INTEGRITY, RESPONSIBILITY, TRANSPARENCY, COLLABORATION, LONGEVITY

ANNUAL REPORT YEAR ENDED DECEMBER 31, 2011

INNERGEX

Renewable Energy.
Sustainable Development.

INNERGEX
RENEWABLE ENERGY INC. IS A LEADING CANADIAN INDEPENDENT RENEWABLE POWER PRODUCER. WE HAVE BEEN ACTIVE SINCE 1990 IN DEVELOPING, OWNING, AND OPERATING RUN-OF-RIVER HYDROELECTRIC FACILITIES, WIND FARMS, AND SOLAR PHOTOVOLTAIC FARMS AND WE CARRY OUT OPERATIONS IN QUÉBEC, ONTARIO, BRITISH COLUMBIA, AND IDAHO, USA. OUR PORTFOLIO OF ASSETS CONSISTS OF 25 OPERATING FACILITIES WITH A TOTAL NET INSTALLED CAPACITY OF 461 MW, 10 PROJECTS UNDER DEVELOPMENT WITH A TOTAL NET INSTALLED CAPACITY OF 264 MW AND FOR WHICH POWER PURCHASE AGREEMENTS HAVE BEEN SECURED, AND SEVERAL PROSPECTIVE PROJECTS WITH AN AGGREGATE NET CAPACITY TOTALLING MORE THAN 2,800 MW. OUR SHARES ARE LISTED ON THE TORONTO STOCK EXCHANGE UNDER THE SYMBOL "INE".

WHAT MAKES INNERGEX STAND OUT

- PURE PLAY RENEWABLE ENERGY PRODUCER
- EXPERIENCED AND DYNAMIC MANAGEMENT TEAM
- PROVEN, LOW-RISK BUSINESS MODEL
- HIGH-QUALITY PORTFOLIO OF ASSETS IN HYDRO, WIND, AND SOLAR
- SIGNIFICANT INTERNAL GROWTH
- LARGE PIPELINE OF PROSPECTIVE PROJECTS
- MULTIPLE EXTERNAL GROWTH OPPORTUNITIES
- STABLE DIVIDEND

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CAUTIONARY STATEMENTS ON FORWARD-LOOKING INFORMATION

In order to inform shareholders of the Corporation as well as potential investors of the Corporation's future prospects, sections of this annual report may contain forward-looking information or statements within the meaning of securities legislation ("Forward-Looking Information"). Forward-Looking Information can generally be identified by the use of words and phrases such as "may," "will," "estimate," "anticipate," "plans," "expects," or "does not expect," "is expected," "budget," "scheduled,""forecasts," "intends" or "believes," or variations of such words and phrases that state that certain events will occur. Forward-Looking Information represents, as of the date of this annual report, the estimates, forecasts, projections, expectations or opinions of the Corporation relating to future events or results. Forward-LookingInformation involves known and unknown risks, uncertainties and other important factors which may cause the actual results or performance to be materially different from those expressed, implied, or presented by the Forward-Looking Information. The material risks and uncertainties that may cause the actual results and developments to be materially different from the current expressed expectations are referred to in this annual report under the "Risks and Uncertainties" heading in the Management Discussion and Analysis section and include, but are not limited to, the ability of the Corporation to execute its corporate strategy; the inability to access sufficient capital from internal and external sources; liquidity risks related to derivative financial instruments; general economic conditions; availability of water flows, wind and sunlight; delays in project development; uncertainty relating to the development of new power generating facilities;uncertainty relating to the amounts of power current or future operating facilities are able to generate; equipment failure; interest rate fluctuations and debt refinancing; contractual restrictions contained in instruments governing current and future indebtedness; penalties for events of default under certain power purchase agreements; the ability to retain qualified personnel and management; the performance of third-party suppliers; reliance on major customers; relationships with communities in which projects or facilities are located and joint venture partners; wind turbine supply; obtainment of permits; changes to governmental regulatory requirements and applicable governing statutes; obtaining new power purchase agreements; securing appropriate land for projects; reliance on power purchase agreements; reliance on transmission systems; water and land rental expenses; dam safety; health, safety and environmental risks; natural disasters; foreign exchange fluctuations and sufficiency of insurance coverage. Although the Corporation believes that the expectations instigated by the Forward-Looking Information are based on reasonable and valid assumptions, there is a risk that the Forward-Looking Statements may be incorrect. The reader of this annual report is cautioned not to rely unduly on this Forward-Looking Information. Forward-Looking Information expressed verbally or in writing by the Corporation or by a person acting on its behalf, is expressly qualified by this cautionary statement. The Forward-Looking Statements contained herein are made as of the date of this annual report and the Corporation does not undertake any obligation to update or revise any Forward-Looking Information, whether as a result of events or circumstances occurring after the date hereof, unless required by legislation.

