.

Donnacona Facility

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 facility was constructed at the site of an existing dam and is located on property purchased from Alliance Forest Products Inc./Produits Forestiers Alliance Inc. ("Alliance"). The powerhouse houses eight identical 600 kilowatt turbine generators. Construction commenced in April 1996 and the facility was commissioned in December 1996. Electricity produced by the facility is delivered to the Hydro-Québec distribution system.

Power Purchase Agreement

Under the power purchase agreement, Hydro-Québec has agreed to purchase all power made available to it from the facility and the Donnacona Partnership has agreed to supply a minimum of 18,790,200 kilowatt hours of energy during each period of 12 consecutive months commencing December 1 in each contract year. If the facility produces less energy than the minimum, a penalty of

approximately 1.1 cents per kilowatt hour for each kilowatt hour the actual production is below the minimum annual production is payable to Hydro-Québec. The term of the agreement is 25 years and it expires 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.

Power purchase rates for contract year 2001 and thereafter will be increased in accordance with the percentage increases in 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%.

Land and Water Rights

The real property interest required for the construction and operation of the facility consists of a deed of transfer of certain land and easement rights obtained from Alliance in April 1996. 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 were transferred to the Donnacona Partnership. Under the deed of transfer, the Donnacona Partnership agrees to allow water flows in the Jacques Cartier River of up to 2.25 cubic metres per second to be utilized by Alliance for the Donnacona paper mill located approximately one kilometre from the facility site until such time as a permanent pumping system is conveyed by the Donnacona Partnership to Alliance. During construction, the deed of transfer required the partnership to design and install a temporary water pumping system to supply the Alliance mill with water if there was a problem with the existing gravity water supply system. This temporary pumping equipment was then transferred to Alliance and the equipment is located in a building on the site. The Donnacona Partnership also has the obligation to construct a permanent pumping station in the unlikely event there is a permanent failure of the existing dam and the existing gravity water supply system is permanently disrupted.

The deed of transfer grants the Donnacona Partnership certain easements across land retained by Alliance, which easements are required to allow access to the dam and other structures located near the powerhouse. Under the terms of the deed of transfer, the Donnacona Partnership has agreed, among other things, to maintain the dam in good condition and maintain certain insurance which will protect Alliance against loss of water caused by negligence of the Donnacona Partnership until completion of a permanent pumping facility.

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. The lease may be terminated by the Province upon, among other events, termination of the power purchase agreement with Hydro-Québec. Notice of any change of control of the Donnacona Partnership or its partners must be given to the Québec Minister of Natural Resources and the Québec Minister of the Environment within 30 days of the change of control. The Ministers have the discretion to approve such change of control or terminate the lease.

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

Ste-Brigitte Facility

The Ste-Brigitte Facility is a 4,200 kilowatt hydroelectric generating facility located on the Nicolet River, in the Municipality of Ste-Brigitte-des-Saults, Québec. The facility is located at the site of an historic mill, but none of the original structures have been utilized for the new powerhouse. The site layout involves an intake canal equipped with a gate structure, a powerhouse containing a single 4,200 kilowatt turbine generator and a tailrace canal which conveys the waterflow back to the natural watercourse. It has been designed as a run-of-the-river facility.

The facility incorporates a 1.1 metre high movable dam utilized to increase available water level differential. The original movable dam was damaged and was replaced in the summer of 1998 by and at the expense of Algonquin Power.

Land and Water Rights

The Ste-Brigitte Facility has been constructed on certain lands purchased by a former owner. In addition, certain easements were granted to the former owner in respect of the access road, transmission line and Hydro-Québec interconnection. The land includes the bed of the river upon which the existing weir structure is located and certain land on either side of the river. Accordingly, no lease with the Province of Québec is required.

On May 10, 2002, certain upstream residents of the Ste-Brigitte Facility commenced an action in the Québec Supreme Court against certain Fund entities and others claiming in excess of \$5 million as a result of a flood event which occurred on April 13, 2001. The flood apparently resulted from an ice jam upstream from the facility that flooded properties near the river. In addition to the claim for damages, the plaintiffs are seeking an order requiring that the facility cease operation and that it be removed. The Fund entities will be vigorously defending the action.

Ste-Raphaël Facility

The Ste-Raphaël Facility is a 3,500 kilowatt facility located on the Rivière de Sud approximately 60 km. east of Québec City, Québec. The site was formerly developed by Hydro Québec and then released by the Ministry of Energy Québec, for private development in 1991. The site was rebuilt by a former owner and placed back into operation in January 1994.

Land and Water Rights

The land and hydraulic rights necessary for the operation of the facility have been leased by the Ministry of Natural Resources and the Ministry of Environment, Québec pursuant to a lease agreement dated December 14, 1993. The lease terminates 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

The Mont Laurier Facility is a 2,725 kilowatt facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec. The site has been historically utilized for the production of power and was refurbished in 1989. The rehabilitation included extensive repairs to the civil works, rebuilding of all three turbines and replacement of all electrical and control works.

Land and Water Rights

The facility is constructed on lands owned by Algonquin Power (Mont Laurier) Limited Partnership (“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.

Hydro Snemo Facility

The Hydro Snemo Facility is located on the Rivière-du-Loup in close proximity to the downtown section of the Town of Rivière-du-Loup, Québec. The site has been historically utilized for the production of power and was decommissioned in 1977. A major refurbishment undertaken in 1995 included complete rehabilitation of the civil works, installation of a new turbine, rebuilding of two existing turbines and replacement of all electrical and control works. The installed capacity of the plant has been increased to 2,600 kilowatts.

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.

Rawdon Facility

The 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.

Land and Water Rights

The land upon which the facility is located and the hydraulic rights necessary for the operation of the facility have been leased by SLI from the Ministry of Natural Resources, Québec pursuant to a 20 year lease agreement, as assigned by SLI to the Fund in June, 1999. The Government of Québec has consented to the assignment. 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, Rawdon and Glenford Power Purchase Agreements

As part of the transfer of title to the Saint-Alban Facility to the Fund, right, title and interest in the power purchase agreement is to be transferred to the Fund. Under the terms of the power purchase agreement, the consent of Hydro-Québec (which consent may not be unreasonably withheld) is required to complete the acquisition of the Saint-Alban Facility and the acquisition of the Glenford Interest. The

consent of Hydro-Québec has been obtained with respect to the acquisition of the Rawdon Facility.

Under the power purchase agreement, Hydro-Québec has agreed to purchase all power made available to it from the Saint-Alban, Glenford and Rawdon Facilities. The standard Hydro-Québec power purchase agreement stipulates a minimum energy production during each 12 consecutive months commencing December 1 in each contract year. If a facility produces less energy than the minimum, a penalty of approximately 1.1 cents per kilowatt hour for each kilowatt hour that the actual production is below the minimum annual production is payable to Hydro-Québec.

The term of the power purchase agreement for the Rawdon Facility and the Saint-Alban Facility 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.

For the Saint-Alban and Rawdon Facilities, power purchase rates under the agreement for each contractual year will be increased in accordance with the percentage increase in 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%. For the Glenford Facility, the power purchase rate is fixed at \$0.0504 per kW-hr until December 1, 1999, after which time the rate will be escalated in a manner similar to the rates for the Saint-Alban and Rawdon Facilities as set out above.

Hydraska Facility

The Hydraska Facility is located on the Yamaska River at Penmans Dam near the Town of St-Hyacinthe, Québec. Construction on the site commenced in 1993 and commissioning was successfully completed in May 1994. The civil works include a 250 meter long tailrace canal and have been designed to be attractively integrated into the park in which the site is located. The capacity of the plant is established at 2,250 kilowatts.

Land and Water Rights

The land rights and existing structures on the site are leased from the City of St-Hyacinthe pursuant to a 20 year lease agreement dated August 30, 1993, the term of which commenced in May 1994. The lease can be extended on the same terms for an additional period of 20 years at the option of the lessee. The hydraulic rights necessary for the operation of the facility have been leased by the lessee from the Ministry of Natural Resources and the Ministry of the Environment, Québec pursuant to a lease agreement dated March 24, 1994. The lease terminates on May 23, 2014 and may be renewed for an additional period of 20 years at the option of the lessee upon terms imposed by the government.

Côte Ste-Catherine, Hydro Snemo, Hydraska, Ste-Raphaël, and Mont Laurier Power Purchase Agreements

Under the power purchase agreements, Hydro-Québec has agreed to purchase all power made available to it from the Côte Ste-Catherine, Hydro Snemo, Hydraska, Ste-Raphaël, and Mont Laurier facilities. The standard Hydro-Québec power purchase agreement stipulates a minimum energy production during each 12 consecutive months commencing December 1 in each contract year. If a facility produces less energy than the minimum, a penalty of approximately 1.1 cents per kilowatt hour for each kilowatt hour that the actual production is below the minimum annual production is payable to Hydro-Québec. The power purchase agreement for Hydraska does not include any penalty provisions.

The term of the power purchase agreements for each of the Côte Ste-Catherine – Phase I, Hydraska, Ste-Rahpaël, Mont Laurier and Hydro Snemo facilities 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, Hydraska, Ste-Raphaël, and Hydro Snemo facilities are 2007, 2014, 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.

For all facilities except Mont Laurier and Côte Ste-Catherine – Phase I, power purchase rates under the agreements for each contractual year will be increased in accordance with the percentage increase in the Consumer Price Index for the Montreal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%. For the Mont Laurier Facility, the power purchase rates will be increased in accordance with the percentage increase in the Montreal Consumer Price Index with a maximum annual escalation of 5.2%. In addition to escalation due to inflation, the rates paid under the Mont Laurier Facility power purchase agreement will be escalated by \$0.01/kW-hr in 2002. For the Côte Ste-Catherine Facility – Phase I, the power purchase rates will be increased in accordance with the percentage increase in the Montreal Consumer Price Index with a maximum annual escalation of 6%.

Belleterre Facility

The Belleterre Facility is a 2,200 kilowatt hydroelectric generating facility located on the Winneway River, in the Municipality of Laforce, Québec. The facility is located at the point of discharge of the Winneway River into Lac Simard/Lac des Quinzes. Commissioning of the Belleterre Facility involved the rehabilitation of a generating facility constructed in the 1930's to supply power to local mining operations. The rehabilitation work included replacement of the turbine-generating equipment, restoration of site structures, including the penstock and gates, and replacement/recommissioning of the electrical interconnection to the Hydro-Québec grid. The rehabilitation and recommissioning was completed and the facility was brought into commercial service with Hydro-Québec in March 1993.

Land and Water Rights

The land and water rights necessary for the Belleterre Facility were originally leased from the Province of Québec to the Town of Belleterre pursuant to a lease dated July 17, 1991. The lease expires in December 2011 and includes a renewal option for an additional 20 year period, exercisable by the lessee upon terms imposed by the Province of Québec. 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.

The Town of Belleterre transferred its interest in the lease to a former owner pursuant to a deed of sale dated May 31, 1992. Consideration paid under the deed of sale included granting the Town of Belleterre a royalty interest which provides an annual payment equal to two percent of the gross revenues earned by the facility from the sale of energy to Hydro-Québec. Certain easements required for the transmission line were granted by the Town of Belleterre under the deed of sale. Under the lease with the Province of Québec, a shareholder of a former owner was required to provide a guarantee of the lessee's obligations thereunder. Following the acquisition of the Belleterre Facility, Algonquin Canada provided an indemnity to such shareholder in respect of its obligations under the guarantee.

Ste-Brigitte and Belleterre Power Purchase Agreements

Under the power purchase agreements, Hydro-Québec has agreed to purchase all power made available to it from the facilities. The standard Hydro-Québec power purchase agreement stipulates a minimum energy production during each 12 consecutive months commencing December 1 in each contract year. If a facility produces less energy than the minimum, a penalty of approximately 1.1 cents per kilowatt hour for each kilowatt hour the actual production is below the minimum annual production is payable to Hydro-Québec.

As a result of unrealistic energy production forecasts and poor operating procedures by a former owner of the Ste-Brigitte Facility and the Belleterre Facility, the facilities failed to meet the minimum production obligations under the Hydro-Québec power purchase agreements. As a result, Hydro-Québec reduced the minimum annual production obligation for the Belleterre Facility to 10,249,200 kilowatt hours and reduced the minimum annual production obligation for the Ste-Brigitte Facility to 10,818,600 kilowatt hours. Under the agreement of purchase and sale in respect of all of the issued and outstanding shares of BCL Energy (Belleterre) Inc. and all the issued and outstanding shares of BCL Energy (Ste-Brigitte) Inc., the Fund is liable for the payment of the fees charged by Hydro-Québec for such reductions in the amounts of \$74,667 during 2001 for the Belleterre Facility and in the amounts of \$63,601 during each of 2001 through 2003 for the Ste-Brigitte Facility. The Manager fully expects to be able to meet the revised minimum annual production obligations set out in the power purchase agreements with Hydro-Québec for both facilities over the remaining term of the contracts.

The term of each of the agreements is 20 years from the commercial start-up date and the Ste-Brigitte Facility agreement expires in 2014 and the Belleterre Facility agreement expires in 2013. The agreements may be renewed at the option of the producer for a period not exceeding the original 20 year term upon terms imposed by Hydro-Québec.

Power purchase rates under the agreements for each contractual year will be increased in accordance with the percentage increase in 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%.

Arthurville Facility

The Arthurville Facility is a 650 kilowatt hydroelectric generating facility located on the Du Sud River near Saint-Raphaël-de-Bellechasse, approximately 40 kilometers east of Québec City. The site was originally developed in the late 1700's as a sawmill, and later, in the early 1900's as a flourmill. It was not until September 15, 1993 that the structure was commissioned as a hydroelectric generating facility by Énergie DLS Inc. The powerhouse building is estimated to be approximately 230 years old.

This run-of-the-river facility consists of a concrete gravity dam and spillway that spans the river, an intake, two penstocks, a stone masonry powerhouse and a tailrace canal.

Land and Water Rights

The Arthurville Facility is constructed on private land, such that the generator owns the land and the associated hydraulic forces. The land owned includes the bed of the river upon which the existing spillway is located. Accordingly, no water lease with the Province of Québec is required.

Power Purchase Agreement

Under the power purchase agreement, Hydro-Québec has agreed to purchase all power made available. The agreement is for a 20 years, commencing September 15, 1993, which was the commissioning date of the facility. The established minimum contractual energy production during each 12 consecutive months commencing December 1st in each contract year is 3,313 megawatt hours. As a result of lower than forecast energy production, the former owner lowered the minimum contractual energy production in 1994 to 2, 847 megawatt hours and again in 1999 to 2,568 megawatt hours.

Under the agreement, if the facility produces less than the established minimum contractual energy, a penalty of approximately 1.13 cents per kilowatt hour for each kilowatt hour the actual production is below the minimum annual production is payable to Hydro-Québec. The Manager fully expects to be able to meet the revised minimum annual production.

Power purchase rates under the agreement will be increased in accordance with the percentage increase in the Consumer Price Index for the Montreal Urban Community, as published by Statistics Canada, with a minimum annual escalation of 3% and a maximum annual escalation of 6%.

Newfoundland Development - Rattle Brook Facility

Rattle Brook Facility

The facility is a 4,000 kilowatt hydroelectric generating facility located on Rattle Brook, approximately four kilometres north of the Town of Jackson's Arm, in the Province of Newfoundland. Construction commenced in September 1997 and the facility was commissioned in December 1998.

The facility is a run-of-the-river facility and there will be no storage of water for peaking purposes. A penstock runs 1,100 metres from a small dam to the powerhouse. The powerhouse is a single storey building which houses a single horizontal turbine attached to a synchronous air cooled generator. The interconnection point for delivery of electricity to the power purchaser is adjacent to the facility and therefore no transmission line is included.

Land and Water Rights

All necessary land and water rights and environmental approvals have been obtained by the Rattle Brook Partnership, including a 50 year lease from the Province of Newfoundland for use of the land required by the facility.

Power Purchase Agreement

Electricity produced by the facility is sold directly to Newfoundland and Labrador Hydro. Pursuant to the power purchase agreement, Newfoundland and Labrador Hydro agrees to purchase all power delivered to the interconnection point and the Rattle Brook Partnership agrees to sell all power produced by the facility to Newfoundland and Labrador Hydro.

The power purchase agreement is for a term of 25 years from the commercial in-service date, which occurred on October 23, 1998, and may be renewed for a further term of 25 years upon terms mutually agreed. Newfoundland and Labrador Hydro has the option to terminate the supply or receipt of power upon reasonable notice if the Rattle Brook Partnership is in default of any obligation under the

agreement. If the Rattle Brook Partnership continues in default after receiving reasonable notice thereof (at least 60 days), Newfoundland and Labrador Hydro has the option to terminate the agreement.

The power purchase agreement provides that payments made by Newfoundland and Labrador Hydro consists of two components: a capacity component and an energy component, for each of the winter period and the summer period. The energy component is adjusted annually by the change in the Consumer Price Index for Canada, provided that any escalation does not exceed 6% year over year. The capacity component is fixed and is not escalated over the term of the power purchase agreement.

Partnership Agreement

The partnership agreement dated October 14, 1997 between Algonquin Power Corporation (Rattle Brook) Inc. and Algonquin Canada governs the affairs of the Rattle Brook Partnership. The partnership agreement specifies, *inter alia*, that income allocations, cash distributions and voting rights at meetings of the partners will be divided as to 55% to be equally divided among the four shareholders of the Manager and 45% to Algonquin Canada. Generally, management decisions for the partnership are made by majority vote of the partners. Certain matters, including capital expansion of the facility, disposition of the facility by the partnership and dissolution of the partnership, require unanimous consent of the partners.

New York Development - Ogdensburg, Forestport, Herkimer, Hollow Dam, Christine Falls, Burt Dam, Cranberry Lake, Kayuta Lake, Adams, Kings Falls, Otter Creek and Phoenix Facilities

Trafalgar Power, Inc. and Christine Falls Corporation

Trafalgar Power, Inc., a Delaware corporation, and Christine Falls Corporation, a New York corporation, own seven hydroelectric generating facilities located in upper New York State. The Trafalgar Companies are each controlled by the same independent businessman. The Ogdensburg facility, Forestport facility, Herkimer facility, Cranberry Lake facility, Kayuta Lake facility and the Adams facility are owned by Trafalgar and the Christine Falls facility is owned by Christine Falls Corporation. Each of the facilities has received a licence or a licence exemption from FERC and each sell electricity to Niagara Mohawk Power Corporation pursuant to separate power purchase agreements. Such agreements are either front-end loaded, whereby the rate paid by Niagara Mohawk is high in the early years to enable the developer to recoup its capital costs and is adjusted downward in later years to compensate for the overpayment based on the balance in a tracking account set up for such purpose, or specified rate, whereby the rate is as set out in the agreement in the early years and thereafter is set as a percentage of Niagara Mohawk's Avoided Costs. Niagara Mohawk has the right to suspend its obligations under such agreements if its transmission system is unable to accept power generated from the facilities. It also retains a right of first refusal to negotiate the acquisition of a facility in the event of a proposed disposition thereof. The Trafalgar Companies must maintain such facilities in good working order, maintain the interconnection with Niagara Mohawk's transmission system and provide insurance coverage.

On August 27, 2001, Trafalgar Power, Inc., Christine Falls of New York, Inc., Marina Development, Inc. (the sole shareholder of the Trafalgar Companies) as well as Franklin Industrial Complex, Inc. and Pine Run of Virginia, Inc. (collectively the "Trafalgar Entities") filed for bankruptcy protection in the United States Bankruptcy Court in Raleigh, North Carolina. At that time, all legal actions involving the Trafalgar Entities were stayed by the bankruptcy court in North Carolina. Included in the bankruptcy filings by the Trafalgar Entities was an adversarial proceeding which named the Fund, the Manager and certain Fund entities in a number of complaints. The complaints filed by the Trafalgar

Entities are identical to the compliant filed by Trafalgar Power, Inc. which is described below.

In December 2001, the United States Bankruptcy Court in Raleigh, North Carolina granted relief from the stay with respect to all actions involving Franklin Industrial Complex, Inc. which owns the Riverbend and Stevens Mill hydroelectric facilities in Franklin, New Hampshire.

On December 13, 2001, the bankruptcy court in North Carolina transferred the bankruptcy proceedings to the United States Bankruptcy Court, Northern District of New York, in Utica, New York.

