INNERGEX RENEWABLE ENERGY INC.

ANNUAL INFORMATION FORM

For the year ended December 31, 2012

March 28, 2013

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INNERGEX RENEWABLE ENERGY INC.

ANNUAL INFORMATION FORM AS AT DECEMBER 31, 2012

The information set out in this Annual Information Form is stated as at December 31, 2012, unless otherwise specified.

*Unless otherwise indicated or the context otherwise requires, the "**Corporation**" refers to Innergex Renewable Energy Inc. and its subsidiaries. Terms not otherwise defined have the meaning set forth in the "Glossary of Terms" included at the end of this document.*

CAUTIONARY STATEMENT ON FORWARD-LOOKING INFORMATION

This Annual Information Form contains forward-looking information within the meaning of applicable securities laws. All information and statements other than statements of historical facts contained in this Annual Information Form are forward-looking information. Such statements and information may be identified by looking for words such as "about", "approximately", "may", "believes", "expects", "will", "intends", "should", "plan", "predict", "potential", "project", "anticipate", "estimate", "continue" or similar words or the negative thereof or other comparable terminology. Such forward-looking information includes, without limitation, statements with respect to: eventual requests for proposal; the anticipated closing of the Magpie Hydroelectric Facility Acquisition; the execution of definitive agreements and closing of the acquisition of the Kapuskasing Projects, Dokis Project and Sainte-Marguerite Facility and the benefits that may accrue to the Corporation and its shareholders as a consequence of the Magpie Hydroelectric Facility Acquisition and the potential acquisition of the Kapuskasing Projects, Dokis Project and Sainte-Marguerite Facility; the future financial position; power production; growth prospects; construction costs; operational efficiencies; the possibility to secure any proposed expansion of the Corporation's facilities and added stability of cash flows relating to the facilities and projects owned by the Corporation or to be acquired; business strategy and plans, and objectives of or involving the Corporation; capital expenditures and investment programs; access to credit facilities and financing; capital taxes; income taxes; risk profile; cash flows and earnings and the components thereof; future income tax treatment; statements with respect to levels of dividends to be paid to shareholders, dividend policy, and the timing of payment of such dividends. Actual events or results may differ materially.

The forward-looking information is based on certain key expectations and assumptions made by the Corporation, including expectations and assumptions concerning availability of capital resources, satisfaction of all conditions of the anticipated closing of the Magpie Hydroelectric Facility Acquisition, absence of exercise of any termination right, economic and financial conditions, the success obtained in developing new facilities and the performance of operating facilities. Although the Corporation believes that the expectations and assumptions on which such forward-looking information is based are reasonable, undue reliance should not be placed on the forward-looking information since no assurance can be given that they will prove to be correct.

Since forward-looking information addresses future events and conditions, by its very nature it involves inherent risks and uncertainties. Actual results could differ materially from those currently anticipated due to a number of factors. These include, but are not limited to, the ability of the Corporation to execute its strategy, availability of capital resources, liquidity risks related to derivative financial instruments, availability of water flows, wind and sunlight, delays and cost over-runs in the construction and design of projects, health, safety and environmental risks, uncertainty relating to the development of new power generating facilities, obtainments of permits, project performance and penalties, equipment failure, interest rate fluctuations and debt refinancing, contractual restrictions contained in instruments governing current and future indebtedness, declaration of dividends is at the discretion of the Board of Directors, the ability to secure new power purchase agreements, the ability to retain qualified personnel and management, litigation risks, the performance of third-party suppliers, relationships with communities in which projects or facilities are located and joint venture partners, equipment supply, changes to governmental regulatory requirements and applicable governing statutes, securing appropriate land for projects, reliance on power purchase agreements, reliance on transmission systems, water and land rental expenses, assessment of water, wind and sun resources and associated energy production, dam safety, natural disasters and force majeure, foreign exchange fluctuations, sufficiency of insurance coverage, credit ratings that may not reflect actual performance of the Corporation, potential undisclosed liabilities associated with acquisitions, integration of the facilities and projects acquired or to be acquired, failure to realize acquisitions benefits, failure to close the Magpie Hydroelectric Facility Acquisition and the acquisition of the Other Hydromega Hydroelectric Facilities and Development Projects, shared transmission and interconnection infrastructure, introduction to Solar PV power facility operation and revenues from the Miller Creek Facility that vary based on the spot price of electricity and the inability to execute a definitive agreement. Readers are cautioned that the foregoing list is not exhaustive. Readers should carefully review and consider the risk factors described under the section "Risk Factors". The information contained in this Annual Information Form identifies additional factors that could affect the operating results and performance of the Corporation. Prospective investors and current shareholders are urged to carefully consider those factors.

To the extent that any forward-looking information in this Annual Information Form constitutes future-oriented financial information or financial outlooks, within the meaning of securities laws, such information is being provided to inform potential investors and current shareholders of the potential financial impact of development projects if and when they will reach commercial operation, recently announced acquisitions or expected results and may not be appropriate for other purposes. Future-oriented financial information and financial outlooks, as with forward-looking information generally, are, without limitation, based on the assumptions and subject to the risks set out above.

The forward-looking information contained herein is expressly qualified in its entirety by this cautionary statement. The forward-looking information contained herein is made as of the date of this Annual Information Form and the Corporation undertakes no obligation to publicly update such forward-looking information to reflect new information, subsequent or otherwise, unless required by applicable securities laws.

1. CORPORATE STRUCTURE

The Corporation was incorporated in Canada under the *Canada Business Corporations Act* by articles of incorporation dated October 25, 2002. The articles of the Corporation were amended as follows:

Dates	Description of the amendment to the Articles of the Corporation
October 25, 2007	To change its name from Innergex Management Inc. to Innergex Renewable Energy Inc. and its French version, Innergex énergie renouvelable inc.
December 4, 2007	To change the authorized capital of the Corporation and the minimum number of directors of the Corporation from one to three.
December 4, 2007	To amend the authorized share capital of the Corporation and to create an unlimited number of common shares (the "**Common Shares**") and an unlimited number of preferred shares, issuable in series (the "**Preferred Shares**").
March 29, 2010	By way of articles of arrangement filed in connection with the Arrangement (as defined below).
September 9, 2010	To create the Cumulative Rate Reset Preferred Shares, Series A (the "**Series A Shares**") and the Cumulative Floating Rate Preferred Shares, Series B (the "**Series B Shares**") in connection with the Corporation's public offering of Series A Shares.
May 12, 2011	To introduce a voting right, in certain limited circumstances, for holders of Preferred Shares of the Corporation.
January 1, 2012	By way of articles of amalgamation filed in connection with the amalgamation between the Corporation and its subsidiary, Cloudworks Energy Inc.
December 6, 2012	To create the Cumulative Redeemable Fixed Rate Preferred Shares, Series C (the "**Series C Shares**") in connection with the Corporation's public offering of Series C Shares.

The Corporation's head and registered office is located at 1111 Saint-Charles Street West, East Tower, Suite 1255, Longueuil, Québec, J4K 5G4.

A corporate chart of the Corporation and its material subsidiaries as well as certain other material ownership interests of the Corporation is attached hereto as Schedule A, which excludes however subsidiaries of the Corporation for which the assets and revenue in the aggregate did not exceed 20% of the total consolidated assets and revenue of the Corporation as at December 31, 2012.

2. GENERAL DEVELOPMENT OF THE BUSINESS

The Corporation is a developer, owner and operator of run-of-river hydroelectric facilities, wind energy farms and solar photovoltaic ("**PV**") farms in North America. The Corporation operates various renewable power generating facilities in the Provinces of Québec, British Columbia and Ontario and in the State of Idaho.

The Corporation has been active in the renewable power industry since 1990 and has developed and brought to commercial operation 11 hydroelectric facilities, five wind farms and one solar photovoltaïc farm, has acquired and refurbished, through various ventures, three hydroelectric facilities and has acquired eight hydroelectric power facilities representing a gross aggregate installed capacity of 1,031.2 MW. The Corporation currently owns, together with its partners, five wind farms, 22 hydroelectric facilities and one solar photovoltaïc farm in operation with respective net aggregate installed capacities of 224.0 MW (gross 589.5 MW), 319.3 MW (gross 408.5 MW) and 33.2 MW (gross 33.2 MW) and, as of March 28, 2013, 7 development projects for which power purchase agreements ("**PPAs**") have been secured with an aggregate net installed capacity of 189.7 MW (gross 262.5 MW). The development projects for which PPAs have been secured are expected to reach the commercial operation stage between 2013 and 2016. The Corporation has also net interests in approximately 2,900 MW (gross 3,125 MW) of prospective power generating projects, which are in various stages of development. See "Description of the Business and Assets of the Corporation - Portfolio of Assets".

THREE-YEAR SUMMARY

Financial Year 2012

On May 15, 2012, the Corporation began commercial operation of its 33.2 MW_{DC} (27 MW_{AC}) Stardale solar farm, located in East-Hawkesbury, in Ontario, Canada. This marked the Corporation's entry into the solar energy sector, providing further diversification of its operations. See "Description of the Business and Assets of the Corporation - Operating Solar Farms – Stardale Solar Farm".

On July 17, 2012, the Corporation announced that it had exercised a portion of the accordion feature on its revolving term credit facility, increasing its borrowing capacity from $350 million to $425 million. All terms and conditions of the revolving term remain unchanged, including the August 2016 maturity.

On July 17, 2012, Kwoiek Creek Resources Limited Partnership ("**Kwoiek Creek LP**") closed a $168.5 million non-recourse construction and term project financing for the Kwoiek Creek run-of-river hydroelectric project located in British Columbia, Canada (the "**Kwoiek Creek Project**").

On July 20, 2012, the Corporation announced that it had entered into a partnership agreement with the Mi'gmawei Mawiomi for the development of a large wind farm on the Gaspé Peninsula of Québec, Canada which the parties intend to submit if and when an eventual request for proposal would be announced.

On July 26, 2012, the Corporation announced that, pursuant to a purchase agreement dated July 26, 2012, the Corporation agreed to acquire from Hydromega Services Inc ("**Hydromega**") and Magpie Trust a 70% interest in the 40.6 MW Magpie Hydroelectric facility ("**Magpie Facility**"), located in the municipality of Rivière-Saint-Jean and approximately 150 km east of Sept-Îles, Québec, Canada for an aggregate final consideration that will be of $28.4 million, subject to certain adjustments, plus the assumption of approximately $51 million of fixed rate limited recourse project debt (the "**Magpie Hydroelectric Facility Acquisition**").

In addition to the Magpie Hydroelectric Facility Acquisition, the Corporation entered into a non-binding letter of intent dated July 26, 2012 with respect to the proposed acquisition of Hydromega's ownership interest, or of certain Hydromega related entities' ownership interest, in the four hydroelectric Kapuskasing projects under construction totaling 22.0 MW in Ontario, the Dokis hydroelectric project under development of 10 MW in Ontario and the 30.5 MW Sainte-Marguerite hydroelectric facility located in Québec (the "**Other Hydromega Hydroelectric Facilities and Development Projects**"). There is no certainty that the Corporation, Hydromega and certain Hydromega related entities will agree on definitive terms and conditions for such transactions. As part of the Magpie Hydroelectric Facility Acquisition and the Other Hydromega Hydroelectric Facilities and Development Projects potential transactions, it entered into a deposit agreement with Hydromega, Magpie Trust, certain of their security holders and certain Hydromega related entities dated July 26, 2012 pursuant to which $25 million was advanced by the Corporation as a deposit on the total consideration payable to acquire the Magpie Hydroelectric Facility or to acquire Hydromega's or Hydromega related entities' ownership interest in any of the Other Hydromega Hydroelectric Facilities and Development Projects.

On July 26, 2012, the Corporation closed a private placement whereby the Caisse de dépôt et placement du Québec and certain subscribers managed by GCIC Ltd acquired 9,632,399 Common Shares and 2,408,100 Common Shares, respectively, at a price of $10.27 per Common Share, for gross proceeds of $123.7 million (the "**Subscription Agreements**").

On July 26, 2012, the Corporation announced that it has entered into a definitive agreement with Finavera Wind Energy Inc. (the "**Finavera Purchase Agreement**") to acquire its 77 MW Wildmare Wind Energy Project located in British Columbia, Canada for an aggregate consideration of $22 million. On October 1, 2012, the Corporation announced that it has terminated the Finavera Purchase Agreement.

On August 31, 2012, the Corporation announced the implementation of a dividend reinvestment plan for the benefit of its holders of Common Shares. The dividend reinvestment plan enables the common shareholders of the Corporation to reinvest all or part of their cash dividends into additional Common Shares of the Corporation. Common Shares purchased under the dividend reinvestment plan will be either issued from treasury or purchased on the market at the discretion of the Board of Directors and their purchase price will be the weighted average trading price of the Common Shares on the Toronto Stock Exchange ("**TSX**") during the five business days immediately preceding the dividend payment less a discount of up to 5%.

On October 12, 2012, the Corporation has completed the acquisition from Capital Power L.P. and Capital Power Generation Services Inc. ("**Capital Power**") of all of the ownership interests in the entity owning the 7.2 MW Brown Lake hydroelectric facility located near Prince Ruppert in the North Region of British Columbia (the "**Brown Lake Facility**") and the 33 MW Miller Creek hydroelectric facility located in the Lower Mainland Region of British Columbia, Canada (the "**Miller Creek Facility**"), for a purchase price of approximately $68.6 million subject to certain adjustments (the "**Partnership Interest Purchase Agreement**"). See "Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Operating hydroelectric facilities – Brown Lake Facility and the Miller Creek Facility".

On November 6, 2012, the Corporation began commercial operation of the 111 MW phase II of the Gros-Morne Wind Farm located in the Municipalities of Mont-Louis and Sainte-Madeleine-de-la-Rivière in the Gaspé Peninsula in the Province of Québec. See "Business and Assets of the Corporation – Operating Wind Farms – Gros-Morne Wind Farm".

On December 11, 2012, the Corporation completed an offering (the "**Series C Offering**") of a total of 2,000,000 series C shares (the "**Series C Shares**") at $25 per Series C Share for aggregate gross proceeds of $50 million. The Series C Offering was made on a bought deal basis through a syndicate of underwriters, the whole as contemplated under the underwriting agreement dated November 27, 2012 between the Corporation and TD Securities Inc., National Bank Financial Inc., BMO Nesbitt Burns Inc., Desjardins Securities Inc., Canaccord Genuity Corp. and GMP Securities L.P., as underwriters for the Series C Offering (the "**Series C Underwriting**

Agreement"). The Series C Shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof. The Series C Shares commenced trading on the TSX on December 11, 2012 under the symbol "INE.PR.C". See "Description of Capital Structure - Preferred Shares - Series C".

Financial Year 2011

On February 14, 2011, the Corporation entered into a definitive agreement (the "**Cloudworks Agreement**") with the shareholders of Cloudworks Energy Inc. ("**Cloudworks**") to acquire all of the issued and outstanding shares of Cloudworks (the "**Cloudworks Acquisition**"). The Cloudworks Acquisition was completed on April 4, 2011. Pursuant to the Cloudworks Agreement, the Corporation acquired Cloudworks for an aggregate consideration of $191.1 million, approximately $149.7 million of which was payable in cash and approximately $39.0 million was payable by the issuance, by way of private placement, of Common Shares at a price of $9.7549 per Common Share to the shareholders of Cloudworks. In addition, the Cloudworks Agreement provides for the potential payment by the Corporation of additional amounts over a period of more than 40 years from the date of closing of the Cloudworks Acquisition to the 40th anniversary of the last development projects of the Cloudworks portfolio, namely the Northwest Stave River Project, the Tretheway Creek Project and the Big Silver-Shovel Creek Projects (as it was formerly known, as of the date of this Annual Information Form, this project was modified and is now referred to as the Big-Silver Creek Project), to achieve COD (or the 50th anniversary of the date of closing of the Cloudworks Acquisition if that date is earlier). These conditional deferred payments are effectively intended to provide for a potential revenue sharing between the Cloudworks shareholders and the Corporation of the value created if the Cloudworks' portfolio of assets performs better than the Corporation's expectations and would result in additional accretion to the Corporation, net of those payments. The maximum aggregate amount of all conditional deferred payments under the Cloudworks Agreement is limited to a value amount of $35 million as of April 4, 2011. As a result of the Cloudworks Acquisition, the Corporation indirectly assumed Cloudworks' $233 million of non-recourse long-term debt associated to Cloudworks' 50.0074% ownership in six run-of-river operating hydroelectric facilities having a combined gross installed capacity of 150 MW (the "**Harrison Operating Facilities**"). See "Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Harrison Operating Facilities".

In addition to the Harrison Operating Facilities, Cloudworks' portfolio of assets was comprised of the full ownership of 76 MW of run-of-river hydroelectric projects under development with 40-year PPAs, namely, the Northwest Stave River Project, the Tretheway Creek Project and the Big Silver Creek Projects (see "Description of the Business and Assets of the Corporation - Hydroelectric Development Projects") and full ownership of run-of-river hydroelectric projects in various stages of development having a potential aggregate installed capacity of over 800 MW.

The Corporation filed a Business Acquisition Report on SEDAR in respect of the Cloudworks Acquisition on June 20, 2011 which was updated on November 21, 2012. The report is available on www.sedar.com .

In order to finance the cash portion of the purchase price payable under the Cloudworks Agreement, the Corporation completed on March 4, 2011, on a bought deal basis, the offering (the "**Subscription Receipts Offering**") of a total of 17,750,000 subscription receipts (the "**Subscription Receipts**") at $9.35 per subscription receipt for aggregate gross proceeds of $165,962,500 (including the over-allotment option which was exercised in full by the syndicate of underwriters), the whole as contemplated under the underwriting agreement (the "**Subscription Receipts Underwriting Agreement**") dated February 17, 2011 between the Corporation and BMO Nesbitt Burns Inc., National Bank Financial Inc., TD Securities Inc., RBC Dominion Securities Inc., CIBC World Markets Inc., Scotia Capital Inc. and Desjardins Securities Inc., as underwriters for the Subscription Receipts Offering. On April 4, 2011, the Subscription Receipts were automatically exchanged on a one-to-one basis for Common Shares of the Corporation. In addition, a dividend equivalent payment of $0.145 per Subscription Receipt was also paid to such holders of record of Subscriptions Receipts as a result of the Corporation having declared a dividend of $0.145 per Common Share which was payable to holders of record of Common Shares on March 31, 2011.

On November 22, 2011, the Régie de l'énergie (Québec) approved the 20-year PPA entered into with Hydro-Québec Distribution on March 17, 2011 in connection with the development of the Viger-Denonville project located in the municipalities of Saint-Paul-de-la-Croix and of Saint-Épiphane, in the Province of Québec, and comprising 12 wind turbines with a total installed capacity of 24.6 MW (the "**Viger-Denonville Project**"). Each of the Corporation and the Regional County Municipality of Rivière-du-Loup own a 50% equity interest in the Viger-Denonville Project and its commercial operation is scheduled to begin in 2013. The Corporation will act as manager in connection with the development, management, operation and administration of the Viger-Denonville Project.

The Corporation submitted, between November 1 and April 30, 2011, six PV ground mount solar projects to the FIT Program in Ontario for a total potential solar installed capacity of 59 MW in the area of the City of Peterborough, Ontario. Other PV ground mount solar projects are under investigation.

On April 6, 2011, the Corporation entered into a share purchase agreement with Enfinity NV to acquire all of the issued and outstanding shares of the entity owning the rights to develop the 33.2 MW_{DC} Stardale PV Solar Project (the "**Stardale Solar Farm**") for an aggregate consideration of approximately $11.8 million. Construction of the Stardale Solar Farm began in November 2010. See "Description of the Business and Assets of the Corporation – Operating Solar Farms – Stardale Solar Farm". On July 28, 2011, the Corporation completed the limited recourse project financing of the Stardale Solar Farm with a syndicate of lenders headed by The Bank of Tokyo-Mitsubishi for a total amount of $117.3 million for an 18-year term.

On August 9, 2011, the Corporation completed the increase and extension of its existing corporate revolving term credit facility from $170 million to $350 million. TD Securities Inc. and BMO Capital Markets acted as Co-Lead Arrangers and Joint Book Managers with The Toronto-Dominion Bank acting as Administrative Agent and Bank of Montreal acting as Syndication Agent for a syndicate of lenders also including: Canadian Imperial Bank of Commerce, Caisse centrale Desjardins, National Bank of Canada, The Bank of Nova Scotia and Laurentian Bank of Canada.

On November 25, 2011, the Corporation began commercial operation of the 58.5 MW Montagne Sèche wind farm, located in the municipalities of Cloridorme and Petite-Vallée, in the Gaspé Peninsula, in the Province of Québec. See "Description of the Business and Assets of the Corporation - Operating Wind Farms – Montagne Sèche Wind Farm".

On November 29, 2011, the Corporation began commercial operation of the 100.5 MW phase 1 of the Gros-Morne wind farm, located in the municipalities of Mont-Louis and Sainte-Madeleine-de-la-Rivière-Madeleine, in the Gaspé Peninsula, in the Province of Québec. See "Description of the Business and Assets of the Corporation - Operating Wind Farms - Gros-Morne Wind Farm".

Financial Year 2010

The Fitzsimmons Creek Facility entered into commercial operation in January 2010. See "Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Fitzsimmons Creek Facility".

On January 31, 2010, the Corporation and Innergex Power Income Fund (the "**Fund**") entered into a definitive arrangement agreement to undertake a strategic combination of the two entities whereby the Fund would acquire the Corporation by way of a reverse take-over, thereby effecting at the same time the conversion of the Fund to a corporation (the "**Arrangement**"). Pursuant to the Arrangement, which was completed on March 29, 2010, Fund unitholders (other than the Corporation) exchanged their Fund units on the basis of 1.460 Common Shares for each unit of the Fund held. Further details regarding the Arrangement may be found in the Joint Information Circular dated February 17, 2010 (the "**Joint Information Circular**"), available on SEDAR at www.sedar.com and on the Corporation's website at www.innergex.com. Upon completion of the Arrangement, the Corporation also announced it had completed the refinancing of certain of its credit facilities and those of certain of its subsidiaries for an aggregate amount of $170 million. Forthwith upon completion of the Arrangement, the Corporation also completed a corporate reorganization, pursuant to which, *inter alia*, (i) Innergex Power Trust (the "**Trust**") distributed all of its assets and transferred all of its liabilities to the Fund and therefore ceased to exist; and (ii) the Fund subsequently distributed all of its assets and transferred all of its liabilities to the Corporation and therefore ceased to exist.

On February 1, 2010, Gilles Lefrançois, founder and former Executive Chairman of the Board of Directors of the Corporation, announced that he was retiring.

On March 8, 2010, the Corporation completed an offering (the "**Debenture Offering**") of extendible convertible unsecured subordinated debentures in the aggregate principal amount of $70 million (the "**Debentures**"). The Debentures have a maturity date of April 30, 2017. The Debentures bear interest at a rate of 5.75% per annum, payable semi-annually, and are convertible at the option of the holder into Common Shares at a conversion price of $10.65 per Common Share. On March 16, 2010, the over-allotment option was exercised by the underwriters for the Debenture Offering to purchase an additional $10.5 million principal amount, bringing the aggregate gross proceeds of this offering to $80.5 million, the whole as contemplated under the underwriting agreement dated February 18, 2010 between the Corporation and BMO Nesbitt Burns Inc., TD Securities Inc., CIBC World Markets Inc., RBC Dominion Securities Inc., Scotia Capital Inc., Desjardins Securities Inc. and Laurentian Bank Securities Inc, as underwriters for the Debentures Offering. The Debentures commenced trading on the TSX on March 8, 2010 under the symbol "INE.DB". See "Description of Capital Structure – General Description of Capital Structure - 5.75% Convertible Debentures".

On March 11, 2010, the Corporation was selected by the British Columbia Hydro and Power Authority ("**BC Hydro**") to enter into a PPA for three run-of-river hydro projects submitted in the BC Clean Call, namely the Upper Lillooet River, Boulder Creek and North Creek projects, with an expected aggregate net installed capacity of 75.3 MW (gross 113.0 MW).

On April 23, 2010, the Ashlu Creek Facility and the Fitzsimmons Creek Facility received their EcoLogo certifications, thereby confirming that the facilities will receive incentive payments under the ecoENERGY Initiative of the Federal government.

On April 29, 2010, the Corporation settled a $110.0 million forward-starting amortizing interest rate swap related to the Ashlu Creek Facility. Concurrently, the Corporation entered into forward-starting amortizing interest rate swaps, thereby fixing the swap interest rate at 4.70% beginning on the effective date of September 30, 2010, and continuing until the end of the related long-term debt amortization schedule in June 2035.

On June 1, 2010, the Corporation issued a notice to proceed to the turbine supplier and the balance-of-plant contractor, thereby launching the construction phase of the Montagne Sèche Wind Farm and the Gros-Morne Wind Farm.

On July 7, 2010, the Corporation announced the submission of eight wind farm development projects, in partnership with local organizations and municipalities. These projects were submitted in response to a call for tenders issued by Hydro-Québec Distribution for the purchase of 250 MW resulting from community projects and resulted in the 24.6 MW Viger-Denonville Project in which the Corporation owns a 50% equity interest being selected by Hydro-Québec Distribution for a 20-year PPA.

On September 14, 2010, the Corporation completed an offering (the "**Series A Offering**") of a total of 3,400,000 Series A Shares at $25 per Series A Share for aggregate gross proceeds of $85 million. The Series A Offering was made on a bought deal basis through a syndicate of underwriters, the whole as contemplated under the underwriting agreement (the "**Series A Underwriting Agreement**") dated August 27, 2010 between the Corporation and BMO Nesbitt Burns Inc., TD Securities Inc., CIBC World Markets Inc., National Bank Financial Inc., RBC Dominion Securities Inc., Scotia Capital Inc., Desjardins Securities Inc., Laurentian Bank Securities Inc., Cormark Securities Inc., Jacob Securities Inc. and NCP Northland Capital Partners Inc., as underwriters for the Series A Offering. Each holder of Series A Shares has the right, at its option, to convert all or any of its Series A Shares into Series B Shares on the basis of one Series B Share for each Series A Share converted, subject to certain conditions, on January 15, 2016 and on January 15 every five years thereafter. The Series A Shares commenced trading on the TSX on September 14, 2010 under the symbol "INE.PR.A". See "Description of Capital Structure – General Description of Capital Structure - Preferred Shares".

On December 22, 2010, the Corporation entered into a credit agreement, subject to the satisfaction of certain closing conditions which were satisfied in March 2011, providing for a $31.7 million non-recourse construction and term project financing for the 38% interest it holds in the 58.5 MW Montagne Sèche Wind Farm located in the Township of Cloridorme, in the Province of Québec.

3. INDUSTRY OVERVIEW AND MARKET TRENDS

RENEWABLE POWER GENERATION INDUSTRY

Renewable power producers are involved in the generation of electricity from renewable sources of energy, including (i) water; (ii) wind; (iii) certain waste products, such as biomass (e.g., waste wood from forest products operations) and landfill gas; (iv) geothermal sources, such as heat or steam; and (v) the sun. Demand for renewable power sources in North America continues to grow and is largely driven by the growing demand for energy, as well as the long-term trend toward stronger policies for protecting the environment. While traditional regulated utilities continue to dominate the North American electricity generation markets, it is recognized that independent power producers play an increasingly important role in the supply of electricity. In recent years, governmental authorities and other policymakers have increasingly recognized the benefits of power generated by independent power producers.

The trend towards increased reliance on independent power producers for the supply of renewable power in North America is fuelled by a number of factors, including (i) the increase in government-sponsored incentives; (ii) the availability of long-term contracts for the purchase of renewable energy with highly creditworthy counterparties, allowing independent power producers to develop new projects in a low-risk environment with the expectation of long-term stable contractual cash flows; (iii) the implementation of non-discriminatory access to transmission systems, providing independent power producers access to regional electricity markets; and (iv) the efficiency of independent power producers.

RENEWABLE POWER IN CANADA

Significant recent growth in renewable power generation in Canada has resulted from: rising electricity prices; rising fossil fuel prices; public concern over nuclear power generation, air quality, and greenhouse gases; improvements in renewable energy technologies; and shorter construction lead times for certain renewable energy projects. Renewable electricity generation in Canada is also supported by federal and provincial incentives such as long-term fixed price contracts, accelerated depreciation, and Renewable Portfolio Standards. Several provinces are also expected to make significant transmission grid investments in order to bring this power to market.

While these favourable underlying fundamental factors should support the growth of renewable power generation over the long term, a number of factors may reduce the short-term demand for renewable power in Canada. These include: government authorities grappling with weak economic conditions and budget deficits; electricity surpluses of some public utilities; and the abundance of shale gas which has resulted in much lower prices for natural gas, one of the fossil fuel sources of electricity production.

Independent Power Producers

In the traditional market structure of the electricity industry, vertically-integrated monopoly utilities produce, transmit (from generation facilities to transformer stations), and distribute (from transformer stations to consumers) electricity. A number of factors, including rising electricity rates and fossil fuel prices, technological advances, and concerns about cost controls in funding future investments in electricity generation and transmission have led several jurisdictions to restructure their electricity markets to move towards regulated or full competition. An integral part of the restructuring effort has been the introduction of new generation supply from third parties, or "independent power producers", that are independent of government and differ from traditional vertically-integrated and regulated utilities.

In recent years there has been a shift to retail and wholesale competition in Alberta and Ontario, and some other provinces have undertaken varying degrees of sector unbundling through the granting of PPAs to independent power producers and greater access to transmission and distribution lines.

Federal Government Support for Renewable Power in Canada

The Canadian Government is favourable to the generation of electricity from natural and renewable energies of the sun, wind, moving water, earth, and biomass, as it improves the sustainability of its energy production and delivers benefits to the environment. Its ecoENERGY for Renewable Power program (2007-2011) resulted in a total of 104 projects qualifying for funds and will represent total investments of $1.4 billion over 14 years and an aggregate of 4,500 MW of additional renewable power capacity (the "**ecoENERGY Initiative**"). The Federal government remains actively involved in the research and development of renewable energy technologies, working not only to meet energy demands but also to reduce the technical and financial risks associated with each technology. However, in Canada, provincial governments are responsible for the management of natural resources within their borders. Therefore, most targets for renewable energies are determined by the provinces.

Provincial Renewable Portfolio Standards and Requests for Proposals

In response to the long-term trend toward stronger environmental protection policies, many provincial governments have introduced Renewable Portfolio Standards ("**RPS**"), which are generally applied as goals or targets rather than mandatory requirements. RPSs typically set a target for an increased component of renewable generation in the electricity generation supply mix in order to reduce greenhouse gas emissions over time.

Current provincial targets for clean or renewable energy in their supply mix are highlighted below:

British Columbia:	To generate at least 93% of total electricity from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;
Manitoba:	To develop 1,000 MW of wind energy capacity by 2015;
New Brunswick:	To generate 10% of total electricity from renewable resources by 2016 and to have 40% of in-province electricity sales provided from renewable energy by 2020;
Newfoundland and Labrador:	To develop 80 MW of wind energy on the island of Newfoundland;
Nova Scotia:	To generate 25% of total electricity from renewable resources by 2015, and 40% by 2020;
Ontario:	To increase hydro energy capacity to 9,000 MW (+10.7%) and to develop 10,700 MW of installed wind, solar and bioenergy capacity by 2018;
Prince Edward Island:	To develop 500 MW of wind energy capacity by 2013 and to double its renewable portfolio standard to 30% of total electricity from renewable resources by 2013;
Québec:	To develop 4,000 MW of installed wind energy capacity by 2015 and an additional 100 MW of wind energy for every 1,000 MW of additional hydroelectric power; and
Saskatchewan:	To develop 200 MW of wind energy capacity by 2015.