NON-IFRS MEASURES

Some measures referred to in this annual report are not recognized measures under IFRS, and therefore may not be comparable to those presented by other issuers. Innergex believes that these indicators are important, as they provide management and the reader with additional information about its production and cash generation capabilities, and facilitate the comparison of results over different periods. EBITDA, adjusted net earnings, and adjusted cash flows from operating activities are not measures recognized by IFRS and have no standardized meaning prescribed by IFRS. References in this annual report to "EBITDA" are to earnings before interest, provision for income taxes, depreciation and amortization, and other items. References in this annual report to adjusted net earnings and adjusted cash flows from operating activities are explained in the tables in the Management Discussion and Analysis section. Investors are cautioned that these non-IFRS measures should not be construed as an alternative to net income as determined in accordance with IFRS.

STRATEGY

OUR STRATEGY FOR BUILDING SHAREHOLDER VALUE IS TO DEVELOP OR ACQUIRE HIGH-QUALITY FACILITIES GENERATING SUSTAINABLE CASH FLOWS AND PROVIDING A HIGH RETURN ON INVESTED CAPITAL, AND TO DISTRIBUTE A STABLE DIVIDEND.

VISION

WE PROVIDE SUSTAINABLE ENERGY FOR A GREENER FUTURE.

MISSION

OUR MISSION IS TO INCREASE OUR PRODUCTION OF RENEWABLE ENERGY BY DEVELOPING AND OPERATING HIGH-QUALITY FACILITIES WHILE RESPECTING THE ENVIRONMENT AND SERVING THE BEST INTERESTS OF THE HOST COMMUNITIES, OUR PARTNERS, AND OUR INVESTORS.

VALUES

WE ENGAGE OUR STAKEHOLDERS, GOVERNED BY CORE VALUES OF INTEGRITY, RESPONSIBILITY, TRANSPARENCY, AND COLLABORATION, IN A PERSPECTIVE OF LONGEVITY AND RESOURCE-SHARING.

THE YEAR IN REVIEW

(in thousands of Canadian dollars, except as noted)

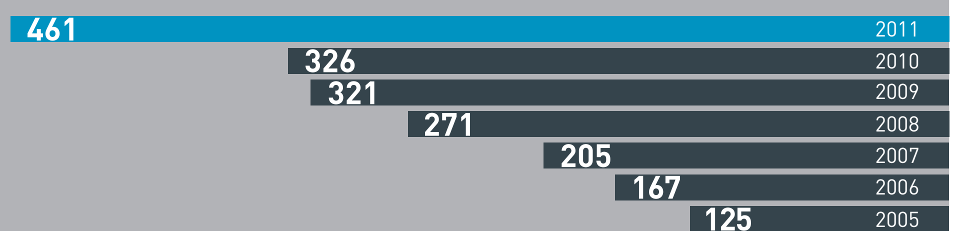
FINANCIAL OVERVIEW FOR THE YEARS ENDED DECEMBER 31

	2011 [1]	2010 [1b]	2009 [2]	2008 [2]	2007 [2]	2006 [2]
POWER GENERATED (MWh)	1,905,426	1,227,435	823,989	862,394	608,509	641,525
GROSS OPERATING REVENUES	148,260	91,385	58,625	59,430	40,372	41,154
EBITDA	111,196	68,111	46,778	47,097	31,293	32,427
ADJUSTED NET EARNINGS (LOSS)[3]	1,176	-1,169	12,685	12,478	9,880	11,763
DIVIDEND DECLARED - $ PER PREFERRED SHARE	1.25	0.42	-	-	-	-
DIVIDEND DECLARED - $ PER COMMON SHARE	0.58	0.61	0.68	0.68	0.66	0.66

1 Prepared in accordance with IFRS.
1b Converted in accordance with IFRS.
2 Prepared in accordance with Canadian GAAP.
3 Refer to the MD&A Section for an explanation of Adjusted Net Earnings (Losses).

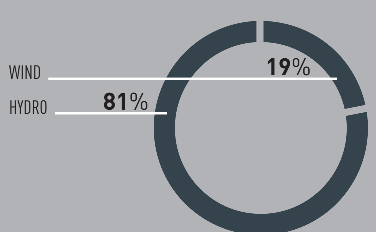
(MW)