Trafalgar Power, Inc. commenced an action in New York District Court against the Fund, Algonquin Canada and Algonquin Power with respect to the Fund's and Algonquin Canada's purchase of certain promissory notes. Trafalgar has alleged that Aetna Life Insurance Company breached an agreement with Trafalgar by selling the notes to the Fund and Algonquin Canada. Trafalgar has also alleged that the Fund, Algonquin Canada and Algonquin Power tortiously interfered with the agreement between Aetna and Trafalgar and that the Fund, Algonquin Canada and Algonquin Power converted Trafalgar's assets. The Manager believes that this action was a result of the Fund taking steps towards initiating foreclosure proceedings against Trafalgar with respect to the Trafalgar notes and pursuant to a loan agreement and a trust agreement with Trafalgar. As a defensive action, Trafalgar has filed this complaint. The Manager believes that this case is without merit and is a nuisance case to confound the foreclosure proceedings. This action has been stayed by the New York bankruptcy court.

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. These funds are being held in escrow pending the outcome of the above matters. The Fund was required to place a bond in the amount of US\$2 million as security for potential costs and damages in the event that the escrow funds are awarded to the owner of Trafalgar.

Trafalgar Class B Note

The Fund acquired the Trafalgar Class B Note on December 23, 1997. The Trafalgar Class B Note was issued jointly and severally by the Trafalgar Companies pursuant to the Trafalgar Indenture, bears interest at the rate of 6.10% per annum. It is secured by a charge against all assets of the Trafalgar Companies including, without limitation, the generating equipment comprising the Trafalgar Facilities and the interest in the key contracts held by the Trafalgar Companies for the operation of the Trafalgar Facilities.

Under the terms of the Trafalgar Indenture, prior to the holder of the Trafalgar Class B Note having received aggregate payments exceeding a certain cumulative target, 50% of Trafalgar Operating Cashflows in amounts up to certain annual targets, and 90% of cash flows in excess of those targets, will be paid to the holder of the Trafalgar Class B Note in respect of interest and principal payments on the note. After the holder of the Trafalgar Class B Note has received aggregate payments exceeding such cumulative target, 33% of Trafalgar Operating Cashflows will be paid to the holder of the Trafalgar Class B Note in respect of interest and principal payments on the note.

Under the terms of the various securities purchased and agreements entered into by the Fund and Algonquin Canada, the Fund is indirectly entitled to a 100% interest in the cash flows generated from the Trafalgar Facilities up to the year 2010 and thereafter until all amounts outstanding under such note are repaid, if the Trafalgar Companies elect not to repay the Trafalgar Class B Note.

If the Trafalgar Companies fully repay the Trafalgar Class B Note upon its maturity on December 31, 2010, the Fund will receive a payment equal to 75% of the equity value of the Trafalgar Facilities which is expected by the Fund to be satisfied by delivery of a 75% equity interest in the Trafalgar Companies.

Trafalgar Operations Subcontract

Algonquin Power entered into the Trafalgar Operations Contract with the Trafalgar Companies, pursuant to which Algonquin Power agreed to provide the Trafalgar Companies with certain services in respect of the Trafalgar Facilities. Algonquin Canada entered into the Trafalgar Operations Subcontract on December 23, 1997 pursuant to which Algonquin Canada provides to Algonquin Power services required in respect of the operation of the Trafalgar Facilities. In addition to receiving certain monthly payments in respect of the operating costs incurred by Algonquin Canada in providing such services, Algonquin Canada is entitled to the Trafalgar Contingency Participation as a bonus payment based on achieving certain target revenue generation and payments on the above-noted note.

Algonquin Canada entered into a services agreement (the "Trafalgar Services Agreement") on December 23, 1997 pursuant to which Power Systems has assumed responsibility for providing the operations services required by the Trafalgar Facilities. Compensation to Power Systems under the Trafalgar Services Agreement does not include any portion of the Trafalgar Contingency Participation.

On an annual basis, the Trafalgar Contingency Participation will be equal to 50% of Trafalgar Operating Cashflows in amounts up to certain annual targets and 10% of the amount of Trafalgar Operating Cashflows which is in excess of those targets. Prior to the holder of the Trafalgar Class B Note having received aggregate payments exceeding a certain cumulative target, the Trafalgar Contingency Participation will be equal to 50% of Trafalgar Operating Cashflows up to certain annual targets and 10% of cash flows in excess of those targets. After the holder of the Trafalgar Class B Note has received aggregate payments exceeding such certain cumulative target, the Trafalgar Contingency Participation will be equal to 33% of Trafalgar Operating Cashflows.

Ogdensburg Facility

The facility is located on the Oswegatchie River, in the City of Ogdensburg, New York. The facility was built at an existing concrete dam located immediately upstream of the St. Lawrence River. The dam is owned by the City of Ogdensburg (the "City") and Trafalgar entered into an agreement with the City to utilize the structures. It is a run-of-the-river facility. The facility is rated at 3,675 kilowatts. The facility has five bevel geared, double regulated Kaplan turbines manufactured by Sulzer Hydro.

Power Purchase Agreement

The agreement is for a term of 20 years from the commencement of commercial operations, which occurred on December 15, 1987. For the period January 1, 2001 through December 31, 2007, the producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs.

FERC Licence

The facility received a licence (Major Project) for a hydroelectric generating facility from FERC on June 15, 1987 (FERC Project No. 9821). The licence is for a 3,675 kilowatt facility. The facility was commissioned on December 18, 1987 and the licence expires in May 2027. The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river

facility and there can be no storage of water upstream of the facility; and (ii) the FERC licence requires a complex and strict minimum flow regime. The first 183 cubic feet per second through the site is spilled over the dam. River flow between 183 to 733 cubic feet per second is discharged through turbine No. 5 which is directed towards the base of the dam and maintains a minimum flow along the downstream reach of the facility. Flows greater than 733 cubic feet per second are discharged through the remaining four turbines, but Turbine No. 5 must always discharge the maximum 733 cubic feet per second.

Agreement with the City of Ogdensburg

In March 1987, Trafalgar entered into an agreement for the development of the facility with the City, pursuant to which Trafalgar is required to pay the City: (i) certain payments relating to the issuance of municipal bonds in the amount of \$143,000 (US\$100,000) plus interest; (ii) repayment of a loan in the amount of \$641,000 (US\$450,000) plus interest; (iii) \$36,600 (US\$25,000) annually, commencing on December 1, 1988 to December 1, 2007; (iv) \$99,800 (US\$70,000) annually, commencing on December 1, 2008 and ending on December 1, 2027; and (v) during the period from January 1, 2028 through to December 31, 2037, Trafalgar is required to pay the City 40% of the net revenues from the facility and during the period from January 1, 2038 to the expiration of the agreement, 50% of the net revenues from the facility. As security for its obligations under the agreement, Trafalgar granted the City a mortgage over the facility. Trafalgar must give notice to the City of its intent to sell, lease or assign control or ownership of the facility to any entity other than an affiliate of Trafalgar. If the City does not object by written notice given to Trafalgar within 30 days of delivery of Trafalgar's notice, the City is deemed to have approved the transaction.

The City has an option to purchase the facility after January 1, 2038. If the City exercises this option, the purchase price will be two-thirds of the facility's value capitalized at 8.5% of the net return after normal operating and maintenance expenses, based on the average of the net facility revenues over the three years immediately preceding the date of purchase. Trafalgar cannot place a mortgage on the property after December 31, 2028 without the consent of the City.

Forestport Facility

The facility is rated at 3,300 kilowatts and is located on an existing canal system along the Black River, near the Town of Boonville, which is located about 30 kilometres north of Utica, New York. The canal system is owned and maintained by the New York State Thruway Authority/Canal Corporation ("NYSTA/CC") and is used mainly by recreational canoers. The facility generates electricity from flows from both the Black River and Alder Creek. The powerhouse is located adjacent to the canal and water is diverted to it by a steel penstock. The powerhouse includes a conventional, horizontal "S" type Kaplan turbine generator set manufactured by Sulzer Hydro. After passing through the turbine, water is discharged into the Black River.

Power Purchase Agreement

The agreement is for a term of 20 years from commencement of commercial operations which occurred on December 30, 1987. From the period January 1, 2001 through the remainder of the term ending on December 31, 2007, the producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs.

FERC Licence

The facility received a licence (Major - Existing Dam) for a hydroelectric facility from FERC on March 20, 1987 (FERC Project No. 4900). The licence is for a 3,300 kilowatt generating facility producing power from one turbine. The facility was commissioned in October 1988 and the licence expires in February 2027. The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; a gate on the barge canal, upstream of the powerhouse, enables the facility to operate in an instantaneous run-of-the-river mode; and (ii) a minimum flow of 140 cubic feet per second must be released downstream of the dam at all times. The minimum flow is required for fisheries and water quality and was based on recommendations from federal and state regulatory agencies. The NYSTA/CC operates the barge canal system and has required an additional minimum flow within the canal for recreation. Presently, approximately 30 cubic feet per second is discharged into the canal during the summer months.

Herkimer Facility

The facility is located on West Canada Creek, upstream of the Village of Herkimer, New York. The facility is rated at 1,680 kilowatts. The facility is located at a new concrete dam and overflow structure. There are four siphon-type, semi-kaplan ESAC turbine generators and one vertical Flygt turbine generator installed at the facility.

Power Purchase Agreement

The power purchase agreement with Niagara Mohawk is for a term of 20 years from the commencement of commercial operations, which occurred on December 29, 1987. From the period January 1, 2001 through the remainder of the contract term on December 31, 2007, the producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs.

FERC Licence

The facility received a licence (Major Project) for a hydroelectric generating facility from FERC on April 22, 1987 (FERC Project No. 9709) for a 1,680 kilowatt facility. The facility was commissioned in February 1988 and the licence expires in March, 2027. The main compliance conditions associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility. The producer is required to install and maintain stream gauging stations for the purpose of measuring the stage and flow of the river; and (ii) the FERC licence requires a minimum flow of 160 cubic feet per second be released downstream of the dam at all times. The minimum flow is required for fisheries and water quality and was based on recommendations from applicable regulatory agencies. A portion of this flow, however, is first passed through the 80 kilowatt Flygt turbine before being discharged back into the stream. The remainder is passed directly over the spillway. In the event that the Flygt turbine is not available, a by-pass gate is opened to pass the minimum flow.

Hollow Dam Facility

The facility is located on the West Branch of the Oswegatchie River in the Town of Fowler, New York, approximately 16 kilometres south of Gouverneur, New York. The facility is rated at 900 kilowatts. The facility was constructed in 1987 and is located at an existing dam of 100 metres in length and includes a 70 metre spillway. The facility is equipped with two submersible Flygt

turbine/generators, each capable of generating 450 kilowatts. The facility is owned by the Hollow Dam Partnership.

Power Purchase Agreement

The power purchase agreement with Niagara Mohawk for the Hollow Dam Facility expired on December 31, 2000. An arrangement has been made for a short term extension of the power purchase agreement. The Fund is looking to enter into a longer term agreement with Niagara Mohawk.

Land and Water Rights

The facility was built in 1987 on land leased to Lavalin Hydro Corporation by Barbara and Robert Sullivan pursuant to a long term lease agreement dated December 13, 1988. The lease has been assigned to the Hollow Dam Partnership. A term of the agreement states that all lands and facilities revert back to the landlord on April 26, 2026.

FERC Licence

The facility received a licence (Minor Project) from FERC on May 30, 1986 (FERC Project No. 6972) for a period of 40 years effective May 1, 1986. The licence was issued for a 1,000 kilowatt generating facility. The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) pursuant to an amending order dated February 27, 1990, the facility must maintain a minimum flow of 21 cubic feet per second by ensuring the water levels within the headpond are not lower than an elevation of 630.8 feet above sea level. The amending order also required continuous recording of the water levels within the headpond.

Christine Falls Facility

The facility is located on the Sacandaga River approximately eight kilometres east of the Town of Specular, which is located within the Adirondack Mountain State Park, in upper New York State. The facility is rated at 850 kilowatts and consists of two horizontal shaft, Francis turbine/generators. The site was previously developed by Niagara Mohawk and was rehabilitated by Christine Falls Corporation. Water from the Sacandaga River is diverted to the plant at an existing concrete dam through a small intake structure and steel penstock. The total head at the site is 15 metres. It is a run-of-the-river facility. Power is delivered to the utility grid at Highway 30.

Power Purchase Agreement

The agreement is for a term of 40 years from the commencement of commercial operations and ends January 2028. The facility commenced commercial operations on April 15, 1988. For years 1 through 15, the specified settlement rates set out in the agreement will be paid to the producer. For years 16 through 18, the producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs. For years 19 through 30, the producer will be paid a rate equal to 90% of Niagara Mohawk's Avoided Costs. For the remainder of the term, the producer will be paid a rate equal to 80% of Niagara Mohawk's Avoided Costs.

FERC Licence

The facility received a licence (Minor Project) for a hydroelectric generating facility from FERC on October 18, 1983 (FERC Project No. 4639). The original licence was for a 725 kilowatt generating facility from two turbines and was amended to 850 kilowatts on February 15, 1989 when the developer purchased two used machines. The facility was commissioned in April 1988 and the licence expires in September 2023. The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) a minimum flow of 25 cubic feet per second must be released downstream of the dam during March, April and May and ten cubic feet per second must be released at all other times of the year. The minimum flow is required for fisheries and water quality and is controlled through a small valve in the dam.

Burt Dam Facility

The facility is a 600 kilowatt hydroelectric generating facility located on the Eighteen Mile Creek in the Town of Newfane, New York. The facility consists of an existing dam with an integrated intake structure, powerhouse and tailrace and the facility is designed to operate as a run-of-the-river facility. The facility was reconstructed in 1987 from an old hydroelectric generating facility at the site of an existing dam. The facility is owned by the Burt Dam Partnership.

Power Purchase Agreement

A power purchase agreement with Niagara Mohawk for the Burt Dam Facility expired on December 31, 2000. An arrangement has been made for a short term extension of the power purchase agreement. The Fund is looking to enter into a longer term agreement with Niagara Mohawk.

Land and Water Rights

The land and certain facility structures are rented from the Olcott Harbor Board of Trade, Inc. pursuant to a lease agreement dated December 5, 1986. The lease agreement is for a term equal to the greater of 50 years or the term of the FERC licence and payment is based on a percentage of net income from the facility.

The Eighteen Mile Creek has been identified as one of six areas of concern in New York State by the Water Quality Board of the International Joint Commission due to high levels of chemicals in the sediments within the river, mainly PCBs and dioxins. A Remedial Action Plan ("RAP") has been jointly developed by the New York State Department of Environmental Conservation ("NYDEC") and SLI, the former owner, to provide environmental protection at this site. The RAP does not affect day-to-day operations of the facility, but the program will have to be considered if major works are required to be constructed with respect to the facility in and around the watercourse.

FERC Licence

The facility received an exemption from licensing for a small hydroelectric generating facility from FERC on May 15, 1986 (FERC Project No. 7477). The exemption order is for a generating facility of less than 5,000 kilowatts and the facility was commissioned in 1988. The major compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) if the NYDEC proceeds with a salmon stocking program, the Burt Dam Partnership must provide a flow over the dam to provide

for downstream passage of fish. NYDEC has stated that it presently has no plans to stock Eighteen Mile Creek.

Cranberry Lake Facility

The facility is located on the Oswegatchie River, at the outlet of Cranberry Lake, in the Town of Clifton. The facility is located on land and utilizes water that is leased pursuant to a long term agreement with the Oswegatchie River Cranberry Reservoir Regulating District ("OR-CRRD") dated October 19, 1987 and expires in 2035. The facility is rated at 500 kilowatts and is a run-of-the-river facility using flow available from Cranberry Lake. The facility was constructed within the existing dam structure at the outlet of the lake. The facility configuration is similar to the Adams and Kayuta Lake facilities and includes an ESAC bulb-type turbine generator set in a small powerhouse. The facility is interconnected to Niagara Mohawk's grid immediately at the facility gate.

Power Purchase Agreement

The agreement is for a term ending December 31, 2025. Commercial operations commenced on December 31, 1987. From the period January 1, 2001 through December 31, 2010, the producer will be paid a rate equal to 90% of Niagara Mohawk's Avoided Costs. For the remainder of the term, the producer will be paid a rate equal to 80% of Niagara Mohawk's Avoided Costs.

FERC Licence

The Cranberry Lake Facility received a licence (Minor Project) for a hydroelectric generating facility from FERC on April 27, 1987 (FERC Project No. 9685). The facility is licensed to generate 595 kilowatts. The facility was commissioned in May 1988 and the licence expires in March 2027. The facility is required to operate according to the direction of the OR-CRRD, which determines the water level of Cranberry Lake and, therefore determines the water flow available for generation. The main compliance condition associated with the facility is that it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility.

Kayuta Lake Facility

The facility is rated at 400 kilowatts. The facility is located on the Black River at the outlet of Kayuta Lake. The site is immediately upstream of the Forestport facility, in the Town of Boonville. The site was developed at an existing concrete control structure at the outlet of Kayuta Lake. It is a run-of-the-river facility with a configuration very similar to the Adams and Cranberry Lake facilities. The powerhouse is built around an ESAC bulb-type turbine generator set located adjacent to the dam. The facility interconnects with the utility grid immediately at the facility fence.

Power Purchase Agreement

The agreement is for a term of 40 years ending January 2028. Commercial operations commenced on January 1, 1988. Power purchase rates are front-end loaded. The front-end loaded rate for the first 15 years is fixed at \$0.1324/kW-hr (US\$0.0929/kW-hr). Pursuant to its right to review the power purchase rate based on the balance of the tracking account, on January 8, 1999, Niagara Mohawk determined that an excessive Advance Payment Account balance was being created and the stabilized rate was decreased to \$0.0991/kW-hr (US\$0.0696/kW-hr). Niagara Mohawk has the right to continue such reviews on an annual basis for the remainder of the first 15 year period. The producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs for years 16 through 22 and a rate equal to 95%

of Niagara Mohawk's Avoided Costs for years 23 through 30. The rate paid during this period will be adjusted positively or negatively to eliminate any balance in the Advance Payment Account by the end of the 30th year. The balance in the Advance Payment Account as at December 31, 2001 was \$1,093,643 (US\$686,703) and given the high balance of the Advance Payment Account, a further reduction in rates paid during this 15 year period may occur. During the period following the 31st year, the producer will be paid a rate equal to 90% of Niagara Mohawk's Avoided Costs, without adjustment. The agreement specifies that, at the end of the 30th year, the unrepaid balance of the Advance Payment Account must be paid to Niagara Mohawk, if the balance is positive, or to the producer, if the balance is negative, as the case may be. Niagara Mohawk has a lien on the facility to secure any positive balance in the Advance Payment Account, which lien is subordinate to the security under the Trafalgar Indenture.

FERC Licence

The facility received a licence (Minor Project) for a hydroelectric generating facility from FERC on September 12, 1984 (FERC Project No. 5000). The facility is built at the outlet of Kayuta Lake at the site of an existing control structure. The facility was commissioned in March 1988 and the FERC licence expires in August 2024. The main compliance condition associated with the facility is that it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility.

Adams Facility

The facility is a 350 kilowatt hydroelectric generating facility located on Sandy Creek, in the Village of Adams, New York. Sandy Creek discharges to the east side of Lake Ontario, south of the City of Watertown. It is a run-of-the-river facility located at an existing concrete dam structure. The dam is 41 metres long. A small powerhouse located at the dam houses an ESAC bulb-type turbine generator set. Electricity produced by the facility is connected to the Niagara Mohawk grid at the facility fence.

Power Purchase Agreement

The power purchase agreement for the Adams facility is for a term of 40 years ending January 2028. The facility commenced commercial operations on January 1, 1988. Power purchase rates under the agreement are front-end loaded. The front-end loaded rate for the first 15 years was initially set at \$0.1391/kW-hr (US\$0.0976/kW-hr). Pursuant to its right to review the power purchase rate based on the balance of the Advance Payment Account, on January 8, 1999 Niagara Mohawk determined that an excessive tracking account balance was being created and the stabilized rate was changed to \$0.1378/kW-hr (US\$0.0967/kW-hr). Niagara Mohawk has the right to continue such reviews on an annual basis for the remainder of the first 15 year period.

The agreement provides that the producer will be paid a rate equal to 100% of Niagara Mohawk's Avoided Costs for years 16 through 22 and a rate equal to 95% of Niagara Mohawk's Avoided Costs for years 23 through 30. The rate paid during this period will be adjusted positively or negatively to eliminate any balance in the Advance Payment Account by the end of the 30th year. The balance in the Advance Payment Account as at December 31, 2001 was \$605,559 (US\$380,233) and given the high balance of the Advance Payment Account, a further reduction in rates paid during this 15 year period may occur.

During the period following the 31st year, the producer will be paid a rate equal to 90% of Niagara Mohawk's Avoided Costs, without adjustment. The agreement provides that, at the end of the 30th year, the unrepaid balance of the Advance Payment Account must be paid to Niagara Mohawk, if

the balance is positive, or to the producer, if the balance is negative, as the case may be. Given the current status of the Advance Payment Account, it can be expected that a large payment will have to be made to Niagara Mohawk at the end of the 30th year. Niagara Mohawk has a lien on the facility to secure any positive balance in the Advance Payment Account, which lien is subordinate to the security under the Trafalgar Indenture.