REGULATORY FRAMEWORK OF AND MARKET FOR RENEWABLE POWER IN THE CORPORATION'S KEY MARKETS

Québec

Hydro-Québec, a corporate agent of the Government of Québec, is one of the largest electricity utilities in North America. Under its incorporation statute, Hydro-Québec is given broad powers to generate, supply, and deliver electric power throughout Québec. Excluding the territories served by municipal or private electric power systems or by a certain cooperative, Hydro-Québec is the holder of exclusive electric power distribution rights throughout the territory of Québec.

The Régie de l'énergie, an economic regulation agency created by the Government of Québec in 1996, sets and modifies the rates and conditions for, inter alia, the transmission of electric power by the electricity carrier and the distribution of electric power by the electricity distributors in the Province of Québec. To that end, Hydro-Québec must present to the Régie de l'énergie a forecast of the needs of the Québec market for the next ten years as well as the nature of the contracts that Hydro-Québec intends to enter into in order to meet the demand over and above 165 TWh (being the heritage electricity pool which must be supplied by Hydro-Québec). To meet demand in excess of this 165 TWh, Hydro-Québec must enter into supply contracts after conducting Requests for Proposals with interested power suppliers. The Régie de l'énergie monitors all Requests for Proposals for the supply of energy in Québec. In 2003, Hydro-Québec issued a Request for Proposals for the supply of nearly 1,000 MW of wind energy, for which it awarded eight projects; seven of those eight projects are in commercial operation today, with total installed capacity 817.5 MW. The eighth project was abandoned. In 2005, another Request for Proposals was issued for the supply of 2,000 MW of wind energy and for which Hydro-Québec awarded 15 projects for a total of 2,004 MW with expected commercial operation dates between 2011 and 2015.

On October 29, 2008, the Government of Québec enacted the Wind Energy - 250 MW Block from Aboriginal Projects Regulation and the Wind Energy - 250 MW Block from Community Projects Regulation (later amended on March 18, 2009). Hydro-Québec subsequently issued a Request for Proposals for the supply of 500 MW of wind energy from aboriginal and community projects in 2009 and in 2010, it announced it had accepted 12 proposals totalling 291.4 MW. Deliveries of electricity must start between December 1, 2013 and December 1, 2015.

In July 2012, the Government of Québec announced plans to issue a new Request for Proposals for the supply of 450 MW of wind energy, as well as a program to purchase 250 MW of wind energy from Aboriginal projects. This additional capacity would enable the province to reach its goal of developing 4,000 MW of installed wind energy capacity, as outlined in its energy strategy for 2006-2015.

British Columbia

BC Hydro is one of the largest electric utilities in Canada, supplying the majority of power generating capacity in the province. The remaining capacity is provided by investor-owned utilities, large and small industrial self-generators, and independent power producers.

In 2001, BC Hydro launched its first green power generation RFP that resulted in 15 projects being awarded PPAs with a total capacity of 172 MW, 12 of which have since been realized. Following the success of this call, BC Hydro launched the 2002-2003 Green Power Generation RFP that resulted in another 16 projects being awarded PPAs with a total capacity of 501 MW or 1,762 GWh of energy (although less than half of these projects have proceeded). This was followed in 2006 by another Request for Proposals which resulted in independent power producers being awarded contracts for 38 projects with a total capacity of 1,428 MW, or more than 7,000 GWh of energy.

In February 2007, the province announced a new energy plan comprising a number of policies, some of which were subsequently expanded by the Clean Energy Act, including a target of zero net greenhouse gas emissions for all new electricity projects, ensuring clean or renewable electricity generation continues to account for at least 93% of total generation (over 90% of generation in British Columbia currently derives from hydroelectric resources), acquiring 66% of BC Hydro's incremental resource needs through conservation and efficiency improvements by 2020, and establishing a Standing Offer Program ("**SOP**") for clean energy projects originally with a maximum project size of 10 MW and recently increased to a maximum project size of 15 MW.

In the spring of 2008, BC Hydro released a Clean Power Call RFP. From March to August 2010, BC Hydro ultimately selected 27 projects (25 PPAs), representing an aggregate total generating capacity of 1,168 MW and 3,188 GWh per year of firm energy.

On June 3, 2010, the BC Government's Clean Energy Act was passed by the BC Legislature, setting the framework for a new regime for electricity self-sufficiency and procurement and for investment in clean and renewable energy in BC. Among the changes introduced by the Clean Energy Act is the exemption of the PPAs awarded under the Clean Power Call and under the Standing Offer Program from the requirement for submission to the British Columbia Utilities Commission for acceptance as being in the public interest. The Clean Energy Act also provided for the consolidation of British Columbia Transmission Corporation into BC Hydro, and introduced an export-oriented power for the Cabinet to require BC Hydro to acquire power from clean or renewable resources for the objective of export.

Also in 2010, the BC Hydro SOP, implemented to encourage the development of small and clean energy projects throughout British Columbia, was broadened under the Clean Energy Act. The current program allows for projects using not just proven technologies but also near commercial and prototype technologies, and provides for the award of PPAs to projects with a maximum nameplate capacity of up to 15 MW. BC Hydro also adjusted the pricing for projects awarded PPAs under the Standing Offer Program in line with the projects awarded PPAs under the Clean Power Call, with the pricing for each project being based on the region in which the project is located. As of November 2012, BC Hydro had offered 10 PPAs with a total capacity of 50 MW and was in the process of reviewing 14 projects with a total capacity of 90 MW.

In May 2012, BC Hydro released a draft Integrated Resource Plan, a 20-year planning report on procuring generation and transmission resources to meet the province's future electricity needs. In November 2012, the government extended the report's final submission due date to August 3, 2013, in order to better assess the volume and timing of future electricity needs arising from several proposed liquefied natural gas projects, as well as projected increased mining and natural gas extraction activity. Earlier in the year, the BC Government announced that natural gas would qualify as a clean source of energy when used to power liquefied natural gas extraction plants in northern BC, pursuant to the Clean Energy Act's objective to generate at least 93% of the electricity in BC from clean or renewable resources.

Ontario

In May 2002, Ontario's electricity market opened to wholesale and retail competition, providing open access to regulated transmission systems, and requiring Ontario Power Generation ("**OPG**") to reduce its share of generation capacity in the market. In 2003, the Government of Ontario took steps that transformed the electricity market into what is now described as a "hybrid market". Such steps included raising the price cap, directing the Ontario Energy Board ("**OEB**") to regulate residential pricing for power generated from OPG's nuclear and large hydroelectric generation assets and setting annual revenue limits with respect to OPG's coal and smaller hydroelectric generation facilities. In late 2004, the Government of Ontario established the Ontario Power Authority ("**OPA**") to address system planning and security of supply in Ontario by reviewing demand and resource reliability forecasts, facilitating supply source investment and diversification, and promoting conservation.

In August 2007, the OPA filed with the OEB a comprehensive Integrated Power System Plan ("**IPSP**") identifying the conservation, generation, and transmission investments required in Ontario from 2007 to 2027. The OPA developed the IPSP based on the supply mix directive (the "**Supply Mix Directive**") issued by the Minister of Energy dated June 13, 2006 and which outlined various generation targets, including an RPS. Once approved by the OEB the IPSP would, among other things, authorize the OPA to procure generation without the need for ministerial directives in order to meet Ontario's RPS targets. The IPSP hearings were put on hold on September 17, 2008 when the Minister of Energy issued a revised Supply Mix Directive, which substantially increased the RPS for the Province and directed the OPA to develop a province-wide feed-in-tariff program for renewable energy.

On February 23, 2009, the Minister of Energy and Infrastructure introduced Bill 150: The Green Energy and Green Economy Act, 2009, which bill enacted the Green Energy Act, 2009 and amended several key pieces of energy related legislation, including the Electricity Act, 1998 and the Ontario Energy Board Act, 1998. Further to Bill 150, the OPA was mandated to develop a feed-in-tariff program and renewable energy-generating facilities were provided with priority access to the Province's transmission and distribution electricity grids.

In September 2009, the OPA launched the Feed-in-Tariff Program (the "**FIT Program**"). The FIT Program offers a fixed 20-year term, fixed price contract (the "**FIT Contract**") for renewable electricity production. The FIT Program is divided into two streams - FIT (projects generating more than 10 KW of electricity) and micro-FIT (projects generating 10 KW or less of electricity). Hydro power projects must not be greater than 50 MW to be eligible under the FIT Program and ground mount solar PV projects are limited to 10 MW. Aboriginal or community projects are eligible for a price adder on the energy price in proportion with the percentage of equity ownership of the aboriginal or community group. In its first round, the OPA awarded 184 FIT Contracts for "large scale" (greater than 5 MW) projects, representing 2,421 MW of renewable energy capacity. Of those, 76 were solar PV projects representing 651 MW, 47 onshore wind projects representing 1,229 MW, 46 hydro power projects representing 192 MW, and one offshore wind project representing 300 MW.

On November 23, 2010, the Government of Ontario issued its Long-Term Energy Plan - Building Our Clean Energy Future (the "**LTEP**"). This LTEP commits to a target of 9,000 MW of hydroelectric generating capacity and 10,700 MW of wind, solar, and bioenergy generating capacity by 2018, which will be accommodated through transmission expansion and maximizing the use of the existing grid. Also, according to the Supply Mix Directive issued by the OEB in February 2011, the LTEP shall provide for renewable sources of energy, excluding hydroelectric, to account for approximately 10-15% of total Ontario electricity generation by 2018. In order to accommodate the growing number of renewable generating projects, the LTEP also included plans to design and build five priority transmission investment projects that have been previously identified by the OPA.

In February 2011, the OPA issued a second round of FIT Contracts for a total of 40 projects totalling 854 MW, including 35 solar PV projects with a total capacity of 257 MW and four wind projects with a total capacity of 615 MW. In May 2011, the OPA also awarded contracts for 839 small-scale projects totalling 140 MW of capacity. As of June 25, 2012, the OPA had executed 1,809 FIT Contracts with a combined capacity of 4,562 MW.

In August 2012, the OPA released revised rules for the FIT Program, following the planned review process undertaken in the fall of 2011. While maintaining the province's commitment to clean energy, rule changes have sought to streamline the submission and selection process using a points system, reduce prices (22% lower for large solar projects and 15% lower for wind projects) and revise them annually, improve municipal engagement, and encourage Aboriginal and community participation. Domestic content requirements have been maintained, although these are currently being challenged at the World Trade Organization. Subsequently, a Small FIT application window was opened from December 14, 2012 to January 18, 2013. A Large FIT application window is expected in 2013.

Ontario is currently leading Canadian provinces with respect to solar PV generation as a result of its FIT Program. As of June 25, 2012, the OPA had executed FIT Contracts with a combined potential solar PV capacity of 1,203 MW, 54 MW of which were in commercial operation. Under its microFIT Program, the OPA had also executed contracts amounting to 114 MW of potential solar PV capacity (including groundmount and rooftop installations). Prior to the implementation of the FIT Program, the OPA had executed a number of PPAs with solar developers under the now-defunct Renewable Energy Standard Offer Program ("**RESOP**"); under this program, at March 31, 2012 there were contracts with a combined solar PV capacity of 348 MW in operation and 130 MW under development.

ACTUAL METHOD OF PRODUCTION

Hydroelectric Power Generating Process

Run-of-river hydroelectric generation facilities, unlike traditional hydroelectric facilities, do not require the flooding of large areas of land. Hydroelectric power is generated by harnessing the force created as water falls. The difference in elevation between the headpond and the tailrace is referred to as "head" or "operating head". The energy in the moving water is ultimately converted into electric energy. The water flows through an intake pipe or tunnel (known as the penstock) to a turbine, which is essentially a water wheel. The water spins the turbine and the hydraulic energy is then converted into mechanical energy which is then converted into electricity by the generator. The electricity is then sent through a transformer where its characteristics are adjusted so that it can be sent along the transmission system. The water, after going through the turbine, exits the powerhouse through the draft tube and the tailrace where it rejoins the main stream of the river.

There are three principal types of hydraulic turbines:

Kaplan:	generally used where there is a low operating head (the difference in elevation between the intake water level and tailrace water level), varying from a few meters to 30 meters.
Francis:	generally used with a medium head, e.g. approximately 30 meters to 200 meters.
Pelton:	generally used where there is a very large head, usually greater than 200 meters.

Below is a list of the principal advantages of hydroelectric power generation.

Reliability	The equipment involved in producing hydroelectric power has relatively few moving parts, resulting in a long life and low maintenance requirements as compared to other generation technologies. Unplanned outage rates for hydroelectric units are among the lowest in the electricity generation industry.
Low Operating Costs	Other than water royalties and license fees paid to governmental authorities, hydroelectric facilities have minimal fuel costs and therefore minimize the volatility of their cost structures compared to fossil-fuelled plants. In addition, most facilities can be operated remotely by a single person from a centralized control centre. As a result of these factors and the reliability of hydroelectric equipment, operating expenses for hydroelectric facilities are low and predictable compared to other types of electricity generation technologies.
Environmentally Preferable	Hydroelectric generation produces virtually no greenhouse gas emissions or emissions that create acid rain, both of which have significant negative impacts on the environment. Hydroelectric generation creates none of the thermal, chemical, radioactive, water, and air pollution associated with fossil fuel and nuclear generated power. No substantial amount of residual waste is produced during the power generation process; the water is simply returned to the river.
Low Environmental Impact	Small hydroelectric generating facilities, generally defined in Canada as facilities of less than 50 MW, are typically run-of-river facilities that do not have significant reservoir capacity. This reduces the potentially harmful effect of upstream flooding and other environmental impacts that may change the flow of water within a given area.

Wind Power Generating Process

Electricity generated from wind is becoming an increasingly important source of power globally, including in North America. Like hydroelectric generation, wind generation is not subject to fuel price volatility and it produces no greenhouse gas or other emissions. Wind turbines can only generate electricity when the wind blows at speeds within a certain operating range.

Energy is produced from the wind power exerted on the blades of the propeller of a wind turbine, which then activates a generator. Wind turbines are equipped with a control system which optimizes electrical production and maintains it during unfavourable climatic conditions.

Below is a list of the principal advantages of wind power generation.

Low Operating Costs	Wind farms do not have any fuel costs and use a remote monitoring system that allows for offsite operation and supervision. In addition, improvements to wind turbine technology have increased the efficiency and reliability of wind energy projects. As a result, operating expenses are low compared to many other traditional methods of electricity generation.
Construction Flexibility	Wind farms are relatively simple to construct compared to more traditional electricity generating facilities. A typical wind farm can be constructed within a much shorter time frame than other power facilities, such as hydro, natural gas, nuclear, or coal facilities, which can take several years to complete. As a result, wind farms are less susceptible to risks associated with construction delays and cost overruns.
Reliability	Modern wind turbines are very reliable. Availability, a measure of an electricity generation system's reliability, is calculated as the percentage of time the system is able to operate relative to total time available. The difference between the two is largely attributable to annual scheduled maintenance. According to the Canadian Wind Energy Association, availability for modern wind turbines is typically approximately 98%, although manufacturers generally warrant at most 96%.
Environmentally Preferable	Wind farms do not produce any greenhouse gas emissions or acid rain, both of which have significant negative impacts on the environment. Wind energy generation does not result in thermal, chemical, radioactive, water, and air pollution associated with fossil fuel and nuclear generated power.
Limited Use of Land	Wind farms require only a small percentage of the land they occupy for road access and foundations. The rest of the project's site is available for other uses, such as agriculture, industry, and recreation.

Solar Photovoltaic Power Generating Process

Solar PV power generating facilities consist of an array of solar panels. These solar panels are made up of smaller solar cells (often encased in glass to protect them from the elements), which convert electromagnetic radiation from the sun into electricity by means of semiconductors. The semiconductors use photons of light to knock electrons into a higher state of energy to create electricity (known as the photovoltaic effect).

The electricity produced by solar PV generating facilities is in the form of direct current (unilateral flow of electricity). An inverter is required to convert the direct current electricity to alternating current, which is the type of current upon which most electricity distribution and transmission grids are based.

Below is a list of the principal advantages of solar PV power generation.

Construction and Operating Costs — Solar power generation by solar PV farms is growing all over the world. Solar PV generation costs remain high in comparison to hydro or wind and still require government incentives for new projects to be built in Canada. However, costs have been decreasing steadily due to efficiencies in the supply chain. The cost of solar PV modules is becoming more affordable for large scale projects, and their reliability has been proven for projects operating for more than 20 years.

Environmentally Preferable — Solar PV farms do not produce any greenhouse gas emissions or acid rain, both of which have significant negative impacts on the environment. Solar energy generation does not result in thermal, chemical, radioactive, water, and air pollution associated with fossil fuel and nuclear generated power. The visual impact of solar projects is negligible and the lands occupied are fully rehabilitable without any negative impact after the end of the project and most of the equipment, such as racking and modules, can be fully removed and recycled.

Reliable Resource — The sun's availability, in both duration and intensity, is well documented and has generally been monitored for a long period of time. The yearly variation of the resource lies in the 3 to 4% range, which is much lower than the variations observed for hydro and wind resources.

Construction, Operation, and Maintenance — Solar PV farms are easy to build and all costs can be quantified in advance of construction. The construction of a solar farm project consists of standard foundation and racking systems, PV modules, wiring, and connection to the power grid. The civil structures are limited to maintenance access roads, fencing, and a small control building.

The maintenance of a solar farm is quite simple considering the fact that there are no mechanical components, such as for turbines. Performance of the PV systems is controlled by a monitoring system and maintenance is limited to some cleaning, minor repairs, and spare part changes.

FACTORS AFFECTING RENEWABLE ENERGY PRODUCTION PERFORMANCE

Renewable energy projects, such as run-of-river hydroelectric facilities, wind farms and solar PV farms depend on "fuel" sources which are, by their very nature, variable. Therefore, the level of production on a day-to-day basis is also variable. However, long-term historical records for hydroelectric energy and site-specific measurements for hydro and wind energy allow for a monthly or annual average or "mean" hydrology or wind speed, which in turn allow for energy production to be estimated using statistical analysis.

Expected annual production for a turbine is calculated as follows:

Annual Production (MWh) = Turbine Capacity (MW) × No. hours in one year (Hours) × Usage Factor (%)

Expected annual production for a solar PV generation facility is calculated as follows:

Annual Production (MWh) = Panel (MW) × No. hours in one year (Hours) × Usage Factor (%)

Turbine capacity, measured in megawatts, is an indication of the energy production capability of a turbine. Turbine capacity multiplied by the number of hours in one year (8,760 hours) gives the maximum theoretical annual production of a turbine measured in MWh. Hydro turbines are typically customized based on the characteristics of the site. Current utility-scale land-based wind turbines have a capacity ranging from less than one MW to over three MW.

As operation of the turbine is dependent on water flow or wind speed, a turbine does not operate every hour of the year. Production from solar farms is dependant of the sunlight. The usage factor is a measure of the productivity of an electricity-generating source. It is defined as the percentage of electricity that an electricity-generating source is expected to produce relative to maximum theoretical production in a given period of time. For example, an energy site that has a theoretical maximum production of 100 MWh per year, but actually only produces an average of 30 MWh per year, has a usage factor of 30%. There are a number of factors that preclude a wind or hydro powered electricity-generating turbine or solar panels from operating at their theoretical maximum. The primary factor is mean water flow, wind speed and sunlight. Therefore, a turbine or solar panels will operate for significant periods of time at power outputs less than the rated capacity. Other factors also affect the usage factor but are generally much less significant. For example, scheduled annual maintenance will reduce the amount of time that equipment is available for production. In addition, there may be periods of unscheduled non-operation resulting from equipment failure.

In general, hydro projects have usage factors ranging from 40% to 70%, wind energy projects have usage factors ranging from 25% to 40% depending on various site-specific factors, and solar PV projects have usage factors from a few percentage points for fixed thin film technology to more than 20% for monocrystalline modules installed with a double axis tracking system.

COMPETITIVE CONDITIONS

The Corporation operates mainly in the Canadian power sector, which is affected by the supply of and demand for power in the provinces in which it operates being Québec, British Columbia and Ontario, the availability of transmission lines and overall economic conditions in Canada and the United States. Within this sector, the Corporation faces competition from large utilities, other independent power producers and other institutions such as investment management funds. The Corporation depends upon the sale of its power to provincially owned utilities through long-term PPAs which are generally obtained through a Request for Proposals process or an acquisition which can attract proposals from many of the Corporation's competitors. The Corporation manages the risk posed by such competitive conditions through its annual and ongoing strategic planning process. In addition, the Corporation's geographically diverse portfolio of projects, its strategy of focusing on low-impact renewable projects, its proven track-record and the experience of its management team mitigate this risk.

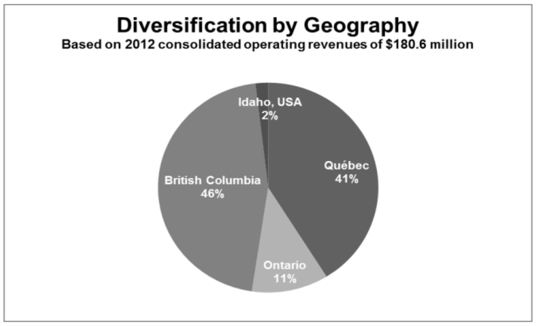
ECONOMIC DEPENDENCE

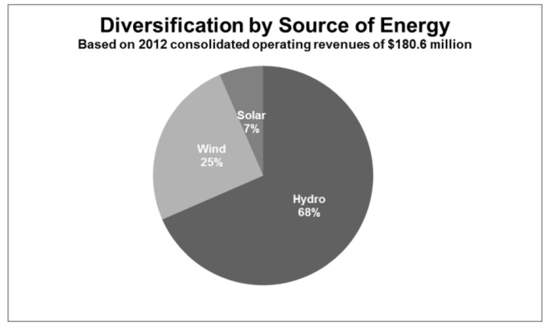
The Corporation's does not believe it is substantially dependant on any single contractual agreement. However, the Corporation has identified three major customers whose sales, under its various PPAs, of the Corporation's annual revenue totalling $180,860,000 ($148,260,000 in 2011), are the following:

For the years ended			**December 31, 2012**	**December 31, 2011**
Major Customer	**Credit Rating From Standard & Poor's**	**Segment**	**000$**	**000$**
British-Columbia Hydro and Power authority	AAA	Hydroelectric generation	73,842	67,204
Hydro-Québec	A+	Hydroelectric and wind power generation	69,560	57,637
Hydro One Network Inc. and its affiliates	A+	Hydroelectric and solar generation	19,586	8,312

SEASONALITY AND CYCLICALITY

The renewable power industry is inherently seasonal due to the industry's dependence on weather for the availability of water, wind and sunlight resources for electrical generation. The Corporation has reduced its exposure to the seasonality of the industry by virtue of the fact that its facilities and projects are geographically diversified (spanning the provinces of Québec, British Columbia and Ontario and the State of Idaho). These facilities and projects also offer a mix of energy sources, providing further diversification and thereby reducing the Corporation's dependence on any one resource in any one region.





The renewable power industry is also inherently cyclical due to the high degree of correlation between demand for electricity and general economic conditions. The Corporation has reduced its exposure to the cyclicality of the industry by virtue of the fact that it has entered into PPAs with a term of 20 years or more with respect to all of its projects under development. Furthermore, the remaining weighted-average life of PPAs for the Corporation's operating facilities was 18.4 years as of December 31, 2012, thereby reducing the Corporation's exposure to variations in the demand for and the price of electricity.

4. DESCRIPTION OF THE BUSINESS AND ASSETS OF THE CORPORATION

GENERAL OVERVIEW - SEGMENT INFORMATION

As of December 31, 2012, the Corporation had four reportable segments: (i) hydroelectric generation; (ii) wind power generation; (iii) solar power generation; and (iv) site development. Through its hydroelectric generation, wind power generation and solar power generation segments, the Corporation sells electricity produced by its hydroelectric, wind farm and solar farm facilities in operation to publicly-owned utilities. Through its site development segment, the Corporation analyses potential sites and develops hydroelectric, solar and wind farm facilities up to commissioning stage.

Operation revenues of Corporation by reportable segments:

	2012 operation revenues		2011 operation revenues	
Reportable Segments	**000 $**	**% of total revenues**	**000 $**	**% of total revenues**
Hydroelectric generation	123,626	68%	117,342	79%
Wind power generation	45,558	25%	30,918	21%
Solar power generation	11,676	7%	NA(1)	NA(1)
Site Development	0	0%	0	0%

(1) The solar power production became a reporting segment of the Corporation on May 15, 2012, with the commencement of commercial operation of the Stardale Solar Farm.

PORTFOLIO OF ASSETS

The Corporation's portfolio is comprised of interests in three groups of power generating projects: (i) facilities that are in commercial operation (the "**Operating Facilities**"); (ii) projects for which PPAs have been secured and which are either under construction or scheduled to begin commercial operation on planned dates (the "**Development Projects**"); and (iii) projects that have secured certain land rights, for which an investigative permit application has been filed or for which a proposal has been submitted under a Request for Proposals or could be submitted under the SOP or the Ontario FIT Program (the "**Prospective Projects**"). The Corporation's portfolio of projects is comprised of 28 Operating Facilities, 7 Development Projects and a number of Prospective Projects.

The Corporation intends to continue to own and operate its Development Projects and Prospective Projects as they become operational.

The Corporation's net capacity, measured on an ownership-weighted basis, represents 189.7 MW out of the 262.5 MW gross capacity of its Development Projects and approximately 2,900 MW out of 3,125 MW gross capacity of its Prospective Projects.

The Corporation often teams up with a strategic partner when submitting projects in response to a Request for Proposals. When this is the case, the Corporation and the strategic partner will typically share in the ownership of such projects. Current strategic partners are TransCanada (undivided co-owner of 62% of the Cartier Wind Farms and Project), the Kanaka Bar Indian Band (owner of 50% of the Kwoiek Creek Project), the Ojibways of the Pic River First Nation (owner of 51% of the Umbata Falls Facility), the Regional County Municipality of Rivière-du-Loup (owner of 50% of the Viger-Denonville Project), Ledcor Power Group Ltd. ("**Ledcor**") (owner of 33.3% of the Fitzsimmons Creek Facility, the Boulder Creek, North Creek and Upper Lillooet Development Projects and various other Creek Power Prospective Projects) and the Mi'gmawei Mawiomi for the development of a wind farm on the Gaspe Peninsula of Québec, a project to be submitted if and when an eventual request for proposal would be announced.

OPERATING FACILITIES

The Saint-Paulin Facility, the Windsor Facility, the Chaudière Facility, the Montmagny Facility, the Portneuf Facilities, the Glen Miller Facility, the Batawa Facility, the Rutherford Creek Facility, the Ashlu Creek Facility, the Brown Lake Facility, the Miller Creek Facility, the Horseshoe Bend Facility and the Stardale Solar Farm are Operating Facilities entirely owned by the Corporation. The Corporation has an economic interest in the Umbata Falls Facility (49%), the Fitzsimmons Creek Facility (66.7%), the Douglas Creek Facility (50.0074%), the Fire Creek Facility (50.0074%), the Lamont Creek Facility (50.0074%), the Stokke Creek Facility (50.0074%), the Tipella Creek Facility (50.0074%), the Upper Stave River Facility (50.0074%), the Baie-des-Sables Wind Farm (38%), the L'Anse-à-Valleau Wind Farm (38%), the Carleton Wind Farm (38%), the Montagne Sèche Wind Farm (38%) and the Gros-Morne Wind Farm (38%). The 22 operating hydroelectric facilities have an aggregate net installed capacity of 319.3 MW (gross 408.5 MW), the 5 operating wind farms have an aggregate net installed capacity of 224.0 MW (gross 589.5 MW) and the solar photovoltaic farm has an aggregate net installed capacity of 33.2 MW (gross 33.2 MW). All Operating Facilities are operating under long-term fixed price PPAs, at the exception of Miller Creek price based on the Mid-C index, with investment grade counterparties. The Operating Facilities are set forth and further described in the following table:

Province	Plant	Gross Capacity (MW)	Equity Interests (1)	Power Purchaser	Estimated Long Term Average Generation (MWh)(2)	PPA Expiry (3)	Average price of electricity (year 2012) (4) ($ per MWh)
Hydroelectric Facilities							
Québec	Saint-Paulin	8.0	100%	Hydro-Québec	41,082	2014	78.60
Québec	Windsor	5.5	100%	Hydro-Québec	31,000	2016	90.94
Québec	Chaudière	24.0	100%	Hydro-Québec	116,651	2019	87.53
Québec	Montmagny	2.1	100%	Hydro-Québec	8,000	2021	82.56

Province	Plant	Gross Capacity (MW)	Equity Interests (1)	Power Purchaser	Estimated Long Term Average Generation (MWh)(2)	PPA Expiry (3)	Average price of electricity (year 2012) (4) ($ per MWh)
Québec	Portneuf - 1	8.0	100%	Hydro-Québec	40,822	2021	78.57
Québec	Portneuf - 2	9.9	100%	Hydro-Québec	68,496	2021	78.57
Québec	Portneuf - 3	8.0	100%	Hydro-Québec	42,379	2021	78.57
Ontario	Glen Miller	8.0	100%	OPA	41,606	2025	67.75
Ontario	Umbata Falls	23.0	49%	OPA	53,461	2028	84.18
Ontario	Batawa	5.0	100%	OEFC	32,938	2029	70.26
B.C.	Brown Lake	7.2	100%	BC Hydro	51,800	2016	69.98
B.C.	Miller Creek	33.0	100%	BC Hydro	97,900	2023	29.03
B.C.	Rutherford Creek	49.9	100%	BC Hydro	180,000	2024	56.71
B.C.	Ashlu Creek	49.9	100%	BC Hydro	265,000	2039	69.08
B.C.	Douglas Creek	27.0	50.0074%	BC Hydro	92,610	2049	86.73
B.C.	Fire Creek	23.0	50.0074%	BC Hydro	94,175	2049	88.21
B.C.	Lamont Creek	27.0	50.0074%	BC Hydro	105,173	2049	86.37
B.C.	Stokke Creek	22.0	50.0074%	BC Hydro	87,991	2049	88.00
B.C.	Tipella Creek	18.0	50.0074%	BC Hydro	69,942	2049	88.76
B.C.	Upper Stave River	33.0	50.0074%	BC Hydro	144,406	2049	87.14
B.C.	Fitzsimmons	7.5	66.7%	BC Hydro	33,000	2050	90.58
Idaho (USA)	Horseshoe Bend	9.5	100%	IPC	46,800	2030	67.91
Subtotal:		408.5			1,745,232		
Wind Farms							
Québec	Baie-des-Sables	109.5	38%	Hydro-Québec	113.360	2026	86.73
Québec	L'Anse-à-Valleau	100.5	38%	Hydro-Québec	113,240	2027	86.67
Québec	Carleton	109.5	38%	Hydro-Québec	129,398	2028	88.75
Québec	Montagne Sèche	58.5	38%	Hydro-Québec	73,492	2031	73.31
Québec	Gros-Morne	211.5	38%	Hydro-Québec	247,000	2032	80.14
Subtotal:		589.5			676,490		
Solar Farms							
Ontario	Stardale	33.2	100%	OPA	38,716	2032	349.9
Total:		**1,031.2**			**2,460,438**		

(1) The Corporation controls, with other partners, the Umbata Falls Facility, the Douglas Creek, the Fire Creek, the Lamont Creek, the Stokke Creek, the Tipella Creek, the Upper Stave River , the Fitzsimmons Creek Facility, the Baie-des-Sables Wind Farm, the L'Anse-à-Valleau Wind Farm, the Carleton Wind Farm, the Montagne Sèche Wind Farm and Gros-Morne Wind Farm.