NET INSTALLED CAPACITY AT DECEMBER 31



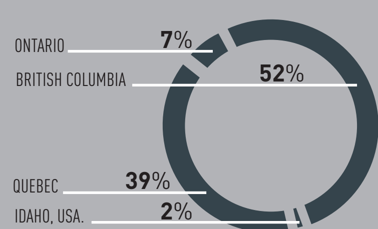
(GWh)
Based on actual production

ENERGY SOURCE DIVERSIFICATION



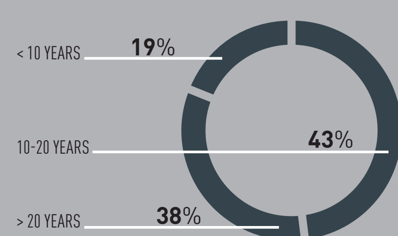
(GWh)
Based on actual production

GEOGRAPHIC DIVERSIFICATION



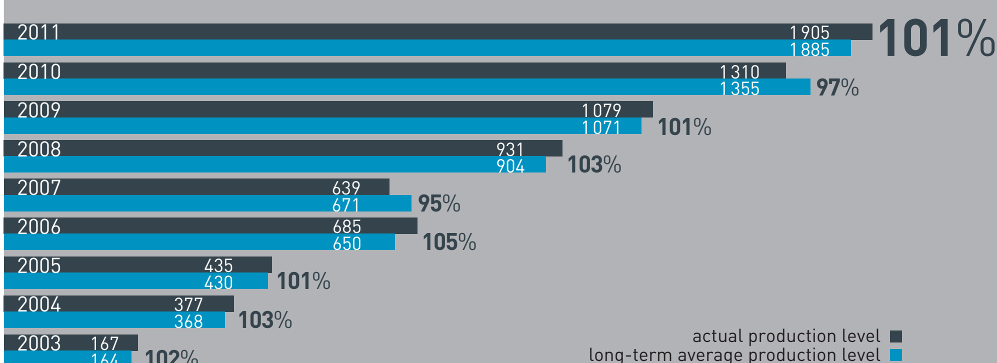
(GWh)
Based on net long-term average production of operating facilities

PPA REMAINING TERMS



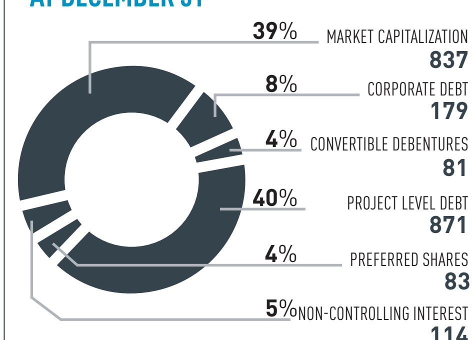
(GWh)

PRODUCTION PREDICTABILITY



($M)