FERC Licence

The facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on July 12, 1983 (FERC Project No. 6878). The exemption order is for a 358 kilowatt generating facility and the facility was commissioned in December 1987. The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) a minimum flow of 15 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality.

Taxes

The Trafalgar Companies are responsible for the payment of municipal taxes with respect to the Trafalgar Facilities. The municipal tax burden at each facility, other than the Ogdensburg facility, is based on the market value of such facility. The market value of the facility is based on the capitalization of the projected revenue stream of the facility from energy sales to Niagara Mohawk. The Manager has renegotiated or is in the process of renegotiating the existing assessments for municipal taxes to reflect the reduced market valuation based on the reduction in power rates.

Under an agreement for the development of the Ogdensburg facility with the City of Ogdensburg, the City is responsible for payment of the City's portion of the municipal taxes for the site. Trafalgar in turn pays the City an annual royalty. In addition to the agreement, the Ogdensburg facility is located in an Economic and Development Zone and therefore, Trafalgar was able to obtain relief from the school and county portion of the taxes for a period of time. These taxes were reduced to zero for the first seven years and then phased in starting in 1995. Currently, Trafalgar is responsible for payment of all school and county taxes. Trafalgar is also responsible for payment of the Cranberry Lake-Oswegatchie River Commission tax, which amounts to approximately \$4,739 (US\$3,159) per annum.

Transmission Lines

Rights to all necessary lands have been obtained in order to operate and maintain the transmission lines for the Trafalgar Facilities.

Kings Falls Facility

The facility is located on the Deer River, near Copenhagen in Lewis County, New York. The facility dam is located approximately 300 feet upstream from Kings Falls. It is a run-of-the-river facility and is rated at 1,750 kilowatts. The facility has one Waplins Vertical Kaplan turbine.

Power Purchase Agreement

A new agreement was entered into on April 12, 2000 with Niagara Mohawk for a term of five years. From January 1, 1999 until December 31, 2003, the specified settlement rates set out in the agreement will be paid to the producer.

Land and Water Rights

Tug Hill Energy Inc. acquired all land necessary for the operation of the facility. As a result of its ownership of the generating station site, Tug Hill Energy Inc. was granted the water rights for the facility.

FERC Licence

The facility received a licence (Minor Project) for a hydroelectric generating facility from the FERC on September 30, 1986. An order approving transfer of licence to Tug Hill Energy Inc. was granted by the FERC on June 30, 2000. The facility was commissioned in 1988.

The main compliance conditions associated with the facility are that: (1) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) the FERC licence requires a minimum flow of 8 cubic feet per second year round. The minimum flow is required for fisheries and water quality and was based on recommendations from applicable regulatory agencies.

Otter Creek Facility

The facility is located on the Otter Creek, near Craig, New York. The facility is located at a rehabilitated stone and masonry dam with a concrete overlay about 115 feet long. It is a run-of-river facility and is rated at 530 kilowatts. The facility has one Ossberger Cross- Flow turbine.

Power Purchase Agreement

A new agreement was entered into on June 22, 2000 with Niagara Mohawk for a term of two years. From May 1, 2000 until October 31, 2001, the specified settlement rates set out in the agreement will be paid to the producer. With respect to the Burt Dam, Hollow Dam and Otter Creek Facilities, each is currently operating under an extension agreement to the original power purchase agreement granted by Niagara Mohawk through April 30, 2002 and each facility received 100% of the spot market price as per the load zone for which it is located and is also able to claim ancillary costs. Each site is no longer able to claim capacity power with these extensions. In late April 2002, Power Systems negotiated an agreement with Niagara Mohawk to extend the agreements one last time until December 31, 2002 with the same contractual terms noted above. Power Systems is negotiating longer term power purchase agreements to be in place by January 1, 2003.

Land and Water Rights

Tug Hill Energy Inc. acquired all land necessary for the operation of the facility. As a result of its ownership of the generating station site, Tug Hill Energy Inc. was granted water rights for the facility.

FERC Licence

The facility received an exemption from licensing for a small hydroelectric generating facility from FERC on September 9, 1985. The exemption order is for a generating facility of less than 5,000 kilowatts. The facility was commissioned in 1986.

The main compliance conditions associated with the facility are that: (1) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; (ii)

there is a minimum flow requirement of 52 cubic feet per second year round to the natural streambed; the minimum flow is required for fisheries and water quality and was based on recommendations from applicable regulatory agencies; and (iii) there is a fish bypass pipe which must pass water at 44 cubic feet per second to the natural streambed.

Phoenix Facility

The 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 the New York State Thruway Authority/ Canal Corporation (“NYSTA/CC”). It is a run-of-the-river facility and is rated at 3,500 kilowatts. The facility has two ESAC single regulated turbines.

Power Purchase Agreement

The original agreement was dated September 19, 1989 and had a term of 40 years from the date of issuance of the project licence by FERC. Therefore, from March 28, 1986 until March 28, 2026, the specified settlement rates set out in the agreement will be paid to the producer. The agreement requires maintenance of an adjustment account based on the difference between the specified rate and 90% of the long run Avoided Cost. The agreement states that the obligation to repay this balance in the adjustment account expires on expiry of the term of the agreement.

Land and Water Rights

The generating station is located on land formerly owned by the Onondaga County Industrial Development Agency. A Fund entity, Oswego Hydro Partners, 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 New York State Thruway Authority/Canal Corporation (NYSTA/CC). The lock is operated by the NYSTA/CC and is open from April through October. However, the NYSTA/CC and Oswego Hydro Partners have an agreement to allow the facility operator to operate and be responsible for three Rodney-Hunt gates at the center of the dam.

FERC Licence

The facility received a licence for a hydroelectric generating facility from FERC on March 28, 1986. The licence is for a 3,500 kilowatt generating facility producing power from two turbines. The facility was commissioned in December 1990.

The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) the FERC licence requires a complex and strict minimum flow regime. On July 16, 1992, FERC provided an order amending minimum flow requirements which requires certain discharges over the flashboards, spillway crest or from the tainter gates of the Phoenix dam. The minimum flow releases from June 1 through October 31 are as follows: inflows to the project less than 1,599 cubic feet per second must be bypassed. With a river flow of between 1,600 to 1,699 cubic feet per second, a bypass flow of 1,200 cubic feet per second is required. With a river flow of between 1,700 to 1,799 cubic feet per second, a bypass flow of 900 cubic feet per second is required. With a river flow of between 1,800 to 1,899 cubic feet per second, a bypass flow of 600 cubic feet per second is required. With river flows in excess of 1,900 cubic feet per second, the requirement is to bypass 300 cubic feet per second. The minimum flow from November 1 through May 31 is as follows: with inflows in excess of 300 cubic

foot per second, the bypass flow is 300 cubic feet per second and for flows of less than 300 cubic feet per second, the requirement is the inflow; and (iii) there is a downstream fish passage which is required to pass fish continuously; this bypass discharges water at the rate of 75 cubic feet per second.

New England Development — Gregg Falls, Pembroke, Clement Dam, Franklin, Moretown, Lochmere, Lower Robertson, Ashuelot, Lakeport, Avery Dam, Hadley Falls, Hopkinton, Milton, Mine Falls, Great Falls and Worcester Facilities

Gregg Falls Facility

The Gregg Falls Facility is located on the Piscataquog River near the Town of Goffstown, New Hampshire. The site was historically used for the generation of electrical energy and was decommissioned in the 1970's. A major refurbishment was undertaken in 1985, which included the installation of two new turbines and generators and the replacement of all electrical and control works. The installed capacity of the facility is 3,500 kilowatts.

Land and Water Rights

The former owner obtained the rights to the existing structures located at the facility site pursuant to a lease agreement dated December 29, 1982, as amended in May 24, 1985, with the New Hampshire Water Resources Board. The lease was assigned to Algonquin America. The leased premises include all physical structures and the water rights necessary for the operation of the facility. The lease expires on December 29, 2032.

FERC Licence

The Gregg Falls Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on July 21, 1983 (FERC Project No. 3180) for a 3,820 kilowatt facility. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; and (ii) a minimum flow of 20 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality.

Pembroke Facility

The Pembroke Facility is located on the Suncook River near the Town of Pembroke, New Hampshire. The site consists of a 500 foot power canal and a 480 foot penstock leading to a concrete powerhouse housing a single turbine generator. The site was constructed in 1986 and has an installed capacity of 2,600 kilowatts.

Land and Water Rights

The land necessary for the operation of the facility is owned and the water rights for the Suncook River available at the facility site for the operation of the facility have been granted to the owner. The terms of the use of such water rights are governed by the New Hampshire Water Resources Board.

FERC Licence

The Pembroke Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC in February, 1983 (FERC Project No. 3185) for a 2,600 kilowatt facility.

The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; and (ii) a minimum flow of 10 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality.

Gregg Falls and Pembroke Power Purchase Agreements

Both the Gregg Falls and Pembroke Facilities sell all electrical energy to the Public Service Company of New Hampshire (“PSNH”) pursuant to separate agreements both dated May 11, 1994. Both agreements terminate on December 31, 2020. Prior to December 31, 2011, the rates paid by PSNH for the energy are indexed to certain increases in the general rate of inflation. After January 1, 2012, the rates paid for energy and capacity are based on the then current PSNH avoided costs.

Clement Dam Facility

The facility is located on the Winnepesaukee River approximately five miles upstream from its confluence with the Pemigewasset River and near the Town of Tilton, New Hampshire. The facility is rated at 2,400 kilowatts and was constructed in 1984 at the location of an existing 120 foot wide dam and includes a 275 foot steel penstock which is 12 feet in diameter.

Power Purchase Agreement

The power purchase agreement with the Public Service Company of New Hampshire for all electrical energy produced at the Clement Dam Facility has a term of 20 years and it will terminate at the end of 2004. Under the terms of the agreement, PSNH is required to purchase all energy for US\$0.09/kW-hr, plus 50% of the positive amount of PSNH's incremental energy cost in excess of US\$0.09. Since incremental energy costs have not risen above this level, payments have been made at the rate of US\$0.09/kW-hr since commissioning of the facility.

Land and Water Rights

The land upon which the Clement Dam Facility is located is leased from the former owners. Payments under the lease commenced on January 1, 2000 and are equal to 10% of the revenues earned by the facility from the sale of energy. The lease terminates in the year 2032 and the Fund has the right to purchase the lands upon the termination of the lease for US\$300,000. The former owners have been granted the option to require the Fund to purchase the lands at any time after January 1, 2010 upon thirty days written notice for US\$200,000, increasing by US\$10,000 each year after 2010 to a maximum of US\$300,000.

Water rights for the site have been obtained from the New Hampshire Water Resources Board pursuant to a water user's agreement dated July 7, 1986. Semi-annual payments under the water user agreement are based on energy production and are expected to be approximately US\$16,500 per year. The current term of the water user's agreement terminates in June 2001. Although the original term of the water user's agreement has expired, the parties continue to operate under the terms of the water user's agreement pending negotiation of a new agreement. The State of New Hampshire, Department of Environmental Services – Water Resources Department is the administrator of State water user agreements and is currently reviewing all expired water user agreements and will be commencing discussions with all stakeholders. There has been no schedule developed by the State to commence these discussions.

Pursuant to an agreement dated June 24, 1985 for payment in lieu of property taxes with the Town of Tilton, the owner is obligated to pay the Town of Tilton 3.75% of gross revenues per annum generated by the facility until June 24, 2000 and 4% of gross revenues per annum generated by the facility from June 25, 2000 until June 24, 2005. As well, pursuant to an agreement dated February 8, 1990 with the Town of Northfield for payment in lieu of taxes, the owner is required to pay to the Town of Northfield US\$2,000 per year for a period of sixteen years or until the owner receives gross revenues from hydroelectric power generated by facilities in the Town of Northfield.

FERC Licence

The Clement Dam Facility received an exemption from the licencing of a small hydroelectric generating facility from the Federal Energy Regulatory Commission ("FERC") on May 17, 1982 (FERC Project No. 2966) for a 1,200 to 1,400 kilowatt facility. An amendment was issued on March 18, 1983 which amended the rated capacity to 2,400 kilowatts. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; and (ii) a minimum flow of 30 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality.

Franklin Facility

The Franklin Facility consists of two independent powerhouses located on the Winnepesaukee River in the Town of Franklin, New Hampshire, and located several kilometers downstream from the Clement Dam Facility. The River Bend Turbine-Generator is rated at 1,600 kilowatts and is located in a powerhouse which was constructed in 1985. The facility is constructed at the location of an existing 70 foot wide dam and includes a 1,000 foot long concrete penstock. The Steven's Mill Turbine-Generator, rated at 228 kilowatts, is housed in a powerhouse located immediately adjacent to the dam. In October 1998, the Steven's Mill building was damaged by fire and the Steven's Mill Turbine-Generator was returned to service in January 2000. Subsequent to coming back in service, the generator malfunctioned and the facility was off-line until February 2000, when the turbine was repaired.

On August 27, 2001, Franklin Industrial Complex, Inc. ("Franklin") filed for bankruptcy protection in the United States Bankruptcy Court in Raleigh, North Carolina. In December 2001, the bankruptcy court granted the Manager's request for relief from the automatic stay of proceedings against the company. In December 2001, the Fund noticed a foreclosure and secured party sale of the collateral securing a promissory note (the "Note") which included the two generating facilities and Franklin's rights under an interconnection agreement and a rate order. The foreclosure sale was held on January 25, 2002 and the Fund purchased the facilities for US\$3,000,000. The Fund has filed an action in the District Court in New Hampshire for the balance of the amount owing on the Note.

Franklin, Marina Development Inc. and Arthur Steckler have filed a complaint against Algonquin Canada, Power Systems, Algonquin Power and others alleging, among other things, that the Algonquin entities conspired against Franklin, mismanaged the facility and breached fiduciary duties owed to Franklin. The Manager believes that this claim lacks substance.

Power Purchase Agreement

Pursuant to an interconnection agreement, together with a long term rate filing issued by the Public Utilities Commission of New Hampshire on December 20, 1984, all electrical energy produced by each of the Steven's Mill Turbine-Generator and the River Bend Turbine-Generator will be sold to PSNH. The term of the rate order is for 20 years, commencing January 1986, which was the

commissioning date of the facility. The rate order expires in 2006. The amount payable under the agreement is based on a time differentiated energy payment plus a capacity payment.

Land and Water Rights

The Franklin Facility is located on lands owned by the Franklin Industrial Complex Inc. The subsurface penstock which connects the intake to the powerhouse is located on an easement granted by the Town of Franklin. There is no transmission line associated with the facility as the interconnection with PSNH is located on the owned lands. The hydraulic rights necessary for the operation of the facility are leased from the New Hampshire Water Resources Board pursuant to a lease dated May 28, 1987. The lease expires in August 2002 and is renewable on a year-to-year basis. The Manager has received confirmation from the New Hampshire Water Resources Board that the lease will be renewed.

Pursuant to an agreement with the Town of Franklin dated September 1, 1987 for payment in lieu of property taxes, the owner is obligated to pay the Town of Franklin 4% of gross revenues per annum generated by the facility until March 31, 2002 and 5% of gross revenues per annum generated by the facility from April 1, 2002 to March 31, 2006.

FERC Licence

The Franklin Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on June 14, 1983 (FERC Project No. 3760) for a 1,940 kilowatt facility. The FERC exemption order was amended on April 16, 1991 to increase the stipulated capacity to 2,161 kilowatts. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; (ii) a minimum flow of 100 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality; and (iii) at the time of issuance of the FERC exemption order, the US Fish and Wildlife Service requested a downstream passage for Atlantic salmon seeded by the resource agencies. The cost of installing such fish passage, if required, is not expected to be significant. In addition, protection measures at the intake will also be required during the downstream migration of smolts, the cost of which is not significant.

Moretown Facility

The facility is a 1,200 kilowatt hydroelectric generating facility located on the Mad River in the Town of Moretown, Vermont. The facility includes a 12 metre dam, forebay, intake structure, penstock, powerhouse and tailrace. The powerhouse includes one Kaplan type turbine generator rated at 1,250 kilowatts. The facility was constructed in 1989 and is owned by the Moretown Partnership.

Power Purchase Agreement

A power purchase agreement was executed between Vermont Power Exchange, Inc. and the Moretown Partnership on July 29, 1988, whereby Vermont Power Exchange, Inc. agreed to purchase all the electrical energy produced from the facility. The term of the contract is 30 years and the power purchase rates include an energy rate, a capacity rate and a payment lag adder rate. Vermont Power Exchange, Inc. is a purchasing agent authorized by the Vermont Public Service Board. As purchasing agent for the utility, the Vermont Power Exchange, Inc. is paid a commission by the producer for the energy sales. On March 15, 1996, the Vermont Electric Power Producers, Inc. ("VEPPI") was designated as the purchasing agent to replace the Vermont Power Exchange, Inc. Moretown Partnership entered into

an interconnection agreement with Washington Electric Cooperative, Inc. on June 22, 1988, so that the facility may interconnect with the electrical system in Moretown, Vermont.

Land and Water Rights

All land and water rights required for the construction and operation of the facility are owned by the Moretown Partnership. The Town of Moretown and the Town School District executed a tax stabilization agreement with the Moretown Partnership dated October 25, 1990. The agreement limited the municipal and school taxes to be paid with respect to the property to a certain amount which may be increased if there is an increase in the power purchase rates paid by the Vermont Power Exchange, Inc. The term of the agreement is approximately 18 years, expiring March 31, 2008.

FERC Licence

The facility received a licence (Minor Project) for a hydroelectric generating facility from FERC on December 7, 1982 (FERC Project No. 5944) and the term of the licence is for a period of 40 years. The main compliance condition associated with the facility is that the facility must maintain an instantaneous minimum flow of 25 cubic feet per second over the dam, when available, to protect the Mad River.

Lochmere Facility

The facility is a 1,200 kilowatt hydroelectric generating facility located on the Winnepesaukee River, in the Village of Lochmere, within the city limits of Tilton, New Hampshire. The facility consists of a dam, intake canal, intake, powerhouse and tailrace structures and is designed and operated as a run-of-the-river facility. The facility was reconstructed from an old hydroelectric generating facility at the site of an existing dam at the outlet of Winnisquam Lake. The Lochmere Facility is owned by the HDI Partnership.

Power Purchase Agreement

A power purchase agreement was executed between PSNH and the HDI Partnership on August 5, 1983 for all electrical energy produced at the facility. The term of the contract is 20 years commencing January 1986.

Land and Water Rights

The land for the facility site was leased by the Town of Belmont from the New Hampshire Water Resources Board pursuant to an agreement dated August 10, 1983. The lease was assigned to the HDI Partnership for development of the facility. The term of the lease is 50 years and payments under the agreement are based on a percentage of adjusted gross revenues generated by the facility, which payments are in lieu of property taxes.

Since the existing dam at this site was once used to generate electricity and is a State-owned structure, there is a water use licence granting the facility the right to utilize the hydraulic resources for hydroelectric generation purposes by the State of New Hampshire. It has a term of 15 years ending March 2000. The lease may be renewed upon mutual agreement. The lease has expired, however, the arrangement is being continued on the same basis as the original lease. Payments are made on a semi-annual basis in accordance with a simple formula contained in the licence. The payment rate escalates by ten percent on every fifth anniversary of the agreement.

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

FERC Licence

The facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on March 15, 1984 (FERC project No. 3128) for a 1,200 kilowatt facility. The main compliance conditions associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; (ii) from October to March, a minimum flow of 35 cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality. During the months of April to September, the minimum flow is 50 cubic feet per second for the benefit of small mouth bass and anglers; and (iii) a series of inexpensive, hand-built check dams constructed of natural river bed material are to be maintained annually downstream of the dam for the creation of fish and macroinvertebrate habitat. The cost of maintaining such check dams is not significant.

Lower Robertson Facility

The facility is a 960 kilowatt hydroelectric generating facility located on the Ashuelot River approximately one kilometre upstream of the Highway bridge at Hinsdale, New Hampshire. The facility consists of a dam, intake, powerhouse and tailrace structures and is designed and operated as a run-of-the-river facility. The facility was constructed in 1988 at the site of an existing concrete dam, which was rebuilt to facilitate the generating facility. The facility is operated in conjunction with the Ashuelot Facility, due to the close proximity of the sites (less than one kilometre away).

Power Purchase Agreement

In 1984, the NHPUC approved a rate order which requires PSNH to purchase from the former owner the entire electrical output from the Lower Robertson Facility at specified rates. The rate order was subsequently assigned to HDI III Partnership. The amount paid by PSNH for electrical output is based on an energy payment plus a capacity payment. The term of the rate order is for a period of 29 years commencing September 1, 1987 and expires in September 2016.