(2) Net interest adjusted in accordance with revenue recognition accounting rules under IFRS.

(3) For several Operating Facilities, PPAs are renewable at the expiry of their initial term for an additional 20 to 25 years. However, the PPAs of the Umbata Falls, Rutherford Creek, Ashlu Creek, Fitzsimmons Creek, Douglas Creek, Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek, Upper Stave River, Horseshoe Bend, Baie-des-Sables, L'Anse-à-Valleau, Carleton, Montagne Sèche, Gros-Morne and Stardale are not renewable. The PPA for the Batawa Facility is renewable at maturity and on each one-year anniversary date thereafter for successive one-year periods. The PPA for the Miller Creek hydroelectric facility is renewable at the option of BC Hydro for two consecutive terms of five years.

(4) The Umbata Falls, Ashlu Creek, Fitzsimmons Creek, Douglas Creek, Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River hydroelectric facilities and the Baie-des-Sables, L'Anse-à-Valleau and Carleton wind farms are certified by EcoLogo and benefit from the ecoENERGY Initiative providing for an incentive payment of $10 per MWh for their first ten years of operations. For Baie-des-Sables, L'Anse-à-Valleau and Carleton wind farms, Hydro-Québec is entitled, under the PPA, to receive 75% of the total incentive payments which those wind farms receive under the ecoENERGY Initiative or any similar program. The average price of electricity is inclusive of the incentive payment. See "Industry Overview and Market Trends -Renewable Power in Canada - Federal Government Support for Renewable Power in Canada".

OPERATING HYDROELECTRIC FACILITIES

A. Saint-Paulin Facility (Québec - 100% ownership)

Description

The Saint-Paulin Facility consists of a single run-of-river hydroelectric power generating facility with a total installed capacity of 8 MW (the "**Saint-Paulin Facility**"). The Saint-Paulin Facility is located in the Municipality of Saint-Paulin, approximately 20 km west of Shawinigan, Québec.

The Saint-Paulin Facility receives its water from the Rivière-du-Loup which has its source in the Mastigouche Reserve, north of Saint-Paulin, and benefits from a total drainage area of 1,372 square kilometers.

The site where the Saint-Paulin Facility is located is known locally as Les Chutes à Magnan. The intake structure is constructed on the west bank of the river in a concrete structure equipped with trash racks. The powerhouse has an architectural treatment consistent with its environment and holds a double runner horizontal Francis turbine. The Saint-Paulin Facility is fully automated and may be operated locally or remotely. The Saint-Paulin Facility is connected to the grid of Hydro-Québec through a short overhead line.

As part of a project with Concept Eco-Plein-Air Le Baluchon Inc. ("**Baluchon**"), Innergex, L.P. undertook a number of improvements to the site with respect to its recreational potential and facilitating public access. These include two pedestrian foot bridges, one at the head of the falls and the other 500 meters downstream. A system of footpaths was also constructed on both banks to access the bridges. A number of lookouts over the falls have also been constructed.

Site and Water Rights

The rights with respect to the Saint-Paulin Facility site, other than river bed and water rights, were initially acquired by Baluchon from La Compagnie d'électricité Shawinigan (a subsidiary of Hydro-Québec) pursuant to an emphyteutic lease executed on December 14, 1993 and amended on May 18, 1994 (the "**Saint-Paulin Emphyteutic Lease**"). Pursuant to the Saint-Paulin Emphyteutic Lease, Baluchon undertook to make improvements to the leased property, namely the construction of a hydroelectric power plant and dam. The Saint-Paulin Emphyteutic Lease has a 20-year term from the commercial operation date of the Saint-Paulin Facility and will expire simultaneously with the Saint-Paulin PPA on November 29, 2014. The Saint-Paulin Emphyteutic Lease may be renewed for an additional 20-year period, on the same terms and conditions if the Saint-Paulin PPA is also renewed for the same period.

Other than river bed and water rights, Baluchon leases the Saint-Paulin Facility site to Innergex, L.P. pursuant to a lease and superficies agreement executed on December 29, 1993 (the "**Superficies Lease**") in which Innergex, L.P. acquired, among other rights, rights to construct and operate the Saint-Paulin Facility. The term of the Superficies Lease is 20 years from the commercial operation date of the Saint-Paulin Facility and will expire simultaneously with the Saint-Paulin PPA on November 29, 2014. The Superficies Lease may be renewed for an additional 20-year term if the Saint-Paulin PPA is also renewed for the same period. Pursuant to the terms of the Superficies Lease, Innergex, L.P. assumed all obligations of Baluchon under the Saint-Paulin Emphyteutic Lease including, construction of the power plant and payment of the royalty payable by Baluchon to La Compagnie d'électricité Shawinigan.

The water rights and river bed with respect to the Saint-Paulin Facility were conveyed to Baluchon pursuant to a lease of hydraulic forces executed between Baluchon and the ministre des Ressources naturelles and the ministre de l'Environnement et de la Faune on August 23, 1996 (the "**Baluchon Lease**"). Innergex, L.P. intervened in the Baluchon Lease to assume all of Baluchon's obligations thereunder. An agreement was also entered into between Baluchon and Innergex, L.P. pursuant to which all of Baluchon's rights and obligations under the Baluchon Lease were assigned, and a right in the river bed and water rights in respect of the Saint-Paulin Facility were granted, to Innergex, L.P. (the "**Innergex Lease**"). The Baluchon Lease expires simultaneously with the Saint-Paulin PPA on November 29, 2014 and the Innergex Lease expires simultaneously with the Superficies Lease. The Baluchon Lease is renewable for an additional 20-year period on conditions to be determined by the ministre des Ressources naturelles and the ministre de l'Environnement et de la Faune.

Upon expiry or other termination of the Saint-Paulin Emphyteutic Lease, the Superficies Lease, the Baluchon Lease or the Innergex Lease, the facilities and other improvements erected on the premises will become the property of one of Baluchon, La Compagnie d'Électricité Shawinigan or the government of Québec, depending on the nature of the terminated right involved.

Power Purchase Agreement

The PPA with respect to the electricity produced by the Saint-Paulin Facility (the "**Saint-Paulin PPA**") has an initial term of 20 years expiring November 29, 2014 and is renewable for a further period not to exceed 20 years. The agreed minimum annual power to be delivered to Hydro-Québec under the Saint-Paulin PPA is 29,609 MWh and the agreed maximum annual power to be delivered is 45,552 MWh for a 365-day year.

The price of the delivered electricity payable by Hydro-Québec is based on a formula set forth in the Saint-Paulin PPA which is adjusted annually, on December 1 of each year, in accordance with the year-over-year change in the CPI, subject to a minimum increase of 3% per annum and a maximum increase of 6% per annum.

B. Windsor Facility (Québec - 100% ownership)

Description

The Windsor Facility is a simple generating station of run-of-river hydroelectricity of a working installed capacity of 5.5 MW. It is located on the St-François River, close to the town of Windsor (the "**Windsor Facility**"). The Windsor Facility was brought into commercial operation in 1996, and the Trust initially acquired it on April 27, 2004.

The Windsor Facility obtains water from the Saint-François, Magog, Massawippi and Coaticook Rivers which have an aggregate drainage area of approximately 8,150 square kilometers comprised of the St-François, Aylmer and Memphrémagog lakes. The power station is located on a site where an old power station was located at the site of a paper mill owned by Domtar. The paper mill was demolished, the power station entirely rebuilt and is now fully automated and may be operated locally as well as remotely. The power generated is transmitted to Hydro-Québec's grid through a short overhead line.

Site and Water Rights

The site of the Facility, the hydraulic forces, the bed of the river as well as the river banks always belong to Domtar and have been leased to Hydro-Windsor pursuant to an emphyteutic lease having an initial term of 42 years, ending on June 6, 2036.

Power Purchase Agreement

The PPA with respect to the electricity payable by Hydro-Québec produced by the Windsor Facility (the "**Windsor PPA**") has an initial term of 20 years expiring on May 28, 2016 and is renewable for a further period not to exceed 20 years. The electricity to be delivered annually by the Windsor Facility during a typical year is 31,000 MWh. The agreed upon minimum annual power to be delivered to Hydro-Québec under the Windsor PPA is 26,280 MWh and the agreed upon maximum annual power to be delivered is 43,800 MWh.

The price of delivered electricity payable by Hydro-Québec is based on a formula set forth in the Windsor PPA which is adjusted annually, on December 1 of each year, in accordance with the inflation rate of the CPI, subject to a minimum increase of 3% per annum and a maximum increase of 6% per annum. Hydro-Québec pays a power rate premium for electricity delivered during winter based on a formula set forth in the Windsor PPA.

C. Chaudière Facility (Québec - 100% ownership)

Description

The Chaudière Facility consists of a single run-of-river hydroelectric power generating station with a total installed capacity of 24 MW and is located on the Chaudière River, near the town of Lévis, Québec, on the south shore of the St-Lawrence River (the "**Chaudière Facility**").

The Chaudière Facility receives its water from the Chaudière River which has an upstream drainage area of approximately 6,605 square kilometers comprising the Lac Megantic and the Beaurivage River.

The Chaudière Facility holds two horizontal double regulated Kaplan-type turbines. The Facility is fully automated and may be operated locally or remotely. The powerhouse is located on the west bank of the Chaudière River and the power generated is transmitted to the Hydro-Québec grid through a 200 meter overhead line.

Site and Water Rights

Innergex, L.P. is a party to a purchase and lease agreement executed on March 12, 1998 with the ministre des Ressources naturelles and the ministre de l'Environnement et de la Faune with respect to the purchase of certain parcels of land and the existing dam and of the equipment contained therein, as well as the lease of certain parcels of land, hydraulic forces and a portion of the bed of the Chaudière River (the "**Chaudière Lease Agreement**"). The term of the Chaudière Lease Agreement is 20 years from the commercial operation date of the Chaudière Facility and expires simultaneously with the Chaudière PPA on March 14, 2019. The Chaudière Lease Agreement may be renewed for an additional 20-year period on conditions to be determined by the ministre des Ressources naturelles and the ministre de l'Environnement et de la Faune. The Chaudière Lease Agreement also grants flooding rights on the river banks forming part of the public domain, as well as rights of way and electrical power lines.

The Chaudière Lease Agreement may be terminated by the ministre des Ressources naturelles and the ministre de l'Environnement et de la Faune upon, among other events, the termination of the Chaudière PPA.

Power Purchase Agreement

The PPA with respect to the electricity produced by the Chaudière Facility (the "**Chaudière PPA**") has an initial term of 20 years expiring on March 14, 2019 and is renewable for a further period not to exceed 20 years. The agreed minimum annual power to be delivered to Hydro-Québec by the Chaudière Facility under the Chaudière PPA is 78,577 MWh and the agreed maximum annual power is 130,962 MWh for a 365-day year.

The price of the delivered electricity payable by Hydro-Québec is based on a formula set forth in the Chaudière PPA which is adjusted annually, on December 1 of each year, in accordance with the year-over-year change in the CPI, subject to a minimum increase of 3% per annum and a maximum increase of 6% per annum. Hydro-Québec pays a power rate premium for electricity delivered during winter based on a formula set forth in the Chaudière PPA.

D. Montmagny Facility (Québec - 100% ownership)

Description

The Montmagny Facility consists of a single run-of-river hydroelectric power generating facility with an installed capacity of 2.1 MW (the "**Montmagny Facility**"). It is located on the Rivière du Sud, in the town of Montmagny on the south shore of the St-Lawrence River, between Québec City and Rivière-du-Loup. The Montmagny Facility was commissioned in May 1996 and purchased by Innergex Montmagny, L.P. on December 19, 2000 from Hydro Montmagny Inc.

The Montmagny Facility obtains water from Rivière du Sud which has a drainage area of approximately 1,927 square kilometers. The plant was upgraded in 2001 to be fully automated and may be operated locally as well as remotely. The power generated is transmitted to Hydro-Québec's grid through a short overhead line. Following improvements made in 2005, the powerhouse holds three single regulated Kaplan-type turbines and two double regulated Kaplan-type turbines.

Site and Water Rights

Hydro Montmagny Inc. was originally party to a lease agreement executed on June 1, 1995 and amended July 27, 1995 with the ministre des Ressources naturelles with respect to the lease of hydraulic forces and a portion of the bed of the Rivière du Sud; such lease was assigned to Innergex Montmagny, L.P. (then known as Innergex II, Limited Partnership) on December 19, 2000 (the "**Montmagny Lease Agreement**"). The term of the Montmagny Lease Agreement is 20 years from the commercial operation date of the Montmagny Facility expiring on May 23, 2016. The Montmagny Lease Agreement may be renewed for an additional 20-year period on conditions to be determined by the ministre des Ressources naturelles.

The fee is adjusted annually in accordance with the inflation rate of the CPI for Canada. The Montmagny Lease Agreement may be terminated by the ministre des Ressources naturelles upon, among other events, termination of the Montmagny PPA. Upon expiry of the term or termination of the Montmagny Lease, the facilities and other improvements erected on the premises will become the property of the government of Québec, unless the latter waives this right.

Power Purchase Agreement

The PPA with respect to the electricity payable by Hydro-Québec produced by the Montmagny Facility (the "**Montmagny PPA**") has an initial term of 25 years expiring on May 28, 2021, and is renewable for a further period not to exceed 25 years. The Montmagny PPA does not specify minimum annual power deliveries.

The price of delivered electricity payable by Hydro-Québec is based on a formula set forth in the Montmagny PPA which is adjusted annually, on December 1 of each year, in accordance with the inflation rate of the CPI, subject to a minimum increase of 3% per annum and a maximum increase of 6% per annum. Hydro-Québec pays a power rate premium for electricity delivered during winter based on a formula set forth in the Montmagny PPA.

E. Portneuf Facilities (Québec - 100% ownership)

Description

The Portneuf Facilities consist of three run-of-river hydroelectric power-generating stations with a total installed capacity of 25.9 MW (the "**Portneuf Facilities**"). The Portneuf Facilities are located on the Portneuf River in Sainte-Anne-de-Portneuf and Saint-Paul-du-Nord-Sault-au-Mouton within the Seigneurie des Milles-Vache, which includes rights to the lands, riverbed, hydraulic and fishing. The Portneuf River has an effective drainage area of 3,110 square kilometers and originates from Lac Portneuf. Sainte-Anne-de-Portneuf is located 300 km east of Québec City.

The PN-1 Facility is located 4 km upstream from the mouth of the river at Chute du Quatre-Milles. The powerhouse is constructed within the east bank and holds two double regulated "S"-type Kaplan turbines. The PN-1 Facility has an installed capacity of 8 MW.

The PN-2 Facility is located at Chute Philias, a further 6.5 km upstream of the PN-1 Facility. The site was developed using a diversion weir, intake and an 800 meter long tunnel to the downstream powerhouse which has two double runner horizontal Francis turbines. The PN-2 Facility has an installed capacity of 9.9 MW.

The PN-3 Facility is located at Rapide des Crans Serrés, a further 19.5 km upstream of the PN-2 Facility on the Portneuf River. The powerhouse is constructed on the east bank and houses two double regulated "S"-type Kaplan turbines identical to those installed in the PN-1 Facility powerhouse. The PN-3 Facility has an installed capacity of 8 MW.

The Portneuf Facilities are fully automated and may be operated locally or remotely and are connected to the grid of Hydro-Québec at an interconnection point in Portneuf-sur-Mer through a privately owned transmission line.

Site and Water Rights

On August 15, 1991, Innergex Inc. entered into an emphyteutic lease with Stone-Container (Canada) Inc. for the development rights of PN-1, PN-2 and PN-3 facilities on the Portneuf River; that emphyteutic lease was amended on October 31, 1991, transferred by Innergex Inc. to Innergex, L.P. on May 21, 1993 and was further amended thereafter (the "**Portneuf Emphyteutic Lease**"). On January 26, 2002, the site was sold by Stone-Container (Canada) Inc. to 3908666 Canada Inc.

Pursuant to the Portneuf Emphyteutic Lease, a right to the land and associated development rights were granted to Innergex, L.P. in connection with the Portneuf Facilities, including all assets, rights of way, water powers and other rights relating to the leased premises and Innergex, L.P. undertook to make improvements to the site, namely the construction of 3 power plants and dams. The term of the Portneuf Emphyteutic Lease expires on the last day of December 2025, and may be renewed, at the option of Innergex, L.P., for an additional 25-year period, on the same terms and conditions.

Upon expiry or termination of the Portneuf Emphyteutic Lease, the facilities and other improvements erected on the premises will become the property of 3908666 Canada Inc., unless the latter waives this right.

Power Purchase Agreement

The PPA with respect to the electricity produced by the Portneuf Facilities (the "**Portneuf PPA**") has an initial term of 25 years expiring May 3, 2021 and is renewable for a further period not to exceed 25 years. The agreed minimum annual power to be delivered to Hydro-Québec by the Portneuf Facilities under the Portneuf PPA is 106,478 MWh and the agreed maximum annual power is 163,812 MWh for a 365-day year.

The price of delivered electricity payable by Hydro-Québec is based on a formula set forth in the Portneuf PPA and is adjusted annually, on December 1 of each year, in accordance with the inflation rate of the CPI, subject to a minimum increase of 3% per annum and a maximum increase of 6% per annum.

On September 27, 2002, Hydro-Québec initiated a partial diversion of the waters naturally flowing in the Portneuf River towards the Bersimis River's basin effectively reducing the flow available for the Portneuf Facilities. Since the date of such diversion, the penalties for delivering less than the agreed upon minimum annual power are no longer applicable. Considering that the Portneuf River's flow is reduced in a way which reduces the amount of water available for the generation of electricity by the Portneuf Facilities, the Portneuf PPA provides that Innergex, L.P. shall receive cash compensation for lost revenues directly resulting from the diversion.

F. Glen Miller Facility (Ontario - 100% ownership)

Description

The Glen Miller Facility is an 8 MW run-of-river hydroelectric facility located on the Trent River in Trenton, Ontario (the "**Glen Miller Facility**"), at the site of a paper mill and a small power plant operated by Sonoco Canada Corporation ("**Sonoco**") until October 2001. Construction of the Glen Miller Facility began in January 2004 and was completed in December 2005.

The generating equipment of the Glen Miller Facility is composed of two 4 MW "Ecobulb" groups with simple regulated Kaplan type turbines to maximize output of approximately 8 MW, with an estimated average energy output of 41,606 MWh per year. The Trent River has a mean annual runoff of 148 cubic metres per second and the Glen Miller Facility has a design flow of 142 cubic metres per second. The Glen Miller Facility includes a dam, which was rehabilitated and improved during renovation by raising the crest, increasing the spill capacity by installing four new automated gates and building a new dyke to prevent any flooding of adjacent properties as had occasionally occurred in the past.

Site and Water Rights

The Glen Miller Facility is located on a site owned by Sonoco and leased to Glen Miller LP under a 30-year long-term lease, expiring in 2035, with a 15-year extension option in favour of Glen Miller LP, the terms and conditions of which are to be agreed upon by the parties. No water power lease is required for this site, as Sonoco has held title to the bed of the river on a continuous basis since the 19th century and as such has acquired the right to generate electricity at this site, with no payments due to provincial or federal authorities which would otherwise control hydraulic rights on the river. Such river bed rights are included in Glen Miller LP's long-term lease from Sonoco. Pursuant to a registered agreement of encroachment dated November 16, 2004, the City of Quinte West granted Glen Miller LP permission to encroach on a municipal roadway for the purpose of maintaining a retaining wall in accordance with the registered site plan.

Glen Miller LP holds a licence of occupation from Parks Canada, expiring on August 1, 2025, authorizing the Glen Miller Facility to occupy a tract of the Trent-Severn Waterway reserve land for the purpose of flooding in the context of the hydroelectric power generation. A 20-year fixed nominal annual rent of 0.7% of the initial PPA contract price (indexed for a 15% portion to the CPI) is payable annually under this Licence of Occupation.

Power Purchase Agreement

The Glen Miller Facility has a PPA with the OPA for all the power produced by the Glen Miller Facility during the 20 years following December 19, 2005. The Glen Miller Facility PPA is subject to customary termination provisions in the event of a material breach of the agreement. On January 1 of each year, a portion equal to 15% of the price of electricity purchased under the Glen Miller Facility PPA is indexed to the percentage increase or decrease in the CPI since January 1 of the previous year.

G. Umbata Falls Facility (Ontario - 49% ownership)

Description

The Umbata Falls Facility is a run-of-river hydroelectric power generating facility with an installed capacity of 23 MW (the "**Umbata Falls Facility**"). It is located on the White River, a tributary of Lake Superior, approximately 30 kilometres southeast of Marathon, Ontario. The Umbata Falls Facility commenced commercial operation on November 12, 2008. The generating equipment is comprised of two Sam Kaplan 11.8 MW horizontal axis turbine units with a combined rated flow of 75 cubic metres per second.

The Umbata Falls Facility is owned by Umbata Falls LP. The general partner of Umbata Falls LP is Begetekong Power Corporation ("**Begetekong**"), 49% of which is indirectly owned by the Corporation and the remaining 51% of which is owned by the Ojibways of the Pic River First Nation. The limited partners of Umbata Falls LP are the Ojibways of the Pic River First Nation (51% interest) and a subsidiary of the Corporation (49% interest). Pursuant to a management agreement entered into between the Corporation, Begetekong and Umbata Falls LP dated December 31, 2006, the Corporation has agreed to provide management services for the Umbata Falls Facility, including administrative, construction, operation, maintenance and other related services.

Site and Water Rights

In accordance with a permit issued by the Ministry of the Environment pursuant to the *Ontario Water Resources Act*, the Umbata Falls Facility is authorized to take water for storage in the Umbata Falls head pond for power generation. This permit expires on May 31, 2016 and the Corporation expects such permit to be renewed upon maturity. The Corporation holds all material regulatory approvals for the operation of the Umbata Falls Facility.

The Umbata Falls Facility is located on public land in respect of which a Crown lease dated June 5, 2007 was granted in favour of Begetekong, the general partner of Umbata Falls LP. The lease expired upon the execution of a waterpower lease agreement on November 4, 2009 and has an initial 30-year term, renewable for additional ten-year terms commencing on August 1st, 2009. Umbata Falls LP also holds an electricity generation licence pertaining to the Umbata Falls Facility issued by the OEB which is valid until September 8, 2025.

Power Purchase Agreement

The Umbata Falls Facility has a PPA with the OPA for all the power that will be produced by the facility during the 20 years following the commencement of commercial operation of the Umbata Falls Facility which was set to November 12, 2008. The Umbata Falls Facility PPA is subject to customary termination provisions in the event of a material breach of the agreement. On January 1 of each year during the term of the Umbata Falls Facility PPA, a portion equal to 15% of the price of electricity purchased under the PPA is indexed to the percentage increase or decrease in the CPI effective as of January 1 of the prior year.

H. Batawa Facility (Ontario - 100% ownership)

Description

The Batawa Facility consists of a single run-of-river hydroelectric generating station with an installed capacity of 5 MW and is located on the Trent-Severn Waterway, near the town of Trenton, Ontario (the "**Batawa Facility**"). IHI acquired Trent-Severn Power Corporation in June 1998 and at, that time, contracted with the management of Innergex Inc. to provide project development and management services. The Batawa Facility was commissioned in December 1999 and commercial operation commenced in March 2000.

The Batawa Facility draws water from the Trent-Severn Waterway which has a drainage area of approximately 12,500 square kilometers comprising the following lakes: Balsam, Sturgeon, Buckhorn, Stony and Rice.

The Batawa Facility holds one double regulated Kaplan turbine. The plant is fully automated and may be operated locally or remotely. The power generated is transmitted to Hydro One Networks Inc.'s distribution system through a short overhead line.

Site and Water Rights

The Batawa Facility has secured a license from the government of Canada (Minister of Canadian Heritage) granting the permission to occupy land and to use surplus water for the purpose of generating electrical power (the "**License**"). The License is valid from January 1, 2001 to December 31, 2030, and is renewable on conditions to be determined by the Minister of Canadian Heritage. The rent payable under the License is adjusted annually in accordance with the inflation rate of the CPI for Canada for the first ten years, and will subsequently be adjusted to rental rates in force at the time. Both the rent and fee payable under the License may be revised from time to time by the Minister of Canadian Heritage.

Power Purchase Agreement

The PPA with respect to the electricity produced by the Batawa Facility, entered into with OEFC (the "**Batawa PPA**") has an initial term of 30 years expiring on December 20, 2029 and will subsequently remain valid unless a party to the Batawa PPA gives the other party thereto a one year prior cancellation notice. The Batawa PPA does not specify annual minimum or maximum annual power deliveries.

For the first 10 years, the Batawa PPA differentiates "on-peak rates" between 7 AM and 11 PM, during week days, excluding public holidays, and "off-peak rates" for the rest of the time. For the 20 subsequent years, the Batawa PPA provides for rates equal to the greater of the rates applicable in the preceding 10 years, and the rates for "new renewable resource based and new high-efficiency energy conversion projects". The latter rates are adjusted annually in accordance with the Ontario Consumer Price Index as published by Statistics Canada. Discussions are ongoing with OEFC in respect of the rates which will apply during the 20 subsequent years.

OEFC may discontinue the receipt of the electrical power produced by the Batawa Facility and ultimately terminate the Batawa PPA upon a reasonable notice if there is a violation of any term or condition of the Batawa PPA and such violation is not remedied within the appropriate cure period.

OEFC has indicated to the holders of existing PPAs that it wishes to negotiate the amendment and/or restatement of the PPAs to adapt them and make them consistent with the restructured Ontario electricity market or alternatively enter into new PPAs. OEFC has submitted a replacement PPA to Trent-Severn Power Corporation. Other than the changes made to address the restructured Ontario electricity market and changes made to clarify OEFC's position on certain matters contained in the Batawa PPA, the terms of the replacement PPA are similar to the terms of the Batawa PPA. Trent-Severn Power Corporation has not yet entered into the replacement PPA and has continued to operate and receive payments under the Batawa PPA since the opening of the new Ontario electricity market. The Electricity Pricing, Conservation and Supply Act, 2002 does not contain specific provisions which relate to or may affect the Batawa PPA**.**

I. *Brown Lake Facility (British Columbia - 100% ownership)*

Description

The Brown Lake Facility is a run-of-river hydroelectric power generating facility with an installed capacity of 7.2 MW. It is located on the Ecstall River approximately 45 km southeast of Prince Rupert, British Columbia.

The Brown Lake Facility achieved commercial operation on December 12, 1996. The generating equipment of the Brown Lake Facility is one horizontal Francis turbine. The Brown Lake Facility substation is located on the east Bank of the Ecstall River immediately adjacent to the 60kv Falls River transmission line of BC Hydro.

The Brown Lake Facility is owned by Brown Miller Power Limited Partnership ("**Brown Miller LP**"). The general partner of Brown Miller LP is Brown Miller Power GP Inc. (the "**Brown Miller GP**"), a direct wholly-owned subsidiary of the Corporation. The Corporation acquired all of the limited partnership interests in Brown Miller LP, and Brown Miller GP acquired the general partnership interest in Brown Miller LP, on October 12, 2012.

Site and Water Rights

The Brown Lake Facility is located on both private land, with respect to the powerhouse, and Crown land which is subject to a license of occupation and rights of way in relation to (i) the transmission and substation (ii) the intake house, intake shaft and tunnel and (iii) the pipeline road and tunnel intake.

Pursuant to water licenses appurtenant to the Crown lands described above, the Brown Lake Facility is authorized to divert and use water as follows:

- up to a maximum of 136.8 cubic feet per second from Brown Lake for generation of up to 3.46 MW of electricity in accordance with a conditional water licence issued pursuant to the *Water Act* (British Columbia) (the "***Water Act***") on May 25, 1995;
- up to a maximum of 141.25 cubic feet per second from Brown Creek and Brown Lake for generation of up to 3.54 MW of electricity and to store water up to a maximum of 23,300 acre feet per annum in the Brown Lake reservoir, all in accordance with a conditional water licence issued pursuant to the *Water Act* on May 25, 1995, as amended; and
- up to a maximum of 150 cubic feet per second from McKnight Lake for storage in the Brown Lake reservoir in accordance with a conditional water licence issued pursuant to the *Water Act* on September 25, 1997, as amended.

Power Purchase Agreement

The Brown Lake Facility has a PPA entered into with BC Hydro (the "**Brown Lake PPA**") for the purchase of all energy generated by the Brown Lake Facility. The Brown Lake PPA has a term of 20 years following COD which will expire December 11, 2016, after which the Brown Lake PPA will continue in force under the same terms subject to either party's right to terminate upon six months' notice. The purchase price for electricity under the Brown Lake PPA is subject to a 3% escalator each year.

J. Miller Creek Facility (British Columbia – 100% ownership)

Description

The Miller Creek Facility consists of a run-of-river hydroelectric power generating facility with an installed capacity of 33 MW located near Pemberton, in British Columbia (the "**Miller Creek Facility**"). The Miller Creek Facility achieved commercial operation on October 2, 2003. Its powerhouse is equipped with two units, a main 30.0 MW vertical axis Pelton wheel turbine and a 3.0 MW horizontal axis Pelton wheel turbine.

The Miller Creek Facility is owned by Brown Miller LP, and was indirectly acquired by the Corporation upon the Corporation's acquisition of all of the limited and general partnership interests in Brown Miller LP on October 12, 2012.

Site and Water Rights

The Miller Creek Facility is located on Crown land which is subject to licences of occupation for the powerhouse, road access and certain storage areas and statutory rights of way for the transmission line, telecommunication line, penstock and intake. The Corporation is in the process of converting its licence of occupation for the powerhouse into a long term lease.

The Miller Creek Facility is authorized to divert and use water up to a maximum of 5.5 cubic meters per second on Miller Creek and South Miller Creek and to take water for storage of up to 23,300 acre feet per year, in accordance with a water licence issued pursuant to the *Water Act* on August 15, 2003.

Power Purchase Agreement

The Miller Creek Facility has a PPA entered into with BC Hydro (the "**Miller Creek PPA**") for the purchase of all energy generated by the Miller Lake Facility. The Miller Creek PPA has a term of 20 years following the COD which will expire on October 1, 2023, with BC Hydro holding two consecutive five-year renewal options. The purchase price for electricity under the Miller Creek PPA is based on a formula using the Dow Jones Mid-C pricing indices.

K. Rutherford Creek Facility (British Columbia 100% ownership)

Description

The Rutherford Creek Facility consists of a run-of-river hydroelectric power generating facility with an installed capacity of 49.9 MW located southwest of Pemberton, British Columbia, approximately 21 km north from Whistler and 130 km north of Vancouver (the "**Rutherford Creek Facility**"). The Rutherford Creek Facility has a drainage area which is fed by melted water from the Appa and Ipsoot Glacier.

Construction of the Rutherford Creek Facility began in August 2002 and it was brought into commercial operation on May 31, 2004. The Rutherford Creek Facility was initially acquired by the Fund on December 15, 2005.

The generating equipment is composed of two six jet 24.95 MW vertical Pelton turbines, with a rated flow of 17.2 cubic meters per second and fed by a 9.3 km long penstock. The power generated by the facility is delivered to BC‑Hydro via a 230 kV line running along the Green River valley.