CAPITAL STRUCTURE AT DECEMBER 31

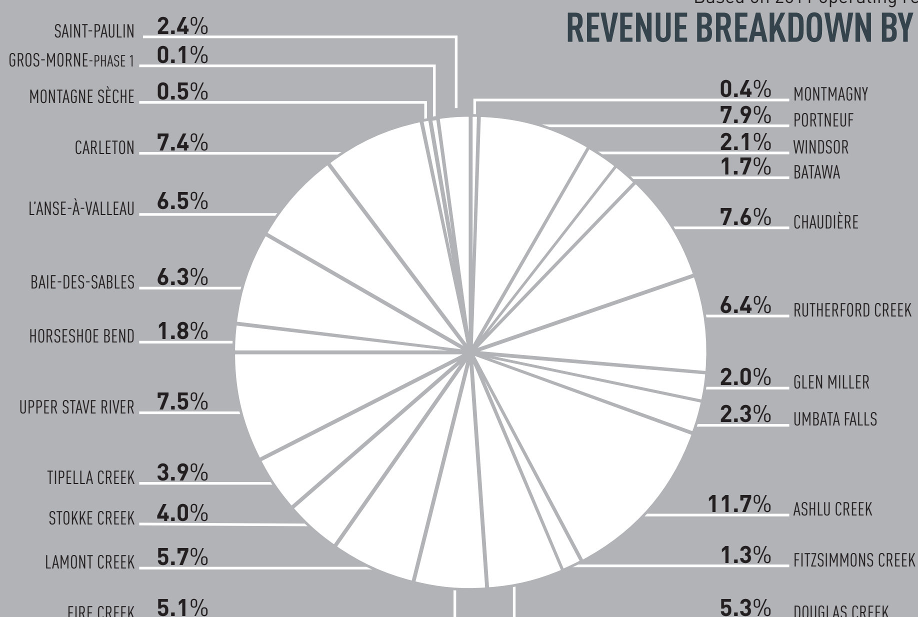


PROJECTS UNDER DEVELOPMENT

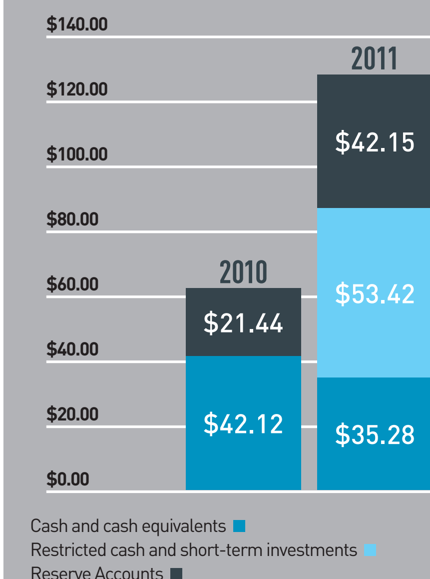
PROJECT NAME	LOCATION	GROSS CAPACITY (MW)	INE'S OWNERSHIP	ESTIMATED PROJECT COSTS ($M)	COSTS AS AT DEC. 31, 2011 ($M)	EXPECTED IN-SERVICE DATE
HYDRO						
KWOIEK CREEK	BC	49.9	50.0%	153.2	21.3	2013
NORTHWEST STAVE RIVER	BC	17.5	100.0%	91.4	21.6	2013
TRETHEWAY CREEK	BC	21.2	100.0%	91.5	13.7	2015
BOULDER CREEK	BC	23.0	66.67%	84.2	-	2015
NORTH CREEK	BC	16.0	66.67%	72.0	-	2016
UPPER LILLOOET	BC	74.0	66.67%	264.2	6.6	2016
BIG SILVER-SHOVEL CREEK	BC	36.9	100.0%	165.4	26.0	2016
WIND						
GROS-MORNE – II[1]	QC	111.0	38.0%	68.0[2]	11.5[2]	2012
VIGER-DENONVILLE	QC	24.6	50.0%	73.3	0.1	2013
SOLAR						
STARDALE	ON	33.2_{DC}	100.0%	141.7	116.6	2012

1 Cartier Wind Energy Joint Venture.
2 Represents Innergex's share of actual project construction costs.

($M)
Based on 2011 operating revenues
REVENUE BREAKDOWN BY SITE



CASH AND RESERVE ACCOUNTS AT DECEMBER 31 ($M)



2011 HIGHLIGHTS

Electricity production increased by **55%** year-over-year

Operating revenues rose 62% to **$148.3 million**

Total net installed capacity increased 41% to **461 MW** at December 31

25 The number of operating facilities at year-end

81% The proportion of energy produced from hydro

The electricity we produced was enough to power **158.785** Canadian households

Over **$700 million** of debt and equity raised in the capital markets

S&P BBB - and **DBRS BBB (low)** corporate credit ratings maintained

WEST GEOGRAPHICAL DISTRIBUTION

Innergex expanded into the British Columbia market in 2002 with the construction of the Rutherford Creek facility. Today, the Company operates nine run-of-river hydroelectric facilities in this province. It also has two hydro projects under construction, five hydro projects under development, and a 1,427 MW portfolio of prospective hydro and wind projects in this region.
Innergex also owns a 9.5 MW run-of-river hydroelectric facility in Idaho, USA.

01 ASHLU CREEK

REGION	BC
DATE OF COMMISSIONING	2009
INSTALLED CAPACITY (gross mw)	49.9
OWNERSHIP (%)	100.00
PPA EXPIRY	2039

02 DOUGLAS CREEK

REGION	BC
DATE OF COMMISSIONING	2009
INSTALLED CAPACITY (gross mw)	27.0
OWNERSHIP (%)	50.01
PPA EXPIRY	2049

OVERVIEW

03 FIRE CREEK

REGION	BC
DATE OF COMMISSIONING	2009
INSTALLED CAPACITY (gross mw)	23.0
OWNERSHIP (%)	50.01
PPA EXPIRY	2049

04 FITZSIMMONS CREEK

REGION	BC
DATE OF COMMISSIONING	2010
INSTALLED CAPACITY (gross mw)	7.5
OWNERSHIP (%)	66.67
PPA EXPIRY	2050

05 HORSESHOE BEND

REGION	USA
DATE OF COMMISSIONING	1995
INSTALLED CAPACITY (gross mw)	9.5
OWNERSHIP (%)	100.00
PPA EXPIRY	2030

06 LAMONT CREEK

REGION	BC
DATE OF COMMISSIONING	2009
INSTALLED CAPACITY (gross mw)	27.0
OWNERSHIP (%)	50.01
PPA EXPIRY	2049

07 RUTHERFORD CREEK

REGION	BC
DATE OF COMMISSIONING	2004
INSTALLED CAPACITY (gross mw)	49.9
OWNERSHIP (%)	100,00
PPA EXPIRY	2024

08 STOKKE CREEK

REGION	BC
DATE OF COMMISSIONING	2009
INSTALLED CAPACITY (gross mw)	22.0
OWNERSHIP (%)	50,01
PPA EXPIRY	2049

09 TIPELLA CREEK

REGION	BC
DATE OF COMMISSIONING	2009
INSTALLED CAPACITY (gross mw)	18.0
OWNERSHIP (%)	50.01
PPA EXPIRY	2049

10 UPPER STAVE RIVER

REGION	BC
DATE OF COMMISSIONING	2009
INSTALLED CAPACITY (gross mw)	33.0
OWNERSHIP (%)	50.01
PPA EXPIRY	2049

OVERVIEW

11 BAIE-DES-SABLES

REGION	QC
DATE OF COMMISSIONING	2006
INSTALLED CAPACITY (gross mw)	109.5
OWNERSHIP (%)	38.00
PPA EXPIRY	2026

12 BATAWA

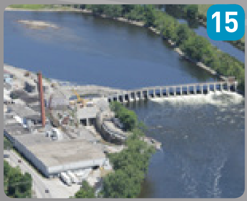
REGION	ON
DATE OF COMMISSIONING	1999
INSTALLED CAPACITY (gross mw)	50.0
OWNERSHIP (%)	100.00
PPA EXPIRY	2029