Land and Water Rights

The real property interest required for the construction and operation of the facility was obtained pursuant to a warranty deed from Paper Service Mills, Inc. on December 29, 1986. Under the terms of the warranty deed, the HDI III Partnership obtained title to the land on which all structures associated with the facility are located, including the dam structure, as well as access to both sides of the Ashuelot River required for the operation and maintenance of the facility. The warranty deed provides an interest in the riparian rights at the site, including all water power rights and privileges on the Ashuelot River.

Hydroelectric Development, Inc. ("HDI") has entered into an agreement with the Town of Winchester for payment in lieu of property taxes for the facility. This agreement was subsequently assigned by HDI to the HDI III Partnership. The agreement requires HDI III Partnership to pay to the Town within 90 days following the end of each fiscal year the greater of two and one-half percent of the gross revenues for that fiscal year or two and one-half percent of the average gross revenues for the previous fiscal year. The term of the agreement is for 30 years commencing on the initial date of commercial operation, which occurred in June 1987.

FERC Licence

The facility received an exemption from licensing for a hydroelectric generating facility of five megawatts or less from FERC on July 31, 1986 (FERC Project No. 8235). The main compliance conditions associated with this facility are that: (i) the facility must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; (ii) a minimum flow of ten cubic feet per second has to be released downstream of the dam, when available, to maintain the instream fisheries and water quality; and (iii) at the time of issuance of the FERC exemption order, the US Fish and Wildlife Service and New Hampshire Department of Fish and Game indicated that there may be a future requirement for the installation of a fish by-pass at the facility, estimated by the Manager to cost approximately \$150,000. To date, no such by-pass system has been installed. The Manager believes that such by-pass system will not be required.

Ashuelot Facility

The facility is a 900 kilowatt hydroelectric generating facility located on the Ashuelot River near the highway bridge at Hinsdale, New Hampshire. The facility consists of a dam, intake, powerhouse and tailrace structures and is designed and operated as a run-of-the-river facility. The facility was constructed in 1988 at the site of an existing concrete dam which was rebuilt to facilitate the generating facility.

Power Purchase Agreement

In 1985, the NHPUC approved a rate order which requires PSNH to purchase from Ashuelot River Partners the entire electrical output from the Ashuelot Facility at specified rates. The rate order was subsequently assigned to HDI III Partnership. The amount payable is based on an energy payment plus a capacity payment. The term of the rate order is for a period of 29 years commencing September 1, 1986 and expires in September 2015.

Land and Water Rights

The land and water rights for the site are leased from the Ashuelot Paper Company pursuant to an agreement dated January 14, 1985. The term of the lease is 55 years commencing on January 14, 1985 and terminating on December 31, 2040 and payments under the agreement are structured as a percentage of gross revenues from the facility.

HDI has entered into an agreement dated August 13, 1986 with the Town of Winchester for payment in lieu of property taxes for the facility. This agreement was subsequently assigned by HDI to HDI III Partnership. The agreement requires HDI III Partnership to pay to the Town within 90 days following the end of each fiscal year the greater of two and one-half percent of the gross revenues for that fiscal year or two and one-half percent of the average gross revenues for the previous fiscal year. The term of the agreement is for 30 years commencing on the initial date of commercial operation, which occurred in June 1987.

FERC Licence

The Ashuelot Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on July 31, 1986 (FERC Project No. 7791) for an 850 kilowatt generating facility. The main compliance conditions associated with this facility are that: (i) the facility must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; (ii) a minimum flow of ten cubic feet per second has to be released downstream of the dam, when

available, to maintain the instream fisheries and water quality; and (iii) at the time of issuance of the FERC exemption order, the US Fish and Wildlife Service and the New Hampshire Department of Fish and Game indicated that there may be a future requirement for the installation of a fish by-pass at the facility, estimated by the Manager to cost approximately \$150,000. To date, no such by-pass system has been installed. The Manager believes that such by-pass system will not be required.

Lakeport Facility

The facility is a 600 kilowatt hydroelectric generating facility located on the Winnepesaukee River near the Town of Lakeport, New Hampshire. The facility consists of a dam, powerhouse and tailrace structures and is designed and operated as a run-of-the-river facility. The facility was constructed in 1984 at the site of an existing concrete dam.

Power Purchase Agreement

In 1985, the NHPUC approved a rate order which requires PSNH to purchase from Lakeport Corporation the entire electrical output from the Lakeport Facility at specified rates. The amount payable is based on an energy payment plus a capacity payment. The term of the rate order is for a period of 20 years commencing September 1, 1985 and expires in September 2005.

Land and Water Rights

The facility is constructed on certain lands purchased by Lakeport Corporation. Certain additional land and water rights necessary for the operation of the facility are leased from the New Hampshire Water Resources Board pursuant to an agreement dated December 29, 1982. The term of the lease is 50 years and payments under the agreement are structured as a percentage of gross revenues from the facility.

As a condition under the lease with the New Hampshire Water Resources Board, Lakeport Corporation has entered into a water user's agreement dated August 30, 1985 with the New Hampshire Water Resources Board in respect of certain water management services provided by the New Hampshire Water Resources Board to users located on the Winnepesaukee River. Payments under the water user's agreement are structured based on energy production from the facility.

Lakeport Corporation has entered into an agreement with the City of Laconia for payment in lieu of property taxes for the facility. The agreement requires Lakeport Corporation to pay to the City of Laconia following the end of each fiscal year an amount equal to five percent of the gross revenues from the facility for that fiscal year. The term of the agreement is for 20 years commencing on October 9, 1985.

FERC Licence

The Lakeport Facility received a licence for a small hydroelectric generating facility from FERC on September 8, 1983 (FERC Project No. 6440) for a 600 kilowatt generating facility. The main compliance conditions associated with this facility are that: (i) the facility must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) a minimum flow of 180 cubic feet per second has to be released downstream of the dam, when available, to maintain the instream fisheries and water quality. The term of the FERC licence is 40 years commencing on the date of issue.

Avery Dam Facility

The facility is a 260 kilowatt hydroelectric generating facility located on the Winnepesaukee River in the City of Laconia, New Hampshire. The facility was constructed in 1985 at an existing site that was used for power generation and consists of a dam, intake structure, powerhouse and tailrace. The generating equipment includes two Flygt submersible turbine/generators. The facility is owned by the Avery Dam Partnership.

Power Purchase Agreement

The NHPUC issued a rate order to Avery Hydroelectric, Inc., on June 20, 1985. This rate order was subsequently assigned by Avery Hydroelectric, Inc. to the Avery Dam Partnership. The rate order requires PSNH to purchase all output from the facility at specified rates. The amount payable is based on an On-peak and Off-peak energy payment and a capacity payment. The term of the rate order is for a period of 29 years commencing September 1, 1986 and expires in September 2015. On August 27, 1986, Avery Dam Partnership signed an interconnection agreement with PSNH concerning operational matters relating to the facility.

Land and Water Rights

Avery Dam Partnership has entered into a lease agreement with the New Hampshire Water Resources Board, a public corporation and an agency of the State of New Hampshire, for the water rights, land and associated facilities of the Avery Dam on the Winnepesaukee River. The lease agreement was amended and restated on November 27, 1985. The term of the lease agreement is the earlier of 50 years or the termination of the FERC licence and the rental payments are five percent of the adjusted gross revenue ("AGR") for years 1 to 5, 10% of AGR for years 6 to 10, 15% of AGR for years 11 to 15 and 20% of AGR for years 16 to 50.

The Avery Dam Partnership entered into a contract with water users with the New Hampshire Water Resources Board dated November 27, 1985. The term of the agreement is 15 years and can be extended after that period on a yearly basis upon mutual agreement. The rent includes both a base fee and an incentive fee.

The Avery Dam Partnership entered into an agreement for payment in lieu of taxes with the City of Laconia pursuant to an agreement dated October 9, 1985. The agreement provides for the owner to pay the City of Laconia an amount equal to five percent of gross revenues from the facility in lieu of municipal taxes. The agreement has a term of 20 years.

FERC Licence

The facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on March 22, 1985 (FERC Project No. 6752). The main compliance conditions associated with the facility are that: (i) it must operate as an instantaneous run-of-the-river facility; and (ii) it must maintain a minimum flow of 30 cubic feet per second from April to September and 20 cubic feet per second during the remainder of the year.

Hadley Falls Facility

The facility is a 250 kilowatt hydroelectric generating facility located on the Piscataquog River near the Town of Goffstown, New Hampshire. The facility consists of a dam, intake canal, powerhouse

and tailrace structures and is designed and operated as a run-of-the-river facility. The facility was commissioned in 1986 at the site of an existing concrete dam which was rebuilt to facilitate the generating facility.

Power Purchase Agreement

In 1986, the NHPUC approved a rate order which requires PSNH to purchase the entire electrical output from the Hadley Falls Facility at specified rates. The amount payable is based on an energy payment plus a capacity payment. The term of the rate order is for a period of 20 years commencing September 1, 1986 and expires in September 2006.

Land and Water Rights

Hydro Dynamic Corp. entered into a lease agreement dated July 30, 1981 with Heritage Door Company for the land and facilities required in order to construct and operate the Hadley Falls Facility. This agreement was assigned to the Hadley Falls Partnership on December 14, 1981. The term of this lease is for 35 years commencing in 1981 and the rent is a negotiated fee based on competitive rents. Hydro Dynamic Corp. also entered into a lease agreement dated September 8, 1981 with the New Hampshire Water Resources Board for the water rights at this location. This agreement was assigned to the Hadley Falls Partnership on October 26, 1981.

FERC Licence

The facility received an exemption from licensing for a small hydroelectric generating facility of five megawatts or less from FERC on January 19, 1982 (FERC Project No. 5379). The main compliance issue is that the facility must operate as an instantaneous run-of-the-river facility.

Hopkinton Facility

The facility is a 250 kilowatt hydroelectric generating facility located on the Contoocook River, in the Village of Contoocook, New Hampshire. The layout of the facility consists of a dam, intake, powerhouse and tailrace structure and is designed and operated as a run-of-the-river facility. The facility was constructed at the site of an existing concrete dam which was rebuilt to facilitate the new generating facility. The Hopkinton Facility is owned by the HDI Partnership.

Power Purchase Agreement

A power purchase agreement was executed between the Public Service Company of New Hampshire and the HDI Partnership on August 5, 1983 for all electrical energy produced at the Hopkinton Facility. The term of the agreement is 20 years, commencing January 1986, which was the commissioning date of the facility. Under the terms of the agreement, PSNH is required to purchase all energy for \$0.1242/kW-hr (US\$0.09/kW-hr), plus 50% of the positive amount of PSNH's incremental energy cost in excess of \$0.1242 (US\$0.09). Since incremental energy costs have not risen above this level, payments have been made at the rate of \$0.1242/kW-hr (US\$0.09/kW-hr) since commissioning of the facility.

Land and Water Rights

Land and water rights for the site are leased from the Town of Hopkinton pursuant to an agreement dated September 2, 1983. The term of the lease is 40 years and payments under the agreement

are based on a step-rated percentage of annual gross revenues from the facility. The lease makes provision to significantly reduce lease payments in the event that dam repairs exceed \$345,000 (US\$250,000). A separate agreement with the Town of Tilton provides for payments in lieu of property taxes based on gross revenues generated by the facility.

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

FERC Licence

The Hopkinton Facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on March 14, 1984 (FERC project No. 5735) for a 250 kilowatt facility. The main compliance conditions associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; (ii) a minimum flow of two cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality; and (iii) at the time of issuance of the FERC exemption order, the US Fish and Wildlife Service requested a downstream passage for Atlantic salmon seeded by the resource agencies. If there is a successful arrival of naturally migrating salmon, an upstream fish ladder will be required. The cost of installing such fish ladder, if required, is not expected to be significant. In addition, protection measures at the intake will also be required during the downstream migration of smolts, the cost of which is not expected to be significant.

Milton Facility

The Milton facility is located on the Salmon River on the Maine-New Hampshire border, approximately 70 km from Manchester, New Hampshire with an installed capacity of 1,335 kilowatts. The facility is located at a site which was historically utilized for electrical and mechanical energy production for mill purposes. The facility was substantially rehabilitated and expanded in 1986 and includes a 3,800 foot penstock leading from the intake to the powerhouse. The Milton facility is owned by SFR Hydro Corporation.

Power Purchase Agreement

The Milton facility sells all energy produced to PSNH pursuant to a power purchase agreement dated July 17, 1982. The agreement terminates on July 1, 2012 and stipulates a fixed rate for the sale of energy over its term.

Land and Water Rights

SFR Hydro Corporation acquired all land necessary for the operation of the Milton facility from Iron Mountain Records Management Inc. In addition to direct ownership of certain parcels of land, SFR Hydro Corporation holds certain permanent easements on land and buildings employed by the facility. As a result of its ownership of the facility site, SFR Hydro Corporation was granted the water rights for the Salmon River available at the facility site for the operation of the facility.

FERC Licence

The Milton facility received an exemption from the licensing of a small hydroelectric generating facility from FERC in June 30, 1981 (FERC Project No. 3984). The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility; and (ii) a minimum

flow of 25 cubic feet per second must be released downstream of the dam between April and June, when available, to maintain the instream fisheries and water quality.

Mine Falls Facility

The Mine Falls facility is a 3,000 kilowatt hydroelectric generating station located on the Nashua River near the City of Nashua, New Hampshire. The site is comprised of two turbine-generators housed in a new concrete powerhouse located at the site of a historic concrete dam. The site was commissioned in 1986. The Mine Falls facility is owned by the Mine Falls Limited Partnership.

Power Purchase Agreement

A power purchase agreement dated March 25, 1984 was entered into between Seaward Development-Mine Falls Inc. and PSNH. The agreement was amended on November 14, 1985 and was assigned to the Mine Falls Partnership on December 10, 1985. The agreement expires on December 31, 2005. Under the amended terms, PSNH continues to purchase all electrical energy from the facility at a fixed rate of US\$0.09/kW-hr over the remainder of the term.

Land and Water Rights

The land, physical structures and water rights associated with the facility are leased from the City of Nashua pursuant to a lease dated May 2, 1984. The lease has a term of 40 years and expires in 2024. Payments pursuant to the lease are based on a percentage of gross revenues earned from the sale of energy from the facility.

FERC Licence

The City of Nashua and Seaward Construction Company Inc. received a FERC Licence (FERC Project No. 3442) for a small hydroelectric generating facility on March 26, 1985 with installed capacity of 3,032 kilowatts. The interest of Seaward Construction Company Inc. was assigned to the Mine Falls Partnership on November 5, 1985. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility; (ii) a minimum flow of 20 cubic feet per second must be released over the dam plus a minimum flow of 10 cubic feet per second must be released into an adjacent watershed, when available, to maintain the instream fisheries and water quality, and (iii) the existing upstream fish hoist system, while it appears to function properly, has not received final acceptance by FERC.

Great Falls Facility

The Great Falls facility is a 10,950 kilowatt hydroelectric generating station located on the Passaic River near the City of Paterson, New Jersey. The site was originally utilized for the production of electrical energy and was decommissioned in January 1969. The powerhouse was declared a National Historic Landmark in 1971. In 1986, the facility underwent a major rehabilitation with the installation of three new turbine-generators and new electrical and control equipment and was recommissioned in December 1986. The Great Falls facility is owned by the Great Falls Hydroelectric Company (the "Great Falls Partnership"), a Maryland limited partnership.

Power Purchase Agreement

A power purchase agreement dated September 6, 1985 was entered into between the Great Falls Hydroelectric Company and Public Service Electric and Gas Company ("PSE&G"). The agreement was amended on February 9, 1998 and expires in 2002. Under the amended terms, PSE&G continues to purchase all electrical energy from the facility. The rates paid for such energy and capacity are based on the local marginal energy pricing paid by PSE&G for energy and capacity. In 2001, the average blended energy price was approximately US \$0.041/kW-hr.

Land and Water Rights

The land, physical structures and water rights associated with the facility are leased from the Paterson Municipal Utilities Authority pursuant to a lease dated September 10, 1984. The lease expires on March 10, 2021. Payments pursuant to the lease are based on a percentage of gross revenues earned from the sale of energy from the facility, with a minimum annual payment.

FERC Licence

The Great Falls facility received an exemption from the licensing of a small hydroelectric generating facility from FERC on March 1, 1981 for a 7,500 kilowatt facility, which exemption was amended on September 6, 1985 (FERC Project No. 2814) to allow for a 10,950 kilowatt facility. The main compliance issues associated with the facility are that: (i) it operate as an instantaneous run-of-the-river facility and there be no storage of water upstream of the facility; and (ii) a minimum flow of 50 cubic feet per second must be released over the dam for aesthetic purposes (increasing to 200 cubic feet per second in 2001), when available, to maintain the instream fisheries and water quality.

Worcester Facility

The facility is located on the North Branch of Winnooskie River, in the Town of Worcester, Vermont approximately 10 miles north of Montpelier, Vermont. The facility is located at a concrete gravity dam 80 feet long and 21 feet in height. It is a run-of-the-river facility and is rated at 180 kilowatts. The facility has one Ossberger Cross- Flow turbine.

Power Purchase Agreement

The agreement with Vermont Power Exchange, Inc. is for a term of 30 years. From August 15, 1986 until August 15, 2016, the specified settlement rates set out in the agreement will be paid to the producer.

Land and Water Rights

A Fund entity, Worcester Hydro Company, Inc., owns all land necessary for the operation of the facility. Certain permanent easements on land and buildings are also held by the Worcester Hydro Company, Inc. As a result of its ownership of the generating station site, Worcester Hydro Company, Inc. was granted the water rights for the facility.

FERC Licence

The facility received an exemption from licensing for a small hydroelectric generating station facility from FERC on June 11, 1985. The exemption order is for a generating facility of less than 5,000 kilowatts. The facility was commissioned in 1985.

The main compliance conditions associated with the facility are that: (1) it must operate as an instantaneous run-of-the-river facility and there can be no storage of water upstream of the facility; and (ii) a minimum flow of ten cubic feet per second must be released downstream of the dam, when available, to maintain the instream fisheries and water quality.

Western Canada Development – Dickson Dam and Drayton Valley Facilities

Dickson Dam Facility

The Dickson Dam Facility is located 20 kilometres west of the Town of Innisfail, Alberta. The Dickson Dam Facility is a 15.0MW 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.

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 12.7MW capacity which is allocated to the facility at rates stipulated by the *Small Power Research and Development Act* (Alberta) (the “Small Power Act”). The price paid by TransAlta during 2001 was \$ \$0.0619 /kw-hr.

Use of Works Agreement

The original owner of the Dickson Dam Facility entered an agreement with the Government of Alberta under which it obtained the right to construct the Dickson Dam Facility and utilize the available waterflows for generating power until March 31, 2030. This agreement has been transferred to a Fund entity. Under the Use of Works Agreement, such Fund entity has accepted the obligation to operate the Dickson Dam Facility in accordance with the requests of the Minister of Environment (Alberta) to accommodate water release changes. Following commercial operation in 1992, the Dickson Dam Facility has been operated in accordance with the terms of the Use of Works Agreement. Under the Use of Works Agreement, the Minister does not guarantee any reservoir water level or any supply of water to the Dickson Dam Facility, which is dependent upon water flows in the Red Deer River. The Minister also reserves the right to control releases and direct that the Dickson Dam Facility be operated to meet certain water management objectives relating to flood control, water quality levels and inter-provincial treaty obligations. The owner of the Dickson Dam Facility is obligated to make annual payments to the Minister of Environment (Alberta) of \$50,000 (measured in 1992 dollars) throughout the term of the Use of Works Agreement and which payments escalate annually by the Alberta Consumer Price Index. In 2001, the annual payment (inclusive of water rental) was \$57,787.

Drayton Valley Facility

The Drayton Valley Facility is a 12.0MW bio-mass fired generating facility which produces electricity from burning wood waste provided by Weyerhaeuser Canada Ltd. ("Weyerhaeuser") using a single steam turbine. The facility was commissioned in 1994 and has operated satisfactorily since its commissioning.

A Fund entity acquired a 50% interest in the partnership which owns the Drayton Valley Facility. The Fund's partner in the Drayton Valley Facility is also the operator. The operator ~~is~~ has extensive experience in operating biomass-fired generating facilities.

Power Purchase Agreement

The Drayton Valley Facility has entered into a 20 year agreement with TransAlta dated December 13, 1994, pursuant to which TransAlta is obligated to purchase all electricity produced at the Drayton Valley Facility up to 10.5MW at prices stipulated by the Small Power Act. Electricity generated at the Drayton Valley Facility is delivered to TransAlta through interconnection facilities erected on and adjacent to the facility site.