Site and Water Rights

The Rutherford Creek Facility is authorized to divert and use water annually up to 18.4 cubic meters per second from Rutherford Creek and Ipsoot Creek pursuant to a conditional water license issued pursuant to the Water Act on October 29, 2002, as amended on January 31, 2006. The conditional water license will remain in force as long as Rutherford Creek LP (i) continues to use the water pursuant to the terms of its license; (ii) pays its annual rent; and (iii) conforms to the conditions of its license and of the *Water Act*. The Rutherford Creek Facility is located on Crown lands which are subject to a lease of occupation issued by the Ministry of Sustainable Resource Management of British Columbia dated October 13, 2005 pursuant to the *Land Act* (British Columbia). This lease of occupation is for a 30‑year period and expires on October 13, 2035.

Power Purchase Agreement

The standard electricity purchase agreement entered into as of June 12, 2002 with BC Hydro (the "**Rutherford Creek PPA**") has a term of 20 years following the COD, and is subject to customary termination provisions in the event of a material breach of the agreement. The Rutherford Creek PPA contemplates the purchase by BC Hydro of all electricity generated by the Rutherford Creek Facility.

On January 1 of each year, the price per MWh is increased or decreased by a percentage equal to 50% of the increase or decrease of the CPI for Canada during the preceding 12 months starting January 1, 2004 and on each January 1 thereafter during the term of the Rutherford Creek PPA.

BC Hydro has retained at no additional cost all rights, titles, interests and benefits in and to any and all green rights and emission reduction rights.

L. Ashlu Creek Facility (British Columbia - 100% ownership)

Description

The Ashlu Creek Facility is a run-of-river hydroelectric power generating facility with a nameplate capacity of 49.9 MW (the "**Ashlu Creek Facility**"). It is located on Ashlu Creek, a tributary of the Squamish River, approximately 35 kilometres northwest of Squamish, British Columbia. Construction of the Ashlu Creek Facility commenced in August 2006 and commercial operation commenced on November 29, 2009. The generating equipment of the Ashlu Creek Facility is comprised of three 16.6 MW Francis turbines. The 230 kV transmission line is approximately three kilometres long and taps into an existing British Columbia Transmission Corporation ("**BCTC**") line.

The Ashlu Creek Facility is owned by Ashlu Creek Investments Limited Partnership ("**Ashlu Creek LP**"). The general partner of Ashlu Creek LP is 675729 British Columbia Ltd, which is indirectly wholly-owned by the Corporation.

Site and Water Rights

The Ashlu Creek Facility is authorized to divert and use water up to a maximum of 29 cubic metres per second from Ashlu Creek in accordance with a water licence issued pursuant to the *Water Act* on July 10, 2006. The water licence has been issued for a term of 40 years expiring on July 9, 2046. The Ashlu Creek Facility is primarily located on Crown land which is subject to a Licence of Occupation pursuant to the *Land Act* (British Columbia). The licence commenced on January 1, 2005 and had a term of five years which expired on December 31, 2009. The license of occupation was replaced by a long-term registered lease for the powerhouse and statutory rights of way for the transmission line, telecommunication line, penstock and intake. The lease and the statutory rights of way are for a 30-year period and expire on November 29, 2039.

The Squamish First Nation is entitled to a royalty based on revenues of the Ashlu Creek Facility from the date of commencement of commercial operation. The Squamish First Nation is also entitled to an incremental share of gross revenues exceeding a yearly threshold of gross revenues set out in the agreement. The agreement also requires the assets of the Ashlu Creek Facility to be transferred to the Squamish First Nation for a nominal price after 40 years of commercial operation.

Power Purchase Agreement

The Ashlu Creek Facility has a PPA with BC Hydro for all the power produced by the Ashlu Creek Facility for the 30 years following November 29, 2009 and subject to customary termination provisions in the event of a material breach of the agreement. The base price for electricity purchased from the Ashlu Creek Facility is adjusted by a percentage equal to 50% of the increase or decrease in the CPI during the preceding 12 months, effective January 1, 2009 and on each January 1 thereafter during the term of the Ashlu Creek Facility PPA.

M. Harrison Operating Facilities (British-Columbia - 50.0074% ownership)

Description

The Corporation owns a 50.0074% interest in the Harrison Operating Facilities indirectly through ownership of 50.0074% of the issued and outstanding limited partnership units of Cloudworks Holdings Limited Partnership ("**CHLP**"), and ownership of 50% of the issued and outstanding shares of Cloudworks Holdings Inc. ("**CHI**"), the general partner of CHLP. The balance of the limited partnership units of CHLP are owned by Connor Clark & Lunn Harrison Hydro Project Limited Partnership ("**CC&L**") (34.9926%), and by Fengate LPF GP Inc., as general partner of LPF Infrastructure Fund which is managed by Fengate Capital Management Ltd. (15%). The balance of the shares of CHI (50%) is owned by CC&L Infrastructure Ltd., the general partner of CC&L.

All six of the Harrison Operating Facilities connect to BC Hydro's high voltage transmission system at a shared 138 kV/360 kV substation located next to BC Hydro's Upper Harrison Terminal (the "**UHT**") adjacent to the Lillooet River and BC Hydro's 3L2 and 3L5 transmission lines (the "**Kwalsa Substation**"). Each of the Harrison Operating Facilities has a substation transforming the generation voltage from 6.9 kV to 138 kV and delivered to the Kwalsa Substation via a private 138 kV transmission line. The energy is transformed to 360 kV at the Kwalsa Substation. The energy is then delivered to the point of interconnection at the UHT. There are three statutory rights of way for the transmission line granted in favour of HHPI, the general partner of each of the Project LPs that expire in 2051.

Power Purchase Agreements

BC Hydro has committed to purchase power produced by the Harrison Operating Facilities pursuant to two 40-year PPAs. One PPA is in respect of four facilities which have an aggregate installed capacity of 90 MW: the Douglas Creek Facility, the Fire Creek Facility, the Stokke Creek Facility and the Tipella Creek Facility. The other PPA is in respect of two projects which have an aggregate installed capacity of 60 MW: the Upper Stave River Facility and the Lamont Creek Facility. The average price for electricity purchased under the PPAs for the Harrison Operating Facilities is adjusted annually by a portion of CPI.

(i) Douglas Creek Facility

Description

The Douglas Creek Facility is a run-of-river hydroelectric facility with an installed capacity of 27 MW (the "**Douglas Creek Facility**"). Construction of the Douglas Creek Facility commenced in May 2007 and COD was achieved on October 19, 2009. The Douglas Creek Facility uses the hydraulic resources of the lower reaches of Douglas Creek, with the point of diversion 3.1 km upstream from the powerhouse, which in turn is 1 km upstream of the confluence of Douglas Creek with Little Harrison Lake. The Douglas Creek Facility is equipped with two 13.5 MW Pelton turbines and its output is delivered by a 300 meter long 138 kV transmission line to a 6.8 km transmission line that is shared with the Stokke Creek Facility and then shares the 3.2 km long Fire Creek Facility transmission line to the UHT.

Site and Water Rights

The Douglas Creek Facility is authorized to divert and use water up to a maximum of 11.3 cubic metres per second from Douglas Creek in accordance with a water licence issued pursuant to the *Water Act* on November 9, 2006. The water licence has been issued for a term of 40 years expiring on November 8, 2046.

The Douglas Creek Facility is primarily located on reserve lands of the Douglas Indian Band known as Douglas Indian Reserve Number 8. The Douglas Indian Band applied to the Minister of Indian and Northern Development Canada (the "**MOI**") for the grant of a lease of two lots to the Takem Ti Qwelsa 7 Eco Resource Corporation ("**Takem Corp**") and for a sublease of one lot from Takem Corp to DCPLP, and for the sublease of the other lot from Takem Corp to HHLP, the limited partner of DCPLP. A referendum was held by the Douglas Indian Band to decide whether a portion of the Douglas Indian Reserve lands can be designated for the Douglas Creek Facility, which referendum was successful.

A lease from MOI was granted to Takem Corp in 2006 for a term of 98 years, expiring in 2104. A sublease for the penstock, powerhouse and transmission lines, was entered into between Takem Corp and DCPLP in 2007 expiring on the earlier of: (i) August 29, 2104 and (ii) the 60th anniversary of the date on which commercial delivery of electricity begins from the Douglas Creek Facility. A second lease from MOI was granted to Takem Corp in 2007 for a term of 97 years, expiring in 2104. A sublease was entered into between Takem Corp and HHLP in 2007, expiring in 2104.

A statutory right of way for the intake and penstock expiring in 2051 was granted in favour of HHPI, the general partner of DCPLP, in November 2009. A statutory right of way for a transmission line expiring in 2051 for both the Douglas Creek Facility and the Stokke Creek Facility was granted in favour of HHPI in November 2010. A statutory right of way for a transmission line for all six Harrison Operating Facilities expiring in 2051 was granted in favour of HHPI in September 2010.

(ii) Fire Creek Facility

Description

The Fire Creek Facility is a run-of-river hydroelectric facility with an installed capacity of 23 MW (the "**Fire Creek Facility**"). Construction of the Fire Creek Facility commenced in May 2007 and COD was achieved on October 19, 2009. The Fire Creek Facility uses the hydraulic resources of the lower reaches of Fire Creek, with the point of diversion 4.3 km upstream from the powerhouse, which in turn is 1 km upstream of the confluence of Fire Creek with the Lillooet River, 6 km upstream of its discharge into Harrison Lake. The Fire Creek Facility is equipped with two 11.5 MW Pelton turbines and its output is delivered by a 414 meter long 138 kV transmission line to the 3.2 km transmission line shared with the Stokke Creek Facility and the Douglas Creek Facility to the UHT.

Site and Water Rights

The Fire Creek Facility is authorized to divert and use water up to a maximum of 10.5 cubic metres per second from Fire Creek in accordance with a water licence issued pursuant to the *Water Act* in 2005. The water licence was issued for a term of 40 years expiring in 2045.

The Fire Creek Facility is located on public land. A Crown lease for the powerhouse expiring in 2051 was granted in 2008 in favour of HHPI, the general partner of FCPLP. A statutory right of way for the penstock expiring in 2051 was granted in favour of HHPI in 2009. The Fire Creek Facility shares a statutory right of way for the transmission line with the other Harrison Operating Facilities.

(iii) Lamont Creek Facility

Description

The Lamont Creek Facility is a run-of-river hydroelectric facility with an installed capacity of 27 MW (the "**Lamont Creek Facility**"). Construction of the Lamont Creek Facility commenced in May 2007 and COD was achieved on November 2, 2009. The Lamont Creek Facility uses hydraulic resources of the lower reaches of Lamont Creek with the point of diversion 3.5 km upstream from the powerhouse, which in turn is 60 meters upstream of the confluence of Lamont Creek with the Stave River. The Lamont Creek Facility is equipped with two 13.5 MW Pelton turbines and its output is delivered by a 590 m 138 kV transmission line to the Upper Stave River Facility transmission line that is shared for 36.5 km to the UHT.

Site and Water Rights

The Lamont Creek Facility is authorized to divert and use water up to a maximum of 8.7 cubic metres per second from Lamont Creek in accordance with a water licence issued pursuant to the *Water Act* in 2006. The water licence has been issued for a term of 40 years expiring in 2046.

The Lamont Creek Facility is located on public land. A Crown lease for the powerhouse expiring in 2052 was granted in favour of HHPI, the general partner of LCPLP, in 2009. A statutory right of way for the intake and penstock expiring in 2052 was granted in favour of HHPI in 2009. The Lamont Creek Facility shares in a statutory right of way in relation to its transmission line.

(iv) Stokke Creek Facility

Description

The Stokke Creek Facility is a run-of-river hydroelectric facility with an installed capacity of 22 MW (the "**Stokke Creek Facility**"). Construction of the Fire Creek Facility commenced in May 2007 and COD was achieved on October 19, 2009. The Stokke Creek Facility uses the hydraulic resources of the lower reaches of Stokke Creek, with the point of diversion 2 km upstream from upstream from the powerhouse, which in turn is 500 m upstream of the confluence of Stokke Creek with the Harrison Lake. The Stokke Creek Facility is equipped with two 11 MW Pelton turbines and its output is delivered by a 11 km long 138 kV transmission line to the Douglas Creek Facility from where it shares a 6.8 km long 138 kV line to the Fire Creek Facility , with the final 3.2 km 138 kV line shared by the three projects.

Site and Water Rights

The Stokke Creek Facility is authorized to divert and use water up to a maximum of 8.4 cubic metres per second from Stokke Creek in accordance with a water licence issued pursuant to the *Water Act* in 2006. The water licence has been issued for a term of 40 years expiring in 2046.

The Stokke Creek Facility is located on public land. A Crown lease for the powerhouse expiring in 2051 was granted in favour of HHPI, the general partner of SCPLP, in 2008. A statutory right of way for the penstock expiring in 2050 was granted in favour of HHPI in 2009. A statutory right of way for the transmission line expiring in 2051 was granted in favour of HHPI in 2009. The Stokke Creek Facility also shares in statutory rights of way in relation to its transmission line.

(v) Tipella Creek Facility

Description

The Tipella Creek Facility is a run-of-river hydroelectric facility with an installed capacity of 18 MW (the "**Tipella Creek Facility**"). Construction of the Tipella Creek Facility commenced in May 2007 and COD was achieved on October 19, 2009. The Tipella Creek Facility uses the hydraulic resources of the lower reaches of Tipella Creek, with the point of diversion 2.4 km upstream from the powerhouse which in turn is 600 m upstream of the confluence of Tipella Creek with Harrison Lake. The Tipella Creek Facility is equipped with two 9 MW Pelton turbines and its output is delivered by a 4 km long 138 kV transmission line to the UHT.

Site and Water Rights

The Tipella Creek Facility is authorized to divert and use water up to a maximum of 7.2 cubic metres per second from Tipella Creek in accordance with a water licence issued pursuant to the Water Act in 2006. The water licence has been issued for a term of 40 years expiring in 2046.

The Tipella Creek Facility is located on public land. A Crown lease for the powerhouse expiring in 2051 was granted in favour of HHPI, the general partner of TCPLP, in 2009. The lease expires on January 24, 2051. A statutory right of way for the penstock expiring in 2051 was granted in favour of HHPI in 2009. A statutory right of way for the transmission line expiring in 2051 was granted in favour of HHPI in 2010. The Tipella Creek Facility shares in statutory rights of way in relation to its transmission line.

(vi) Upper Stave River Facility

Description

The Upper Stave River Facility is a run-of-river hydroelectric facility with an installed capacity of 33 MW (the "**Upper Stave River Facility**"). Construction of the Upper Stave River Facility commenced in May 2007 and COD was achieved on November 2, 2009. The Upper Stave River Facility uses the hydraulic resources of the middle reach of the Stave River, with the point of diversion 1.9 km upstream from the powerhouse, which in turn is 18 km upstream of the discharge of Stave River into Stave Lake. The Upper Stave River Facility is equipped with three 10 MW Francis turbines and one 3 MW Francis turbine, and its output is delivered by a 37.1 km long 138 kV transmission line of which it shares 36.5 km with the Lamont Creek Facility to the UHT.

Site and Water Rights

The Upper Stave River Facility is authorized to divert and use water up to a maximum of 43.8 cubic metres per second from Stave River in accordance with a water licence issued pursuant to the Water Act in 2006. The water licence has been issued for a term of 40 years expiring in 2046.

The Upper Stave River Facility is located on public land. A Crown lease for the powerhouse expiring in 2052 was granted in favour of HHPI, the general partner of USPLP, in 2009. A statutory right of way for the penstock expiring in 2052 was granted in favour of HHPI in 2009. The Upper Stave River Facility shares in a statutory right of way in relation to its transmission line.

N. Fitzsimmons Creek Facility (British-Columbia - 66.7% ownership)

Description

The Fitzsimmons Creek Facility is a run-of-river hydroelectric power generating facility with a nameplate capacity of 7.5 MW (the "**Fitzsimmons Creek Facility**"). It is located on Fitzsimmons Creek between Whistler and Blackcomb mountains in the Resort Municipality of Whistler, British Columbia. Construction of the Fitzsimmons Creek Facility commenced in July 2008 and commercial operation commenced on January 26, 2010. The generating equipment of the Fitzsimmons Creek Facility is one Pelton turbine. The buried 25 kV transmission line is approximately 450 m long and taps into an existing BC Hydro line.

The Fitzsimmons Creek Facility is owned by Fitzsimmons Creek Hydro Limited Partnership ("**Fitzsimmons LP**"). The general partner of Fitzsimmons LP is Fitzsimmons Creek Investments Ltd., which is indirectly wholly-owned by the Corporation. The limited partner of Fitzsimmons LP is Creek Power, 66.7 of which is owned by the Corporation and the remaining 33.3% of which is owned by Ledcor.

The Mount Currie Indian Band and the Squamish Indian Band (the "**Nations**") are entitled to a royalty based on revenues of the Fitzsimmons Creek Facility from the date of commencement of commercial operation. The Nations are also entitled to an incremental share of gross revenues exceeding a yearly threshold of gross revenues set out in the agreement.

Site and Water Rights

The Fitzsimmons Creek Facility is authorized to divert and use water up to a maximum of 4.0 cubic meters per second from Fitzsimmons Creek, in accordance with a water license issued pursuant to the *Water Act* on April 11, 2008. The water license was issued for a term of 40 years, expiring April 10, 2048. The Fitzsimmons Creek Facility is located on Crown land which is subject to a license of occupation pursuant to the *Land Act* (British Columbia). The license commenced on April 14, 2008 and has a term of ten years, expiring on April 13, 2018. Such license of occupation will be replaced by a long term registered lease for the powerhouse and statutory rights of way for the transmission line, penstock and intake. Such Crown land tenures are expected to have a term consistent with the term of the PPA.

Power Purchase Agreement

The Fitzsimmons Creek Facility has a PPA with BC Hydro for all power produced by the Fitzsimmons Creek Facility during the 40 years following January 26, 2010, subject to customary termination provisions in the event of a material breach of the agreement. The base price for electricity purchased from the Fitzsimmons Creek Facility is adjusted by a percentage equal to 50% of the increase or decrease in the CPI during the preceding 12 months, effective January 1, 2009 and on each January 1 thereafter during the term of the Fitzsimmons Creek Facility PPA.

O. *Horseshoe Bend Facility (Idaho (USA) - 100% ownership)*

Description

The Horseshoe Bend Facility consists of a run-of-river hydroelectric power generating facility with a total installed capacity of 9.5 MW and is located on the Payette River, in the city of Horseshoe Bend in the State of Idaho, (USA) (the "**Horseshoe Bend Facility**"). The Horseshoe Bend Facility started commercial operation in 1995 and was acquired by the Trust on December 3, 2004.

The Horseshoe Bend Facility draws water from the Payette River which has a drainage area of approximately 5,776 square kilometers upstream from the Facility. Three rivers, North Fork, Middle Fork and South Fork, and two drainage areas feed the Payette River. The source of the water in these rivers comes from the high peaks North of Idaho. The powerhouse holds five single regulated "S" Kaplan-type turbines. The power station was modernized in 2005 and is now entirely automated and can be operated locally as well as remotely. Power generated is conveyed into the network of Idaho Power Company.

Site and Water Rights

The water rights up to 3,500 cubic feet per second are licensed by Idaho Department of Water Resources under License number 65-12563 and are subject to review on or after May 21, 2036.

Power Purchase Agreement

The PPA with respect to the electricity payable by Idaho Power Company produced by the Horseshoe Bend Facility (the "**Horseshoe Bend PPA**") has an initial term of 35 years expiring in 2030. On December 23, 2005, the expected annual production of electricity to be delivered by the Horseshoe Bend Facility increased by 11% or 4,800 MWh, as a consequence of improvements to the Facility, and is now 46,800 MWh. The Horseshoe Bend PPA does not specify annual minimum or maximum annual power deliveries.

The price of delivered electricity payable by Idaho Power Company is adjusted according to a formula provided for in the Horseshoe Bend PPA.

OPERATING WIND FARMS

A. *Cartier Wind Farms (Québec - 38% ownership)*

Ownership Structure

The Corporation and TransCanada respectively own, as undivided co-owners, 38% and 62% of the following wind power generating projects: (i) the Carleton Wind Farm, described below; (ii) the L'Anse-à-Valleau Wind Farm, described below; (iii) the Baie-des-Sables Wind Farm, described below, (iv) the Montagne Sèche Wind Farm, described below; and (v) the Gros-Morne Wind Farm, described below (collectively, the "**Cartier Wind Farms**").

The Corporation and TransCanada each hold, as undivided co-owners, their respective interests in the Cartier Wind Farms through single purpose limited partnerships (each, together with the owners a "**Cartier Owner**"). For each of the Cartier Wind Farms, the respective Cartier Owners have, pursuant to a management agreement, appointed an operator, which is owned equally by the Corporation and TransCanada, for the management of the construction, operation and maintenance of these wind farms.

B. Baie-des-Sables Farm (Québec - 38% ownership)

Description

The Baie-des-Sables Wind Farm is a 109.5 MW wind farm facility located in Baie-des-Sables and Métis-sur-Mer, in the Province of Québec (the "**Baie-des-Sables Wind Farm**"). Construction of the Baie-des-Sables Wind Farm began in March 2006. The wind farm was brought into commercial operation on November 22, 2006. The 38% undivided co-ownership interest in the Baie-des-Sables Wind Farm was initially acquired on December 6, 2007.

The Baie-des-Sables Wind Farm is comprised of 73 GE 1.5 MW wind turbines. The Baie-des-Sables Wind Farm is connected to Hydro-Québec's grid through a 70 km long, 34.5 kV collector system and a transformer station which steps up the voltage for connection to an adjacent 230 kV Hydro-Québec transmission line.

Site Rights

The right to use the site on which the wind turbines are installed at the Baie-des-Sables Wind Farm was initially acquired through option award contracts. Furthermore, deeds of superficies ownership rights and servitudes were later granted in favour of Innergex BDS, L.P. and TransCanada BDS, L.P., for the installation of wind turbines on the territory of the Baie-des-Sables Wind Farm.

Power Purchase Agreement

The electricity generated by the Baie-des-Sables Wind Farm is sold to Hydro-Québec pursuant to a power purchase agreement executed on February 25, 2005 (the "**BDS PPA**") which expires 20 years after the commencement date of delivery. The BDS PPA is subject to customary termination provisions in the case of a material breach of the agreement. The BDS PPA provides that Hydro-Québec must purchase all the electricity generated by the Facility.

The price payable by Hydro-Québec under the BDS PPA is calculated in accordance with the BDS PPA and provides for an increase equal to approximately 18% of the CPI as of January 1st of each year.

C. L'Anse-à-Valleau Wind Farm (Québec - 38% ownership)

Description

The L'Anse-à-Valleau Wind Farm is a 100.5 MW wind farm facility located in L'Anse-à-Valleau within the limits of the municipality of Gaspé, in the Province of Québec (the "**L'Anse-à-Valleau Wind Farm**"). Construction of the L'Anse-à-Valleau Wind Farm began in October 2006. The wind farm was brought into commercial operation on November 10, 2007. The 38% undivided co-ownership interest in the L'Anse-à-Valleau Wind Farm was initially acquired by the Fund on December 6, 2007.

The L'Anse-à-Valleau Wind Farm is comprised of 67 GE wind turbines, each with a capacity of 1.5 MW. The L'Anse-à-Valleau Wind Farm is connected to Hydro-Québec's grid through a 43 km long 34.5 kV collector system, a transformer station which steps up the voltage to 161 kV and a 14 km long 161 kV transmission line which taps into an existing Hydro-Québec transmission line near Rivière-au-Renard.

Site Rights

The right to use the privately-owned sites on which the wind turbines are installed at the L'Anse-à-Valleau Wind Farm was initially acquired through option award contracts. Furthermore, deeds of superficies ownership rights and servitudes were later granted in favour of Innergex AAV, L.P. and TransCanada AAV, L.P., for the installation of wind turbines on the territory of the L'Anse-à-Valleau Wind Farm.

Since most of the wind turbines of the L'Anse-à-Valleau Wind Farm are built on public land, the leases were granted by the *Ministère des Ressources naturelles et de la Faune du Québec* ("**MRNF**") to Innergex AAV, L.P. and TransCanada AAV, L.P., for the purposes of erecting wind turbines on the public territory of the L'Anse-à-Valleau Wind Farm. Under these leases, rent must be paid to the MRNF.

Power Purchase Agreement

The electricity generated by the L'Anse-à-Valleau Wind Farm is sold to Hydro-Québec pursuant to a standard power purchase agreement executed on February 25, 2005 (the "**AAV PPA**") which expires 20 years after the commencement date of delivery. The AAV PPA is subject to customary termination provisions in the case of a material breach of the agreement. The AAV PPA provides that Hydro-Québec must purchase all the electricity generated by the L'Anse-à-Valleau Wind Farm.

The price payable by Hydro-Québec under the AAV PPA is calculated in accordance with the AAV PPA and provides for an increase equal to approximately 18% of the CPI on January 1st of each year.

D. Carleton Wind Farm (Québec - 38% ownership)

Description

The Carleton Wind Farm is a wind power facility located in the Town of Carleton-Sur-Mer and the Regional County Municipality of Bonaventure, in the Province of Québec (the "**Carleton Wind Farm**"). It has an installed capacity of 109.5 MW. The Corporation holds a 38% undivided co-ownership interest in the Carleton Wind Farm.

Construction of the Carleton Wind Farm was completed on schedule and within budget. The Carleton Wind Farm commenced commercial operation in November 2008. The generating equipment consists of 73 GE wind turbines, each with a capacity of 1.5 MW. The Carleton Wind Farm connects to the transmission system via a 62 km long 34.5 kV collector system and a transformer station which steps up the voltage to 230 kV to connect to a 10 km long 230 kV transmission line which was constructed by Hydro-Québec.

Site Rights

The Carleton Wind Farm site is located entirely on public lands of an approximate total area of 4,445 hectares. Leases were granted by the MRNF to the Cartier Owners for the installation of wind turbines on the territory of the Carleton Wind Farm. Royalties payable to the government of Québec under such leases are based on the established rates pursuant to applicable regulation.

The Corporation holds a 50% interest in Cartier Wind Energy (CAR) Inc., which is the manager of the Carleton Wind Farm. Cartier Wind Energy (CAR) Inc. has entered into agreements with each of the Town of Carleton-Sur-Mer and the Regional County Municipality of Bonaventure for the development of the wind power industry, voluntary contributions and the dismantling of wind turbines at the end of their useful life. Pursuant to these agreements, Cartier Wind Energy (CAR) Inc. agreed to remove the wind turbines within two years following the definitive termination of operations of the Carleton Wind Farm. In order to guarantee such obligation, Cartier Wind Energy (CAR) Inc. agreed to provide to the Town of Carleton-Sur-Mer and the Regional County Municipality of Bonaventure, an irrevocable standby letter of credit or other form of guarantee from the 11th year of operation of the Carleton Wind Farm in the amount of $5,000 per year per turbine.

Power Purchase Agreement

The Carleton Wind Farm has a PPA with Hydro-Québec for all the electricity that is produced by the Carleton Wind Farm, expiring 20 years from November 22, 2008 and subject to customary termination provisions in the case of a material breach of the agreement (the "**Carleton PPA**"). The price of the delivered electricity payable by Hydro-Québec is determined pursuant to a formula set forth in the Carleton Wind Farm PPA and provides an increase equal to approximately 18% of the CPI as of January 1st of each year.

E. <u>Montagne Sèche Wind Farm (Québec - 38% ownership)</u>

<u>Description</u>

The Montagne Sèche Wind Farm is a 58.5 MW wind farm located in the municipalities of the township of Cloridorme and Petite-Vallée, in the Province of Québec (the "**Montagne Sèche Wind Farm**"). Construction of the Montagne Sèche Wind Farm began in June 2010. The wind farm was brought into commercial operation on November 25, 2011.

The Montagne Sèche Wind Farm is comprised of 39 GE wind turbines, each with a capacity of 1.5 MW. The wind farm is connected to the Hydro-Québec grid through a 34.5 kV collector system and a transformer station which will increase the voltage to 161 kV for connection to a 161 kV transmission line**.**

<u>Site Rights</u>

The total area of the Montagne Sèche Wind Farm site is approximately 1,747 hectares and is entirely located on public lands. On July 21, 2010, leases were granted by the MRNF to Innergex MS, L.P. and TransCanada MS, LP, for the purposes of erecting wind turbines on the public territory of the Montagne Sèche Wind Farm. Under these leases, rent must be paid to the MRNF. The Leases will expire on December 1, 2032 and may be renewed upon demand.

<u>Power Purchase Agreement</u>

The Montagne Sèche Wind Farm has a PPA with Hydro-Québec, expiring 20 years from November 25, 2011, for all electricity that it will produce subject to customary termination provisions in the case of a material breach (the "**Montagne Sèche PPA**"). The price of the delivered electricity payable by Hydro-Québec is determined pursuant to a formula set forth in the Montagne Sèche PPA and provides an increase equal to approximately 18% of the CPI as of January 1st of each year.

F. <u>Gros-Morne Wind Farm (Québec - 38% ownership)</u>

<u>Description</u>

The Gros-Morne Wind Farm is a 211.5 MW wind farm located in the Municipality of Mont-Louis and the Municipality of Sainte-Madeleine-de-la-Rivière-Madeleine, in the Province of Québec (the "**Gros-Morne Wind Farm**"). The construction of the Gros-Morne Wind Farm began in June 2010 and was performed in two phases. The construction of phase I of the Gros-Morne Wind Farm which consisted in 67 GE Turbines for a total of 100.5 MW was brought into commercial operation on November 29, 2011. The construction of the phase II of Gros Morne Wind Farm which consisted in 74 GE Turbine for a total of 111 MW was brought into commercial operation on November 6, 2012.

The Gros-Morne Wind Farm consists of 141 GE wind turbines, each with a capacity of 1.5 MW. The Gros-Morne Wind Farm connects to the transmission system via a 34.5 kV collector system and a transformer station, which increases up the voltage to 230 kV for connection to a 230 kV transmission line.

<u>Site Rights</u>

The total area of the site of the Gros-Morne Wind Farm is approximately 7,134 hectares, of which 91% is located on public lands. The Cartier Owners of the Gros-Morne Site have secured the access rights to the private lands comprised in the Gros-Morne Site. As for public lands, on July 21, 2010, leases were granted by the MRNF to Innergex GM, L.P. and TransCanada GM, L.P., for the purpose of erecting wind turbines on the public territory of the Gros-Morne Site. Under these leases, rent must be paid to the MRNF. The Leases will expire on December 1, 2033 and may be renewed upon demand.

<u>Power Purchase Agreement</u>

The Gros-Morne Wind Farm has a PPA with Hydro-Québec for all electricity that will be produced by the Gros-Morne Wind Farm expiring 21 year from November 29, 2011 and subject to customary termination provisions in the case of a material breach of the agreement (the "**Gros-Morne PPA**"). The price for the delivered electricity payable by Hydro-Québec is determined pursuant to a formula set forth in the Gros-Morne PPA and provides an increase equal to approximately 18% of the CPI as of January 1st of each year.

OPERATING SOLAR FARMS

A. Stardale Solar Farm (Ontario - 100% ownership)

Description

The Stardale Solar Farm is a solar farm at two sites, 500 meters apart from each other, the South site and the North site (the "**Stardale Solar Farm**"). A total of more than 144,000 SolarWorld SW 230 polycrystalline modules were installed at the solar farm. These modules have a fixed tilt angle of 30 degrees to the horizontal surface. The total installed capacity is 33.2 MW in direct current (DC). 54 inverters were installed to transform the DC energy in order to generate 27 MW of alternative current (AC) on the 44 kV feeder.

Construction of the Stardale Project began in November 2010 and it was brought into commercial operation on May 15, 2012.