13 CARLETON

REGION	QC
DATE OF COMMISSIONING	2008
INSTALLED CAPACITY (gross mw)	109.5
OWNERSHIP (%)	38.00
PPA EXPIRY	2028

14 CHAUDIÈRE

REGION	QC
DATE OF COMMISSIONING	1999
INSTALLED CAPACITY (gross mw)	24.0
OWNERSHIP (%)	100.00
PPA EXPIRY	2019



15 GLEN MILLER

REGION	ON
DATE OF COMMISSIONING	2005
INSTALLED CAPACITY (gross mw)	8.0
OWNERSHIP (%)	100,00
PPA EXPIRY	2025

16 GROS-MORNE - I

REGION	QC
DATE OF COMMISSIONING	2011
INSTALLED CAPACITY (gross mw)	100.5
OWNERSHIP (%)	38.00
PPA EXPIRY	2032

17 L'ANSE-À-VALLEAU

REGION	QC
DATE OF COMMISSIONING	2007
INSTALLED CAPACITY (gross mw)	100.5
OWNERSHIP (%)	38.00
PPA EXPIRY	2027

18 MONTAGNE SÈCHE

REGION	QC
DATE OF COMMISSIONING	2011
INSTALLED CAPACITY (gross mw)	58.5
OWNERSHIP (%)	38.00
PPA EXPIRY	2031

19 MONTMAGNY

REGION	QC
DATE OF COMMISSIONING	1996
INSTALLED CAPACITY (gross mw)	2.1
OWNERSHIP (%)	100.00
PPA EXPIRY	2021

20 PORTNEUF

REGION	QC
DATE OF COMMISSIONING	1996
INSTALLED CAPACITY (gross mw)	8.0
OWNERSHIP (%)	100.00
PPA EXPIRY	2021

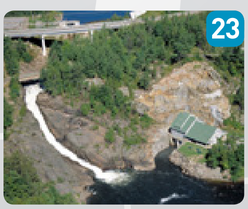
21 PORTNEUF2

REGION	QC
DATE OF COMMISSIONING	1996
INSTALLED CAPACITY (gross mw)	9.9
OWNERSHIP (%)	100.00
PPA EXPIRY	2021

EAST GEOGRAPHICAL DISTRIBUTION

22 PORTNEUF3

REGION	QC
DATE OF COMMISSIONING	1996
INSTALLED CAPACITY (gross mw)	8.0
OWNERSHIP (%)	100.00
PPA EXPIRY	2021



23 SAINT-PAULIN

REGION	QC
DATE OF COMMISSIONING	1994
INSTALLED CAPACITY (gross mw)	8.0
OWNERSHIP (%)	100.00
PPA EXPIRY	2014

24 UMBATA FALLS

REGION	ON
DATE OF COMMISSIONING	2008
INSTALLED CAPACITY (gross mw)	23.0
OWNERSHIP (%)	49.00
PPA EXPIRY	2028

25 WINDSOR

REGION	QC
DATE OF COMMISSIONING	1996
INSTALLED CAPACITY (gross mw)	5.5
OWNERSHIP (%)	100.00
PPA EXPIRY	2016

Innergex commissioned its first run-of-river hydroelectric facility, Saint-Paulin, in 1994. In 1999, the Company expanded into the Ontario market with the commissioning of its Batawa run-of-river hydroelectric facility. Today, the Company operates ten run-of-river hydroelectric facilities in Eastern Canada. Since 2006, it has also diversified its operations, becoming a leading wind energy producer with five wind farms in Quebec. Innergex also has two projects under construction, including its very first solar farm, one wind project under development, and a 1,550 MW portfolio of prospective wind, hydro, and solar projects in this region.

ANOTHER BUSY YEAR IN 2011

Innergex continued on its growth path in 2011, increasing the electricity it generated by 55% to 1,905,426 MWh. Operating revenues grew 62.2% to $148.3 million and – more importantly – operating profitability kept pace, with EBITDA rising 63.3% to $111.2 million. Adjusted cash flows from operating activities rose from $44.9 million last year to $77.0 million in 2011. Such performance stems mainly from the integration of our Cloudworks Acquisition, which successfully closed on April 4, 2011. A testimony to our significant ongoing development activity levels, capital expenditures totalled approximately $179 million, six times the level of the previous year. These figures also reflect the first full year of consolidation following the strategic combination by way of reverse takeover of the Corporation by Innergex Power Income Fund. Meanwhile, the commercial start-up of two wind farms in late November had only a small impact on our performance in 2011 and will contribute fully to operating results starting in 2012.