Fuel Supply

The Drayton Valley Facility entered into an agreement with Weyerhaeuser on January 30, 1995 pursuant to which Weyerhaeuser is obligated to supply, without charge, all wood waste produced at the Weyerhaeuser sawmill plant which is co-located with the Drayton Valley Facility. The agreement, which expires in 2017, requires the Drayton Valley Facility to establish a storage pile of wood waste in an amount which will enable the Drayton Valley Facility to operate at an 87% capability factor for more than six months without further wood waste deliveries. The Drayton Valley Facility operating at approximately 95% of maximum annual capacity consumes approximately 84,000 oven dried tonnes (odt) of wood waste each year. The Weyerhaeuser mill currently delivers approximately 90,000 odt of wood waste each year. Weyerhaeuser is one of Canada's largest forest products companies and the Drayton Valley sawmill and strandboard plant is a core asset. This plant currently produces approximately 113 million feet of lumber board from the sawmill and approximately 390 million feet from the strandboard facility. Weyerhaeuser plans to operate the Drayton Valley plant beyond the term of the fuel agreement with the Drayton Valley Facility. If Weyerhaeuser fails to fulfil its obligations under the fuel supply agreement with the Drayton Valley Facility, it is estimated that there is approximately 100,000 odt of alternative bio-mass wood waste available within a 160 kilometre radius of the Drayton Valley Facility. No assessment has been made of the impact of transportation costs for such alternative bio-mass fuel upon the economics of the Drayton Valley Facility.

Wastewater Treatment Development – Black Mountain and Gold Canyon Facilities

Black Mountain Facility

The Black Mountain Sewer Corporation ("Black Mountain"), formerly the Boulders Carefree Sewer Corporation, was established in 1978 to support the development of the Boulders Resort and golf course. This exclusive resort is located ten miles north of Scottsdale, Arizona and is in the town of Carefree. Black Mountain currently serves approximately 1,700 residential and commercial customers.

The existing plant is located in the residential portion of the Boulders Resort. The plant was designed to treat 150,000 US gallons per day of sewage, and is currently permitted for 120,000 US gallons per day. The plant currently runs at capacity and the reclaimed water it produces is piped to a lake on the Boulders golf course for re-use. The utility currently bypasses up to 228,000 US gallons per day during the year to the City of Scottsdale wastewater treatment plant in accordance with an agreement entered into in 1996. Black Mountain has purchased capacity on this system for US\$6.00 per US gallon in the past for a total of 318,000 US gallons and pays US\$1.50 per 1,000 US gallons to process this sewage in such facility.

The Black Mountain facility is an activated sludge plant and produces a good quality effluent that meets or exceeds quality standards for effluent discharges. This is accomplished by post-process filtration utilizing a sand filter.

Black Mountain has expanded to service the town of Carefree under a regulated agreement called a Certificate of Convenience and Necessity (“CC&N”).

Certificate of Convenience and Necessity

This facility has had a CC&N, or mandate to provide wastewater services to its customers, for 23 years. The utility is regulated by the Arizona Corporation Commission, which regulates rates.

Arizona Department of Environmental Quality

This facility is also regulated and must comply with guidelines established by the Arizona Department of Environmental Quality to meet or exceed certain environmental conditions for discharge and re-use.

Gold Canyon Facility

The Gold Canyon Sewer Company (“Gold Canyon”) was established in 1989 to provide wastewater treatment services to the Town of Gold Canyon, Arizona. Gold Canyon currently serves approximately 3,360 residential and commercial customers.

The existing plant is located in an industrial area of the Town of Gold Canyon. The plant was originally designed to treat 500,000 US gallons per day of sewage and was expanded in 2000 to increase permitted capacity to 1,000,000 US gallons per day. Peak demand on the plant currently does not exceed approximately 200,000 US gallons per day and the reclaimed water it produces is piped to nearby golf courses for irrigation purposes.

The Gold Canyon facility is an activated sludge plant and produces a good quality effluent that meets or exceeds quality standards for effluent discharges. This is accomplished by post-process filtration utilizing a sand filter.

Gold Canyon serves the Town of Gold Canyon under a regulated agreement called a Certificate of Convenience and Necessity.

Certificate of Convenience and Necessity

This facility has had a CC&N, or mandate to provide wastewater services to its customers, for 23 years. The utility is regulated by the Arizona Corporation Commission, which regulates rates.

Arizona Department of Environmental Quality

The physical plant comprising the Gold Canyon Facility complies with guidelines established by the Arizona Department of Environmental Quality regarding discharge and re-use of effluent.

Recent Additions to Energy Related Developments

Pursuant to an agreement with Confederation Life Insurance Company, in liquidation dated September 5, 2001 (the "Confederation Life Agreement"), Algonquin Power Trust acquired note and share interests in certain companies which own the following generating facilities:

Kirkland Lake Facility

The Kirkland Lake 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 23MW gas turbines and two steam turbines. The facility was commissioned in 1991 by Northland Power Inc. ("Northland") and Northland remains the operator of the facility. Electricity produced by the facility is sold to OEFC pursuant to a 40 year contract executed in 1989. Amendments to such power purchase agreement have been made so that 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 by Gulf Canada Resources Limited and Chevron Canada Resources under supply contracts with 20 year terms 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. The capital structure of Kirkland is comprised of approximately \$87.5 million of senior debt outstanding and 3,562,963 Class A voting shares and 37,000,000 Class B non-voting shares. The Class A and Class B shares are identical in all respects except the Class A shares have voting rights.

Under the Confederation Life Agreement, Algonquin Power Trust acquired 32.4% of the Class B non-voting shares issued by Kirkland. The management agreement between Northland and Kirkland contemplates that Kirkland will achieve specified target operating profits from the operation of the Kirkland Lake Facility, failing which, among other things, Kirkland may terminate the management agreement. It is Kirkland's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income, and the amount of dividends to date have been consistent with the targeted operating profits (net of applicable tax) established in the management agreement. Northland has granted Kirkland a put option to sell the Kirkland Facility to Northland with an exercise date of February 28, 2011 at 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

The Cochrane Facility is a 35.8 MW combined cycle co-generation facility located in Cochrane, Ontario owned by Cochrane Power Corporation ("Cochrane") which burns natural gas and wood waste to generate power using a 26.5MW gas turbine and a steam turbine. The facility was commissioned in 1990 by Northland and Northland remains the operator of the facility. Electricity produced by the facility is sold to OEFC pursuant to a 25 year contract executed in 1989. Amendments to such power purchase agreement have been made so that energy 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 by Canadian Natural Resources Limited under a supply contract with a 20 year term which expires in 2012. Price increases under such gas supply agreement 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. The capital structure of Cochrane has no debt and consists of 6,000,000 Class A voting shares representing 11.54% of the equity interests and 46,000,000 Class B non-voting shares representing approximately 88.46% of the equity interests.

Under the Confederation Life Agreement, Algonquin Power Trust acquired 25.0% of the Class B non-voting shares issued by Cochrane. The management agreement between Northland and Cochrane contemplates that Cochrane will achieve specified target operating profits from the operation of the Cochrane Facility, failing which, among other things, Cochrane may terminate the management agreement. It is Cochrane's policy to declare and pay quarterly dividends on its shares equal to substantially all of its after-tax income, and the amount of dividends to date have been consistent with the targeted operating profits (net of applicable tax) established in the management agreement. Northland has granted Cochrane a put option to sell the Cochrane Facility to Northland with an exercise date of February 28, 2011 at exercise price of \$3.0 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.

Cardinal Facility

Cardinal Power of Canada L.P. ("Cardinal") owns the Cardinal Facility which is a 150 MW combined cycle co-generation facility fuelled by natural gas located in Cardinal, Ontario and which generates and sells electricity exclusively to OEFC at contracted rates for a minimum of 20 years commencing in 1992. In addition to electricity, the facility generates and sells steam to Canada Starch Operating Company pursuant to a 20 year steam sales agreement. The Cardinal Facility purchases natural gas from Husky Oil Limited under a 20 year gas supply agreement maturing in 2014 and under which the facility is provided with all required natural gas at predetermined prices, subject to pricing changes within fixed ranges. Natural gas for the facility is transported by TransCanada PipeLines Limited and Centra Gas Ontario, Inc. pursuant to 20 year and three year firm service agreements, respectively. The facility is operated by Sithe Energies Canada Power Service Inc. and the operator is paid a monthly fee for operations services, which fee is subject to annual escalations equivalent to changes in the consumer price index. The capital structure of Cardinal includes \$145.5 million of senior debt maturing October 1, 2014 and paying 9.68% per annum, compounded quarterly. Pursuant to the credit agreement entered into in respect of the senior debt, a debt service escrow account has been established to provide continued debt service payments in the event of unforeseen business disruptions.

Under the Confederation Life Agreement, Algonquin Power Trust acquired a 16.9% interest in the senior debt issued by Cardinal. The outstanding principal amount of the interest in the senior debt acquired by Algonquin Power Trust as at October 1, 2001 was approximately \$20.7 million.

Chapais Facility

Chapais Energie, Societe en Commandites ("Chapais") owns an electricity generating facility which burns wood waste and is located in the Town of Chapais, Québec. The Chapais Facility was placed into commercial operation after significant commissioning difficulties and delays in August 1995.

The Chapais Facility sells electricity to Hydro Québec pursuant to a power purchase agreement with a 20 year term 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. The Chapais Facility is operated by a third party operator. 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 has been temporarily exchanged for certain preferred shares until July 31, 2004. The capital structure of Chapais is comprised of 50 common shares, 400 Class A non-voting shares and 336 Class B non-voting preferred shares. Chapais is also the debtor under a term loan held by CHEL Subco Inc. ("CHEL"). The authorized capital of CHEL consists of common shares (all of which are held by Chapais), as well as Class A preferred shares (the "Tranche A Shares"), Class B preferred shares (the "Tranche B Shares") and Class C preferred shares. There are approximately \$47.5 million of Tranche A Shares and \$15.3 million of Tranche B Shares outstanding. Both tranches of preferred shares are expected to pay dividends at the rate of 6.5% per annum. On July 31, 2004, the Tranche A and Tranche B Shares are expected to be exchanged for term loan interests issued by Chapais, which loans will bear interest at the rate of 10.789% and 4.91%, respectively.

Under the Confederation Life Agreement, Algonquin Power Trust acquired a 12.1% interest in both the Tranche A and Tranche B Shares and a 33.9% interest in the Class B non-voting preferred shares of Chapais.

Brooklyn Facility

Brooklyn Power Corporation ("Brooklyn") owns a 28.0 MW bio-mass-fired electric generating facility located in Queen's County, Nova Scotia. The Brooklyn Facility was commissioned in December 1995 and consumes the wood waste produced by the Bowater Mersey Paper Company Limited ("Bowater") facility 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. The capital structure of Brooklyn is comprised of approximately \$54.0 million of senior debt and 1,000,000 common shares.

Under the Confederation Life Agreement, Algonquin Power Trust acquired 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 acquired by Algonquin Power Trust as at October 1, 2001 was approximately \$8.1 million.

Thermal Development - Peel Facility, KMS Joliet Facility, KMS Bakery Facility, KMS Crossroads Facility and Sanger Facility

KMS Power Income Fund

At the beginning of March 2002, Algonquin Power Trust, a trust of which the Fund is the sole beneficiary, completed the acquisition of approximately 86.7% of the outstanding trust units and approximately 47.3% of the outstanding convertible debentures of the KMS Power Income Fund. Algonquin Power Trust intends to effect a subsequent acquisition transaction so as to acquire the remaining KMS Power Income Fund trust units not tendered under the offer.

KMS Power Income Fund owns the following generating facilities:

Peel Facility

The Peel Facility is a 10.0 MW generating station which produces electricity from incinerating non-recyclable materials, including municipal solid waste, using steam to drive a turbine generator to produce electricity.

Power Purchase Agreement

KMS Peel Inc. and OEFC have entered into a power purchase agreement which expires in 2012. Pursuant to the power purchase agreement, OEFC is required to purchase all the electricity produced by the facility. The current electricity rates are as follows (escalating price based on changes in the consumer price index): (1) winter peak - \$0.0961/ kWhr, (2) winter off-peak -\$0.0373/ kWhr, (3) summer peak - \$0.0797 /kWhr, (4) summer off-peak - \$0.0326/kWhr.

Fuel Supply

KMS Peel Inc. and the Regional Municipality of Peel (the “Regional Municipality”) have entered into a “tip or pay” waste supply agreement and an expanded capacity agreement which expire in 2012. Pursuant to these agreements, the Regional Municipality supplies the facility with a minimum of 127,000 tonnes and up to 36,000 tonnes per year of acceptable municipal solid waste, respectively. At the end of the waste supply agreement the Regional Municipality has the option to renew the agreement for an additional five year term. The current agreement requires the Regional Municipality to pay a “tipping fee” for each tonne of acceptable waste delivered. This fee is adjusted monthly throughout the term of the agreement based on changes in the Toronto-area consumer price index. 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 waste supply 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 on KMS Peel Inc. by the taxes or revised standards.

KMS Joliet Facility

The KMS Joliet facility is a landfill gas to electricity facility at the CDT landfill located near Joliet, Illinois. KMS Joliet Power Partners, L.P. (“KMS Joliet”) owns and operates the electrical generating facility at the landfill. The facility is designed to generate approximately 1.6 MW of electrical power.

Power Purchase Agreement

KMS Joliet has entered into an electrical purchase agreement with Commonwealth Edison Company (“CECo”), a major mid-western utility company. Pursuant to the agreement, CECo has agreed to purchase all electricity produced by the facility under a one year contract, automatically renewable yearly thereafter.

Fuel Supply

The CDT landfill occupies approximately 20.2 hectares. Gas from 20 wells drilled in the CDT landfill flows into an underground pipeline system where it is compressed. The pressurized gas then

fuels two Caterpillar reciprocating engines to generate electricity. Mank, L.P. owns the rights to extract gas from the CDT landfill. Pursuant to a gas sales agreement, KMS Joliet purchases landfill gas necessary to operate the generating facility at a fixed price of US \$0.70 per MMBTU through December 31, 2007. Under the gas sales agreement, KMS Joliet is obliged to make an annual minimum purchase of gas in an amount not to exceed \$65,000. KMS Joliet is obligated under an agreement with CDT to make payments of US \$25,000 per year during the term of the agreement, commencing upon commercial production. In addition, KMS Joliet must pay to CDT a royalty of 25% of the revenue received by Mank, L.P. for the gas sold to KMS Joliet, but in no event less than US \$0.40 per one million British Thermal Units of landfill gas sold. A production royalty of 1% of gross revenues from electricity sales is also payable to CDT.

KMS Bakery Facility

In 1989, a cogeneration facility was constructed at the site of an Entenmann's bakery located near Chicago, Illinois. In 1992, the cogeneration facility was acquired by KMS Bakery Power Partners, L.P. ("KMS Bakery"). The Entenmann's facility generates approximately 1.6 MW of electricity which, in addition to hot water, is used by the bakery for production processes and sanitation purposes.

Energy Services Agreement

Pursuant to an energy services contract between KMS Bakery and Entenmann's, KMS Bakery is obliged to use its reasonable efforts to provide electrical and thermal energy to Entenmann's for use in its bakery and Entenmann's must purchase or pay for a minimum of 5.0 million kilowatt hours of electrical power and purchase or pay for a minimum of 150,000 therms of thermal energy from KMS Bakery's cogeneration facility in each year. The price for electrical and thermal energy is as follows: (1) electrical \$0.12827/kW-hr and (2) thermal \$0.25651/kW-hr.

Entenmann's provided notice of its intention to terminate the energy services contract effective August 2002, at a pre-determined price of US\$735,400.

KMS Crossroads Facility

KMS Crossroads, Inc. operates the KMS Crossroads cogeneration facility located in an office building complex in Mahwah, New Jersey and utilizes one 7.0 MW Solar Taurus 70 natural gas fired turbine to produce electricity and thermal energy.

Power Purchase Agreement

KMS Crossroads, Inc. has entered into a power sales agreement with Orange and Rockland Utilities Inc. ("O&R") for the purchase of up to 3.88 MW of capacity. The power sales agreement expires on December 31, 2008. The sales price of electricity under the power sales agreement includes both a variable and a fixed component. The variable component is redetermined once each calendar quarter for the term of the power sales agreement. The variable component is based on the weighted average price at which O&R transfers natural gas to its electric department for the purpose of generating electricity, as ordered by the New York Public Service Commission, in the previous calendar quarter. In the event no natural gas is transferred in a calendar quarter, the variable component will be based on the weighted average price of number six fuel oil burned by O&R at its Lovett and Bowline generating facilities in that calendar quarter. The fixed component is US \$0.0995 /kW-hour for on peak hours, US \$0.0770 for mid-peak hours and US \$0.02704 for off-peak hours. Effective for the second quarter of

2002, the variable component is US\$0.0166 /kW-hour. The variable component remains constant regardless of the hour during which the kilowatts are generated.

Pursuant to an energy services agreement, KMS Crossroads, Inc. is obliged to use reasonable efforts to provide firm electrical and thermal energy to the Crossroads Corporate Park, owned by Crossroads Developers Associates L.L.C (“CDA”) and CDA must purchase all of its required electricity from the KMS Crossroads, Inc. and all thermal power produced by KMS Crossroads, Inc. Pursuant to the energy services agreement the sales price paid by CDA for electricity for the year ended December 31, 2001 was an average price of US\$0.09362 /kW-hr. for each kilowatt hour generated and US\$5.95941 / million British Thermal Unit of thermal energy sold.

Sanger Facility

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 General Electric steam turbine and has demonstrated a successful operating history since its commissioning in 1991.

Power Purchase Agreement

Output of the facility is governed by the terms and conditions of a firm capacity and energy power purchase agreement between Sanger Power, L.L.C. and Pacific Gas and Electric Company. The original agreement was signed in 1984 and has been amended five times, the last amendment occurring in July 2001. The agreement is for a term of 30 years and calls for delivery of 38,000 kW of firm capacity and is effective through April 2022.

Capacity payments are based on a fixed amount of \$190 per kW/ year and is paid monthly on the basis of a capacity allocation factor and a transmission loss factor which is fixed. To qualify for the full capacity payment, the facility must maintain a capacity factor of 80% during the peak and/ or partial-peak hours of each monthly billing period. Annual capacity payments are estimated to be \$7,140,000.

In July 2001 there was a fifth amendment to the power purchase agreement. This change fixes the energy price at an annual average of \$0.0537 per kWhr. Actual energy prices vary depending on a time-of-day adjustment as well as a seasonal adjustment. The fixed price arrangement remains in place until July 15, 2006. After this date, barring any decision to revise Pacific Gas and Electric Company’s short-term avoided cost pricing by the California Public Utility Commission, energy pricing will revert back to the existing short term avoided cost transition formula.

The power purchase agreement requires that the facility meet and maintain its status as a FERC Qualifying Facility under PURPA. PURPA requires that a Qualifying Facility be owned by an entity which is not primarily engaged in the sale or generation of electric power. In order to meet the ownership criteria, the applicant must demonstrate that no more than 50% of the equity interest in a Qualifying Facility site is held, directly or indirectly, through subsidiaries, by electric utilities and/or electric utility holding companies. The Manager is of the view that the Sanger Facility qualifies as a Qualifying Facility.

Fuel Supply

Natural gas for the facility is delivered under the terms of a gas supply agreement with Sempra Energy Trading Corp. Deliveries under the agreement take place weekdays between September 1, 2001 and July 31, 2006. The agreement provides for a fixed price for all quantities below a base amount. All natural gas required above the base amount is purchased at the spot price available on the day burned.

Energy Lease

Pursuant to a lease, energy supply and common services agreement between Sanger Power, L.L.C. and Dyna Fibers Inc., 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 3% 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 Pacific Gas and Electric Company on an annual basis.

SHARE AND LOAN CAPITAL

Loan Capital of the Fund

The Fund has available a line of credit (the "Credit Line") provided by a major Canadian bank in the maximum principal amount of \$100,000,000 to be utilized in respect of the acquisition of facilities by the Fund. As security for repayment of such line of credit, the Fund has, among other things, pledged the shares of certain Fund entities.

Interest

Any amounts outstanding under the Credit Line bears interest at a rate equal to bank prime rate plus 25 basis points, payable monthly. An annual standby fee equal to 42.5 basis points of the undrawn portion of the Credit Line is payable monthly.

Redemption

The credit agreement in respect of the Credit Line stipulates that the amount outstanding under the Credit Line is due and payable as of the maturity of the Credit Line, which is April 26, 2004. As of May 17, 2002, the Fund had \$43.1 million outstanding under the Credit Line and certain letters of guarantee totalling \$34.8 million, posted as security.

Share Capital of Algonquin Canada

The authorized share capital of Algonquin Canada consists of 500,000,000 common shares without par value. At December 31, 2001, there were 49,429,363 common shares of Algonquin Canada outstanding and all shares are presently owned by Algonquin Holdco.