Site Rights

The Stardale Solar Farm is located 5 km southwest from the village of St. Eugene (East Hawkesbury Township); the entire solar farm totals 244 acres. Stardale Solar LP is the sole owner of both the South and North sites.

Power Purchase Agreement

All the energy, which will be delivered by the Stardale Solar Farm, will be sold pursuant to three RESOP Contracts with the OPA at a rate fixed at $420 per MWh with a 20-year term beginning on May 15, 2012 (the "**Stardale PPAs**"), which will be subject to customary termination provisions in the case of a material breach of the Stardale PPAs.

DEVELOPMENT PROJECTS

As of December 31, 2012, the Corporation had interests in 8 sites for which PPA's have been secured and as at March 28, 2013, subject to the consent of BC Hydro, the Corporation intends to cancel the North Creek Project which is therefore no longer considered by the Corporation as a Development Project. Excluding the North Creek Project, the Development Projects represent an aggregate net installed capacity of 189.7 MW (gross 262.5 MW). The projects are expected to reach the commercial operation stage between 2013 and 2016. All of the Development Projects are set forth in the following table and further described below:

Development Projects

Province	Plant	Expected Capacity (MW)	Equity Interest	Estimated Construction Costs(1) ($mms)	Revised Estimated Construction Costs ($mms)	Power Purchaser	Estimated Long Term Average Generation (MWh)	Expected Commercial in Service Date	PPA Term(2) (years)
Hydroelectric Projects(3)									
B.C.	Kwoiek Creek	49.9	50%	153.2	-	BC Hydro	215,000	2013	40
B.C.	Boulder Creek	25.3	66.7%	84.2	116.9(4)	BC Hydro	92,500	2015	40
B.C.	Upper Lillooet River	81.4	66.7%	264.2	317.6(4)	BC Hydro	334,000	2016	40
B.C.	Northwest Stave River	17.5	100%	91.4	-	BC Hydro	61,900	2013	40

Province	Plant	Expected Capacity (MW)	Equity Interest	Estimated Construction Costs[1] ($mms)	Revised Estimated Construction Costs ($mms)	Power Purchaser	Estimated Long Term Average Generation (MWh)	Expected Commercial in Service Date	PPA Term[2] (years)
B.C.	Tretheway Creek	23.2	100%	91.5	108.5[4]	BC Hydro	81,900	2015	40
B.C.	Big Silver Creek	40.6	100%	165.4	191.8[4]	BC Hydro	139,800	2016	40
Subtotal:		237.9					925,100		
Wind Farm Projects									
Québec	Viger-Denonville	24.6	50%	36.6[5]	-	Hydro-Québec	67,600	2013	20
Subtotal:		24.6					67,600		
Total:		**262.5**					**992,700**		

(1) This information is intended to inform the reader of the project's potential impact on the Corporation's results. The actual results may vary. See "Forward looking information".

(2) The PPAs for the Development Projects do not contain provisions regarding their renewal. Prior to their expiry, Management will explore opportunities to renew these PPAs.

(3) As of December 31, 2012, the North Creek Project was included in the Development Projects but as at March 28, 2013, subject to the consent of BC Hydro, the Corporation intends to cancel the North Creek Project a run-of-river hydroelectric project which had a potential installed capacity of 16 MW and an expected yearly output of 53.4 GWh.

(4) The total project costs are expected to increase as a result, among others, of greater installed capacity, higher than expected civil costs and the return to a provincial sales tax system.

(5) Corresponding to the Corporation's 50% interest in this project.

HYDROELECTRIC DEVELOPMENT PROJECTS

A. *Kwoiek Creek Project (British-Columbia - 50% ownership)*

Description

The Kwoiek Creek Project is a proposed run-of-river hydroelectric power generating facility with a nameplate capacity of 49.9 MW and an estimated yearly energy output of 215 GWh (the "**Kwoiek Creek Project**"). It is located at the confluence of Kwoiek Creek and the Fraser River, approximately 14 kilometres south of Lytton, British Columbia. It is expected to commence commercial operation in 2013. The generating equipment, which will be fed by a 7.2 kilometre long penstock, is expected to be comprised of four horizontal-shaft three-jet Pelton turbines, each with a maximum designed flow of 3.375 cubic metres per second, a design net head of 515 metres and a rated capacity of 12.475 MW. The Kwoiek Creek Project will include a 70 kilometre long 138 kV transmission line from the project substation to the Highland Valley Substation at the north end of Mamit Lake.

The Kwoiek Creek Project is owned by Kwoiek Creek Resources LP, the general partner of which is Kwoiek Creek Resources GP Inc. Kwoiek Creek Resources Inc. (a company wholly-owned and controlled by the Kanaka Bar Indian Band) and a subsidiary of the Corporation each own 50% of the limited partnership units of Kwoiek Creek Resources LP and 50% of the interests of Kwoiek Creek Resources GP Inc.

The revised estimated construction costs of the Kwoiek Creek Project are $153.2 million, which is principally financed with a $168.5 million non-recourse construction facility arranged with a group of life insurance companies, and the use of the Corporation's corporate credit facilities and the cash flow generated by the Corporation's operations from time to time.

As at December 31, 2012, all necessary construction permits were granted and the construction was progressing on schedule, the power house steel superstructure was completed, the intake construction was still under way and the transmission line construction and penstock installation were ongoing. As at the date of this Annual Information Form, the construction was progressing as scheduled and budgeted. Current activities also include assembly and installation of the turbines and generators. The fish habitat compensation channel construction has been halted for the winter period and will resume in the spring of 2013 and construction of this facility is expected to be completed during the fourth quarter of 2013.

Site and Water Rights

Kwoiek Creek Resources LP has applied for a water licence to divert and use water from Kwoiek Creek. The initial application was made in February 1990. The powerhouse of the Kwoiek Creek Project is located on reserve lands of the Kanaka Bar Indian Band known as Whyeek Indian Reserve Number 4. A lease between Kwoiek Creek Resources Inc. and the Minister of Indian and Northern Development Canada was executed on December 1st, 2010 for such lands and a sublease of those lands from Kwoiek Creek Resources Inc. to Kwoiek Creek Resources LP was executed on January 25, 2011 for a term of 40 years expiring in 2051.

Kwoiek Creek Resources Inc. is entitled to a royalty which is based on a percentage of the gross revenues less project costs for the first 20 years after the date of commencement of commercial operation of the Kwoiek Creek Project and an increased royalty for 20 years thereafter. Forty years following the commencement of commercial operation, Kwoiek Creek Resources Inc. will be entitled to purchase the Corporation's interest in Kwoiek Creek Resources LP and Kwoiek Creek Resources GP Inc. for a nominal price.

Power Purchase Agreement

The Kwoiek Creek Project has a PPA with BC Hydro for all the power that will be produced by the Kwoiek Creek Project, expiring 40 years following the commercial operation date of the facility and subject to customary termination provisions in the event of material breach of the agreement (the "**Kwoiek Creek PPA**"). Under the term of the PPA, 30% of the price of the Kwoiek Creek PPA is adjusted based on the increase or decrease in the CPI during the preceding 12 months starting on January 1, 2006 and on each January 1 thereafter during the term of the Kwoiek Creek Project PPA.

Under the Kwoiek Creek PPA, BC Hydro is entitled to all rights, titles and interests in and to any environmental attributes which the Kwoiek Creek Project may receive.

B. North Creek Project (British-Columbia - 66.7% ownership)

Description

As at December 31, 2012, North Creek Project was a run-of-river hydroelectric project with a potential installed capacity of 16 MW and an expected yearly output of 53.4 GWh (the "**North Creek Project**"). However, subject to BC Hydro's consent, the North Creek Project will be cancelled. As at March 28, 2013 such consent was not obtained from BC Hydro. The Project as it was planned as of December 31, 2012 was located on North Creek in the Lillooet River drainage basin, 38 km northwest of Pemberton, British Columbia.

The Corporation intends to continue advancing a revised version of the North Creek project in view of a future request for proposal and will be considered as a prospective project.

C. Boulder Creek Project (British-Columbia - 66.7% ownership)

Description

Boulder Creek Project is a run-of-river hydroelectric project with a potential installed capacity of 25.3 MW and an expected yearly output of 92.5 GWh (the "**Boulder Creek Project**"). It is located on Boulder Creek in the Lillooet River drainage basin, 56 km northwest of Pemberton, British Columbia.

The Boulder Creek plant will divert partial flows from the creek through an intake structure to a buried 1.5 km long low pressure penstock followed by a 1.5 km high pressure steel penstock to three 7.6 MW vertical Pelton turbines and generating equipment located in the powerhouse. The powerhouse will also contain all necessary ancillary equipment including protection, controls, switchgear and communications.

Preliminary interconnection studies indicate the preferred interconnection is to BCTC 230 kV line south of Pemberton. The proposed transmission line will be approximately 1 km long and tap into the 230 kV line constructed for the Upper Lillooet Project.

Construction of the Boulder Creek Project is expected to commence in 2013 and commercial operation is expected to commence in 2015.

Site and Water Rights

Creek Power has applied for a water licence to divert and use water from Boulder Creek in March 2001. Creek Power has made an application to obtain a Licence of Occupation for the lands in the project area for the construction of the project. All permits necessary for the construction of the project are expected to be obtained in 2013. Upon completion of the project, Creek Power will lease the area of land beneath the powerhouse and obtain a Statutory Right-of-Way in the substation, penstock, intake, and transmission line areas. Once lease and Right-of-Way tenures are in place, the Licence of Occupation will be released.

Power Purchase Agreement

The Boulder Creek Project has a PPA with BC Hydro for all the power that will be produced by the Boulder Creek Project, expiring 40 years following the commercial operation date of the facility and subject to customary termination provisions in the event of material breach of the agreement. BC Hydro has the right to terminate the PPA in the event the Corporation has failed to obtain all material permits for the Boulder Creek Project by April 22, 2013 or has not reached commercial operation by August 1, 2016, subject to any extensions for force majeure as provided in the PPA, not to exceed 180 days. Construction of the Boulder Creek Project is expected to begin in 2013.

The price payable by BC Hydro under the PPA is calculated in accordance with the PPA and provides for an increase equal to the CPI on January 1st of each year, before commercial operation occurs and, thereafter, for an increase equal to 10% of the CPI. Under the PPA, BC Hydro is entitled to all rights, titles and interests in and to any environmental attributes which the Upper Lillooet River Project may receive.

BC Hydro has committed to purchase power produced by the Boulder Creek Project pursuant to a 40-year PPA. BC Hydro has indicated that the hydro projects awarded PPAs under the latest clean power call, under which the PPA for the Boulder Creek Project was awarded, had a range of firm energy bid price from $95 to $156 per MWh, with a weighted average firm energy bid price of $139.90 per MWh.

D. *Upper Lilloet River Project (British-Columbia - 66.7% ownership)*

Description

Upper Lillooet River Project is a run-of-river hydroelectric project with a potential installed capacity of 81.4 MW and an expected yearly output of 334.4 GWh (the "**Upper Lillooet River Project**"). It is located on the Lillooet River, a tributary of the Fraser River, approximately 70 km northwest of Pemberton, British Columbia.

The Upper Lillooet plant will divert partial flows from the river, through an intake structure directly into a 2.6 km long tunnel followed by a 1 km high pressure penstock to the four 18.5 MW horizontal Francis turbines and a smaller turbine of 7.4 MW and generating equipment located in the powerhouse. The powerhouse would also contain all necessary ancillary equipment including protection, controls, switchgear and communications.

Preliminary interconnection studies indicate the preferred interconnection is to BCTC 230 kV line south of Pemberton. The proposed transmission line would be approximately 72 km long.

Construction of the Upper Lillooet River Project is expected to commence in 2013 and commercial operation is expected to commence in 2016.

Site and Water Rights

Creek Power has applied for a water licence to divert and use water from Upper Lillooet River in December 2001. Creek Power has made an application to obtain a Licence of Occupation for the lands in the project area for the construction of the project. All permits necessary for the construction of the project are expected to be obtained in 2013. Upon completion of the project, Creek Power would lease the area of land beneath the powerhouse and obtain a statutory right-of-way in the substation, penstock, intake, and transmission line areas. Once lease and Right-of-Way tenures will be in place, the Licence of Occupation would be released.

The project is located within the Lil'wat Nation Traditional Territory (Mount Currie Indian Band). A Participation Agreement was signed between the parties on December 13, 2012.

Power Purchase Agreement

The Upper Lillooet River Project has a PPA with BC Hydro for all the power that will be produced by the Upper Lillooet River Project, expiring 40 years following the commercial operation date of the facility and subject to customary termination provisions in the event of material breach of the agreement. BC Hydro has the right to terminate the PPA in the event the Corporation has failed to obtain all material permits for the Upper Lillooet River Project by April 22, 2013 or has not reached commercial operation by June 1, 2017, subject to any extensions for force majeure as provided in the PPA, not to exceed 180 days.

The price payable by BC Hydro under the PPA is calculated in accordance with the PPA and provides for an increase equal to the CPI on January 1st of each year, before commercial operation occurs and, thereafter, for an increase equal to 10% of the CPI. Under the PPA, BC Hydro is entitled to all rights, titles and interests in and to any environmental attributes which the Upper Lillooet River Project may receive.

E. *Northwest Stave River Project (British-Columbia - 100% ownership)*

Description

The Northwest Stave River Project is a proposed run-of-river hydroelectric power generating facility with an expected installed capacity of 17.5 MW and an estimated yearly energy output of 61.9 GWh (the "**Northwest Stave River Project**"). It is located approximately 35 km north of Mission, British Columbia. Construction of the Northwest Stave River Project began in 2011 and it is expected to begin commercial operation in the last quarter of 2013.

The generating equipment, which will be fed by a 200 meter long low pressure conduit connected to a 1,040 meter long penstock and a design flow of 29 cubic metres per second, is expected to be comprised of three Francis turbines: two turbines with a unit capacity of 7.4 MW, and one turbine with a unit capacity of 2.7 MW. The Northwest Stave River Project is expected to include a 2.2 km long 138 kV transmission line to the existing Upper Stave River Facility and Lamont Creek Facility transmission line.

By the end of 2012, all civil work at the powerhouse was nearly completed and the river diversion was completed. As of the date of this Annual Information Form, the construction was progressing as scheduled and budgeted.

The revised estimated construction costs of the Northwest Stave River Project are $91.4 million, which is expected to be financed with an anticipated project financing, the use of the Corporation's credit facility and the cash flow generated by the Corporation's operations, from time to time.

The Northwest Stave River Project is owned by Northwest Stave River Hydro Limited Partnership, the general partner of which is Northwest Stave River Hydro Inc., which are wholly owned by the Corporation.

Site and Water Rights

A conditional water license dated November 21, 2008 was issued for a term of 40 years to divert and use water up to a maximum of 31.5 cubic meters per second from the Northwest Stave River. The Northwest Stave River Project is located on Crown land that is subject to a licence of occupation pursuant to the *Land Act* (British Columbia). The initial licence commenced on December 1, 2009 and was replaced by another Licence of occupation, effective as of December 2012 for term of 10 years, expiring on November 30, 2022. Upon completion of construction, such licence of occupation will be replaced by a long term registered lease for the powerhouse and statutory rights of way for the transmission line, penstock and intake. Such Crown land tenures are expected to have a term consistent with the term of the PPA.

Power Purchase Agreement

The Northwest Stave River Project has a PPA with BC Hydro for all the power that will be produced by the Northwest Stave River Project, expiring 40 years following the commercial operation date of the facility and subject to customary termination provisions in the event of material breach of the agreement. BC Hydro has the right to terminate the PPA in the event the Corporation has failed to obtain all material permits for the Northwest Stave River Project by April 22, 2013 or has not reached commercial operation by December 1, 2014, subject to any extensions for force majeure as provided in the PPA, not to exceed 180 days. BC Hydro has indicated that the hydro projects awarded PPAs under the latest clean power call, under which the PPA for the Northwest Stave River Project was awarded, had a range of firm energy bid price from $95 to $156 per MWh, with a weighted average firm energy bid price of $139.90 per MWh.

F. Tretheway Creek Project (British-Columbia - 100% ownership)

Description

The Tretheway Creek Project is a proposed run-of-river hydroelectric power generating facility with an expected installed capacity of 23.2 MW and an estimated yearly energy output of 81.9 GWh (the "**Tretheway Creek Project**"). It is located approximately 50 km north of Harrison Hot Springs, British Columbia. Construction of the Tretheway Creek Project is expected to commence in 2013.

The generating equipment, which will be fed by a 4,730 meter long penstock and a design flow of 11.4 cubic metres per second, is expected to be comprised of three 7.8 MW Pelton turbines. The Tretheway Creek Project is expected to include an 8 km long 138 kV transmission line from the project substation to the existing Tipella Creek Facility transmission line.

The Tretheway Creek Project is owned by Tretheway Creek Hydro Limited Partnership, the general partner of which is Tretheway Creek Hydro Inc., which are both wholly owned by the Corporation.

Site and Water Rights

The initial application for a water license to divert and use water up to a maximum of 17 cubic meters per second from Tretheway Creek was made on October 14, 2005. All permits necessary for the construction of the project are expected to be obtained in 2013. Upon completion of the project, the license of occupation expected to be obtained for the initial development of the project will be converted into a lease for the area of land beneath the powerhouse and into statutory rights of way or long-term licenses of occupation for the penstock, intake and transmission line areas.

Power Purchase Agreement

The Tretheway Creek Project has a PPA with BC Hydro for all the power that will be produced by the Tretheway Creek Project, expiring 40 years following the commercial operation date of the facility and subject to customary termination provisions in the event of material breach of the agreement. BC Hydro has the right to terminate the PPA in the event the Corporation has failed to obtain all material permits for the Tretheway Creek Project by April 22, 2013 or has not reached commercial operation by December 1, 2016, subject to any extensions for force majeure as provided in the PPA, not to exceed 180 days. BC Hydro has indicated that the hydro projects awarded PPAs under the latest clean power call, under which the PPA for the Tretheway Creek Project was awarded, had a range of firm energy bid price from $95 to $156 per MWh, with a weighted average firm energy bid price of $139.90 per MWh.

The price payable by BC Hydro under the PPA is calculated in accordance with the PPA and provides for an increase equal to the CPI on January 1st of each year, before commercial operation occurs and, thereafter, for an increase equal to 50% of the CPI. Under the PPA, BC Hydro is entitled to all rights, titles and interests in and to any environmental attributes which the Tretheway Creek Project may receive.

G. Big Silver Creek Project (British-Columbia – 100 % ownership)

Description

The Big Silver Creek Project is a proposed run-of-river hydroelectric power generating facility with an expected installed capacity of 40.6 MW and an estimated yearly energy output of 139.8 GWh (the "**Big Silver Creek Project**"). It is located approximately 40 km north of Harrison Hot Springs, British Columbia. Construction of the Big Silver Creek Project is expected to commence in 2014 and commercial operation is expected to commence in 2016.

The generating equipment, which will be fed by a 3,140 m long penstock and a design flow of 26 cubic metres per second, is expected to be comprised of four Francis turbines (three of 11.6 MW, one of 5.8 MW) capable of producing an expected annual energy output of 139.8 GWh. The Big Silver Creek Project generating equipment will include a 36 km long 138 kV transmission line from the project substation to the existing Tipella Creek Facility transmission line.

Site and Water Rights

The initial application for a water licence to divert and use water up to a maximum of 40.4 and 23 cubic metres per second from Big Silver Creek and the Shovel Creek respectively was made on November 9, 2007. All permits necessary for the construction of the project are expected to be obtained by March 2014. The Big Silver Creek Project is located on Crown Land and is subject to a Licence of Occupation pursuant to the *Land Act* (British-Columbia) for a five year term expiring on August 6, 2017. Upon completion of the project, the licences of occupation will be converted into leases for the area of land beneath the powerhouses and into statutory rights of way or long-term licences of occupation for the penstock, intake and transmission line areas.

Power Purchase Agreement

The Big Silver Creek Project has a PPA with BC Hydro for all the power that will be produced by the Big Silver Creek Project, expiring 40 years following the commercial operation date of the facility and subject to customary termination provisions in the event of material breach of the agreement. BC Hydro has the right to terminate the PPA in the event the Corporation has failed to obtain all material permits for the Big Silver Creek Project by April 22, 2013 or has not reached commercial operation by November 1, 2017, subject to any extensions for force majeure as provided in the PPA, not to exceed 180 days. The PPA was amended to remove Shovel Creek facility and the gross installed capacity was raised from 36.9MW to 40.6 MW. BC Hydro has indicated that the hydro projects awarded PPAs under the latest clean power call, under which the PPA for the Big Silver Creek Project was awarded, had a range of firm energy bid price from $95 to $156 per MWh, with a weighted average firm energy bid price of $139.90 per MWh.

The price payable by BC Hydro under the PPA is calculated in accordance with the PPA and provides for an increase equal to the CPI on January 1st of each year, before commercial operation occurs and, thereafter, for an increase equal to 50% of the CPI. Under the PPA, BC Hydro is entitled to all rights, titles and interests in and to any environmental attributes which the Big Silver Creek Project may receive.

Wind Development Projects

A. Viger-Denonville Project (Québec - 50% ownership)

Description

The Viger-Denonville Project is a wind farm project located in the Municipalities of Saint-Paul-de-la-Croix and Saint-Épiphane, in the Province of Québec. The Viger-Denonville Project has a planned aggregate installed capacity of 24.6 MW. It is expected that the Viger-Denonville Project will commence commercial operation by December 2013. The Viger-Denonville Project calls for the installation of 12 model MM92 wind turbines from Repower, each consisting of an output of 2.05 MW. The Viger-Denonville Project will connect to the transmission system via a 34.5 kV collector system and a transformer station which will increase the voltage to 120 kV for connection to an existing 120 kV transmission line by Hydro-Québec.

The Viger-Denonville Project is owned by Parc éolien communautaire Viger-Denonville, S.E.C. ("**Viger-Denonville LP**"), the general partner of which is Parc éolien communautaire Viger-Denonville Inc. ("**Viger-Denonville GP**"). The Corporation and the Municipalité régionale de comté de Rivière-du-Loup each owns a 50% equity interest in the Viger-Denonville Project.

Site Rights

The Viger-Denonville Project is entirely located on private lands. Viger-Denonville LP has secured the rights by way of land option agreements for 732 hectares, including all lands required for the installation of wind turbine generators, meteorological towers, collector system, access roads and sub-station of the Viger-Denonville Project.

Power Purchase Agreement

Viger-Denonville LP is party to a PPA with Hydro-Québec (the "**Viger-Denonville PPA**") for the purchase of all electricity that will be produced by Viger-Denonville Project, expiring 20 years after the commencement of commercial operation of the Viger-Denonville Project and subject to customary termination provisions in the case of a material breach of the PPA.

Viger-Denonville LP is subject to penalty payments under the PPA if commercial operation of the Viger-Denonville Project has not commenced by December 1, 2013, subject to certain delays caused by Hydro-Québec or third parties or any extensions due to force majeure provided in the PPA. Pursuant to the Viger-Denonville PPA, Viger-Denonville LP has agreed to deliver and sell 67,6 GWh per year after the commencement of commercial operation of the Viger-Denonville Project.

Prospective Projects

All of the Prospective Projects, with a combined potential net installed capacity, of more than 2,900 MW (gross 3,125 MW), are in the preliminary development stage. Some Prospective Projects are targeted toward specific future Request for Proposals and others will be available for future Request for Proposal, SOPs or FIT Programs yet to be announced. There is no certainty that any Prospective Project will be realized.

A. Various Other Creek Power Prospective Projects (British Columbia – 66.7% *ownership)*

In addition to the three projects submitted to BC Hydro under the Clean Power Call Request for Proposals that were awarded a PPA, namely the Upper Lillooet River, the Boulder Creek and North Creek projects, Creek Power holds the rights to 7 other prospective projects located in southwestern British Columbia for which the Corporation evaluates the aggregate potential installed capacity at more than 132 MW. Some of these projects may be pursued under the BC Hydro SOP.

B. Various Other Prospective Québec Wind Projects (Québec – 50-100% ownership)

The Corporation continues to develop potential wind projects in Québec (the "**Prospective Québec Wind Projects**") for which the Corporation evaluates the aggregate potential installed capacity at 1,145 MW. The Prospective Québec Wind Projects include projects located on private land for which the Corporation has entered into land lease option agreements with the private landowners and projects on public lands, for which, in the past, the Corporation has obtained lease reservation agreements with the government of Québec. The Corporation owns or has, or will have, rights to sufficient meteorological data and land access to propose any and all of the Prospective Québec Wind Projects within the expected requirements of any future requests for proposals for wind farms from Hydro-Québec.

C. Prospective Ontario Feed-In Tariff Projects (Ontario - 49-100% ownership)

As of the date of this Annual Information Form, the Corporation submitted several applications into the FIT Program for an aggregate potential installed capacity of 465 MW for wind projects. Depending on the implementation of transmission expansion, some of these applications may be positioned for eventual award of FIT Contracts and an additional potential installed capacity of 40 MW has been submitted to the FIT Program for ground mount solar PV farm projects.

D. Other Prospective British Columbia Wind Projects (British Columbia - 100% ownership)

The Corporation has identified potential wind projects in British Columbia (the "**Prospective BC Wind Projects**") for which the Corporation evaluates the aggregate potential installed capacity at 475 MW.

The Corporation has been granted licenses of occupation and investigative use permits by the Integrated Land Management Bureau on six sites, which secures a first-ranking claim to the land and prevents other applicants from applying for lands within one kilometre of the permit boundary. The investigative use permit and licence of occupation allow for the installation of meteorological towers to collect wind data, engineering data and environmental data and secure a development option for the Corporation for a period of two years.

Although the Prospective BC Wind Projects are 100% owned by the Corporation, it is probable that the Corporation's interests in one or more of these projects could ultimately be shared with a strategic partner.

E. Various Other Prospective British Columbia Hydro Projects (British Columbia - 100% ownership)

The Corporation owns prospective projects, with a combined potential net installed capacity of over 880 MW, which consist of various run-of-river hydroelectric projects for which certain land rights have been secured, for which an investigative permit application has been filed and for which a proposal has been submitted under a request for proposals or could be submitted under the BC Hydro SOP.

F. Other Prospective Québec Hydro Projects (Québec – 48% ownership)

The Corporation owns interests in a prospective run-of river hydroelectric community project with a potential installed capacity of 42 MW, for which certain land rights have been secured and which could be submitted to a future request for proposal.

INTANGIBLE ASSETS

The intangible assets of the Corporation consist mainly of various PPAs, permits and licenses. The Corporation reported $440.5 million in intangible assets as at December 31, 2012. The Corporation's intangible assets are related to the following assets:

Segments	Hydroelectric facilities 000 $	Wind farm facilities 000 $	Solar facilities 000 $	Facilities under construction 000 $	Total 000 $
Net Value as at December 31, 2012	$362,488	$61,579	$9,240	$7,191	$440,498

ENVIRONMENTAL PROTECTION

The majority of financial costs associated with environmental protection requirements are incurred by the Corporation at the development and construction phases of a power project. Therefore, these costs are capitalized to the project, when a PPA is secured for the project or if the project is eligible under a SOP and sufficiently advanced to have a high degree of confidence that it will be realized and amortized once the project is operational or are charged to earnings if the project does not go ahead. These costs will vary from project to project; however, in order for management to proceed with any project, it must support a pre-determined return on the capital costs invested, including capitalized environmental protection costs. The Corporation does incur ongoing costs associated with environmental protection requirements on operational plants, which are charged to operating costs as incurred. .

EMPLOYEES

The Corporation has 120 employees. This workforce includes 46 employees in operations and maintenance, 28 employees in development and construction and 46 employees in administration, accounting, finance and legal. The operations of the Corporation's reportable segments are conducted by different teams, as each segment has different skill requirements. The Corporation's employees have the specialized knowledge and skills to carry out its business and the Corporation has a proven ability to complement this internal capacity with an efficient use of external consultants, when required. In addition, the Corporation uses the services of several independent engineering firms to assist with the feasibility analysis of its projects.

SOCIAL AND ENVIRONMENTAL PROTECTION POLICIES

The Corporation is committed to Social, Health & Safety and Environmental protection. The Corporation has adopted and implemented a Code of Conduct and a Health & Safety and Environmental Mission Statement. This Code and Mission Statement have been communicated to employees through various training sessions and communications. All Directors, officers and employees of the Corporation have to sign and acknowledge the Code of Conduct.

The Code of Conduct provides that all employees shall ensure that the activities of the Corporation are integrated harmoniously into the community with regard to natural heritage and, in particular observe applicable environmental laws and regulations at all times, support the economic, social and cultural development of the communities in which the Corporation carries on its activities, cooperate, to the extent possible, with programs established for the betterment of the community, mitigate the environmental impact of the Corporation's activities, to the extent possible, work with the community and the authorities to reduce the environmental impact of its activities and implement remedial measures, when necessary.

The Corporation has an environmental team consisting of employees with specialized skills and knowledge and have implemented 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. The Corporation has a Health and a Safety working teams with specialized knowledge and skills responsible for developing safety policies and program, developing and delivering environmental and safety training, conducting internal audits of safety performance, and monitoring and reporting safety risks, events or issues. The Board of Directors monitors compliance with the Corporation Code of Conduct and Health & Safety and Environment corporate policies through regular reporting from Management.

5. RISK FACTORS

The following are certain risk factors relating to the Corporation. 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.

RISKS RELATING TO THE CORPORATION

Execution of Strategy

The Corporation's strategy for building shareholder value is: (i) to acquire or develop high-quality power production facilities that generate sustainable and stable cash flows, with the objective of achieving a high return on invested capital, and (ii) to distribute a stable dividend. However, there is no certainty that the Corporation will be able to acquire or develop high-quality power production facilities at attractive prices to supplement its growth.

The successful execution of a value investment strategy requires careful timing and business judgment, as well as the resources to complete the development of power generating facilities. The Corporation may underestimate the costs necessary to bring power generating facilities into commercial operation or may be unable to quickly and efficiently integrate new acquisitions into its existing operations.

Capital Resources

Future development and construction of new facilities and the development of the Development Projects and the Prospective Projects and other capital expenditures will be financed out of cash generated from the Corporation's operating facilities, borrowing and/or sales of additional equity. To the extent that external sources of capital, including issuance of additional securities of the Corporation, become limited or unavailable, the Corporation's ability to make necessary capital investments to construct or maintain existing project facilities and remain in business would be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund further development or expansion. There are a substantial number of renewable energy projects to be constructed in the coming years that will result in competition for capital. In addition, payment of dividends may impair the Corporation's ability to finance its ongoing and future projects.

The Corporation's capital-raising efforts could involve the issuance and sale of additional Common Shares, or debt securities convertible into its Common Shares, which, depending on the price at which such shares or debt securities are issued or converted, could have a material dilutive effect on holders of the Corporation's Common Shares and adversely impact the trading price of the Corporation's Common Shares.

Derivative Financial Instruments

Derivative financial instruments are entered into with important financial institutions and their effectiveness is dependent on the performance of these institutions. Failure by one of them to perform its obligations could involve a liquidity risk. Liquidity risks related to derivative financial instruments also include the settlement of bond forward contracts on their maturity dates and the early termination option included in some interest rate swap contracts. The Corporation uses derivative financial instruments to manage its exposure to the risk of an increase in interest rates on its debt financing. The Corporation does not own or issue financial instruments for speculation purposes.