Major acquisition to start off the year

Innergex hit the ground running in 2011 when we announced in February the acquisition of Cloudworks Energy Inc. for a total consideration of $191 million. With its balanced mix of high quality assets consisting of a 50.01% interest in six run-of-river hydroelectric facilities in operation, three wholly-owned projects under development with 40-year Power Purchase Agreements (PPA), and more than 800 MW of prospective projects, Cloudworks represented an excellent fit, not only operationally, but culturally. It also provided greater exposure to hydro assets and enhanced our geographic diversification. The acquisition of Cloudworks truly marked a milestone for Innergex, as we demonstrated over the course of the year our ability to successfully acquire and integrate a sizeable operating entity.

Diversification into a new energy source

We reached yet another milestone, further diversifying our renewable energy sources with the acquisition of the Stardale solar photovoltaic farm. This 33.2 MW_{DC} project located near Hawkesbury, Ontario had been awarded three 20-year PPAs with the Ontario Power Authority under the province's Renewable Energy Standing Offer Program (RESOP). We firmly believe the solar technology is proven, reliable and simple, and that construction and operational risks are minimal. In addition, the sun provides for a very stable and predictable resource which complements our wind and hydroelectric facilities.

New community wind farm project

In late 2010, Innergex had been awarded a 20-year PPA for the Viger-Denonville wind farm project as part of the Québec government's 250 MW Community Wind Request for Proposals. This PPA was approved by Québec's Régie de l'énergie in November 2011, giving us the green light to proceed with development activities under a 50-50 joint venture with the Rivière-du-Loup Regional County Municipality ("RCM"). We believe community projects such as this one will become increasingly prevalent, as local communities seek to participate in the economic and social benefits of renewable energy installations.

Commissioning of two new wind farms

In late 2011, we began commercial operations of the 58.5 MW Montagne Sèche wind farm (22.2 MW net capacity) and the 100.5 MW Gros-Morne I wind farm (38.3 MW net capacity). Both were developed by our Cartier Wind Energy joint venture, in which Innergex owns a 38% interest and a 50% stake in the management entities that oversee all aspects of development, construction, and operation.

Breaking ground for two hydroelectric facilities

During 2011, we also began construction activities in British Columbia on two hydroelectric facilities, having obtained all requisite permits and approvals. Kwoiek Creek is a 49.9 MW run-of-river hydroelectric facility being developed through a 50-50 joint venture with the Kanaka Bar Indian Band. Northwest Stave River is a wholly owned 17.5 MW run-of-river hydroelectric facility. Pursuing these two projects simultaneously represents a significant undertaking in itself; furthermore, we are particularly proud of the fact that one project originated from the Innergex development pipeline, while the other originated from the Cloudworks development pipeline.

Financial position solidified

Despite the ongoing credit crisis and the extremely volatile financial markets which continued to plague most developed economies, Innergex completed several successful transactions in the capital markets last year. Payment for the Cloudworks acquisition included the issuance of shares to its owners by way of a $39.3 million private placement. We concurrently completed a $166 million public share offering at a price of $9.35 per share to help finance the acquisition and build our equity base. In August, we increased and extended our corporate credit facility with a syndicate of lenders to $350 million, with a five-year term. As a result, last November both Standard & Poor's and DBRS confirmed their credit ratings for the Corporation and its Series A preferred shares.

OUR OBJECTIVE FOR 2012: STAY THE COURSE

Commissioning

We have much to look forward to in the year to come. First and foremost, we will continue to grow production levels with the commissioning of two additional operating facilities. In the spring, we expect to begin commercial operations at Stardale, our first solar farm. While it should start producing electricity during the first quarter of 2012, official operations are expected to commence early in the second quarter. In the fall, we expect to begin commercial operations at the Gros-Morne II wind farm, which will have a total installed capacity of 111 MW (42.2 MW net).

Construction

We also remain very busy on the project development front. We will simultaneously advance construction activities at both the Kwoiek Creek and the Northwest Stave River run-of-river hydroelectric facilities in British Columbia. We expect to finalize long-term financing arrangements for both Kwoiek and Northwest Stave River in the first half of 2012. Both are expected to begin commercial operations in 2013.

Permitting

At the same time, we will simultaneously advance the permitting phase for our five other run-of-river hydroelectric projects with PPAs in British Columbia, which will have a combined installed capacity of 171 MW (133.4 MW net). The first cluster, known as "Upper Lillooet" and in which Innergex owns a 66.67% interest, is comprised of the Boulder Creek, North Creek, and Upper Lillooet projects. The second cluster, known as "TBS", is comprised of two wholly owned projects, Tretheway Creek and Big Silver-Shovel Creek.

In Québec, we will advance on the permitting phase for the Viger-Denonville wind farm project. Our relations with our community partner, the Rivière-du-Loup RCM, are excellent and development activities are progressing well. We will pursue the permitting process and construction preparations throughout 2012 and expect to begin commercial operations in the fourth quarter of 2013.