The distribution policy of Algonquin Canada will continue to be to distribute all of its available cash, subject to applicable law and to Algonquin Canada retaining appropriate working capital reserves. At the end of each month, Algonquin Canada's board of directors will determine whether Algonquin Canada has sufficient cash to return as capital or declare as a dividend for that month and, if so, what the

amount of capital returned or dividend will be. The decision of what amount, if any, to return as capital or declare as a dividend is to be a conservative estimate based on the results of each month. An adjustment, if appropriate, to the total amount of capital returned or dividend payable for a fiscal year will be paid prior to January 31 of the following year.

Loan Capital of Algonquin Canada

At December 31, 2001, Algonquin Canada has issued and outstanding the Canada 1999 Note in the principal amount of approximately \$6.3 million due June 30, 2039. The Canada 1999 Note was issued by Algonquin Canada with respect to the acquisition of the Franklin Facility. Algonquin Canada has issued and outstanding the Canada 2001 Note for the purpose of acquiring the Phoenix, Kings Falls, Otter Creek and Worcester Facilities in the aggregate principal amount of approximately \$11.6 million due March 21, 2041, for the purpose of acquiring the Black Mountain Facility in aggregate principal amount of approximately \$6.8 million due March 16, 2041 and for the purpose of acquiring the Gold Canyon Facility in aggregate principal amount of approximately \$7.1 million due March 16, 2041.

Interest

The Canada 1999 Note bears interest at the rate of 11% per annum, payable quarterly. The Canada 2001 Note bears interest at the rate of 9% per annum, payable quarterly.

The Canada 1999 Note and Canada 2001 Note provide that Algonquin Canada may defer payment of interest to the extent that its earnings before interest, taxes, depreciation and amortization are inadequate to pay interest thereon. Any interest deferred for a period exceeding 12 months will be capitalized as part of the principal outstanding under such notes, as applicable.

Redemption

The principal amounts of the Canada 1999 Note and Canada 2001 Note shall be retired prior to their maturity from available cash after payment of interest on the Canada 1999 Note and interest on the Canada 2001 Note in respective amounts as may be determined by Algonquin Canada's board of directors. In any event, the principal amount of the Canada 1999 Note and the Canada 2001 Note remaining outstanding on their respective due dates will be immediately due and payable.

Ranking

The Canada 1999 Note ranks *pari passu* with the Canada 2001 Note. The Canada 1999 Note and Canada 2001 Note are jointly secured by all assets of Algonquin Canada. At the discretion of its board of directors, Algonquin Canada has the ability to postpone repayment of the Canada 1999 Note and the Canada 2001 Note and subordinate the security related thereto to any indebtedness and related security that may be incurred by Algonquin Canada in the future.

Default

Each of Canada 1999 Note and the Canada 2001 Note provide that any of the following will constitute an event of default: (i) default in payment of the principal when due; (ii) default on any senior indebtedness for borrowed money; (iii) certain events of winding-up, liquidation, bankruptcy, insolvency, receivership, general assignment for the benefit of creditors or proceedings with respect to a compromise or arrangement under applicable bankruptcy or insolvency legislation; (iv) the taking of possession by an encumbrancer of all or substantially all of the property of Algonquin Canada; (v) ceasing to carry on in

the ordinary course the business of Algonquin Canada; (vi) default in performing any material lease, licence or other agreement whereby any material property or rights of Algonquin Canada may be forfeited or terminated; and (vii) default in the observance or performance of any other covenant or condition of the note and the continuance of such default for a period of 30 days after notice in writing has been given to Algonquin Canada specifying such default and requiring Algonquin Canada to rectify same.

Limitations on Issuances of Shares and Debt

The Governance Agreement provides that Algonquin Canada is not permitted to issue any shares or incur any debt other than in the ordinary course of business without the approval of the Fund and contains restrictions on further borrowings by Algonquin Canada. The Fund has approved the issue of the additional common shares as disclosed herein.

Share Capital of Algonquin America

The authorized share capital of Algonquin America consists of 1,000 shares of common stock without par value. There are 301 shares of Algonquin America outstanding and all shares are presently held by Algonquin Canada.

The distribution policy of Algonquin America will continue to be to distribute all of its available cash, subject to applicable law and to Algonquin America retaining appropriate working capital reserves. At the end of each month, Algonquin America's board of directors will determine whether Algonquin America has sufficient cash to return as capital or declare as a dividend for that month and, if so, what the amount of capital returned or dividend will be. The decision of what amount, if any, to return as capital or declare as a dividend is to be a conservative estimate based on the results of each month. An adjustment, if appropriate, to the total amount of the capital returned or dividend payable for a fiscal year will be paid prior to January 31 of the following year.

Loan Capital of Algonquin America

At December 31, 2001, Algonquin America had issued and outstanding the US 1999 Note (No. 2) in the aggregate principal amount of approximately \$20.3 million (approximately US\$12.7 million), US 2000 Notes (Nos. 1, 2 and 3) in the aggregate principal amount of approximately \$11.3 million (approximately US\$ 7.1 million) and the US/Canada 2001 Note in the aggregate principal amount of approximately \$11.6 million (approximately US\$ 7.3 million).

Interest

The US 1999 Note (No. 2) bears interest at the rate of 11% per annum, payable quarterly. The US 2000 Notes bear interest at the rate of 7% per annum, payable quarterly. The US/Canada 2001 Note bears interest at the rate of 9.1% per annum, payable quarterly.

The interest and principal on the US 1999 Note (No. 2), the US 2000 Notes and the US/Canada 2001 Note are payable in Canadian funds. The US 1999 Note (No. 2), the US 2000 Notes and the US/Canada 2001 Note provide that Algonquin America may defer payment of interest to the extent that its earnings before interest, taxes, depreciation and amortization are inadequate to pay the interest on such notes. Any interest deferred for a period exceeding 12 months will be capitalized as part of the principal outstanding under such notes, as applicable.

Redemption

The principal amounts of the US 1999 Note (No. 2), the US 2000 Notes and the US/Canada 2001 Note shall be retired prior to their maturity from available cash after payment of interest on the US 1999 Note (No. 2), interest on the US 2000 Notes and interest on the US/Canada 2001 Note in respective amounts as may be determined by Algonquin America's board of directors. In any event, the principal amount of the US 1999 Note (No. 2), the US 2000 Notes and the US/Canada 2001 Note remaining outstanding on their respective due dates will be immediately due and payable by Algonquin America.

Ranking

The US 1999 Note (No. 2), the US 2000 Notes and the US/Canada 2001 Note all rank pari passu with each other. The US 1999 Note (No. 2), the US 2000 Notes and the US/Canada 2001 Note are jointly secured by all assets of Algonquin America. At the discretion of Algonquin America's board of directors, Algonquin America has the ability to postpone any repayment of any of the US 1999 Note (No. 2), the US 2000 Notes and the US/Canada 2001 Note and subordinate the security related thereto to any indebtedness and related security that may be incurred by Algonquin America in the future.

Default

Each of the US 1999 Note (No. 2), the US 2000 Notes and the US/Canada 2001 Note provide that any of the following will constitute an event of default: (i) default in payment of the principal when due; (ii) default on any senior indebtedness for borrowed money; (iii) certain events of winding-up, liquidation, bankruptcy, insolvency, receivership, general assignment for the benefit of creditors or proceedings with respect to a compromise or arrangement under applicable bankruptcy or insolvency legislation; (iv) the taking of possession by an encumbrancer of all or substantially all of the property of Algonquin America; (v) ceasing to carry on in the ordinary course the business of Algonquin America; (vi) default in performing any material lease, licence or other agreement whereby any material property or rights of Algonquin America may be forfeited or terminated; and (vii) default in the observance or performance of any other covenant or condition of the note and the continuance of such default for a period of 30 days after notice in writing has been given to Algonquin America specifying such default and requiring Algonquin America to rectify same.

Limitations on Issuances of Shares and Debt

The Governance Agreement provides that Algonquin America is not permitted to issue any shares or incur any debt other than in the ordinary course of business without the approval of the Fund and Algonquin Canada and contains restrictions on further borrowings by Algonquin America.

Unit and Loan Capital of Algonquin Power Trust

All of the outstanding units of the Algonquin Power Trust are held beneficially and of record by the Fund. In addition, Algonquin Power Trust has issued certain notes to the Fund which have terms and provisions which are substantially the same as those contained in the US 2000 Notes.

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

Description of a Hydroelectric Facility

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. Virtually all dam structures used for hydroelectric generation purposes have spillways for discharging water which is surplus to the demand of the generating station. A spillway dam can be either an overtopping section of the dam (uncontrolled spillway) or an opening within the dam itself (sluiceway). Sluiceway structures must be equipped with a mechanism for blocking the opening(s) during periods when the hydroelectric generating facility can adequately handle the river flow. This can be accomplished using a variety of methods ranging from simple wooden logs (referred to as stoplogs) to automatically controlled and sophisticated steel gates.

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. Intake structures are normally equipped with steel or plastic screens (referred to as trashracks) which prevent debris and ice found in the reservoir from entering into the turbine equipment. Intake structures must be adequately submerged to prevent the entrainment of air into the water passages.

The electromechanical equipment consists of the turbine(s) and generator(s) used to transform the hydraulic energy into electrical energy. A turbine is a series of blades which rotate a shaft as a result of water flowing over or through the blades. A variety of turbines are used depending on the site. The generator is connected to the turbine (sometimes using a gearbox) and converts mechanical energy into electrical energy.

The electromechanical equipment is typically contained within a powerhouse building. The purpose of the powerhouse is to provide a solid structural foundation for the equipment and protect the equipment from the environment.

The water which has flowed through the hydraulic turbine(s) is discharged back to the natural watercourse through a draft tube and tailrace. The purpose of these two components is to return the flows back to the environment in a “hydraulically smooth” fashion.

The electrical equipment consists of switchgear, controls, a transformer substation and frequently a transmission line. The purpose of the electrical equipment is to transform the electrical energy produced by the generator into a form which is acceptable to the receiving electrical grid. This usually involves increasing the voltage and controlling the electrical frequency. 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 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 extract greater value from 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, Canadian provinces and in other countries.

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

Many landfill sites produce gas which can be burned to produce energy. Typically, an underground pipe system is installed and the gas produced is compressed and the pressurized gas is then piped off to engines or turbines to be burned to generate electricity.

Canada

In Canada, the provinces have legislative authority over the supply of energy. In the past, the majority of the electrical supply within the Canadian provinces was provided by large Crown corporations such as Ontario Hydro 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 mid-1980's, however, the rapid growth of projected energy demand, projections of dramatic increases in energy rates and advances in new generation technology led provincial governments to develop policies to encourage independent power generation. These policies were meant to encourage larger

utilities to purchase power from independent power producers pursuant to long term power purchase agreements which would supply power to the provincial power grid in parallel to the utilities' own generation. In the late 1980's and early 1990's, British Columbia, Alberta, Ontario, Québec, Nova Scotia and Newfoundland 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.

Ontario

By the mid-1980's, the majority of energy produced in Ontario was the responsibility of Ontario Hydro. In 1987 however, 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.

In 1998, the provincial government started the process of restructuring the energy market in Ontario. This restructuring includes the elimination of the large provincial utility, Ontario Hydro, that had enjoyed a monopoly in Ontario and the introduction of new generators and retailers of electricity into a competitive market.

Ontario has continued this process of reshaping the electricity industry throughout 1999 and into the year 2000. Following the passage of the Energy Competition Act, 1998 (the "Energy Act") in October, 1998, Ontario Hydro has been successfully restructured and separated into a number of new, successor companies such as Ontario Power Generation Inc. and Ontario Electricity Financial Corporation, among others. 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.

The restructuring of Ontario Hydro and the Ontario energy market 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. Ontario Electricity Financial Corporation 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.

Québec

In September 1990, the Québec government adopted a policy allowing private power producers to build, operate and manage hydroelectric generating facilities with a capacity of less than 25 megawatts, as well as the development of larger cogeneration facilities. The program set out the terms and conditions of long term waterpower leases with the Québec government and power purchase agreements with Hydro-Québec which would apply to all private power producers. 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.

Alberta

The government of Alberta passed the *Electric Utilities Act* (the “EU Act”) in 1996 and the EU Act was amended in 1998 and 2000 to separate generation, transmission and distribution of electrical power in Alberta for regulatory purposes. The EU Act permits the development of a competitive marketplace for electricity in Alberta. The EU Act also created the Alberta Power Pool (the “Power Pool”) through which all electrical power must be traded in Alberta.

The amendments to the EU Act and corresponding regulations in 2000 created the Alberta Balancing Pool (the “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 Research and Development Act* (Alberta) 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.

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. By 1992, however, the energy demand forecast for the province changed significantly and the utility indicated that it would limit the number of private generators that could sell power to the utility pursuant to long term power purchase agreements. In April 1992, the utility issued a request for proposals from private generators for a total of 50 megawatts of new generation. 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 totalling 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 and Star Lake facilities were the two facilities completed and commissioned in 1998.

United States

In 1978, The United States Congress enacted the Public Utility Regulatory Policies Act (“PURPA”) in response to a belief that the electric generation industry in the United States was too heavily dependent on foreign oil. Energy production in the United States is regulated by the Federal Energy Regulatory Commission. By enacting PURPA, Congress enabled private power producers to supply electricity to the large utilities throughout the country. FERC, pursuant to the PURPA legislation, mandated 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.

In 1992, the United States Congress empowered FERC to begin opening up the wholesale electric marketplace to competition. Order 888 issued by FERC on April 24, 1996 established the rules associated with wholesale market competition. It is projected by FERC and others that the United States and Canada will evolve to the point where the generating component of electricity will be open to competition and no longer be subject to price regulation.

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.

New Hampshire

New Hampshire has one large, investor-owned utility, Public Service Company of New Hampshire, which is a subsidiary of Northeast Utilities ("NU"), 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 New Hampshire Public Utilities Commission 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.

The State of New Hampshire is now going through the deregulation process pursuant to FERC's Order 888. During this period of industry restructuring, the State's utilities are requesting that the NHPUC consider rescinding or amending the rate orders the NHPUC has issued which require the purchases of power from independent power producers' generating facilities. The NHPUC has determined that the State's utilities should divest themselves of all generating assets and sell their power purchase agreements with independent power producers to third parties. The utilities, most notably PSNH and NU, are now negotiating with the NHPUC to determine how to deal with the Stranded Costs of selling above market priced power purchase agreements to third parties. PSNH is attempting to reduce its costs associated with these power purchase agreements with independent power producers and this action may impact the current rates paid for independently produced power.

As part of the review of PSNH's claim in respect of Stranded Costs, the NHPUC has requested a hearing into the issue that PSNH has and continues to purchase power from independent power producers during periods of "light loading". Light loading is defined as those periods of time during which the base load generating units are supplying energy on the margin, which has been estimated to occur approximately 15% of the time. The NHPUC is reviewing whether PSNH should have curtailed purchases of energy and capacity from independent power producers pursuant to both long term agreements and rate orders during such periods of light loading. PSNH asserts that the costs of purchases from independent power producers during periods of light loading has been factored into the calculation of the rates paid to the independent power producers under their rate orders and agreements and therefore

the decision of PSNH not to curtail any purchases should not be considered in the review of Stranded Costs. PSNH maintains that it is required to purchase all energy produced by independent power producers under the agreements and rate orders at all times, including during periods of light loading.

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. In August 1999, 18 electric utilities petitioned the Vermont Public Service Board requesting the board to alter, modify and construe existing power purchase agreements, including the one power purchase contract held by the Fund. The independent power producers affected by the petition, including the Fund, are aggressively opposing the utilities' position before the board.

New Jersey

In the late 1970's, with an energy crisis emerging, the federal government enacted the Public Utility Regulatory Policies Act. This government legislation was intended to encourage private power producers to develop generating facilities using renewable energy (for example, small hydro). Under the new PURPA regulation, the Federal Energy Regulatory Commission was allowed to implement its own directives to ensure utilities purchase energy under long term contracts produced by PURPA "Qualifying Facilities". In 1981 and 1983 the New Jersey Board of Public Utilities ordered the PURPA be executed, which in turn authorized State utilities and Qualifying Facilities to negotiate long term contracts.

In 1992, the federal Energy Policy Act was passed, which brought competition to the wholesale electric marketplace. This legislation bestowed upon the FERC the authorization to ensure fair competition, more specifically open access, non-discriminatory transmission and access to information in the wholesale marketplace. In the early 1990's, 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.

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 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. Currently, while still under bankruptcy protection, Pacific Gas and Electric Company is profitable and is paying its obligations.

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. Over 30 utilities in the United States now offer their customers Green Power at a premium price. 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 will 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. Natural Resources Canada has announced that the Green Power Procurement program is one of several initiatives that form a new federal strategy on renewable energy.

Studies prepared for IPPSO and the Fund by an independent consultant found that for existing generating assets, small hydroelectric generating facilities are the lowest cost producer compared to all other forms of generating sources. This is due to such facilities having the lowest fuel, maintenance, capital addition, operating and environmental costs. For new generation, small hydroelectric is the lowest cost producer, after industrial co-generation, in relation to total costs and the lowest cost producer with respect to variable production costs. Hydroelectric generating facilities have a long useful operating life and many facilities over 80 years old continue to operate reliably today.

Deregulation and competition will expand the existing market for electricity for generators that can compete at market rates.

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. Reference is made to "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, 2001. 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 25 employees who are involved in the operation of the hydroelectric facilities. In addition, Algonquin Power and Power Systems currently have approximately 125 employees who may in the course of their duties perform duties which would customarily be performed by employees of the Fund. Labour relations have been stable to date and there has not been any disruption in operations as a result of labour disputes with employees. These employees are non-unionized.

Foreign Operations

For 2001, 35% of the gross revenue of the Fund was generated in the United States. The Fund had interests in 30 facilities located in the United States, including two 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 licensed to the Fund by Algonquin Power under a non-exclusive, royalty-free trademark licence agreement (the "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 nine 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 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.

Customers

The Fund Businesses derive their revenues from the sale of electricity to large utilities. For the twelve months ended December 31, 2001, the Fund Businesses' revenues were derived as follows: Niagara Mohawk - approximately 10% Ontario Electricity Financial Corporation - approximately 19%; Hydro Québec - approximately 38%; PSNH - approximately 23%; and others - approximately 10%.

Reorganization

In 2001, the Fund caused certain of its indirect subsidiaries to be wound up into other Fund entities and caused Algonquin Canada to amalgamate with certain other indirect subsidiaries of the Fund, so as to streamline the corporate structure of the Fund and reduce administrative expenses.

SELECTED FINANCIAL INFORMATION

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

	Three months ended March 31, 1999	Three months ended June 30, 1999	Three months ended September 30, 1999	Three months ended December 31, 1999	Year ended December 31, 1999
(thousands of dollars, except for per Trust Unit amounts)					
Operating Revenue	3,510	4,004	3,944	8,096	19,604
Operating Expenses	2,028	1,748	2,197	4,899	10,872
Interest Expense	98	100	503	809	1,510
Income Taxes	0	0	0	13	13
Net Income	1,384	2,156	1,294	2,375	7,209
Net Income per Trust Unit	0.10	0.11	0.06	0.10	0.37
Total Assets	133,136	213,497	236,381	325,988	325,988
Total Long Term Debt	4,224	3,782	30,714	83,985	83,985
Distributions per Trust Unit	0.240	0.200	0.220	0.240	0.900

	Three months ended March 31, 2000	Three months ended June 30, 2000	Three months ended September 30, 2000	Three months ended December 31, 2000	Year ended December 31, 2000
(thousands of dollars, except for per Trust Unit amounts)					
Operating Revenue	12,710	14,260	8,929	10,794	46,693
Operating Expenses	6,081	6,022	5,544	5,109	22,756
Interest Expense	2,294	2,234	2,286	2,133	8,947
Income Taxes	635	234	(103)	860	1,626
Net Income	3,700	5,770	1,202	2,692	13,364
Net Income per Trust Unit	0.15	0.24	0.05	0.10	0.54
Total Assets	321,759	319,502	343,020	328,502	328,502
Total Long Term Debt	83,780	82,659	84,365	74,115	74,115

Distributions per Trust Unit	0.2425	0.2425	0.2425	0.2425	0.97
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	Three months ended March 31, 2001	Three months ended June 30, 2001	Three months ended September 30, 2001	Three months ended December 31, 2001	Year ended December 31, 2001
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(thousands of dollars, except for per Trust Unit amounts)

Operating Revenue	10,501	12,894	8,064	13,511	44,969
Operating Expenses	5,399	6,378	7,405	7,125	26,307
Interest Expense	2,111	1,904	1,447	1,238	6,700
Income Taxes	(845)	593	(2,595)	3,084	237
Net Income	3,836	(2,498)	1,807	3,719	6,864
Net Income per Trust Unit	0.12	(0.08)	0.05	0.09	0.17
Total Assets	400,583	367,398	435,527	512,384	512,384
Total Long Term Debt	73,875	51,796	51,787	52,075	52,075
Distributions per Trust Unit	0.23	0.23	0.23	0.23	0.92

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 interest, royalty and dividend income, taxable deemed dividends, lease payments or other income from the Leases received by the Fund in the year less: (i) administrative expenses of the Fund; (ii) amounts which may be paid by the Fund in connection with any cash redemptions of Trust Units; (iii) amounts required for the business and operations of the Fund, including amounts required to pay the deferred portion of the purchase price for any assets acquired by the Fund, directly or indirectly; and (iv) capitalized interest with respect to any notes held by the Fund. Any income of the Fund which is applied to any cash redemptions of Trust Units or is otherwise unavailable for cash distribution will be distributed to Unitholders in the form of additional Trust Units. 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, on December 31 of each year, Unitholders will be entitled to receive a distribution of the amount, if any, by which the income of the Fund including any net capital gains for purposes of the Tax Act in respect of the year (calculated without reference to paragraph 82(1)(b) and to subsection 104(6) of the Tax Act) less any deductible non-capital or capital losses of prior years exceeds all amounts otherwise distributed or made payable in respect of the year.