Hydrology, Wind and Solar Regime

The amount of energy generated by the Corporation's hydroelectric facilities is dependent upon the availability of water flows. There is no certainty that the long-term availability of such resources will remain unchanged. The Corporation's revenues may be significantly affected by events that impact the hydrological conditions of the Corporation's hydroelectric project facilities such as low and high water flows within the watercourses on which the Corporation's hydroelectric facilities are located. In the event of severe flooding, the Corporation's hydroelectric facilities may be damaged. Similarly, the amount of energy generated by the Corporation's wind power facilities will be dependent upon the availability of wind, which is naturally variable. A reduced or increased amount of wind at the location of one of the wind power project facilities over an extended period may reduce the production from such facility and may reduce the Corporation's revenues and profitability. Finally, the amount of energy to be generated by the Corporation's solar power projects will depend on the availability of solar radiation, which is naturally variable. A reduced or increased amount of solar radiation at the location of one of the solar farm projects over an extended period may reduce the production from such facility and may reduce the Corporation's revenues and profitability.

Construction and Design

Delays and cost over-runs may occur in completing the construction of the Development Projects, the Prospective Projects and future projects that the Corporation will undertake. A number of factors which could cause such delays or cost over-runs include, but are not limited to, permitting delays, construction pricing excalation, changing engineering and design requirements, the performance of contractors, labour disruptions, adverse weather conditions and the availability of financing. Even when complete, a facility may not operate as planned due to design or manufacturing flaws, which may not all be covered by warranty. Mechanical breakdown could occur in equipment after the period of warranty has expired, resulting in loss of production as well as the cost of repair. In addition, if the Development Projects are not brought into commercial operation within the delay stipulated in their respective PPA, the Corporation may be subject to penalty payments or the counterparty may be entitled to terminate the related PPA.

Health, Safety and Environmental Risks

The ownership and operation of the Corporation's power generation assets carry an inherent risk of liability related to worker health and safety and the environment, including the risk of government imposed orders to remedy unsafe conditions and/or to remediate or otherwise address environmental contamination, potential penalties for contravention of health, safety and environmental laws, licenses, permits and other approvals, and potential civil liability. Compliance with health, safety and environmental laws (and any future changes) and the requirements of licenses, permits and other approvals will remain material to the Corporation's business. The Corporation has incurred and will continue to incur significant capital and operating expenditures to comply with health, safety and environmental laws and to obtain and comply with licenses, permits and other approvals and to assess and manage its potential liability exposure. Nevertheless, the Corporation may become subject to government orders, investigations, inquiries or other proceedings (including civil claims) relating to health, safety and environmental matters. The occurrence of any of these events or any changes, additions to or more rigorous enforcement of, health, safety and environmental laws, licenses, permits or other approvals could have a significant impact on operations and/or result in additional material expenditures. As a consequence, no assurances can be given that additional environmental and workers' health and safety issues relating to presently known or unknown matters will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to its business and operations.

Development of New Facilities

The Corporation participates in the construction and development of new power generating facilities. These facilities have greater uncertainty surrounding future profitability than existing operating facilities with established track records. In certain cases many factors affecting costs are not yet determined, such as land royalty payments, water royalties, or municipal taxes. The Corporation is in some cases required to advance funds and post performance bonds in the course of development of its new facilities. In the event that certain of these power generating facilities are not completed or do not operate to the expected specifications, or unforeseen costs or taxes are incurred, the Corporation could be adversely affected.

Permits

The Corporation does not currently hold all of the approvals, licenses and permits required for the construction and operation of the Development Projects or the Prospective Projects, including environmental approvals and permits necessary to construct and operate the Development Projects or the Prospective Projects. The failure to obtain or delays in obtaining all necessary licenses, approvals or permits, including renewals thereof or modifications thereto, could result in construction of the Development Projects or the Prospective Projects being delayed or not being completed. There can be no assurance that any one Prospective Project will result in any actual operating facility.

Federal and provincial environmental permits to be issued in connection with any of the Development Projects may contain conditions that need to be satisfied prior to construction, during construction and during and after the operation of the Development Projects. It is not possible to forecast the conditions imposed by such permits or the cost of any mitigating measures required by such permits. See “Description of the Business and Assets of the Corporation - Development Projects”.

Project Performance and Penalties

The ability of the Corporation’s facilities to generate the maximum amount of power which can be sold to Hydro-Québec, BC Hydro and the OPA or other purchasers of electricity under PPAs is an important determinant of the revenues of the Corporation. If one of the Corporation’s facilities delivers less than the required quantity of electricity in a given contract year or is otherwise in default under its respective PPA, penalty payments may be payable to the relevant purchaser by the Corporation. The payment of any such penalties by the Corporation could adversely affect the revenues and profitability of the Corporation.

Equipment Failure

The Corporation’s facilities are subject to the risk of equipment failure due to deterioration of the asset from use or age, latent defect and design or operator error, among other things. To the extent that a facility’s equipment requires longer than forecasted down times for maintenance and repair, or suffers disruptions of power generation for other reasons, the Corporation’s business, operating results, financial condition or prospects could be adversely affected.

Interest Rate and Refinancing Risk

Interest rate fluctuations are of particular concern to a capital-intensive industry such as the electric power business. The Corporation faces interest rate and debt refinancing risk in respect of floating-rate bank credit facilities used for construction and long-term financings. The Corporation’s ability to refinance debt on favourable terms is dependent on debt capital market conditions, which are inherently variable and difficult to predict.

Financial Leverage and Restrictive Covenants

The Corporation’s and its subsidiaries’ operations are subject to contractual restrictions contained in the instruments governing any of their current and future indebtedness. The degree to which the Corporation and its subsidiaries are leveraged could have important consequences to shareholders, including: (i) the Corporation’s and its subsidiaries’ ability to obtain additional financing for working capital, capital expenditures, acquisitions or other project developments in the future may be limited; (ii) a significant portion of the Corporation’s and its subsidiaries’ cash flows from operations may be dedicated to the payment of the principal of and interest on their indebtedness, thereby reducing funds available for future operations; (iii) certain of the Corporation’s and its subsidiaries’ borrowings will be at variable rates of interest, which exposes the Corporation and its subsidiaries to the risk of increased interest rates; and (iv) the Corporation and its subsidiaries may be more vulnerable to economic downturns and be limited in their ability to withstand competitive pressures.

The Corporation and its subsidiaries are subject to operating and financial restrictions through covenants in certain loan and security agreements. These restrictions prohibit or limit the Corporation’s and its subsidiaries’ ability to, among other things incur additional debt, provide guarantee for indebtedness, create liens, dispose of assets, liquidate, dissolve, amalgamate, consolidate or effect any corporate or capital reorganization, make distributions or pay dividends, issue any equity interests and create subsidiaries. These restrictions may limit the Corporation’s and its subsidiaries’ ability to obtain additional financing, withstand downturns in the Corporation’s and its subsidiaries’ business and take advantage of business opportunities. Moreover, the Corporation and its subsidiaries may be required to seek additional debt financing on terms that include more restrictive covenants, require repayment on an accelerated schedule or impose other obligations that limit the Corporation’s or its subsidiaries’ ability to grow the business, acquire needed assets or take other actions the Corporation or its subsidiaries might otherwise consider appropriate or desirable.

Declaration of Dividends is at the Discretion of the Board of Directors

Holders of Common Shares, Series A Shares and Series C Shares do not have a right to dividends on such shares unless declared by the Board of Directors. The declaration of dividends is at the discretion of the Board of Directors even if the Corporation has sufficient funds, net of its liabilities, to pay such dividends.

The Corporation may not declare or pay a dividend if there are reasonable grounds for believing that (i) the Corporation is, or would after the payment be, unable to pay its liabilities as they become due, or (ii) the realizable value of the Corporation's assets would thereby be less than the aggregate of its liabilities and stated capital of its outstanding shares.

Securing New Power Purchase Agreements

Securing new PPAs, which is a key component of the Corporation's growth strategy, is a risk factor in light of the competitive environment faced by the Corporation. The Corporation expects to continue to enter into PPAs for the sale of its power, which PPAs are mainly obtained through participation in competitive Requests for Proposals processes. During these processes, the Corporation faces competitors ranging from large utilities to small independent power producers, some of which have significantly greater financial and other resources than the Corporation. There is no assurance that the Corporation will be selected as power supplier following any particular Request for Proposals in the future or that existing PPAs will be renewed or will be renewed on equivalent terms and conditions upon the expiry of their respective terms.

Senior Management and Key Employees

The Corporation's executives and other senior officers play a significant role in the Corporation's success. The conduct of the Corporation's business and the execution of the Corporation's growth strategy rely heavily on teamwork and the Corporation's future performance and development depend to a significant extent on the abilities, experience and efforts of its management team. The Corporation's ability to retain its management team or attract suitable replacements should key members of the management team leave is dependent on the competitive nature of the employment market. The loss of services from key members of the management team or a limitation in their availability could adversely impact the Corporation's prospects, financial condition and cash flow.

Further, such a loss could be negatively perceived in the capital markets. The Corporation's success also depends largely upon its continuing ability to attract, develop and retain skilled employees to meet its needs from time to time.

Litigation

In the normal course of its operations, the Corporation may become involved in various legal actions, typically involving claims relating to contract disputes, personal injuries, property damage, property taxes and land rights. The Corporation maintains adequate provisions for its outstanding or pending claims. The final outcome with respect to outstanding, pending or future actions cannot be predicted with certainty, and therefore there can be no assurance that their resolution will not have an adverse effect on the financial position or results of operation of the Corporation in a particular quarter or financial year. See "Legal Proceedings".

Performance of Major Counterparties

The Corporation enters into purchase orders with third-party suppliers for generation equipment for projects under construction, which involve deposits prior to equipment being delivered. Should one or more of these suppliers be unable to meet their obligations under the contracts, this would result in possible loss of revenue, delay in construction and increase in construction costs for the Corporation. Failure of any equipment supplier to meet its obligations to the Corporation may result in the Corporation not being able to meet its commitments and thus lead to potential defaults under PPAs.

Relationship with Stakeholders

The Corporation enters into various types of arrangements with communities or joint venture partners for the development of its projects. Certain of these partners may have or develop interests or objectives which are different from or even in conflict with the objectives of the Corporation. Any such differences could have a negative impact on the success of the Corporation's projects. The Corporation is sometimes required through the permitting and approval process to notify and consult with various stakeholder groups, including landowners, First Nations and municipalities. Any unforeseen delays in this process may negatively impact the ability of the Corporation to complete any given project on time or at all.

Equipment Supply

The Corporation's development and operation of power facilities is dependent on the supply of equipment from third parties. Equipment pricing availability may rapidly increase depending among others on the raw material prices and on the market for such product. Any significant increase in the price of supply of equipment could negatively affect the future profitability of the Corporation's facilities and the Corporation's ability to develop other projects. There is no guarantee that manufacturers will meet all of their contractual obligations. Failure of any supplier of the Corporation to meet its commitments would adversely affect the Corporation's ability to complete projects on schedule and to honour its obligations under PPAs.

Regulatory and Political

The development and operation of power generating facilities are subject to changes in governmental regulatory requirements and the applicable governing statutes, including regulations related to the environment, unforeseen environmental effects, general economic conditions and other matters beyond the control of the Corporation.

The operation of power generating facilities is subject to extensive regulation by various government agencies at the municipal, provincial and federal levels. There is always the risk of changes being made in government policies and laws which may result in increased rates, such as for water rentals, and for income, capital and municipal taxes.

The Corporation holds permits and licenses from various regulatory authorities for the construction and operation of its facilities. These licenses and permits are critical to the operation of the Corporation's business. The majority of these permits and licenses are long-term in nature, reflecting the anticipated useful life of the facilities. In some cases these permits may need to be renewed prior to the end of the anticipated useful life of such facilities and there is no guarantee that such renewals will be granted or on which conditions they will be renewed. These permits and licenses require the Corporation's compliance with the terms thereof. In addition, delays may occur in obtaining necessary government approvals required for future power projects.

From time to time, and in order to secure long lead times required for ordering equipment, the Corporation may place orders for equipment and make deposits thereon or advance projects prior to obtaining all requisite permits and licenses. The Corporation only takes such actions where it reasonably believes that such licenses or permits will be forthcoming in due course prior to the requirement to expend the full amount of the purchase price. However, any delay in permitting could adversely affect the Corporation.

Ability to Secure Appropriate Land

There is significant competition for appropriate sites for new power generating facilities. Optimal sites are difficult to identify and obtain given that geographic features, legal restrictions and ownership rights naturally limit the areas available for site development. There can be no assurance that the Corporation will be successful in obtaining any particular site in the future.

Reliance on PPAs

The power generated by the Corporation is sold under long-term PPAs. If for any reason any of the purchasers of power under such PPAs were unable or unwilling to fulfill their contractual obligations under the relevant PPA or if they refuse to accept delivery of power pursuant to the relevant PPA, the Corporation's business, operating results, financial condition or prospects could be adversely affected. If the Development Projects are not brought into commercial operation within the delay stipulated in their respective PPA, the Corporation may be subject to penalty payments or the counterparty may be entitled to terminate the related PPA.

Reliance Upon Transmission Systems

The Corporation's ability to sell electricity is impacted by the availability of the various transmission systems in each jurisdiction. The failure of existing transmission facilities or the lack of adequate transmission capacity would have a material adverse effect on the Corporation's ability to deliver electricity to its various counterparties, thereby affecting the Corporation's business, operating results, financial condition or prospects.

Water Rental Expense

The Corporation is required to make rental payments for water rights once its projects are in commercial operation. Significant increases in water rental costs in the future or changes in the way that the governments of Québec, British Columbia and Ontario regulate water supply could have a material adverse effect on the Corporation's business, operating results, financial condition or prospects.

Assessment of Water, Wind and Sun Resources and Associated Energy Production

The strength and consistency of the water, wind and sun resources at power facilities of the Corporation may vary from what the Corporation anticipates. Energy production estimates of the Corporation are based on assumptions and factors that are inherently uncertain, which may result in actual energy production being different from the estimates of the Corporation, including (i) the extent to which the limited time period of the site-specific wind data accurately reflects long-term wind speeds; (ii) the extent to which historical data accurately reflects the strength and consistency of the water, wind and sun in the future; (iii) the strength of the correlation between the site-specific water, wind and sun data and the longer-term regional data; (iv) the potential impact of climatic factors; (v) the accuracy of assumptions on a variety of factors, including but not limited to weather, icing and soiling of water and wind turbines and solar panels, site access, wake and line losses and wind shear; (vi) the accuracy with which anemometers measure wind speed, and the difference between the hub height of the wind turbines and the height of the meteorological towers used for data collection; (vii) the potential impact of topographical variations, turbine placement and local conditions, including vegetation; (viii) the inherent uncertainty associated with the specific methodologies and related models, in particular future-orientated models, used to project the water, wind and sun resource; and (ix) the potential for electricity losses to occur before delivery.

Dam Safety

The occurrence of dam failures at any of the Corporation's hydroelectric power facilities could result in a loss of generating capacity and repairing such failures could require the Corporation to incur significant expenditures of capital and other resources. Such failures could result in the Corporation being exposed to significant liability for damages. There can be no assurance that the dam safety program will be able to detect potential dam failures prior to occurrence or eliminate all adverse consequences in the event of failure. Safety regulations relating to dam safety could change from time to time, potentially impacting a facility's costs and operations. The consequences of dam failures could have a material adverse effect on the Corporation's business, operating results, financial condition or prospects.

Natural Disasters; Force Majeure

The Corporation's facilities and operations are exposed to potential damage, partial or full loss, resulting from environmental disasters (e.g. floods, high winds, fires, and earthquakes), equipment failures and the like. The occurrence of a significant event which disrupts the ability of the Corporation's power generation assets to produce or sell power for an extended period, including events which preclude existing customers under PPAs from purchasing electricity, could have a material negative impact on the business of the Corporation. The Corporation's generation assets could be exposed to effects of severe weather conditions, natural disasters and potentially catastrophic events such as a major accident or incident. The occurrence of such an event may not release the Corporation from performing its obligations pursuant to PPAs or other agreements with third parties. In addition, many of the Corporation's projects are located in remote areas which make access for repair of damage difficult.

Foreign Exchange

The Corporation occasionally purchases equipment from foreign suppliers. As such, the Corporation may be exposed to changes in the Canadian dollar in relation to the foreign currency denominated equipment purchases. Where possible, the Corporation will fix the purchase price in Canadian dollars or enter into a foreign exchange swap to fix the exchange rate.

Insurance Limits

While the Corporation believes that the insurance coverage for its projects addresses all material insurable risks, provides coverage that is similar to what would be maintained by a prudent developer/owner/operator of similar projects, and is subject to deductibles, limits, and exclusions which are customary or reasonable given the cost of procuring insurance and current operating conditions, there is no certainty that such insurance will continue to be offered on an economically feasible basis, nor that all events that could give rise to a loss or liability are insurable, nor that the amounts of insurance will at all times be sufficient to cover each and every loss or claim that may occur involving the operation of the projects.

Credit rating may not reflect actual performance of the Corporation

The credit ratings applied to the Corporation, the Series A and Series C Shares (the "**Credit Ratings**") is an assessment, by the rating agencies, of the Corporation's ability to pay its obligations. The Credit Ratings are based on certain assumptions about the future performance and capital structure of the Corporation that may or may not reflect the actual performance or capital structure of the Corporation. Changes in the Credit Ratings in the future may affect the market price or value and the liquidity of the securities of the Corporation. There is no assurance that any Credit Ratings will remain in effect for any given period of time or that any rating will not be lowered or withdrawn entirely by the rating agencies. The Corporation decided to terminate its agreement with DBRS, effective September 8, 2012. Despite such termination, DBRS continues for the time being and of its own volition to rate the Corporation and certain of its securities, but does not have access to non-public information, including forecasts and budgets. There can be no assurance that DBRS will continue to provide ratings, nor are there indications as to when DBRS might cease to provide such ratings.

Potential Undisclosed Liabilities Associated with Acquisitions

There may be liabilities and contingencies that management of the Corporation did not discover in its due diligence prior to consummation of acquisitions and the Corporation may not be indemnified for these liabilities and contingencies. The discovery of any material liabilities or contingencies relating to the shares, assets or business acquired following such acquisitions could have a material adverse effect on the Corporation's business, financial condition and results of operations.

Integration of the Facilities and Projects Acquired and to be Acquired

The integration of facilities and assets acquired or to be acquired through the acquisitions of the Corporation may result in significant challenges, and management of the Corporation may be unable to accomplish the integration successfully or without spending significant amounts of money. There can be no assurance that management will be able to integrate successfully the assets acquired or to be acquired through acquisitions or fully realize the expected benefits of any such acquisitions.

Failure to Realize Acquisition Benefits

The Corporation believes that the acquisitions recently completed and to be completed will provide benefits for the Corporation. However, there is a risk that some or all of the expected benefits will fail to materialize, or may not occur within the time periods anticipated by the management of the Corporation. The realization of such benefits may be affected by a number of factors, many of which are beyond the control of the Corporation.

Failure to Close the Magpie Hydroelectric Facility Acquisition and the Acquisition of the Other Hydromega Hydroelectric Facilities and Development Projects

The closing of the Magpie Hydroelectric Facility Acquisition is subject to the fulfillment or waiver of certain closing conditions, including third-party consents and certain other customary closing conditions. The failure to have such closing conditions satisfied or, if applicable, waived, will prevent the Corporation from completing the Magpie Hydroelectric Facility Acquisition. There is no assurance that such closing conditions will be satisfied or waived. Accordingly, there can be no assurance that the Corporation will complete the Magpie Hydroelectric Facility Acquisition in its timeframe or on the terms and conditions described herein, if at all. In addition, there is no certainty the Corporation will be successful in negotiating a definitive agreement for the acquisition of the Kapuskasing Projects, Dokis Project and Sainte-Marguerite Facility or that such transaction will close.

Shared Transmission and Interconnection Infrastructure

The six Harrison Operating Facilities and the Northwest Stave Project (the "**Sharing Facilities and Project**") all share joint transmission and interconnection infrastructure to transmit their electrical energy generation to a joint substation, the Kwalsa Substation, which then interconnects to the common point of interconnection for the Sharing Facilities and Project at the adjacent BC Hydro Upper Harrison terminal substation. Therefore damage to or a failure of the shared transmission and interconnection infrastructure may result in the Sharing Facilities and Project being unable to deliver their electrical energy generation to the point of interconnection with BC Hydro's transmission system in accordance with the requirements for sale of energy under the PPAs with BC Hydro in respect of the six Harrison Operating Facilities. All six Harrison Operating Facilities also share one common interconnection agreement with BC Hydro and act as agent for the Northwest Stave Project. Therefore, a default by any one of the Sharing Facilities and Project of its obligations under the interconnection agreement may result in BC Hydro disconnecting all the Sharing Facilities and Project from the BC Hydro transmission system.

Introduction to Solar PV Power Facility Operation

The Stardale Solar Farm represents the Corporation's first operational experience with a solar PV power project. For the duration of the PPA, Enfinity will provide all operations and maintenance services required for the Stardale Solar Farm. The Stardale Solar Farm may possibly not operate as planned and such performance issues could have an adverse impact on the Corporation's results.

Revenues from the Miller Creek Facility will vary based on the Spot Price of Electricity

Because the price for electricity purchased from the Miller Creek Facility is based on a formula using the mid-C spot price for electricity, revenues under the applicable power purchase agreement will vary. If the mid-C index declines from its current levels, the Miller Creek Facility's revenues and Adjusted EBITDA will be negatively impacted. An increase in the volatility of the mid-C spot price would add uncertainty to the determination of potential revenues and Adjusted EBITDA of the Miller Creek Facility.

6. DIVIDENDS

The declaration and payment of dividends on the Corporation's shares is within the discretion of the Board of Directors. The Board of Directors will determine if and when dividends should be paid in the future based on all relevant circumstances, including the desirability of maintaining capital to finance further growth of the Corporation and the Corporation's financial position at the relevant time. As publicly disclosed, the Corporation intends to pay a dividend of $0.58 per Common Share per annum, payable on a quarterly basis and the dividend rate applicable to the Series A Shares and Series C Shares. See "Description of Capital Structure – General Description of Capital Structure - Preferred Shares - Series A Shares and Series B Shares and Series C Shares".

The following table sets forth the dividends declared by the Corporation to its shareholders of Common Shares during its 2010 financial year after the Arrangement and financial years 2011 and 2012.

Date Declared	Amount paid per Corporation Common Share	Dividend Payment	Aggregate Dividend Amount
May 10, 2010	$0.14818	July 15, 2010	$8,821,542
August 12, 2010	$0.145	October 15, 2010	$8,632,228
November 8, 2010	$0.145	January 17, 2011	$8,632,228
March 23, 2011	$0.145	April 15, 2011	$8,632,228

Date Declared	Amount paid per Corporation Common Share	Dividend Payment	Aggregate Dividend Amount
June 7, 2011	$0.145	July 15, 2011	$11,785,957
August 10, 2011	$0.145	October 17, 2011	$11,785.957
November 9, 2011	$0.145	January 16, 2012	$11,785.957
March 21, 2012	$0.145	April 16, 2012	$11,785,956
May 14, 2012	$0.145	July 16, 2012	$11,785,956
August 7, 2012	$0.145	October 15, 2012	$13,540,225
November 6, 2012	$0.145	January 15, 2013	$13,580,680

The following table sets forth the distributions made by the Fund (which acquired, as of March 29, 2010, the Corporation by way of a reverse take-over pursuant to the Arrangement) to its unitholders during financial year 2010.

Date Declared	Amount paid per Fund unit	Distribution Date	Aggregate Amount Distributed
January 2010	$0.08334	February 25, 2010	$2,450,552
February 2010	$0.08334	March 25, 2010	$2,450,552
March 2010	$0.07946	March 29, 2010	$2,336,646

The following table sets forth the dividends declared by the Corporation to its shareholders of Series A Shares during its 2010 financial year after the Series A Offering and financial years 2011 and 2012.

Date Declared	Amount paid per Series A Shares	Dividend Payment	Aggregate Dividend Amount
November 8, 2010	$0.42123	January 17, 2011	$1,432,182
March 23, 2011	$0.3125	April 15, 2011	$1,062,500
June 7, 2011	$0.3125	July 15, 2011	$1,062,500
August 10, 2011	$0.3125	October 17, 2011	$1,062,500
November 9, 2011	$0.3125	January 16, 2012	$1,062,500
March 21, 2012	$0.3125	April 16, 2012	$1,062,500
May 14, 2012	$0.3125	July 16, 2012	$1,062,500
August 7, 2012	$0.3125	October 15, 2012	$1,062,500
November 6, 2012	$0.3125	January 15, 2013	$1,062,500

7. DESCRIPTION OF CAPITAL STRUCTURE

GENERAL DESCRIPTION OF CAPITAL STRUCTURE

The Corporation's authorized share capital consists of an unlimited number of Common Shares and an unlimited number of Preferred Shares issuable in series. As of March 28, 2013, 93,964,093 Common Shares, 3,400,000 Series A Shares, 2,000,000 Series C Shares and $80.5 million of Debentures were issued and outstanding. The Corporation's Common Shares, Series A Shares, Series C Shares, and the Debentures are listed on the TSX under the symbols "INE", "INE.PR.A", "INE.PR.C" and "INE.DB" respectively.

Common Shares

Holders of Common Shares are entitled to one vote per share on all matters to be voted on at all meetings of shareholders of the Corporation except meetings at which only the holders of a specified class or series of the share capital of the Corporation are entitled to vote.

Subject to the prior rights of the holders of Preferred Shares, the holders of Common Shares are entitled to receive, as and when declared by the Board of Directors out of the moneys of the Corporation properly applicable to the payment of dividends, dividends in such amounts and payable at such times as the Board of Directors will determine.

In the event of the liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, or other distribution of the assets of the Corporation among its shareholders for the purpose of winding-up its affairs, the remaining assets of the Corporation, after payment to the holders of Preferred Shares to the amounts they are entitled to in such event, will be paid to or distributed equally and rateably among the holders of the Common Shares.

There are no rights of pre-emption, redemption or conversion in respect of the Common Shares.

Preferred Shares

Preferred Shares are issuable in series. The Board of Directors has the right to fix the number of and to determine the designation, rights, privileges, restrictions and conditions attaching to the Preferred Shares of each series.

The Preferred Shares of each series, with respect to the payment of dividends and the distribution of assets or return of capital in the event of liquidation, dissolution or winding-up of the Corporation, whether voluntary or involuntary, rank on a parity with the Preferred Shares of every other series and are entitled to a preference and priority over the Common Shares.

The holders of any series of Preferred Shares are entitled to receive, in priority to the holders of Common Shares, as and when declared by the Board of Directors, dividends in the amounts specified or determinable in accordance with the rights, privileges, restrictions and conditions attaching to the series of which such Preferred Shares form part.

The holders of Preferred Shares are not (except as otherwise provided by law and except for meetings of the holders of Preferred Shares as a class and meetings of holders of Series A Shares, Series B Shares or Series C Shares as a series, as applicable) entitled to receive notice of, attend, or vote at, any meeting of shareholders of the Corporation, unless and until the Corporation shall have failed to pay eight quarterly dividends on the Series A Shares or the Series B Shares or Series C Shares. In the event of such non-payment, and for only so long as the dividends remain in arrears, the holders of the Series A Shares, the Series B Shares or the Series C Shares, as applicable, will be entitled to receive notice of and to attend each meeting of the Corporation's shareholders, other than meetings at which only holders of another specified class or series are entitled to vote, and be entitled to vote together with all of the voting shares of the Corporation on the basis of one vote in respect of each Series A Share, Series B Share or Series C Shares held by such holder, until all such arrears of such dividends have been paid, whereupon such rights shall cease.

The Corporation, subject to any rights attached to any particular series of Preferred Shares, may, at its option, redeem all or from time to time any part of the outstanding Preferred Shares on payment to the holders thereof, for each share to be redeemed, of the redemption price per share, together with all dividends declared thereon and unpaid. If entitled to pursuant to the conditions attached to any particular series of Preferred Shares, a holder of Preferred Shares is entitled to require the Corporation to redeem at any time and from time to time after the date of issue of any Preferred Shares, upon giving notice, all or any number of the Preferred Shares registered in the name of such holder on the books of the Corporation, at the redemption price per share, together with all dividends declared thereon and unpaid.

The Corporation may at any time or from time to time purchase for cancellation the whole or any part of the Preferred Shares outstanding at the lowest price at which, in the opinion of the directors of the Corporation, such shares are obtainable, provided that such price or prices does not in any case exceed the redemption price current at the time of purchase for the shares of the particular series purchased, plus costs of purchase together with all dividends declared thereon and unpaid.

<u>Series A Shares and Series B Shares</u>

On September 14, 2010, the Corporation completed the Series A Offering, which resulted in the issuance of a total of 3,400,000 Series A Shares. The rights and privileges attached to Series A Shares and Series B Shares are set forth in the Certificate of amendment dated September 10, 2010 issued by Industry Canada in connection with the Series A Offering (the "**Series A and Series B Shares Terms**"). The following text is a description of the terms of the Series A Shares and the Series B Shares, a copy of which has been filed with the Canadian securities regulatory authorities on SEDAR at www.sedar.com . The following summary of certain provisions of the Series A and Series B Shares Terms is subject to, and is qualified in its entirety by reference to the Series A and Series B Shares Terms available on SEDAR at www.sedar.com .

For the initial five year period from and including the date of issuance of the Series A Shares to, but excluding January 15, 2016 (the "**Initial Fixed Rate Period**"), holders of Series A Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board of Director, payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to $1.25 per Series A Share. For each five-year period after the Initial Fixed Rate Period (each a "**Subsequent Fixed Rate Period**"), holders of Series A Shares will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board of Directors, payable quarterly on the 15th day of January, April, July and October in each year during the Subsequent Fixed Rate Period, in an annual amount per share determined by multiplying the Annual Fixed Dividend Rate (as defined in the Series A Shares Prospectus) applicable to such Subsequent Fixed Rate Period by $25.00. The Annual Fixed Dividend Rate for each Subsequent Fixed Rate Period will be equal to the sum of the government of Canada Yield (as defined in the Series A Shares Prospectus) on the 30th day prior to the first day of such Subsequent Fixed Rate Period plus 2.79%.

Each holder of Series A Shares has the right, at its option, to convert all or any of its Series A Shares into Series B Shares on the basis of one Series B Share for each Series A Share converted, subject to certain conditions, on January 15, 2016 and on January 15 every five years thereafter. The holders of Series B Shares are entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board of Directors, payable quarterly on the 15th day of January, April, July and October in each year, in the annual amount per Series B Share determined in accordance with the formula set out in the short form prospectus for the Series A Shares dated September 7, 2010 (the "**Series A Shares Prospectus**").

In addition, the Series A Shares are not redeemable by the Corporation prior to January 15, 2016. On January 15, 2016 and on January 15 every five years thereafter, subject to certain other restrictions set out in the Series A Shares Prospectus, the Corporation may, at its option, on at least 30 days and not more than 60 days prior written notice, redeem for cash any number of the outstanding Series A Shares for $25.00 per Series A Share, in each case together with all accrued and unpaid dividends thereon up to, but excluding, the date fixed for redemption (less any tax required to be deducted or withheld by the Corporation).

The Series B Shares are not redeemable by the Corporation on or prior to January 15, 2016. Subject to certain other restrictions set out in the Series A Shares Prospectus, the Corporation may, at its option, on at least 30 days and not more than 60 days prior written notice, redeem all or any number of the outstanding Series B Shares by payment in cash of a per share sum equal to (i) $25.00 in the case of redemptions on January 15, 2021 and on January 15 every five years thereafter (each a "**Series B Conversion Date**"), or (ii) $25.50 in the case of redemptions on any date which is not a Series B Conversion Date after January 15, 2016, in each case together with all accrued and unpaid dividends thereon up to, but excluding, the date fixed for redemption (less any tax required to be deducted or withheld by the Corporation).