Project submissions for PPAs

As always, we remain ready to respond to requests for proposals made by various provincial government authorities, including those in Québec, Ontario and British Columbia.

As we write this report, the Ontario government has not yet completed the first scheduled two-year review of its FIT Program, which began in the fall of 2011. Recommendations are expected to include a reduction of the feed-in tariff, especially for solar photovoltaic projects, which reduction would reflect the declining costs of raw materials and components worldwide. Furthermore, it is also expected that local content requirements for solar and wind projects will be maintained. We will be reviewing our portfolio of prospective projects in Ontario in order to determine which ones remain competitive and economically viable under the new program terms. We currently have 452 MW (net) of wind projects and 59 MW (net) of solar projects submitted under the FIT Program, for which awards will depend on the results of the Economic Connection Test and subsequent implementation of transmission expansion.

We also have several projects that would be eligible under the current Standing Offer Program (SOP) in British Columbia, including at least six projects of up to 15 MW each, which we continue to investigate for submission. Indeed, in accordance with the terms of this program, all permits and approvals must be obtained prior to submitting a project for a PPA.

External growth opportunities

Merger and acquisition activity levels remain strong in the renewable energy sector. Projects at all stages of development are being marketed, sometimes quite aggressively. As our size and presence in the sector has grown, so has our ability to evaluate, finance, and structure competitive bids. We are increasingly being recognized as an industry consolidator and are seeing a greater deal flow. We have studied a number of opportunities in the last year, and we expect to continue doing so in the foreseeable future. Throughout this process, we will remain extremely selective and disciplined in our approach, choosing only projects which correspond to our stated strategy of building or acquiring high-quality installations that provide a high return on invested capital, in order to generate sustainable cash flows and pay a steady dividend.

Capital requirements

With 10 projects with PPAs currently under construction or under development, Innergex will grow its net installed capacity from its current level of 461 MW to 725 MW by the end of 2016. Our capital expenditure program now stands at approximately $1.0 billion. All of these projects are expected to be financed with project-level financing, and do not require us to raise additional equity capital at this time. Furthermore, we expect to continue growing our pipeline of projects over the next several years, given the vigorous activity in the Canadian renewable energy sector. In financing this new growth, we are committed to maintaining a balanced capital structure, so as to preserve the Corporation's low risk profile.

JEAN LA COUTURE
Chairman of the Board

Mr. Jean La Couture, Fellow Chartered Accountant, is President of Huis Clos Ltée, a management and mediation firm. He also acts as President of "Regroupement des assureurs de personnes à charte du Québec (RACQ)".

Mr. La Couture is also Chairman of the Board of Groupe Pomerleau and the Institute of Corporate Directors, Quebec Chapter. He is also a Director of Quebecor Inc. (public company), Quebecor Media Inc., Videotron Ltd., Jevco Insurance Company and CFC Dolmen.

From 1972 to 1994, he was President and Chief Executive Officer of three organizations, the last one being a Canadian specialty line insurance company. Mr. Jean La Couture holds a Bachelor of Business Administration degree (Accounting) from HEC Montréal.

CREATING VALUE THROUGH GOVERNANCE

"THE BOARD OF DIRECTORS' MANDATE FOR THE FUTURE REMAINS UNCHANGED, NAMELY TO ASSIST SENIOR MANAGEMENT IN ITS EFFORTS TO CREATE VALUE, TO FOSTER GROWTH THAT IS BOTH CONTINUOUS AND SECURE, AND TO ENSURE THE DEVELOPMENT OR ACQUISITION OF VERY HIGH QUALITY ASSETS."

2011 was a year of combined stability and growth for the Company, its management team, and its Board of Directors. Once again, our achievements speak for themselves:

- A stable and secure dividend policy;
- The acquisition of quality assets;
- Ongoing project development;
- Financing that is well matched to our long-term operations; and
- An investment in an additional energy source to hydro and wind, namely solar power.

All of these were achieved in strict adherence to the values of the Corporation and the standards of a responsible corporate citizen. Our product of the future corresponds to the needs of communities and society as a whole, and the environment remains a constant priority for both employees and board members. Furthermore, the Board of Directors works to serve the interests of shareholders and bondholders alike, and concerns itself with all of the Corporation's stakeholders, including its employees, its suppliers, governments, and society.

The Board of Directors' mandate for the future remains unchanged, namely to assist senior management in its efforts to create value, to foster growth that is both continuous and secure, and to ensure the development or acquisition of very high quality assets.

We wish to thank our shareholders for the confidence they continue to place in the Corporation. We also wish to thank the management team and the employees for their dedication in maintaining a company of which we are very proud.