The Trustees declared and made annual distributions totalling \$37,302,000 during 2001. Such amounts were broken down into four quarterly payments based upon anticipated Distributable Cash flows of the Fund for that quarter. The Trustees of the Fund have determined to have the Fund make distributions monthly and not quarterly. The Fund will include in its monthly distributions cash dividends, distributions or returns of capital, if any, received from Fund Businesses. Monthly distributions are due and payable 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

Management's Discussion and Analysis of Financial Condition and Results of Operations

The Fund is a publicly traded Canadian income fund and an active consolidator of generating and infrastructure facilities in Canada and the United States. Market capitalization has grown from \$80 million in 1997 to \$529 million in 2001 as a result of its acquisition strategy. At December 31, 2001, the Fund had 50,875,772 trust units issued and outstanding and has interests directly or indirectly in 59 generating and wastewater treatment facilities.

Significant Transactions

2001 was a very active year for the Fund as it completed three public offerings and raised gross proceeds of approximately \$235 million by issuing 23.9 million Trust Units. The net proceeds from the public offerings were used to pay down debt and to acquire investment interests which helped the Fund diversify its portfolio to include interests in alternative fuel generating assets, natural gas co-generating assets and infrastructure assets in addition to its hydroelectric generating facilities.

The Fund acquired interests in seven additional hydroelectric generating facilities to increase geographic diversification. The seven acquired facilities have a total installed capacity of 25.6 megawatts. The facilities acquired are located in Ontario (1), Québec (1), Alberta (1), New York (3) and Vermont (1).

The Fund initiated its diversification strategy to mitigate the impact of recent drought and drought-like conditions and low power purchase rates in the New York region by acquiring interests in three alternative fuel (biomass-fired) generating facilities with a total installed capacity of 67 MW. The acquisition of investment interests in three natural gas-fired co-generation facilities with a total installed capacity of 290 MW further expanded the Fund's diversification.

The Fund's diversification strategy also included infrastructure facilities. Two wastewater treatment facilities in Arizona with a combined base of 4,500 customers were acquired during 2001.

During the fourth quarter of 2001, the Fund entered into a loan arrangement with KMS Power Income Fund. KMS is a publicly traded income fund which owns one energy-from-waste generating facility in Ontario, one bio-gas-fired generating facility in Illinois and two natural gas-fired co-generation facilities in New Jersey and Illinois. The Fund advanced \$35.0 million to KMS.

Operating Results

For the year ended December 31, 2001, the Fund reported total revenues of \$45.0 million compared to \$46.7 million reported for 2000. 2001 earnings before loan repayment fees were \$13.6 million, consistent with 2000. Net earnings for 2001 were \$6.9 million compared to \$13.4 million in 2000. 2001 net earnings per Trust Unit were \$0.17 compared to \$0.54 in 2000.

Energy sales reported were \$37.3 million compared to \$44.0 million in 2000, a decline of 15%. The decline resulted from poor hydrologic conditions in the Fund's major regions and the fact that six hydroelectric facilities in New York State reverted to low current market rates at the beginning of the year. The decline in revenue was partially offset by the acquisition of interests in seven hydroelectric and one biomass-fired generating facilities during 2001 which contributed \$3.8 million. Incremental

revenue from the three generating facilities acquired during 2000 contributed \$1.8 million. The chart below highlights energy revenues by region. The Fund also added \$2.5 million of wastewater treatment revenues as a result of the acquisition of two facilities in Arizona.

	(in thousands of dollars)	
	2001	2000
Consolidated energy sales		
United States sites		
New York	4,945	11,325
New England	8,076	10,110
Subtotal	13,021	21,435
Canadian sites		
Quebec	14,733	15,100
Ontario	7,421	7,461
Alberta	2,115	
Subtotal	24,269	22,561
Total energy sales	37,290	43,996

Interest and dividend income totaled \$5.2 million compared to \$2.7 million in 2000, a 91% increase due to the addition of certain debt and participation interests and the Fund being in a positive cash position throughout the year due to the proceeds from the public offerings, partially offset by lower net revenues at the hydroelectric generating facilities accounted for on an equity basis. The Fund also earned \$2.0 million from holding cash balances during the year.

2001 operating expenses increased by \$2.2 million over 2000 to \$14.8 million due to the addition of interests in eight facilities during 2001. Amortization costs were higher than the prior year due to the addition of more facilities during the year.

Overall administrative costs decreased during 2001 compared to 2000. Management fees were lower in 2001 as compared to 2000 because the Fund directly hired an employee from the Manager who is performing the daily accounting functions, causing the Manager's fee to be reduced and administrative expenses to increase by an equivalent amount. Administrative expenses were reduced during 2001 as a result of lower tax assessments in New York State.

During 2001, the Fund repaid the outstanding loan on the Cote Ste Catherine facility (\$28.7 million, including a prepayment fee of \$6.8 million) to reduce debt and avoid future high rate interest expense. As a result, the Fund incurred a \$6.8 million prepayment charge against current year earnings. Proceeds from the public offering at the beginning of the year were utilized for the prepayment.

During the fourth quarter, the owner of the biomass generating facility in Alberta repaid its debt outstanding to a Fund entity along with a net prepayment fee of \$1.9 million. The net prepayment fee was recognized in income.

The Fund recorded total interest expense during 2001 of \$6.7 million, a reduction of \$2.2 million from 2000 as a result of the elimination of the Cote Ste Catherine debt. Currently, interest expense primarily represents project debt.

Operating cash flow before working capital adjustments during 2001 was \$22.2 million compared to \$23.2 million in 2000. Net earnings before the loan prepayment fee were consistent with 2000. Distributions to Unitholders increased by \$12.5 million to \$37.3 million during 2001 as a result of additional Trust Units issued.

Liquidity and Capital Reserves

As at December 31, 2001, the Fund had positive net working capital of \$19.0 million compared to \$2.0 million in 2000. At the end of 2001, the Fund had \$31.7 million of cash and cash equivalents. The excess of funds not distributed to Unitholders will be invested by the Fund in revenue-producing assets in due course.

Long-term liabilities at December 31, 2001 were \$52.1 million compared to \$74.1 million in 2000. These long-term liabilities primarily represent the non-recourse project debt at the Long Sault Rapids Facility and the Glenford Facility. The project debt relating to the Côte Ste-Catherine Facility was paid during the year.

Risk Management

Due to the Fund's ownership of hydroelectric generating and infrastructure facilities in the United States, the Fund's results from operations are affected by the exchange rate between the Canadian and US dollar. The Fund has attempted to reduce the impact of exchange rate fluctuations by agreeing to pay certain of its obligations in US dollars. The management fees payable to the Manager and the operations supervisory fees payable to Power Systems are in US dollars. As well, the principal payments on certain promissory notes are payable in US dollars. Together, this has the effect of transferring much of the foreign exchange risk out of the Fund.

On an annual basis, the Fund utilizes currency options as required to hedge distributions and protect a minimum downside position. At the end of 2001, the Fund had no foreign exchange hedges in place.

At the beginning of 2001, six facilities in New York State reverted to current market rates either due to the expiry of the power purchase agreements or contract stipulations, exposing the Fund to fluctuating market rates. The Fund intends to enter into longer term power purchase agreements with respect to these facilities at the appropriate time.

Outlook

2001 was a year of diversification for the Fund, as the Trustees and the Manager focused on broadening the Fund's investment portfolio to enhance the stability and sustainability of cash flows to Unitholders. During 2001, the Fund added interests in alternative fuel (biomass-fired) generating facilities, natural gas co-generation facilities and wastewater treatment facilities. At the end of 2001 the Fund's asset portfolio based on initial investment values was composed of investment interests in hydroelectric generating facilities (71%), natural gas co-generating facilities (12%), alternative fuel (biomass-fired) generating facilities (13%) and wastewater treatment infrastructure facilities (4%).

The Fund will continue to consider investment opportunities which provide stable cash flow from generating and infrastructure facilities. Potential investment candidates could include co-generation and alternative fuel powered generating stations or wastewater treatment facilities within a regulated utility. Opportunities which provide long-term, statistically predictable future cash flows whose risk profile is generally consistent with the existing portfolio of hydroelectric generating assets will be considered. All investment opportunities will continue to be required to meet the Fund's Acquisition Guidelines established by the Trustees. These guidelines provide that all acquisitions must be expected to result in an increase in Distributable Cash per Trust Unit.

The Fund will continue to grow through a combination of issuing units, raising capital and utilizing its line of credit. During the first quarter of 2002, the Fund has entered into an agreement with a major Canadian bank to increase its current line of credit from \$50.0 million to \$100.0 million.

At the beginning of March 2002, Algonquin Power Trust completed the acquisition of approximately 86.7% of the outstanding trust units and approximately 47.3% of the outstanding convertible debentures of KMS Power Income Fund. The offer consisted of the exchange of each KMS trust unit for 0.7428 Trust Units and each \$100 of KMS convertible debentures for 10.34 Trust Units. This transaction resulted in the Fund issuing a total of 6,099,557 Trust Units. Algonquin Power Trust intends to exercise its rights under KMS' trust declaration and effect a subsequent acquisition transaction so as to acquire the remaining KMS trust units not tendered under the offer. This will result in the Fund issuing an additional 713,616 Trust Units.

Recently Issued Accounting Standards

During 2001, the Canadian Institute of Chartered Accountants ("CICA") issued new Handbook Sections 1581, "Business Combinations" ("Section 1581") and Handbook Section 3062, "Goodwill and Other Intangible Assets" ("Section 3062"). Section 1581 requires that the purchase method of accounting be used for all business combinations. Section 1581 specifies criteria that intangible assets acquired in a business combination must meet to be recognized and reported separately from goodwill. Section 3062 will require that goodwill and intangible assets with indefinite useful lives no longer be amortized, but instead tested for impairment at least annually by comparing carrying value to the respective fair value in accordance with the provisions of Section 3062. Section 3062 also requires that intangible assets with estimable useful lives be amortized over their respective estimated useful lives to their estimated residual values, and reviewed for impairment by assessing the recoverability of the carrying value. The Fund adopted the provisions of Section 1581 as of July 1, 2001 and Section 3062 is effective January 1, 2002.

Also in 2001, the CICA amended Handbook Section 1650, "Foreign Currency Translation" ("Section 1650") and issued Accounting Guideline 13, "Hedging Relationships" ("AcG 13"). The revision to Section 1650 eliminates the deferral and amortization of foreign currency translation differences resulting from the translation of long-term monetary assets and liabilities denominated in foreign currencies. All such translation differences will be charged directly to income. Section 1650 will be in effect as of January 1, 2002. Accounting Guideline 13 establishes new criteria for hedge accounting and will apply to all hedging relationships in effect on or after January 1, 2003.

In December 2001, Handbook Section 3870, Stock-based Compensation and Other Stock-based Payments ("Section 3870") was issued. Section 3870 establishes standards for the recognition, measurement and disclosure of stock-based compensation and other stock-based payments made in

exchange for goods and services provided by employees and non-employees. It applies to transactions in which shares of common stock, stock options or other equity instruments are granted or liabilities incurred based on the price of common stock or other equity instruments. Section 3870 sets out a fair value based method of accounting that is required for certain, but not all, stock-based transactions.

The Fund does not believe that the adoption of these standards will have a material impact on the Fund's financial condition or results of operations and anticipates no transitional impact to the historic financial statements from adoption of these standards.

Quarterly Financial Information

The following is a summary of unaudited quarterly financial information for the two years ended December 31, 2001.

(\$ millions except per Trust Unit amounts)

2001	1st Qtr	2nd Qtr	3rd Qtr	4th Qtr	Total
Revenues	10.50	12.90	8.10	13.50	45.00
Net earnings (loss)	3.80	(2.50)	1.80	3.80	6.90
Net earnings per Trust Unit	0.11	(0.08)	0.05	0.09	0.17
2000					
Revenues	12.60	14.10	8.80	11.20	46.70
Net earnings	3.70	5.80	1.20	2.70	13.40
Net earnings per Trust Unit	0.15	0.24	0.05	0.10	0.54

CANADIAN FEDERAL INCOME TAX CONSIDERATIONS

In the opinion of Blake, Cassels & Graydon LLP, counsel to the Fund ("Counsel"), 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 (the “Proposed Amendments”), certificates of the Fund, Algonquin Canada, Algonquin Power and others as to certain factual matters and Counsel’s understanding of the current published administrative and assessing policies of the Canada Customs and Revenue Agency (“CCRA”). This summary is also based on the assumption that the Fund will at all times comply with the Declaration of Trust.

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 or assessing policies of CCRA, 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.

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. 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, 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.

If the Fund ceases to qualify as a mutual fund trust, the Fund may be required to pay a tax under Part X.2 or Part XII.2 of the Tax Act. The payment of Part XII.2 tax by the Fund may have adverse income tax consequences for certain Unitholders, including non-resident persons.

The Fund has been registered by CCRA as a registered investment for purposes of the Tax Act. Accordingly, the Fund may be subject to a special tax under Part XI of the Tax Act if it acquires or holds foreign property in excess of the limits provided in the Tax Act, or enters into certain agreements to acquire shares of a corporation at a price that may differ from the fair market value of the shares at the time of acquisition. Counsel has been advised by the Fund that it does not expect to make excessive investments in foreign property or enter into any such agreements, and accordingly the Fund should not be subject to tax under Part XI of the Tax Act.

Taxation of the Fund

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. Counsel can express no opinion with respect to matters of fact, such as the reasonableness of expenses or the accuracy of capital costs. The Rawdon Facility Equipment, the Donnacona Facility Equipment, the Ste-Brigitte Facility Equipment and the Belleterre Facility Equipment are currently leasing properties and specified energy property of the Fund and, accordingly, capital cost allowance claimed in respect thereof is currently deductible by the Fund only to the extent of the Fund's income from such property (determined without reference to paragraph 20(1)(a) of the Tax Act). 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 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, income of the Fund may be used to finance cash redemptions of Trust Units and accordingly such income so utilized will not be payable to holders of the Trust Units by way of cash distributions but rather will 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 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, 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 income 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 the full amount available for deduction in each year to the extent of its taxable income for the year otherwise determined. Therefore, as a result of such deduction from income and the Fund's entitlement to a capital gains refund within the meaning of the Tax Act, 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. However, Counsel can provide no opinion in this regard.

Taxation of the Unitholders

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 a 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. Such amounts will also be taken into account in determining the Unitholder's liability, if any, for alternative minimum tax under the Tax Act.

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.

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 amount that is paid or made payable in a year out of the income or capital gains of the Fund for the year or any amount that is payable by the Fund which must otherwise be included in the Unitholder's income).

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. 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. Subject to certain specific rules in the Tax Act (including certain transitional provisions therein), 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 excluding, in the case of a Fund Note, any accrued interest thereon. 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.

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. Where, at the end of a month, a Plan holds Trust Units or other properties that are not qualified investments, the Plan may, in respect of that month, be required to pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Trust Units or other properties at the time such Trust Units or other properties were acquired by the Plan. In addition, where a trust governed by an RRSP (or an RRIF) holds (or acquires, respectively) Trust Units or other properties that are not qualified investments, the trust will become taxable on income attributable to the Trust Units or other properties while they are not qualified investments. Where a trust governed by an RESP acquires or holds Trust Units or other properties that are not qualified investments, the Plan may become revocable and its registration may be revoked by the Minister of National Revenue. Where a trust is governed by a DPSP and acquires property that is not a qualified investment, the trust will be required to pay a tax equal to the fair market value of the property at the time of its acquisition. Where a trust governed by an RRSP or RRIF acquires property that is not a qualified investment the annuitant under the RRSP or RRIF will be required to include the fair market value of such property in income for tax purposes.

Under the Tax Act, trusts governed by RRSPs, RRIFs, DPSPs, registered pension plans, registered investments and certain other entities are subject to a special tax under Part XI of the Tax Act in respect of investments in foreign property in excess of limits specified within the Tax Act. Provided the Fund continues to be a registered investment for purposes of the Tax Act, Counsel is of the opinion that the Trust Units will not, at the time of their issue pursuant hereto, constitute foreign property for Plans, registered pension plans or other persons subject to tax under Part XI of the Tax Act.

If the Trust Units are acquired by a Unitholder at a time when they are not foreign property and subsequently Trust Units become foreign property, such Trust Units will not be treated as "foreign property" of such Unitholder for the 24 month period commencing at the beginning of the month in which they became foreign property. Unitholders are advised to consult with their own tax advisors in this regard.

ELIGIBILITY FOR INVESTMENT

In the opinion of Blake, Cassels & Graydon LLP ("Counsel") 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)
an Act respecting insurance (Québec) (in respect of insurers other than guarantee fund corporations, mutual associations and professional corporations)
Trust and Loan Companies Act (Canada)
Loan and Trust Corporations Act (Alberta)

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)

Pension Benefits Standards Act, 1985 (Canada)

Pension Benefits Act (Ontario)

Supplemental Pension Plans Act (Québec)

Financial Institutions Act (British Columbia)

Pension Benefit Standards Act (British Columbia)

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 and will not constitute foreign property for trusts governed by RRSPs, RRIFs, DPSPs or other entities subject to Part XI of the Tax Act. The Trust Units will not be prohibited investments for registered pension plans, so long as the Fund is not (i) an employer who participates in such a registered pension plan; (ii) a person connected with such an employer; (iii) a person that controls, directly or indirectly, in any manner whatever, such an employer or connected person; or (iv) a person that does not deal at arm’s length with a member of such a registered pension plan or with any persons or partnerships described in (i), (ii) or (iii) above, each for purposes of the Tax Act. See “Canadian Federal Income Tax Considerations” for additional comments. Trusts governed by RESPs are not subject to restrictions on their holdings of foreign property under the Tax Act.

MARKET FOR SECURITIES

The Trust Units have been listed and posted for trading on the Toronto Stock Exchange since December 23, 1997 under the symbol “APF.UN”.

TRUSTEES OF THE FUND

The following table sets forth certain information with respect to the Trustees of the Fund. The Fund has no officers.

Name and Municipality of Residence	Principal Occupation
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GEORGE L. STEEVES Markham, Ontario	Energy Consultant.
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KENNETH MOORE Toronto, Ontario	Managing Partner, Newpoint Capital Partners Inc., an investment banking firm.
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R. IAN BRADLEY Mississauga, Ontario	President and Chief Executive Officer, Grand Toys International Inc., a toy company.
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All of the Trustees have served in such capacity since September 8, 1997, with the exception of Mr. Moore, who became a Trustee on December 18, 1998. 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.

Approximately 0.2% of the Trust Units are beneficially owned, directly or indirectly, by the Trustees of the Fund and the directors and senior officers of the Manager, as a group.

The Fund does not have an executive committee of the Trustees. The Fund is required to have an audit committee. Messrs. Steeves, Moore and Bradley are members of the audit committee.

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.

Name and Municipality of Residence	Office	Principal Occupation
CHRISTOPHER K. JARRATT Oakville, Ontario	Chief Executive Officer and Director of the Manager and Director of Powers Systems	Principal of Algonquin Power
IAN E. ROBERTSON Oakville, Ontario	Director of the Manager and of Power Systems	Principal of Algonquin Power
JOHN M.H. HUXLEY Toronto, Ontario	Director of the Manager and of Power Systems	Principal of Algonquin Power
DAVID C. KERR Toronto, Ontario	Director of the Manager and Secretary and Director of Power Systems	Principal of Algonquin Power
PETER KAMPIAN Cambridge, Ontario	Chief Financial Officer of the Manager and of Power Systems	Chief Financial Officer of Algonquin Power
ROBERT DODDS Mississauga, Ontario	President of Power Systems	President of Power Systems

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.