Series C Shares

On December 11, 2012, the Corporation completed the Series C Offering, which resulted in the issuance of a total of 2,000,000 Series C Shares. The rights and privileges attached to Series C Shares are set forth in the Certificate of amendment dated December 6, 2012 issued by Industry Canada in connection with the Series C Offering (the "**Series C Shares Terms**"). The following text is a description of the terms of the Series C Shares, a copy of which has been filed with the Canadian securities regulatory authorities on SEDAR at www.sedar.com . The following summary of certain provisions of the Series C Shares Terms is subject to, and is qualified in its entirety by reference to the Series C Shares Terms available on SEDAR at www.sedar.com.

The holders of Series C Shares are entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board of Directors, payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to $1.4375 per Series C Share.

The Series C Shares will not be redeemable by the Corporation prior to January 15, 2018. On or after January 15, 2018, the Corporation may, at its option, on at least 30 days and not more than 60 days prior written notice, redeem all or any number of outstanding Series C Shares by payment in cash of a per share sum equal to (i) $26.00 if redeemed on or prior to January 15, 2019; (ii) $25.75 if redeemed thereafter and on or prior to January 15, 2020; (iii) $25.50 if redeemed thereafter and on or prior to January 15, 2021; (iv) $25.25 if redeemed thereafter and on or prior to January 15, 2022; and (v) $25.00 if redeemed thereafter, in each case together with all accrued and unpaid dividends thereon up to, but excluding, the date fixed for redemption.

The Series C Shares do not have a fixed maturity date and are not redeemable at the option of the holders thereof.

5.75% Convertible Debentures

On March 8, 2010, the Corporation completed the offering of Debentures in the aggregate principal amount of $70 million. The Corporation granted the underwriters of the Debentures Offering an option, for a period of 30 days following the closing of the Debenture Offering, to purchase up to an additional 15% of the principal amount of Debentures purchased to cover over-allotments. On March 16, 2010, the over-allotment option was exercised by the underwriters of the Debentures Offering to purchase an additional $10.5 million principal amount of Debentures, bringing the aggregate gross proceeds of the offering to $80.5 million. The Debentures were issued under an indenture, dated March 8, 2010, between the Corporation and Computershare Trust Company of Canada (the "**Debenture Indenture**"). The following text is a description of the terms of the Debenture Indenture, copy of which has been filed with the Canadian securities regulatory authorities on SEDAR at www.sedar.com . The following summary of certain provisions of the Debenture Indenture is subject to, and is qualified in its entirety by reference to, the provisions of the Debenture Indenture, available on SEDAR at www.sedar.com .

The Debentures have a maturity date of April 30, 2017 and bear interest at a rate of 5.75% per annum, payable semi-annually, and are convertible at the option of their holders into Common Shares of the Corporation at a conversion rate of 93.8967 Common Shares per $1,000 principal amount of Debentures, which is equal to a conversion price of $10.65 per Common Share.

The Debentures may not be redeemed by the Corporation on or before April 30, 2013 (except in certain limited circumstances following a "change of control", as such term is defined in the Debenture Indenture). After April 30, 2013 and prior to April 30, 2015, the Debentures may be redeemed by the Corporation, in whole or in part on not more than 60 day and not less than 30 day prior notice, at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the volume weighted average trading price of the Common Shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given is not less than 125% of the conversion price (the "**Current Market Price**").

On or after April 30, 2015 and prior to the maturity date, the Debentures may be redeemed, in whole or in part, at the option of the Corporation at a price equal to their principal amount plus accrued and unpaid interest. Subject to required regulatory approval and provided that there is not a current event of default (as defined in the Debenture Indenture), the Corporation may, at its option, elect to satisfy its obligation to pay the principal amount of the Debentures on redemption or at maturity, in whole or in part, through the issuance of freely tradeable Common Shares upon at least 40 day and not more than 60 day prior notice, by delivering that number of Common Shares obtained by dividing the principal amount of the Debentures by 95% of the Current Market Price. Any accrued or unpaid interest will be paid in cash.

RATINGS

Credit ratings are intended to provide investors with an independent measure of credit quality of an issue of securities.

The following table sets out the ratings of the Corporation, of its Series A Shares and of its Series C Shares received from Standard & Poor's ("**S&P**") and DBRS Limited ("**DBRS**") as at March 28, 2012.

Credit Agency	S&P	DBRS
Innergex Renewable Energy Inc.	BBB-	BB (high)
Series A Shares	P-3	Pfd-4 (high)
Series C Shares	P-3	Pfd-4 (high)

The Corporation is rated BBB- with a stable rating outlook by S&P. An S&P's issuer credit rating is a forward-looking opinion about an obligor's overall financial capacity (its creditworthiness) to pay its financial obligations. Such opinion focuses on the obligor's capacity and willingness to meet its financial commitments as they come due. S&P ratings for long-term debt instrument range from a high of AAA to a low CC. Ratings from AA to CCC may be modified by the addition of a plus (+) or minus (-) sign to show relative standing within the major rating categories. According to S&P rating system, an obligor rated BBB has adequate capacity to meet its financial commitments. However, adverse economic conditions or changing circumstances are more likely to lead to a weakened capacity of the obligor to meet its financial commitments. An S&P rating outlook assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). The outlook may be qualified as Positive, Negative, Stable, Developing or N.M. (not meaningful). A Stable rating outlook means that a rating is not likely to change.

The Series A Shares and the Series C Shares have each been given a Canadian scale rating of P-3 by S&P. Such P-3 rating is the tenth of twenty ratings used by S&P in its Canadian preferred share rating scale (the first rating being the highest and the twentieth rating being the lowest). According to S&P, such a P-3 rating indicates that although the obligation is considered to be less vulnerable to non-payment than other speculative issues, it faces major ongoing uncertainties or exposure to adverse business, financial, or economic conditions which could lead to the obligor's inadequate capacity to meet its financial commitment on the obligation.

The Corporation has paid applicable service fees to S&P for the rating of the Corporation, of the Series A Shares and the Series C Shares and the Annual Review thereof. The Corporation has not paid any other amounts for other services provided by S&P within the last two years.

The Corporation is rated BB (high) with a stable trend by DBRS. On March 25, 2013, DBRS announced it had downgraded the rating of the Corporation from BBB (low) with a negative trend to BB (high) with a stable trend. The DBRS long-term rating scale provides an opinion on the risk of default. That is the risk that an issuer will fail to satisfy its financial obligations in accordance with the terms under which an obligation was issued. DBRS long-term ratings range from a high AAA to a low D. The assignment of a “high” or “low” designation within each rating categories other that AAA and D indicates relative standing within that category, while the absence of such designation indicates that the rating is in the “middle” of such category. According to DBRS’s rating system, a rating of BB is defined to be speculative and non-investment grade, where the capacity for the payment of financial obligations is uncertain and vulnerable to future events. The rating trend indicates the direction in which DBRS considers the rating is headed should present tendencies continue, or in some cases, unless challenges are addressed.

The Series A Shares and Series C Shares have been given a rating of Pfd-4 (high) by DBRS. On March 25, 2013, DBRS announced it had downgraded the rating of the Series A Shares and the Series C Shares from Pfd-3 (low) with a negative trend to Pfd-4 (high) with a stable trend. Pfd-4 (high) is the tenth of sixteen ratings used by DBRS for preferred shares (the first rating being the highest and the sixteenth rating being the lowest). According to DBRS, preferred shares rated Pfd-4 are speculative where the degree of protection afforded to dividends and principal is uncertain, particularly during periods of economic adversity. DBRS further subcategorizes each rating by the designation of “high” and “low” to indicate where an entity falls within the rating category. The absence of either a “high” or “low” designation indicates the rating is in the middle of the category. The rating trend indicates the direction in which DBRS considers the rating is headed should present tendencies continue, or in some cases, unless challenges are addressed.

The Corporation has paid applicable services fees to DBRS for the rating of the Corporation and of its Series A Shares and the Annual Review for services ending September 8, 2012. The Corporation has not paid any other amount for other services provided by DBRS within the last two years.

Ratings are intended to provide investors with an independent assessment of the credit quality of an issue or issuer of securities and do not speak to the suitability of particular securities for any particular investor. A security rating or a stability rating is not a recommendation to buy, sell or hold securities and may be subject to revision or withdrawal at any time by the rating organization.

8. MARKET FOR SECURITIES

COMMON SHARES

The Common Shares are listed for trading on the TSX under the symbol “INE”.

The following table sets forth the price range and daily average trading volume, in Canadian dollars, of the Common Shares on the TSX for each month of the most recently completed financial year and the first three months of 2013.

	Highest price	Lowest price	Daily Average Volume
January 2012	10.93	10.06	75,606
February 2012	10.47	9.96	77,126
March 2012	10.50	10.00	61,439
April 2012	10.58	10.02	155,455
May 2012	10.95	10.30	42,988
June 2012	10.94	9.69	54,769
July 2012	11.10	10.08	40,471
August 2012	11.23	10.71	53,673
September 2012	11.27	10.55	66,085

	Highest price	Lowest price	Daily Average Volume
October 2012	11.00	10.50	46,146
November 2012	10.92	10.12	70,761
December 2012	10.53	10.04	93,272
January 2013	10.46	10.00	138,201
February 2013	10.75	10.22	94,340
March 1 to 27, 2013	10.52	9.36	210,604

5.75% CONVERTIBLE DEBENTURES

The Debentures are listed on the TSX under the symbol “INE.DB”.

The following table sets forth the price range and daily average trading volume, in Canadian dollars, of the Debentures on the TSX for each month of the most recently completed financial year and the first three months of 2013.

	Highest price	Lowest price	Daily Average Volume
January 2012	106.70	104.00	703
February 2012	109.23	104.50	330
March 2012	107.60	104.75	546
April 2012	108.98	105.5	540
May 2012	109.89	105.71	351
June 2012	108.27	102.76	390
July 2012	114.89	104.55	278
August 2012	110.28	108.00	730
September 2012	110.99	108.00	822
October 2012	111.00	108.62	1,180
November 2012	110.70	107.26	394
December 2012	108.46	105.22	227
January 2013	107.50	105.45	2,003
February 2013	109.00	106.60	416
March 1 to 27, 2013	107.83	101.50	1,416

SERIES A SHARES

The Series A Shares are listed on the TSX under the symbol “INE.PR.A”.

The following table sets forth the price range, in Canadian dollars and daily average trading volume, of the Series A Shares on the TSX for each month of the most recently completed financial year and the first three months of 2013.

	Highest price	Lowest price	Daily Average Volume
January 2012	25.00	23.01	3,463
February 2012	25.50	24.70	2,306
March 2012	25.01	24.20	1,435
April 2012	25.10	24.75	1,922
May 2012	25.25	24.60	2,899
June 2012	25.00	23.85	1,135
July 2012	25.30	24.85	3,052
August 2012	25.60	24.91	2,194
September 2012	25.53	24.70	1,750
October 2012	25.59	24.85	1,385
November 2012	25.35	24.36	1,153
December 2012	24.85	23.30	2,003
January 2013	24.75	23.55	4,957
February 2013	25.00	24.00	2,695
March 1 to 27, 2013	25.15	22.00	6,625

SERIES C SHARES

The Series C Shares are listed on the TSX under the symbol “INE.PR.C”.

The following table sets forth the price range, in Canadian dollars and daily average trading volume, of the Series C Shares on the TSX since they began trading on December 11, 2012 and the first three months of 2013.

	Highest price	Lowest price	Daily Average Volume
December 11 2012 to December 31, 2012	24.76	23.17	40,681
January 2013	23.70	23.12	7,777
February 2013	23.75	23.52	6,842
March 1 to 27, 2013	23.75	20.76	6,811

9. DIRECTORS AND EXECUTIVE OFFICERS

DIRECTORS

The following table sets forth the name, municipality, province or state and country of residence of each director of the Corporation as of the date of this Annual Information Form, his or her principal occupation, the period during which each has acted as a director and the Common Shares in number and percentage each director holds. Each director is elected until the next annual meeting of shareholders or until a successor is elected by shareholders, unless the director resigns or his or her office becomes vacant by removal, death or other cause.

Name and Municipality of Residence	Director since	Principal Occupation	Common Shares beneficially owned or controlled or directed(1)	% of Common Shares
MICHEL LETELLIER, St-Lambert, Québec, Canada	2002	President and Chief Executive Officer of the Corporation	606,808	0.648%
WILLIAM A. LAMBERT(2)(3) Toronto, Ontario, Canada	2007	Corporate Director	153,300	0.163%
JOHN A. HANNA(3)(4)(7)(8) Toronto, Ontario, Canada	2003	Corporate Director	53,800	0.057%
JEAN LA COUTURE(6)(7)(9) Montréal, Québec, Canada	2003	President, Huis Clos Ltée	17,348	0.018%
LISE LACHAPELLE(2)(3)(7) Montreal, Québec, Canada	2003	Corporate Director	10,220	0.011%
RICHARD LAFLAMME(2)(3)(5)(7) St-Laurent, Île d'Orléans, Québec, Canada	2003	Corporate Director	11,100	0.012%
DANIEL L. LAFRANCE(3)(4)(5)(7) Montréal, Québec, Canada	2003	Senior Vice President, Finance and Procurement, Chief Financial Officer and Secretary of Lantic Inc.	25,000	0.027%

(1) The information as to Common Shares beneficially owned, controlled or directed by each director has been furnished by the respective directors individually.

(2) Member of Corporate Governance Committee.

(3) Member of Nominating Committee.

(4) Member of Audit Committee.

(5) Member of Human Resources Committee.

(6) Chairman of the Board of Directors, Chair of the Nominating Committee, member the Audit Committee and all other committees of the Corporation.

(7) John A. Hanna, Lise Lachapelle, Jean La Couture, Richard Laflamme and Daniel Lafrance were appointed directors of the Corporation on March 29, 2010 upon completion of the Arrangement. Prior to the Arrangement, they had all been trustees of the Fund (which acquired the Corporation by way of a reverse take-over) since its initial public offering in 2003.

(8) John A. Hanna also holds 4,000 Series A Shares, representing 0.117% of the issued and outstanding Series A Shares.

(9) Jean La Couture also holds indirectly $200,000 principal amount of Debentures.

During the past five years, each of the above directors has held his or her present principal occupation or other management positions with the same firm or with other associated companies or firms, including affiliates and predecessors, indicated beside his or her name, except for William A. Lambert, who, prior to January 2010, was a partner of Birch Hill Equity Partners and for Richard Laflamme who was, prior to December 2012 General Manager, Université du Québec Pension Funds.

EXECUTIVE OFFICERS

The following table sets forth the name, municipality, province or state and country of residence of each executive officer, his or her office and principal occupation and the period of service as an executive officer of the Corporation.

Name and Municipality of Residence	Officer since	Office/Principal Occupation
MICHEL LETELLIER, MBA St-Lambert, Québec, Canada	2003	President and Chief Executive Officer
JEAN PERRON, CPA, CA, CMA Brossard, Québec, Canada	2003	Chief Financial Officer and Senior Vice President
JEAN TRUDEL, MBA Montréal, Québec, Canada	2003	Chief Investment Officer and Senior Vice President Communications
FRANÇOIS HÉBERT Bromont, Québec, Canada	2003	Senior Vice President Operations and Maintenance
RICHARD BLANCHET, P. Eng., M.Sc. North Vancouver, British Columbia, Canada	2004	Senior Vice President Western Region
PETER GROVER, Eng. St-Bruno, Québec, Canada	2005	Senior Vice President – Project Management

During the past five years, each of the above executive officers has held his present principal occupation or other management positions with the Corporation.

The directors and executive officers of the Corporation as a group beneficially own, directly or indirectly, or exercise control or direction over 1,611,706 Common Shares, representing 1.72% of the Corporation's total issued and outstanding Common Shares.

BANKRUPTCY, INSOLVENCY, CEASE TRADE ORDER AND PENALTIES

As a director of Quebecor Inc., the controlling shareholder of Quebecor World Inc., Jean La Couture was asked to join the Board of Directors of Quebecor World Inc. on December 10, 2007. On January 21, 2008, Quebecor World Inc. filed for protection under the *Companies Creditors Arrangement Act* in Canada and Chapter 11 of the U.S. Bankruptcy Code. Jean La Couture resigned as Director of Quebecor World Inc. on December 16, 2008. In July 2009, Quebecor World Inc. emerged from Canadian and U.S. bankruptcy proceedings.

Lise Lachapelle was a director of AbitibiBowater Inc. since 2007 until December 2010. In April 2009, AbitibiBowater Inc., together with certain of its U.S. and Canadian subsidiaries, filed voluntary petitions in the United States Bankruptcy Court for the District of Delaware for relief under the provisions of Chapter 11 and Chapter 15 of the United States Bankruptcy Code, as amended, and certain of its Canadian subsidiaries sought creditor protection under the *Companies' Creditors Arrangement Act* with the Superior Court of Québec in Canada. In December 2010, AbitibiBowater Inc. emerged from Canadian and U.S. bankruptcy proceedings.

With the exception of the foregoing, to the knowledge of the Corporation, none of the directors and executive officers of the Corporation (a) is, as of the date of this Annual Information Form, nor has been within ten years before the date of this Annual Information Form, a director, chief executive officer or chief financial officer of a corporation that (i) was subject to an order issued while such director or executive officer of the Corporation was acting in the capacity of director, chief executive officer or chief financial officer, or (ii) was subject to an order that was issued after such director or executive officer of the Corporation ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity of director, chief executive officer or chief financial officer, (b) is not, as of the date of this Annual Information Form, nor has been within ten years before the date of this Annual Information Form, a director or executive officer of any company that, while that person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement or compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or (c) has, within ten years before the date of this Annual Information Form, become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of such director or executive officer of the Corporation.

For the purposes of the paragraph above, "order" means a cease trade order, an order similar to a cease trade order or an order that denied the relevant corporation access to any exemption under securities legislation, that was in effect for a period of more than 30 consecutive days.

10. CONFLICTS OF INTEREST

There are no existing or potential material conflicts of interest between the Corporation or any of its subsidiaries and their respective directors and officers. Certain of the Corporation's directors and officers also serve as directors or officers of other corporations. Such associations may give rise to conflicts of interest from time to time. Management of the Corporation and the Board of Directors will address any such conflict of interest which may arise in the future in accordance with reasonable expectations and objectives of the Corporation and will act in accordance with any duty of care and any duty to act in good faith owed to the Corporation.

11. LEGAL PROCEEDINGS AND REGULATORY ACTIONS

Neither the Corporation nor its properties is, nor was it during the year ended December 31, 2012, subject to any legal proceedings that would have a material adverse effect on it. To the Corporation's knowledge, no such legal proceedings involving the Corporation or its property are contemplated.

12. INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

Except as set forth below, no director, executive officer or shareholder who beneficially owns, directly or indirectly, or exercises control or direction over more than 10% of any category of shares of the Corporation or known associate or affiliate of any such person, has or had any material interest, direct or indirect, in any transaction within the last three years or during the current financial year or in any proposed transaction, that has materially affected or will materially affect the Corporation.

In the context of the Arrangement, Gilles Lefrançois and Michel Letellier, as board members and shareholders of the Corporation, on the one hand and trustees of the Trust and unitholders of the Fund, on the other hand, immediately prior to the closing of the Arrangement, have disclosed their interests and abstained from voting on such transaction.

13. TRANSFER AGENT AND REGISTRAR

The transfer agent and registrar of the Corporation is Computershare Investor Services Inc., for the Common Shares, the Series A Shares, the Series B Shares and the Series C Shares and Computershare Trust Company of Canada for the Debentures at their offices in Toronto and Montréal.

14. MATERIAL CONTRACTS

Prior to the last financial period, the Corporation entered into the following material contracts, which are still valid. A copy of all such agreements is available on SEDAR at www.sedar.com .

- the Cloudworks Agreement, the particulars of which are contained under "General Development of the Business - Three-Year Summary - Financial Year 2011"; and

- the Fourth Amended and Restated Credit Agreement, the particulars of which are contained under "General Development of the Business - Three-Year Summary - Financial Year 2011".

During financial year 2012, the Corporation entered into the following material contracts, all of which are available on SEDAR at www.sedar.com .

- the Partnership Interest Purchase Agreement, the particulars of which are contained under “General Development of the Business - Three-Year Summary - Financial Year 2012”;

- the Subscription Agreements, the particulars of which are contained under “General Development of the Business - Three-Year Summary - Financial Year 2012”; and

- the Series C Underwriting Agreement, the particulars of which are contained under “General Development of the Business - Three-Year Summary - Financial Year 2012”.

15. INTEREST OF EXPERTS

Deloitte s.e.n.c.r.l. (formerly known as Samson Bélair / Deloitte & Touche LLP) is the independent auditor of the Corporation and has advised that it is independent with respect to the Corporation within the meaning of the Code of ethics of the *Ordre des comptables professionnels agréés du Québec.*

PricewaterhouseCoopers LLP have audited the consolidated financial statements of Cloudworks Energy Inc. as at December 31, 2010 attached to the Business Acquisition Report filed on SEDAR on June 20, 2011 and updated on November 21, 2012 in respect of the Cloudworks Acquisition which was incorporated by reference to the Series C Shares Prospectus. The report is available at www.sedar.com.

16. AUDIT COMMITTEE DISCLOSURE

The Audit Committee is composed entirely of directors who meet the independence and experience requirements of *Regulation 52-110 Respecting Audit Committees* adopted under the *Securities Act* (Québec). John A. Hanna is Chair of the Audit Committee and Jean La Couture and Daniel L. Lafrance are its other current members. Each of them is independent and financially literate within the meaning of *Regulation 52-110 Respecting Audit Committees*. The charter of the Audit Committee is attached hereto as Schedule B.

In addition to being operationally literate (having substantial experience in the execution of day to day business decisions and strategic business objectives acquired as a result of meaningful past experience with a broad responsibility for operations), the members of the Board of Directors who serve on the Corporation’s Audit Committee must be financially literate in the sense of having the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally compared to the breadth and complexity of the issues that can reasonably be expected to be raised by the Corporation’s financial statements, and otherwise in keeping with applicable governance standards under applicable securities laws and regulations. All members of the Audit Committee are operationally as well as financially literate.

The education and related experience of each of the members of Audit Committee is described below.

John A. Hanna (Chair) - John A. Hanna has acted as a corporate director as his principal occupation since November 2005. From 2003 until July 2005, he was Chief Executive Officer of Rexel Canada Electrical Inc. Graduated from Loyola University (now Concordia University) with a bachelor’s degree of commerce (accounting), John A. Hanna is also a FCPA and Fellow of CGA Canada (1990). He currently acts as a director of Uni-Select Inc. and of Russel Metals Inc., both reporting issuers and since April 2009, has acted as a member of the independent committee of Transport Canada and Infrastructure Canada.

Daniel L. Lafrance - Daniel L. Lafrance is Senior Vice-President Finance and Procurement, Chief Financial Officer and Secretary of Lantic Inc., wholly-owned by Rogers Sugar Inc. He holds a bachelor’s degree in accounting (1977) from the University of Ottawa. Daniel L. Lafrance has also been member of the *Ordre des Comptables professionnels agréés du Québec* since 1980 and of the Institute of Chartered Accountants of Ontario. He currently acts as a director of the Canadian Sugar Institute.

Jean La Couture - Jean La Couture is President of Huis Clos Ltd., a management and mediation firm. He is a Fellow of the *Ordre des Comptables professionnels agréés du Québec* and member of the *Ordre des Comptables professionnels agréés du Québec* since 1967. Jean La Couture headed Le Groupe Mallette (an accounting firm) before becoming President and Chief Executive Officer of The Guarantee Company of North America. In 1995, Jean La Couture created Huis Clos Ltd., which specializes in management and mediation as well as in civil and commercial negotiations. Jean La Couture currently acts as a director of Quebecor Inc., a reporting issuer, Jevco Insurance Company, a principal affiliate of The Westaim Corporation, which is a reporting issuer. He is also Chairman of the Board of Groupe Pomerleau and since January 16, 2013, a director of Caisse de dépôt et placement du Québec.

The aggregate fees paid, including the Corporation's pro rata share of the fees paid by its joint ventures, for professional services rendered by Deloitte s.e.n.c.r.l. and its affiliates for the year ended December 31, 2012 and for the year ended December 31, 2011, are presented below.

FEES	FINANCIAL YEAR ENDED DECEMBER 31, 2012	FINANCIAL YEAR ENDED DECEMBER 31, 2011
Audit fees	$578,000	$523,000
Audit-related fees	Nil	$31,000
Tax fees	Nil	Nil
All other fees	Nil	Nil
Total fees(1):	$578,000	$554,000

(1) The aggregate fees paid to Deloitte s.e.n.c.r.l., irrespective of the Corporation's proportionate interest in its joint ventures, totalled $624,000 in 2012 and $602,000 in 2011.

In the above table, the terms in the column "**Fees**" have the following meanings: "**Audit fees**" refer to all fees for professional services rendered for the audit of the annual financial statements. They also comprise fees for audit services provided in connection with other statutory and regulatory filings, such as the audit of the financial statements of the subsidiaries of the Corporation or the Fund, as applicable, as well as services that generally only the Corporation's, auditors can provide, such as comfort letters, consents and assistance with and review of documents filed with the securities commissions; "**Audit-related fees**" refer to the fees for due diligence related to potential mergers and acquisitions and are not reported under "Audit fees"; "**Tax fees**" refer to the aggregate fees for income, consumption and other tax compliance, advice and planning services relating to domestic and international taxation; and "**All other fees**" refer to the aggregate fees billed for products and services provided by the Corporation's external auditor, other than "Audit fees", "Audit-related fees" and "Tax fees".

17. ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of the Corporation's securities and securities authorized for issuance under equity compensation plans is contained in the Corporation's information circular prepared in connection with the Corporation's most recent annual shareholders' meeting and is available on SEDAR at www.sedar.com.

Additional financial information on the Corporations' audited financial statements and management's discussion and analysis of financial condition and results of operations for the most recently completed financial year is available on SEDAR at www.sedar.com .

All requests for the above-mentioned documents must be addressed to the Corporate Secretary of Innergex Renewable Energy Inc. at 1111 Saint-Charles Street West, East Tower, Suite 1255, Longueuil, Québec, J4K 5G4 or by fax at 450-928-2544.

18. GLOSSARY OF TERMS

"**AAV PPA**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Wind Farms - L'Anse-à-Valleau Wind Farm - Power Purchase Agreement";

"**L'Anse-à-Valleau Wind Farm**" means the 100.5 MW wind power facility located in L'Anse-à-Valleau, Québec;

"**Arrangement**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2010";

"**Ashlu Creek LP**" means Ashlu Creek Investments Limited Partnership;

"**Ashlu Creek Facility**" means the 49.9 MW hydroelectric power facility located on Ashlu Creek in British Columbia;

"**Audit Fees**" has the meaning attributed thereto under "Audit Committee Disclosure";

"**Audit-related Fees**" has the meaning attributed thereto under "Audit Committee Disclosure";

"**Baie-des-Sables Wind Farm**" means the 109.5 MW wind power facility located in Baie-des-Sables and Métis-sur-Mer, Québec;

"**Baluchon**" means Concept Eco-Plein-Air Le Baluchon Inc.;

"**Baluchon Lease**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Saint-Paulin Facility - Site and Water Rights";

"**Batawa Facility**" means the 5 MW hydroelectric power generating facility located on the Trent-Severn Waterway near Trenton, Province of Ontario;

"**Batawa PPA**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Batawa Facility - Power Purchase Agreement";

"**BC**" means the Province of British Columbia;

"**BC Hydro**" means British Columbia Hydro and Power Authority;

"**BCTC**" means British Columbia Transmission Corporation;

"**BDS PPA**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Wind Farms - Baie-des-Sables Wind Farm - Power Purchase Agreement";

"**Begetekong**" means Begetekong Power Corporation, the general partner of Umbata Falls Limited Partnership;

"**Big Silver Creek Project**' means the 40.6 MW hydroelectric project located approximately 40 km north of Harrison Hot Springs in British Columbia;

"**Boulder Creek Project**" means the 25.3 MW hydroelectric power project located 56 km northwest of Pemberton, British Columbia;

"**Brown Lake Facility**" means the run-of-river hydroelectric power generating facility with a nameplate capacity of 7.2 MW located on the Ecstall River, approximately 45 km southeast of Prince Rupert, British Columbia;

"**Brown Miller GP**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Brown Lake Facility - Description"

"**Brown Miller LP**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Brown Lake Facility - Description"

"**Brown Lake PPA**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Brown Lake Facility - Power Purchase Agreement";

"**Capital Power**" means collectively Capital Power L.P. and Capital Power Generation Services Inc.;

"**Carleton Wind Farm**" means the 109.5 MW wind farm located in the Town of Carleton-Sur-Mer and the Regional County Municipality of Bonaventure, Québec;

"**Cartier Owners**" means collectively the Corporation and TransCanada Energy Ltd;

"**Cartier Wind Farms**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Wind Farms - Cartier Wind Farms";

"**CC&L**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Harrison Operating Facilities";

"**Chaudière Facility**" means the 24 MW hydroelectric power generating facility located on the Chaudière River near Lévis, Province of Québec;

"**Chaudière Lease Agreement**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Chaudière Facility - Site and Water Rights";

"**Chaudière PPA**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Chaudière Facility - Power Purchase Agreement";

"**CHI**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Harrison Operating Facilities";

"**CHLP**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Harrison Operating Facilities";

"**Cloudworks**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2011";

"**Cloudworks Acquisition**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2011";

"**Cloudworks Agreement**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2011";

"**COD**" means commercial operation date in respect of a project in accordance with its PPA;

"**Common Shares"** has the meaning attributed thereto under "Corporate Structure";

"**Corporation**" means Innergex Renewable Energy Inc. and includes its subsidiaries, unless the context requires otherwise;

"**CPI**" means the consumer price index for Canada;

"**Credit Ratings**" has the meaning attributed thereto under sub-section "Credit rating may not reflect actual performance of the Corporation" under "Risk Factors".

“**Creek Power**” means Creek Power Inc.;

“**Current Market Price**” has the meaning attributed thereto under “Description of Capital Structure - 5.75% Convertible Debentures”;

“**DBRS**” means DBRS Limited;

“**Debentures**” has the meaning attributed thereto under “General Development of the Business - Three-Year Summary - Financial Year 2010”;

“**Debenture Offering**” has the meaning attributed thereto under “General Development of the Business - Three-Year Summary - Financial Year 2010”;

“**Debenture Indenture**” has the meaning attributed under “Description of Capital Structure - 5.75% Convertible Debentures”;

“**Development Projects**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Portfolio of Assets”;

“**DCPLP**” means the Douglas Creek Project Limited Partnership;

“**Dokis Project**” means the 10 MW hydroelectric project under development located on the French River near the Dokis First Nation Reserve, Ontario;

“**Douglas Creek Facility**” means the 27 MW hydroelectric power project located near Harrison Lake in south-western British Columbia on Douglas Creek;

“**ecoENERGY Initiative**” has the meaning attributed thereto under “Industry Overview and Market Trends - Renewable Power in Canada - Federal Government Support for Renewable Power in Canada”;

“**FCPLP**” means the Fire Creek Project Limited Partnership;

“**Fire Creek Facility**” means the 23 MW hydroelectric power project located near Harrison Lake in south-western British Columbia on Fire Creek;

“**FIT Contract**” has the meaning attributed thereto under “Industry Overview and Market Trends - Regulatory Framework of and Market for Renewable Power in the Corporation’s Key Markets - Ontario”;

“**FIT Program**” has the meaning attributed thereto under “Industry Overview and Market Trends - Regulatory Framework of and Market for Renewable Power in the Corporation’s Key Markets - Ontario”;

“**Fitzsimmons Creek Facility**” means the 7.5 MW hydroelectric power facility located on Fitzsimmons Creek in British Columbia;

“**Fitzsimmons LP**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Fitzsimmons Creek Facility”;

“**Fund**” means Innergex Power Income Fund;

“**GE**” means General Electric Company;

“**Glen Miller Facility**” means the 8 MW hydroelectric power facility located on the Trent River in Trenton, Ontario;

“**Glen Miller LP**” means Glen Miller Power, Limited Partnership;

“**Gros-Morne Phase I Wind Farm**” means the 100.5 MW wind power facility located in the Municipalities of Mont-Louis and Sainte-Madeleine-de-la-Rivière-Madeleine, Québec;

“**Gros-Morne Phase II Wind Farm**” means the 111 MW wind power facility located in the Municipalities of Mont-Louis and Sainte-Madeleine-de-la-Rivière-Madeleine, Québec;

“**Gros-Morne Site or Farm**” means, collectively, the Gros-Morne Phase I and Phase II Wind Farms;

“**Gros-Morne PPA**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Wind Farms - Gros-Morne Wind Farm - Power Purchase Agreement”;

“**GWh**” means one thousand megawatt per hour;

“**Harrison Operating Facilities**” means the six run-of-river hydroelectric facilities having a combined installed gross capacity of 150 MW, namely the Douglas Creek Facility, the Fire Creek Facility, the Stokke Creek Facility, the Tipella Creek Facility, the Upper Stave River Facility and the Lamont Creek Facility;

“**HHLP**” means Harrison Hydro Limited Partnership;

“**HHPI**” means Harrison Hydro Project Inc.;

“**Horseshoe Bend Facility**” means the 9.5 MW hydroelectric power generating facility located on the Payette River, in the State of Idaho in the United States;

“**Horseshoe Bend PPA**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Horseshoe Bend Facility - Power Purchase Agreement”;

“**Hydromega related entities**” means certain entities directly or indirectly related to Hydromega and holding an interest in one or several Hydromega Hydroelectric Facilities and Development Projects;

“**Hydromega**” means Hydromega Services Inc.;

“**IHI**” means IHI Hydro Inc.;

“**Initial Fixed Rate Period**” has the meaning attributed thereto under “Description of Capital Structure - Preferred Shares”;

“**Innergex Lease**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Saint-Paulin Facility- Site and Water Rights”;

“**IPC**” Idaho Power Corporation;

“**IPSP**” means Integrated Power System Plan;

“**Joint Information Circular**” means the joint information circular of the Corporation and the Fund dated February 17, 2010 filed in connection with the Arrangement;

“**km**” means kilometer;

“**kV**” means one kilovolt or 1,000 volts;

“**Kapuskasing Projects**” means four hydroelectric projects which are under construction totalling 22 MW, being the Big Beaver Falls, Camp Three Rapids, White Otter Falls and Old Woman Falls projects located on the Kapuskasing River, near Kapuskasing Ontario;

“**Kwalsa Substation**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Harrison Operating Facilities”;

“**KWh**” means one kilowatt per hour or 1,000 watts per hour;

“**Kwoiek Creek Project**” means the 49.9 MW hydroelectric power project located on Kwoiek Creek in British Columbia;

"**LCPLP**" means the Lamont Creek Project Limited Partnership;

"**Lamont Creek Facility**" means the 27 MW hydroelectric power project located near Harrison Lake in south-western British Columbia on Lamont Creek;

"**Ledcor**" means Ledcor Power Group Ltd.;

"**Letter of Intent**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2012;

"**License**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Batawa Facility - Site and Water Rights";

"**LTEP**" has the meaning attributed thereto under "Industry Overview and Market Trends - Regulatory Framework of and Market for Renewable Power in the Corporation's Key Markets - Ontario";

"**Magpie Facility**" means the single run-of-river hydroelectric power generating station with a total installed capacity of 40.6 MW located on the Magpie River, in the municipality of Rivière-Saint-Jean and approximately 150 km east of Sept-Îles, Québec;

"**Magpie Hydroelectric Facility Acquisition**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2012;

"**Miller Creek Facility**" means the run-of-river hydroelectric power generating facility with a nameplate capacity of 33.0 MW located on Miller Creek, near Pemberton, British Columbia, approximately 30 km northeast of the Resort Municipality of Whistler, British Columbia;

"**Miller Creek PPA**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Miller Creek Facility - Power Purchase Agreement";

"**MOI**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Harrison Operating Facilities";

"**Montagne Sèche Wind Farm**" means the 58.5 MW wind power facility located in the Municipality of the Canton of Cloridorme, Québec;

"**Montmagny Facility**" means 2.1 MW hydroelectric power generating facility located on Rivière du Sud in Montmagny, Québec;

"**Montmagny Lease Agreement**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Montmagny Facility - Site and Water Rights";

"**Montmagny PPA**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Montmagny Facility - Power Purchase Agreement";

"**MRNF**" means the Ministère des Ressources naturelles et de la Faune du Québec;

"**MW**" means one million watts or one megawatt;

"**MWh**" means one million watts per hour or one megawatt per hour;

"**Nations**" means the Mont Currie Indian Band and the Squamish Indian Band;

"**North Creek Project**" means the 16 MW hydroelectric power project located approximately 38 km northwest of Pemberton, British Columbia;

"**Northwest Stave River Project**" means the 17.5 MW hydroelectric power project located approximately 35 km north of Mission, British Columbia;

"**OEB**" means Ontario Energy Board;

"**OEFC**" means the Ontario Electricity Financial Corporation;

"**OPA**" means Ontario Power Authority;

"**Operating Facilities**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Portfolio of Assets";

"**OPG**" means Ontario Power Generation;

"**Other Hydromega Hydroelectric Facilities and Development Projects**" means the Dokis Project, the Kapuskasing Projects and the Sainte-Marguerite Facility;

"**Partnership Interest Purchase Agreement**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2012"

"**PN-1 Facility**" means the 8.0 MW hydroelectric power generating facility located 4 km upstream from the confluence of the St-Lawrence River on the Portneuf River in Sainte-Anne-de-Portneuf, Province of Québec;

"**PN-2 Facility**" means the 9.9 MW hydroelectric power generating facility located 10.5 km upstream from the confluence of the St-Lawrence River on the Portneuf River in Sainte-Anne-de-Portneuf, Province of Québec;

"**PN-3 Facility**" means the 8.0 MW hydroelectric power generating facility located 30 km upstream from the confluence of the St-Lawrence River on the Portneuf River in Longue-Rive, Province of Québec;

"**Portneuf Emphyteutic Lease**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operation Facilities - Operating Hydroelectric Facilities - Portneuf Facilities *(Québec - 100% ownership)* - Site and Water Rights";

"**Portneuf Facilities**" means, collectively, PN-1 Facility, PN-2 Facility and PN-3 Facility;

"**Portneuf PPA**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Portneuf Facilities - Power Purchase Agreement";

"**PPA**" means a power purchase agreement, an electricity supply agreement, an electricity purchase agreement or a renewable energy supply contract;

"**Preferred Shares**" has the meaning attributed thereto under "Corporate Structure";

"**Prospective BC Wind Projects**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Prospective Projects - Other Prospective British Columbia Wind Projects";

"**Prospective Projects**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Portfolio of Assets";

"**Prospective Québec Wind Projects**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Prospective Projects - Various Other Prospective Québec Wind Projects";

"**PV**" means photovoltaic;

"**Renewable Portfolio Standards**" or "**RPS**" means such standards, policies, goals or regulations, established by the respective government or entity established by the government for such purpose, targeting or mandating the development of, increase in, or purchase of renewable forms of electricity generation in such province;

“**Request for Proposals**” or “**RFP**” means a request for proposals issued by a provincial government or an entity created by such government for such purpose;

“**RESOP**” has the meaning attributed thereto under “Industry Overview and Market Trends - Regulatory Framework of and Market for Renewable Power in the Corporation’s Key Markets - Ontario”;

“**RPS**” has the meaning attributed thereto under “Industry Overview and Market Trends - Renewable Power in Canada - Provincial Renewable Portfolio Standards and Requests for Proposals”;

“**Rutherford Creek Facility**” means the 49.9 MW hydroelectric facility located near Pemberton, British Columbia;

“**Rutherford Creek PPA**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Rutherford Creek Facility - Site and Water Rights”;

“**S&P**” means Standard & Poor’s;

“**Sainte-Marguerite Facility**” means the 30.5 MW run-of-river hydroelectric operating facilities known as the SM-1 project, located on the Saint-Marguerite River, near Sept-Île, Québec;

“**Saint-Paulin Emphyteutic Lease**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Rutherford Creek Facility - Site and Water Rights”;

“**Saint-Paulin Facility**” means the 8.0 MW hydroelectric power-generating facility located on Rivière-du-Loup near Shawinigan, Province of Québec;

“**Saint-Paulin PPA**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Saint-Paulin Facility - Power Purchase Agreement”;

“**SCPLP**” means the Stokke Creek Project Limited Partnership;

“**Series A Shares**” has the meaning attributed thereto under “Corporate Structure”;

“**Series A Offering**” has the meaning attributed thereto under “General Development of the Business - Three-Year Summary - Financial Year 2010”;

“**Series A and Series B Terms**” has the meaning attributed thereto under “Description of the Capital Structure - Preferred Shares - Series A Shares and Series B Shares”;

“**Series A Shares Prospectus**” means the short form prospectus for the Series A Shares dated September 7, 2010;

“**Series A Underwriting Agreement**” has the meaning attributed thereto under “General Development of the Business - Three-Year Summary - Financial Year 2010”;

“**Series B Shares**” has the meaning attributed thereto under “Corporate Structure”;

“**Series B Conversion Date**” has the meaning attributed thereto under “Description of Capital Structure - Preferred Shares”;

“**Series C Shares**” has the meaning attributed thereto under “Corporate Structure”.

“**Series C Offering**” has the meaning attributed thereto under “General Development of the Business - Three-Year Summary - Financial Year 2012;

“**Series C Terms**” has the meaning attributed thereto under “Description of the Capital Structure - Preferred Shares - Series C Shares;

"**Series C Underwriting Agreement**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2012";

"**Sharing Facilities and Project**" has the meaning attributed thereto under "Risk Factors – Risks Relating to the Corporation – Shared Transmission and Interconnection Infrastructure;

"**Sonoco**" means Sonoco Canada Corporation;

"**Standing Offer Program**" or "**SOP**" means a program or mechanism, established by a provincial government or an entity created by such government for such purpose, through which a standard and simplified contracting process and contractual terms are provided for independent power producers to enter into PPAs for relatively small renewable electricity generating projects;

"**Stardale PPAs**" has the same meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Solar Farms - Stardale Solar Farm - Power Purchase Agreement";

"**Stardale Solar Farm**" has the same meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2011";

"**Stokke Creek Facility**" means the 22 MW hydroelectric power project located near Harrison Lake in south-western British Columbia on Stokke Creek;

"**Subscription Agreements**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2012"

"**Subscription Receipts**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2011";

"**Subscription Receipts Offering**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2011";

"**Subscription Receipts Underwriting Agreement**" has the meaning attributed thereto under "General Development of the Business - Three-Year Summary - Financial Year 2011";

"**Subsequent Fixed Rate Period**" has the meaning attributed thereto under "Description of Capital Structure - Preferred Shares";

"**Superficies Lease**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Hydroelectric Facilities - Saint-Paulin Facility - Site and Water Rights";

"**Supply Mix Directive**" means the supply mix directive issued by the by the Minister of Energy (Ontario) on June 13, 2006 outlining various generation targets, including RPS;

"**Takem Corp**" has the meaning attributed thereto under "Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Harrison Operating Facilities";

"**TCPLP**" means the Tipella Creek Project Limited Partnership;

"**Tipella Creek Facility**" means the 18 MW hydroelectric power project located near Harrison Lake in south-western British Columbia on Tipella Creek;

"**TransCanada**" means TransCanada Energy Ltd.;

"**Tretheway Creek Project**' means the 23.2 MW hydroelectric project located approximately 50 km north of Harrison Hot Springs in British Columbia;

"**TSX**" means the Toronto Stock Exchange;

“**TWh**” means 1,000 gigawatts per hour or one million megawatts per hour;

“**Trust**” means Innergex Power Trust;

“**UHT**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Harrison Operating Facilities”;

“**Umbata Falls Facility**” means the 23 MW Umbata Falls hydroelectric power facility located on the White River in Ontario;

“**Upper Lillooet River Project**” means the 81.4 MW hydroelectric power project located approximately 70 km northwest of Pemberton, British Columbia;

“**USPLP**” means the Upper Stave Project Limited Partnership;

“**Upper Stave River Facility**” means the 33 MW hydroelectric power project located near Harrison Lake in south-western British Columbia on Stave River;

“**Viger-Denonville Project**” has the meaning attributed thereto under “General Development of the Business - Three-Year Summary - Financial Year 2011”;

“**Water Act**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Rutherford Creek Facility”;

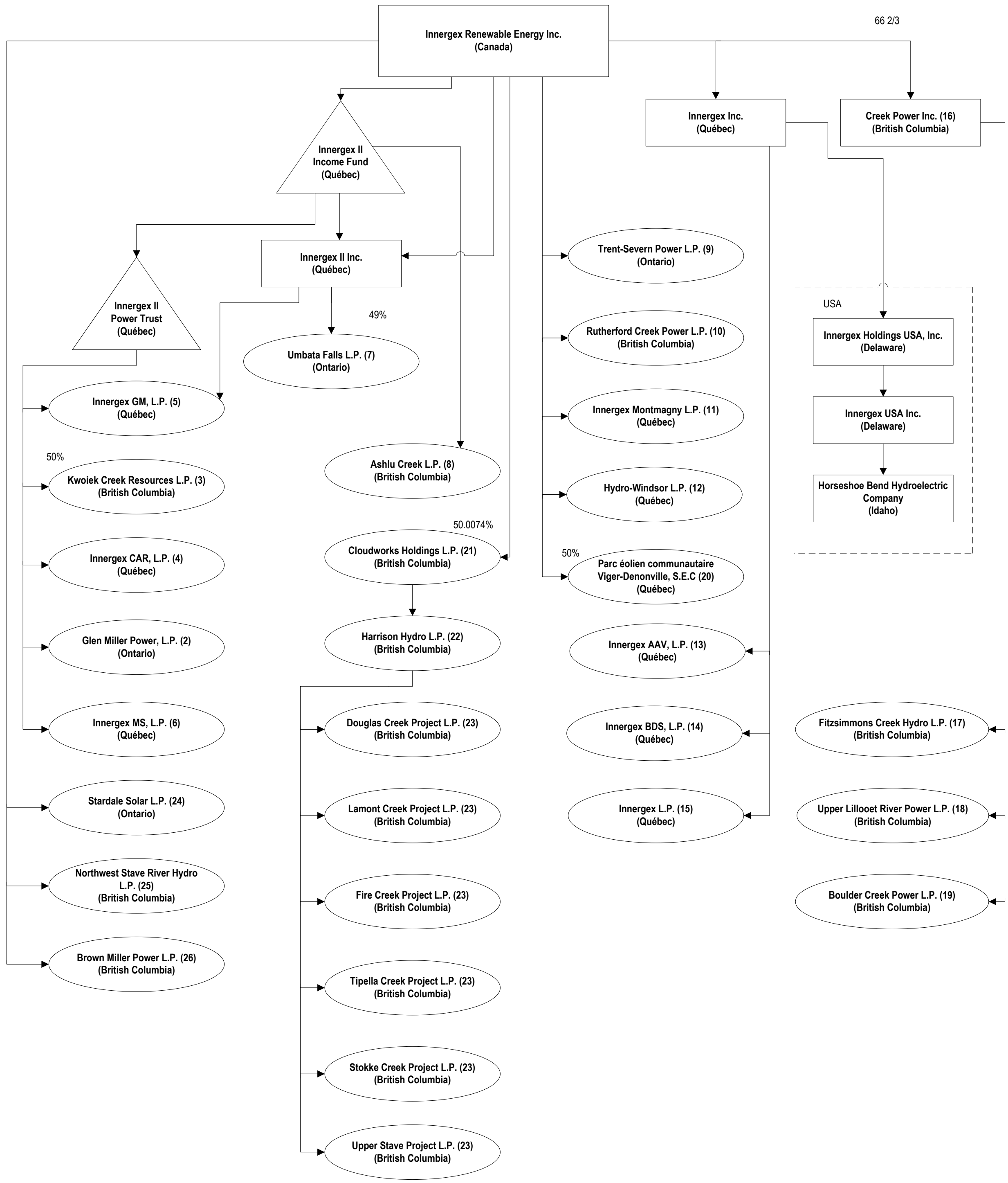
“**Windsor Facility**” means the 5.5 MW hydroelectric power generating facility located on the St-François River, near Windsor, Province of Québec; and

“**Windsor PPA**” has the meaning attributed thereto under “Description of the Business and Assets of the Corporation - Operating Facilities - Operating Hydroelectric Facilities - Windsor Facility - Power Purchase Agreement”.

SCHEDULE A

CORPORATE STRUCTURE

The following chart outlines the corporate structure of the Corporation and its material subsidiaries(1) as well as certain other material ownership interests held by the Corporation.



(1) Unless otherwise indicated, the Corporation has a 100% direct or indirect interest in the entity.

(2) Glen Miller Power, LP owns a 100% interest in the Glen Miller Facility and its general partner is Glen Miller Power Inc., a wholly-owned subsidiary of Innergex II Inc.

(3) Kwoiek Creek Resources L.P. owns 100% of the Kwoiek Creek Project and its general partner is Kwoiek Creek Resources GP Inc., which is 50% owned by Innergex II Inc.

(4) Innergex CAR, L.P. owns a 38% undivided co-ownership interest in the Carleton Wind Farm and its general partner is Innergex CAR Inc., a wholly-owned subsidiary of Innergex II Inc.

(5) Innergex GM, L.P. owns a 38% undivided co-ownership interest in the Gros-Morne Facilities and its general partner is Innergex GM Inc., a wholly-owned subsidiary of Innergex II Inc.

(6) Innergex MS, L.P. owns a 38% undivided co-ownership interest in the Montagne Sèche Facility and its general partner is Innergex MS Inc., a wholly-owned subsidiary of Innergex II Inc.

(7) Umbata Falls L.P. owns 100% of the Umbata Falls Facility and its general partner is Begetekong Power Corporation, which is 49% owned by Innergex II Inc.

(8) Ashlu Creek Investments L.P. owns 100% of the Ashlu Creek Facility and it general partner is 675729 British Columbia Ltd., wholly-owned subsidiary of Innergex II Inc.

(9) Trent-Severn Power, LP owns 100% of the Batawa Facility and its general partner is Trent-Severn Power Corporation, wholly-owned subsidiary of Innergex II Inc.

(10) Rutherford Creek Power L.P. owns 100% of the Rutherford Creek Facility and its general partner is Rutherford Creek Power Ltd., which is 0.02% owned by Innergex Inc. and 99.98% by the Corporation.

(11) Innergex Montmagny, L.P. owns 100% of the Montmagny Facility and its general partner is Innergex Windsor-Montmagny Inc., a wholly-owned subsidiary of Innergex Inc.

(12) Hydro-Windsor, L.P. owns 100% of the Windsor Facility and its general partner is Innergex Windsor-Montmagny Inc., a wholly-owned subsidiary of Innergex Inc.

(13) Innergex AAV, L.P. owns a 38% undivided co-ownership interest in the L'Anse-à-Valleau Facility and its general partner is Innergex AAV Inc., a wholly-owned subsidiary of Innergex Inc.

(14) Innergex BDS, L.P. owns a 38% undivided co-ownership interest in the Baie-des-Sables Facility and its general partner is Innergex BDS Inc., a wholly-owned subsidiary of Innergex Inc.

(15) Innergex, L.P. owns 100% of the Chaudière Facility, the Portneuf Facilities and the Saint-Paulin Facility and its general partner is Innergex Inc., a wholly-owned subsidiary of Innergex Renewable Energy Inc.

(16) The Corporation holds 66.7% of all issued and outstanding common shares of Creek Power Inc. and 19,242,408 Series 1 preferred shares of Creek Power Inc. Creek Power Inc. owns rights in relation to 3 Development Projects (Upper Lillooet River, Boulder Creek and North Creek) and 9 prospective hydroelectric projects in British Columbia.

(17) Fitzsimmons Creek Hydro LP owns 100% of the Fitzsimmons Creek Facility and its general partner is Fitzsimmons Creek Investments Ltd., a wholly-owned subsidiary of Innergex II Inc.

(18) Upper Lillooet River Power Limited Partnership owns 100% of the Upper Lillooet Project and its general partner is Upper Lillooet River Power Inc., which is 100% owned by the Corporation.

(19) Boulder Creek Power Limited Partnership owns 100% of the Boulder Creek Project and its general partner is Boulder Creek Power Inc., which is 100% owned by the Corporation.

(20) Parc éolien communautaire Viger-Denonville, S.E.C. owns 100% of the Viger-Denonville Project and its general partner is Parc éolien communautaire Viger-Denonville Inc., which is 50% owned by Innergex Inc.

(21) Cloudworks Holdings Limited Partnership owns 100% of the limited partnership units of Harrison Hydro Limited Partnership and its general partner is Cloudworks Holdings Inc., which is 50% owned by the Corporation.

(22) Harrison Hydro Limited Partnership owns 100% of the limited partnership units of each of the 6 Harrison Operating Facilities and its general partner is Harrison Hydro Inc., which is 100% owned by Cloudworks Holdings Limited Partnership.

(23) The 6 Harrison Operating Facilities consisting of Douglas Creek Project Limited Partnership, Fire Creek Project Limited Partnership, Lamont Creek Project Limited Partnership, Stokke Creek Project Limited Partnership, Tipella Creek Project Limited Partnership and Upper Stave Project Limited Partnership own 100% of their respective projects and their general partner is Harrison Hydro Project Inc., which is 100% owned by Harrison Hydro Limited Partnership.

(24) Stardale Solar LP owns 100% of the Stardale Solar Farm and its general partner is Solaris Energy Partners Inc., which is 100% owned by the Corporation.

(25) Northwest Stave River Hydro Limited Partnership owns 100% of the Northwest Stave Project and its general partner is Northwest Stave River Hydro Inc., which is 100% owned by the Corporation.

(26) Brown Miller Power Limited Partnership owns 100% of the Brown Lake and the Miller Creek Facilities and its general partner is Brown Miller Power GP Inc., which is 100% owned by the Corporation.

SCHEDULE B

CHARTER OF THE AUDIT COMMITTEE

This Charter prescribes the role of the Audit Committee of the Board (the "**Committee**") of Innergex Renewable Energy Inc. (the "**Corporation**"). This Charter is subject to the provisions of the Corporation's Articles and By-Laws and to applicable laws. This Charter is not intended to limit, enlarge or change in any way the responsibilities of the Committee as determined by such Articles and By-Laws and applicable laws.

1. Role

In addition to the powers and authorities conferred upon the Directors in the Corporation's Articles and By-Laws and as prescribed by applicable laws, the mandate of the Committee is primary as follows:

A. *To ensure compliance of the Corporation in respect to applicable governmental and authorities' legislation and regulation pertaining to financial information disclosure;*

B. *Adequacy of the accounting principles and decisions regarding the presentation of financial statements, in accordance with generally accepted accounting principles;*

C. *Fair presentation of the Corporation's financial situation in its quarterly and annual financial statements;*

D. *Timely disclosure of relevant information to shareholders and to the general public; and*

E. *Implementation of efficient internal controls for all of the Corporation's transactions and review of such controls on a regular basis.*

2. Composition

2.1 Number and criteria

The Committee must be constituted as required under Regulation 52-110 - *Respecting Audit Committees*, as it may be amended from time to time ("**Regulation 52-110**"). The Committee is comprised only of members who are qualified as independent (as that term is defined in Regulation 52-110) and are financially literate (which is defined as the ability to read and understand a set of financial statements that present a breadth and level of complexity of issues that can reasonably be expected to be raised by the Corporation's financial statements).

The Committee shall consist of at least three members.

2.2 Selection and Chair

The members of the Committee and its Chair shall be elected by the Board on an annual basis after the shareholders' annual meeting at which the directors are elected, or until their successors are duly appointed. The Chair shall designate from time to time a person who may, but not necessarily, be a member of the Committee to act as secretary.

Unless a Chair is elected by the full Board, the members of the Committee may designate a Chair by majority vote of the full Committee Membership.

Any member of the Committee may be removed or replaced at any time by the Board and shall cease to be a member of the Committee on ceasing to be a director of the Corporation. The Board may fill vacancies on the Committee by electing from among the Board. If and whenever a vacancy shall exist on the Committee, the remaining members may exercise all of its powers so long as a quorum remains.

2.3 Remuneration

Members of the Committee and its Chair shall receive such remuneration for their services as the Board may determine from time to time.

2.4 Term Limit

No person shall serve on the Committee for a period of more than six consecutive years, unless the Board shall, on a particular case, specifically determine to make exception from such limitation.

3. Meetings

The Committee shall meet at least four times annually, or more frequently as circumstances require.

Quorum for the transaction of business at any meeting of the Committee shall be a majority of members of the Committee or such greater number as the Committee shall determine by resolution.

Meetings of the Committee shall be held from time to time and at such place as any member of the Committee shall determine upon reasonable notice to each of its members, which shall not be less than 48 hours. The notice period may be waived by all members of the Committee. The Chairman of the Board, the President and Chief Executive Officer, the Chief Financial Officer, the Corporate Secretary or the external auditor of the Corporation, shall be entitled to request that any member of the Audit Committee call a meeting.

The Committee shall determine any desired agenda items.

The Committee should record minutes of its meetings and the Chair shall report to the whole Board on a timely basis.

The Chair may ask members of Management or others to attend meetings and provide pertinent information as necessary. For purposes of performing their duties, members of the Committee shall have full access to all corporate information and any other information deemed appropriate by them, and shall be permitted to discuss such information and any other matters relating to the financial position of the Corporation with senior employees, officers and the external auditor of the Corporation and others as they consider appropriate.

In order to foster open communication, the Committee or its Chair shall meet at least quarterly with Management and the external auditor, in separate sessions, to discuss any matters that the Committee or each of these groups believes should be discussed privately. In addition, the Committee or its Chair should meet with Management quarterly in connection with the Corporation's quarterly financial statements.

4. Responsibilities

Without limiting the generality of its role as described in section 1 above, the Committee shall, inter alia:

4.1 Relationship with external auditor

- Recommend to the Board the appointment and compensation of the external auditor;
- Review the scope and plans of the external auditor's audit and reviews. The Committee may authorize the external auditor to perform supplemental reviews or audits as the Committee may deem desirable;
- Oversee the work of the external auditor, including the resolution of any issues between the external auditor and Management;
- Pre-approving all non-audit services (or delegating such pre-approval if and to the extent permitted by law) to be provided to the Corporation or its subsidiaries by the external auditor;
- Review and discuss, on an annual basis, with the external auditor all significant relationships they have with the Corporation to assess their independence;
- Review the performance of the external auditor and any proposed discharge of the external auditor when circumstances warrant;

- Periodically consult with the external auditor without Management about significant risks or exposures, internal controls and other steps that Management has taken to control such risks, and the fullness and accuracy of the financial statements, including the adequacy of internal controls to expose any payments, transactions or procedures that might be deemed illegal or otherwise improper;

- Arrange for the external auditor to be available to the Committee and the Board as needed; and

- Consider the external auditor's judgment about the quality, transparency, appropriateness and not just the acceptability, of the Corporation's accounting principles and financial disclosure practices, as applied in its financial reporting, including the degree of aggressiveness or conservatism of its accounting principles and underlying estimates, and whether those principles are common practices or are minority practices.

4.2 Financial information and public disclosure

- Review all material balance sheet issues, material contingent obligations (including those associated with material acquisitions or dispositions) and material related to third party transactions;

- Consider any proposed major changes to the Corporation's accounting principles and practices;

- If considered appropriate, establish separate systems of reporting to the Committee by the Management and the external auditor;

- Review and recommend the approval of the annual and quarterly financial statements, related management discussion and analysis, and annual and interim earnings press releases before such information is publicly disclosed;

- Ensure that adequate procedures are in place for the review of the Corporation's public disclosure of financial information, other than those described in the above paragraph, extracted or derived from its financial statements, including periodically assessing the adequacy of such procedures;

- Review the public disclosure regarding the Committee required by Regulation 52-110;

- Review the integrity of the financial reporting processes, both internal and external, in consultation with the external auditor;

- Periodically consider the need for an internal audit, if not already provided for;

- Following completion of the annual audit and, if applicable, quarterly reviews, review separately with the Management and the external auditor any significant changes to planned procedures, any difficulties encountered during the course of the audit and, if applicable, reviews, including any restrictions on the scope of work or access to required information and the cooperation that the external auditor received during the course of the audit and, if applicable, reviews; and

- Review with the external auditor and Management significant findings during the year and the extent to which changes or improvements in financial or accounting practices, as approved by the Committee, have been implemented. This review should be conducted at an appropriate time subsequent to implementation of changes or improvements, as decided by the Committee.

4.3 Other matters

- Establish procedures for (i) the receipt, retention, and treatment of complaints received by the Corporation regarding accounting, internal accounting controls or audit matters, and (ii) the confidential anonymous submission by employees of the Corporation of concerns regarding questionable accounting or auditing matters;

- Review and approving the Corporation's hiring policies regarding current or former partners or employees of the current and former auditors of the Corporation or its subsidiaries;

- Review activities, organizational structure and qualifications of the Chief Financial Officer and the staff in the financial reporting area and see to it that matters related to succession planning are raised for consideration by the Board; and

- Review Management's program of risk assessment and steps taken to address significant risks or exposures of all types, including insurance coverage and tax compliance and, in particular, assess the Corporation's financial risks and supervise Management's program to address such risks.

- Notwithstanding the foregoing, it is not the duty of the Committee to prepare financial statements, to plan or conduct audits, to determine that the financial statements are complete and accurate and are in accordance with Canadian generally accepted accounting principles, to conduct investigations, or to assure compliance with laws and regulations or the Corporation's internal policies, procedures and controls, as these are the responsibility of Management and in certain cases the external auditor, as the case may be.

5. Advisors

The Committee may hire outside advisors at the expense of the Corporation in order to assist the Committee in the performance of its duties and set and pay the compensation for such advisors.

The Committee is authorized to communicate directly with the external (and, if applicable, internal) auditor as it sees fit.

If considered appropriated by it, the Committee is authorized to conduct or authorize investigations into any matters within the Committee's scope of responsibilities, and to perform any other activities as the Committee deems necessary or appropriate.

The Board has determined that any committee who wishes to hire a non-management advisor to assist on matters involving the committee members' responsibilities at the expense of the Corporation, should review the request with, and obtain the authorization of, the Chairman of the Board.

6. Assessment

On an annual basis the Committee shall follow the process established by it (and approved by the Board) for assessing performance and effectiveness of the Committee.

7. Charter review

The Committee should review this Charter on an annual basis and recommend to the Board changes, as considered appropriate from time to time.

8. General

The Committee is a committee of the Board and is not and shall not be deemed to be an agent of the Corporation's shareholders for any purpose whatsoever. The Board may, from time to time, permit departures from the terms hereof, either prospectively or retrospectively, and no provision contained herein is intended to give rise to civil liability to securityholders of the Corporation or other liability whatsoever.