Investment Eligibility

The Fund will endeavour to ensure that the Trust Units continue to be qualified investments for trusts governed by RRSPs, RRIFs, DPSPs and, under the Proposed Amendments, RESPs (collectively, the “Plans”), under the Tax Act and will not be “foreign property” to such Plans. If the Fund ceases to qualify as a mutual fund trust, the Trust Units will cease to be qualified investments for the Plans. Where, at the end of any month, a Plan holds Trust Units that are not qualified investments, the Plan must, in respect of that month, pay a tax under Part XI.1 of the Tax Act equal to 1% of the fair market value of the Trust Units at the time Trust Units were acquired by the Plan. The annuitant under a Plan could also be subject to penalty taxes in such a case. 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. There can be no assurance that income tax laws and the treatment of mutual fund trusts will not be changed in a manner which adversely affects Unitholders (see also “Canadian Federal Income Tax Considerations”).

Dependence upon Fund Businesses

The Fund will be entirely dependent upon the operations and assets of the Fund Businesses. Accordingly, distributions to Unitholders will be 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.

Completion of Acquisitions

In any additional offerings, the Manager intends to utilize the net proceeds from the additional offering (the “Net Proceeds”) 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.

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 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.

In the United States, FERC issues licences for the construction, operation and maintenance of generating facilities. Facilities are required to be licensed 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 licensed facility and could adversely affect Distributable Cash.

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.

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.

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 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.

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 Peel Facility, employees of the Fund Businesses and their material subcontractors are non-unionized. The Peel Facility is unionized and a new collective bargaining agreement is currently being negotiated. In the event of a strike or lock-out, the ability of Fund Businesses to generate Distributable Cash may be impaired.

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.

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 would decline.

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.

Unitholder Limited Liability

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.

The operations of the Fund will be conducted, upon the advice of counsel, in such a way and in such jurisdictions so as to avoid as far as reasonably possible any material risk of liability on the Unitholders for claims against 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.

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.

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

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.

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.

Revolving Credit Facility

The Fund has negotiated a \$100 million revolving credit facility with a major Canadian bank, which will mature April 26, 2004. Under the terms of the revolving credit facility, the Fund may acquire generating facilities and infrastructure assets that meet the Fund's acquisition guidelines. At December 31, 2001, no amounts were outstanding under the facility, with the exception of certain letters of

guarantee totalling \$4.2 million, posted as security. The terms of the credit agreement require the Fund to pay a standby charge of 0.425% 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.

Tax Related Risks

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. 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 Revenue Canada will agree. If Revenue Canada successfully challenges the deductibility of such expenses or the correctness of such cost amounts, the return to Unitholders may be adversely affected.

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 prospectus dated October 11, 2001 and the Fund's information circular for the annual and special meeting of Unitholders to be held on May 23, 2002. Additional financial information is provided in the Fund's financial statements for the year ended December 31, 2001. 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.

SCHEDULE A GLOSSARY

In this Annual Information Form, unless the context otherwise requires:

"**Administration Agreement**" means the agreement between the Manager and the Fund dated December 23, 1997, pursuant to which the Manager provides administrative services to the Fund;

"**Advance Payment Account**" means a provision in the power purchase agreements between Niagara Mohawk and Trafalgar in respect of the Kayuta Lake facility and the Adams facility which tracks the amounts paid to Trafalgar from these two facilities which is either above or below Niagara Mohawk's actual Avoided Costs. Payments to Trafalgar above the Avoided Costs results in a positive balance to the account and a payment below the Avoided Costs results in a negative balance to the account. At the end of the contract period, a positive balance results in Trafalgar owing Niagara Mohawk the balance and a negative balance results in Niagara Mohawk owing Trafalgar the balance;

"**affiliate**" means an affiliate within the meaning of the *Securities Act* (Ontario);

"**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 LSR Companies**" means Algonquin Power (Long Sault) Corporation Inc., an Ontario corporation, and Energy Acquisition (Long Sault) Ltd., an Ontario corporation;

"**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 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;

"**Arthurville Facility**" means a 650 kilowatt hydroelectric generating facility located on the Du Sud River near Saint-Raphaël-de-Bellechasse, approximately 40 kilometers east of Québec City;

"**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 Winnepesaukee 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;

"**Belleterre Facility**" means the 2,200 kilowatt hydroelectric generating facility located on the Winneway River, in the Municipality of Laforce, Québec and which is owned by Algonquin Canada;

"**Belleterre Facility Equipment**" means the equipment relating to the Belleterre Facility and related personal property, but does not include the real property on which the equipment is located or any other immovables;

"**Belleterre Facility Lease**" means the lease agreement dated February 3, 1998 pursuant to which the Fund leases the Belleterre Facility Equipment to Algonquin Canada;

"**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;

"**Brooklyn Facility**" means a 23.8 MW biomass-fired electric generating facility located in Queen's County, Nova Scotia;

"**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;

"**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;

"**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 kilometers north of Campbellford, Ontario;

"**Canada 1999 Note**" means the 11% secured, subordinated note due on June 30, 2039 of Algonquin Canada in the original principal amount of approximately \$7.3 million issued by Algonquin Canada to the Fund on May 4, 1999;

"**Canada 2001 Note**" means the 9% secured, subordinated note due on March 16, 2041 in the original principal amount of approximately \$13.9 million and due on March 21, 2041 in the additional original principal amount of approximately \$11.6 million, issued by Algonquin Canada to the Fund;

"**Cardinal Facility**" means a 150 MW combined cycle co-generation facility fuelled by natural gas located in Cardinal, Ontario;

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

"**Clement Dam Facility**" means the 2,400 kilowatt hydroelectric generating facility located on the Winnepesaukee River near the Town of Tilton, New Hampshire;

“**Cochrane Facility**” means a 35.8 MW combined cycle co-generation facility located in Cochrane, Ontario;

"**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 11,120 kilowatt hydroelectric generating facility located on the St. Lawrence River near Montreal, Québec, which facility was constructed in three separate phases commissioned in 1989, 1993 and 1996, respectively;

"**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 kilometers west of the Town of Innisfail, Alberta;

"**Distributable Cash**" means all amounts received by the Fund in respect of dividends, distributions or return of capital on the Algonquin Canada Shares and interest or repayment of principal on the Fund Notes, lease payments pursuant to the Leases, payments pursuant to the LSR Royalty Interests, plus the income, if any, from other permitted investments, less amounts that may be paid by the Fund in connection with any cash redemptions of Trust Units, capitalized interest with respect to the Fund Notes and amounts reasonably required for the business and operations of the Fund;

"**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 Facility Equipment**" means certain equipment relating to the Donnacona Facility and related personal property, but does not include the real property on which the equipment is located or any other immovables;

"**Donnacona Facility Lease**" means the lease agreement dated November 30, 1997 pursuant to which the Fund leases the Donnacona Facility Equipment to 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;

“**Drayton Valley Facility**” means the 12 MW biomass-fired generating facility located in the Town of Drayton Valley, Alberta;

"Extraordinary Resolution" means a resolution passed by a majority of not less than $66\frac{2}{3}\%$ 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 $66\frac{2}{3}\%$ 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 Federal Energy Regulatory Commission;

"Franklin Facility" means the 1,820 kilowatt hydroelectric generating facility located on the Winnepesaukee River near the Town of Franklin, New Hampshire;

"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 and notes of the Algonquin Power Trust, the Fund Notes, the Lease Payment Rights, the LSR Royalty Interests and any other securities or assets held directly or indirectly by the Fund from time to time;

"Fund Businesses" means the businesses carried on by Algonquin Holdco, Algonquin Canada, Algonquin Power Trust, Algonquin America, Algonquin America Holdco, Donnacona Holdco, the Donnacona Partnership, the Nicholls LSR Companies, the Algonquin LSR Companies, the Co-Owners, the HDI Partnership, the Glenford Partnership, the Rattle Brook Partnership, the Avery Dam Partnership, the Burt Dam Partnership, the Hadley Falls Partnership, the HDI III Partnership, the Hollow Dam Partnership, the Lakeport Corporation, the Moretown Partnership, Clement Dam Hydroelectric LLC, Algonquin Power (Mont-Laurier) Limited Partnership, Gregg Falls Hydroelectric Associates Limited Partnership, Pembroke Hydro Associates Limited Partnership, SFR Hydro Corporation, Mine Falls Limited Partnership, Great Falls Hydroelectric Company, Great Falls Energy, L.L.C., Tug Hill Energy, Inc., Worcester Hydro Company, Inc., Oswego Hydro Partners, L.P., CSI Oswego Corp., Oswego Energy Corp., Court Street Investments, Inc., Oswego Power Company, Inc., Algonquin Water Resources of America, Inc., Black Mountain Sewer Corporation, Gold Canyon Sewer Company, Drayton Valley Power Income Fund, KMS Power Income Fund, KMS Peel Inc., KMS America, Inc., KMS Crossroads, Inc., KMS Joliet Power Partners, L.P., KMS Bakery Power Partners, L.P., Peel Resource Recovery Operations Inc., Sanger Power, L.L.C., 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 Notes" means any notes issued by Algonquin Power Trust to the Fund, the Canada 1999 Note, the US 1999 Note (No. 2), the US 2000 Note, the Canada 2001 Note, the LSR Subordinate Note and the Trafalgar Class B Note;

"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 Note**" means the 8.5% secured, subordinated note due July 1, 2023 of Algonquin Power 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 \$6.1 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;

"**Governance Agreement**" means the agreement entered into on December 23, 1997 between the Fund, the Manager, Algonquin Canada and Algonquin America dealing with the composition of the board of directors of 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;

"**Gregg Falls Facility**" means the 3,500 kilowatt hydroelectric generating facility located at the Piscataquog River near the Town of Goffstown, New Hampshire;

"**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;

"**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;

"**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;

"**Hydraska Facility**" means the 2,250 kilowatt hydroelectric generating facility located on the Yamaska River near the Town of Ste-Hyacinthe, Québec;

"**Hydro Snemo Facility**" means the 2,600 kilowatt hydroelectric generating facility located on the Rivière-du-Loup near the Town of Rivière-du-Loup, Québec;

"**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;

"**Kings Falls Facility**" means a 1,750 kilowatt hydroelectric generating facility located on the Deer River, near the Town of Copenhagen in Lewis County, New York;

"**Kirkland Lake 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;

"**Lakeport Corporation**" means Lakeport Hydroelectric Corporation, an S Corporation under United States law whose sole shareholder is Algonquin America, and which owns the Lakeport Facility;

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

"**Leases**" means the Donnacona Facility Lease, the Ste-Brigitte Facility Lease and the Belleterre Facility Lease;

"**Lochmere Facility**" means the 1,200 kilowatt hydroelectric generating facility located on the Winnepesaukee River, in the Village of Lochmere, New Hampshire and which facility is owned by the HDI Partnership;

"**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 Algonquin Note**" means the 9% secured, subordinated note due January 1, 2038 of Algonquin Power in the principal amount of approximately \$10.3 million issued to Algonquin Canada on April 17, 1998;

"LSR Brace Royalty Interest" means the cash flows generated by the Long Sault Rapids Facility paid pursuant to an agreement dated November 1, 1989, as amended November 2, 1989, between N-R Power, Nirabro Industries Ltd., Mr. Tim Richardson and Mr. John Brace respecting certain payments to be paid for ten years commencing April 1, 1998, which obligation was assigned by N-R Power to the Co-Owners and which was acquired by the Fund on April 17, 1998;

"LSR McKenzie Royalty Interest" means the cash flows generated by the Long Sault Rapids Facility paid pursuant to an agreement dated September 12, 1994 between N-R Power and Mr. Rodney S. McKenzie respecting payments of \$150,000 per year payable in arrears for a period of 20 years commencing April 1, 1998, which obligation was assigned by N-R Power to the Co-Owners and which was acquired by the Fund on April 17, 1998;

"LSR Nicholls Note" means the 9% secured, subordinated note due January 1, 2038 of N-R Power in the principal amount of approximately \$6.6 million issued to Algonquin Canada on April 17, 1998;

"LSR Richardson Royalty Interest" means the cash flows generated by the Long Sault Rapids Facility paid pursuant to an agreement dated December 11, 1992 between N-R Power and Mr. Tim Richardson respecting payments of \$83,333 per year payable in arrears for a period of six years commencing April 1, 1998, which obligation was assigned by N-R Power to the Co-Owners and which was acquired by the Fund on April 17, 1998;

"LSR Senior Debt" means financing in the principal amount of approximately \$45,000,000 provided jointly and severally to Algonquin Power (Long Sault) Partnership and N-R Power Partnership as co-owners of the Long Sault Rapids Facility by a syndicate of life insurance lenders, with The Clarica Life Insurance Company as one of the lenders and acting as agent for the other lenders;

"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 agreement between the Manager, Algonquin Canada, Algonquin America and certain of the Fund Businesses, entered into on December 23, 1997, as amended, and pursuant to which the Manager or its delegate provides management services to Algonquin Canada and certain other Fund Businesses;

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

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

"megawatt" or **"MW"** means 1,000,000 watts of electrical power;

"Milton Facility" means the 1,335 kilowatt hydroelectric generating facility located on the Salmon River on the Maine-New Hampshire border, approximately 70 km from Manchester, New Hampshire and which is owned by SFR Hydro Corporation;

"**Mine Falls Facility**" means the 3,000 kilowatt hydroelectric generating facility located on the Nashua River near the City of Nashua, New Hampshire and which is owned by the Mine Falls Hydroelectric Limited Partnership;

"**Mont Laurier Facility**" means the 2,725 kilowatt hydroelectric generating facility located on the Rivière-du-Lièvre in the Town of Mont Laurier, Québec;

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

"**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;

"**Newfoundland Development**" means the Rattle Brook Facility;

"**New England Development**" means the Gregg Falls Facility, the Pembroke Facility, the Clement Dam Facility, the Franklin Facility, the Moretown Facility, the Lochmere Facility, the Lower Robertson Facility, the Ashuelot Facility, the Lakeport Facility, the Avery Dam Facility, the Hadley Falls Facility, the Hopkinton Facility, the Milton Facility, the Mine Falls Facility, the Great Falls Facility and the Worcester Facility;

"**Newspring**" means Newspring Water LLC, a partnership formed between Algonquin Power and third parties to manage and operate wastewater treatment facilities in Arizona;

"**New York Development**" means the following hydroelectric generating facilities: Ogdensburg, Forestport, Herkimer, Hollow Dam, Christine Falls, Burt Dam, Cranberry Lake, Kayuta Lake, Adams, Kings Falls, Otter Creek and Phoenix;

"**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**" means N-R Power & Energy Corp., 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;

"**Ontario Development**" means the following hydroelectric generating facilities: Long Sault Rapids, Hurdman Dam, Drag Lake Dam, Burgess Dam and Campbellford;

"Operations Supervisory Agreement" means the agreement between Algonquin Canada and Power Systems entered into on December 23, 1997, as amended, and pursuant to which Power Systems provides operations and supervisory services to certain of the Fund Businesses;

"Otter Creek Facility" means the 530 kilowatt hydroelectric generating facility located on the Otter Creek, near the Town of Craig, New York;

"Peel Facility" means the 10 MW energy from waste generating facility located in the Regional Municipality of Peel, Ontario and which is owned by KMS Peel Inc.;

"Pembroke Facility" means the 2,600 kilowatt hydroelectric generating facility located on the Suncook River near the Town of Pembroke, New Hampshire;

"Phoenix Facility" means the 3,500 kilowatt hydroelectric generating facility located on the Oswego River, in the Town of Phoenix, Onondaga County, New York;

"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;

"Québec Development" means the Côte Ste-Catherine Facility, the Ste-Raphaël Facility, the Mont Laurier Facility, the Hydro Snemo Facility, the Hydraska Facility, the Saint-Alban Facility, the Glenford Facility, the Donnacona Facility, the Ste-Brigitte Facility, the Rawdon Facility, the Belleterre Facility and the Arthurville Facility;

"Rattle Brook Facility" means the 4,000 kilowatt hydroelectric generating facility located on the Rattle Brook, near the Village of Jackson's Arm, Newfoundland and which is owned by the Rattle Brook Partnership;

"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;

"Rawdon Facility Equipment" means the equipment relating to the Rawdon Facility and related personal property, but does not include the real property on which the equipment is located or any other immovables;

"Rawdon Facility Lease" means the lease agreement pursuant to which the Fund leases the Rawdon Facility Equipment to 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;

"**Saint-Alban Transfer Date**" means the date upon which the title of the leasehold interest may be transferred to Algonquin Canada in accordance with the terms of the lease and which is expected to occur on or after May, 2001;

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

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

"**SLI Saint-Alban Note**" means the secured note due on the Saint-Alban Transfer Date of SLI in the principal amount of approximately \$15.0 million issued to a trust company acting on behalf of Algonquin Canada on July 7, 1998;

"**Ste-Brigitte Facility**" means the 4,200 kilowatt hydroelectric generating facility located on the Nicolet River, in the Municipality of Ste-Brigitte-des-Saults, Québec and which is owned by Algonquin Canada;

"**Ste-Brigitte Facility Equipment**" means the equipment relating to the Ste-Brigitte Facility and related personal property, but does not include the real property on which the equipment is located or any other immovables;

"**Ste-Brigitte Facility Lease**" means the lease agreement dated November 30, 1997 pursuant to which the Fund leases the Ste-Brigitte Facility Equipment to Algonquin Canada;

"**Ste-Raphaël Facility**" means the 3,500 kilowatt hydroelectric generating facility located on the Rivière de Sud near Québec City;

"**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;

"**Tax Act**" means the *Income Tax Act* (Canada);

"**Thermal Development**" means the Fund's indirect interests in the Peel Facility, the KMS Joliet facility, the KMS Bakery facility, the KMS Crossroads facility and the Sanger Facility;

"**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 in the principal amount of approximately \$31.9 million (US\$20.2 million) as at December 31, 2001;

"**Trafalgar Companies**" means Trafalgar and Christine Falls Corporation, a New York corporation;

"**Trafalgar Contingency Participation**" means the contingent management fee paid to the operator of the Trafalgar Facilities pursuant to the Trafalgar Operations Contract and the Trafalgar Indenture;

"**Trafalgar Facilities**" means the following hydroelectric generating facilities: Ogdensburg, Forestport, Herkimer, Christine Falls, Cranberry Lake, Kayuta Lake and Adams;

"Trafalgar Indenture" means the collateral trust indenture between the Trafalgar Companies and a security trustee dated July 1, 1988, as amended and restated on January 15, 1996, which governs the terms of the Trafalgar Class B Note, among other things;

"Trafalgar Operating Cashflow" means the cash flows generated from the operation of the Trafalgar Facilities after payment of direct operating costs, including, without limitation, property taxes, supplies and consumables and amounts due to Algonquin Power under the Trafalgar Operations Contract, prior to deduction of amounts payable in respect of the Trafalgar Contingency Participation;

"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 Ogdensburg, Forestport, Herkimer, Christine Falls, Cranberry Lake, Kayuta Lake and Adams facilities;

"Trafalgar Operations Subcontract" means the agreement dated December 23, 1997 between Algonquin Power and Algonquin Canada, pursuant to which Algonquin Canada provides those services to be provided by Algonquin Power in connection with the operation of the Ogdensburg, Forestport, Herkimer, Christine Falls, Cranberry Lake, Kayuta Lake and Adams facilities under the Trafalgar Operations Contract;

"Trust 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;

"Unitholders" means the holders of Trust Units from time to time;

"US 1999 Note (No. 2)" means the 11% secured, subordinated note due June 30, 2039 of Algonquin America in the aggregate principal amount of approximately \$20.3 million (approximately US\$13.2 million) to be issued by Algonquin America to the Fund on December 2, 1999;

"US 2000 Notes" means the 7% secured subordinated note due June 30, 2039 for No. 1 and August 31, 2039 for Nos. 2 and 3 in the aggregate principal amount of \$0.9 million (approximately US \$0.6 million) for No. 1, \$4.9 million (approximately US\$3.3 million) for No. 2 and \$5.4 million (approximately US \$3.7 million) for No. 3 issued by Algonquin America to the Fund on July 7, 2000, September 6, 2000 and September 15, 2000, respectively;

"US/Canada 2001 Note" means the 9.1% secured, subordinated note due March 21, 2041 of Algonquin America in the aggregate principal amount of approximately \$11.6 million (approximately US\$ 7.3 million) issued by Algonquin America to Algonquin Canada on March 21, 2001;

"Wastewater Treatment Development" means the Black Mountain Facility and the Gold Canyon Facility;

"Western Canada Development" means the Dickson Dam Facility and the Drayton Valley Facility; and

"Worcester Facility" means the 180 kilowatt hydroelectric generating facility located on the North Branch of Winnooskie River, in the Town of Worcester, Vermont.