Jean La Couture, FCA
Chairman of the Board

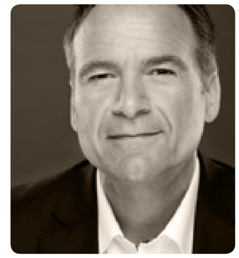
MESSAGE FROM THE PRESIDENT AND CHIEF EXECUTIVE OFFICER

"2011 WILL HAVE BEEN A YEAR OF GROWTH AND MATURATION FOR THE CORPORATION. GROUNDED BY ITS SUCCESS, INNERGEX LOOKS DECIDEDLY TO THE FUTURE AND WILL CONTINUE ON THE COURSE IT HAS SET."

As we look back on what we have accomplished to date, we find confirmation that the mission and strategy we set more than 20 years ago remain absolutely relevant today.

When we completed the reverse takeover of the Corporation by the Innergex Power Income Fund, we made the decision to offer shareholders a sustainable dividend. This decision has given rise to a rigorous management discipline. We must maintain a balanced portfolio of assets, in terms of geographic markets, energy sources and development stages of our sites – power stations in operation, projects under construction or under development with power purchase agreements, and projects still at the prospective stage. We are well aware that in order to ensure our future growth, we must maintain a solid foundation of cash flow-producing operating facilities, whereby part of these cash flows can be reinvested in development projects. Hence, each new installation we commission increases our capacity to develop projects and in turn, sustains our ability to grow. This reality is compounded by our strict adherence to our business model, founded on securing long-term power purchase contracts and reducing risks.

We have a full plate for the next five years, with 10 projects currently under construction or



MICHEL LETELLIER, MBA
President and Chief Executive Officer

Michel Letellier first joined Innergex in 1997 as Vice President – Finance. He was appointed Executive Vice President and Chief Financial Officer in 2003, and later appointed President and Chief Executive Officer in October 2007. Mr. Letellier is responsible for providing strategic leadership and overseeing all of the Corporation's business activities, in order to ensure its sound financial management and long-term sustainability.

Prior to joining Innergex, Mr. Letellier worked at Boralex Inc. from 1990 to 1997, where he was involved in the development and operation of several run-of-river hydroelectric projects and where he held positions of increasing responsibility. Prior to that, he spent two years as a member of the Corporate Finance group at Brault Guy O'Brien Inc. Mr. Letellier holds a Bachelor of Commerce (Finance) degree from Université du Québec à Montréal (1986) and a Master of Business Administration degree from Université de Sherbrooke (1988).

under development, each one of those with a long-term power purchase agreement. Canada remains our priority for as long as there will be projects to develop, requests for proposals to answer, and business opportunities to seize. Our incursion into the US market in 2003, with the acquisition of a run-of-river hydroelectric facility in the state of Idaho, has proved successful; however, it has been difficult to obtain long-term power purchase agreements in this market. Expansion beyond North America could be possible over the long term, but here again, we would insist on strictly adhering to our proven business model, our culture, and our values and we would require generating added value for the Corporation and our shareholders.

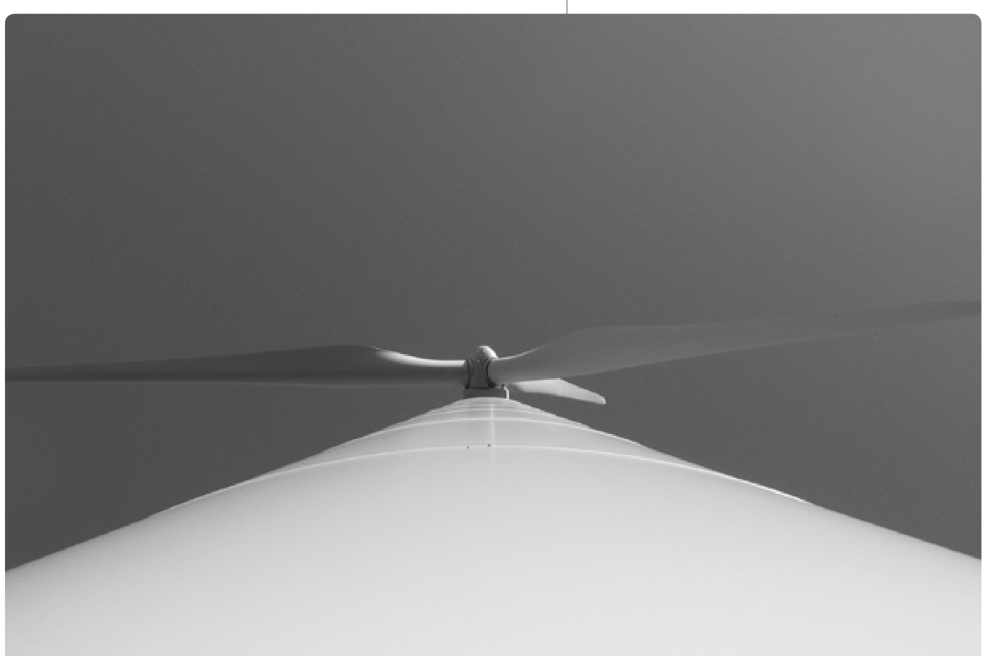
Our industry is subjected to the whims of short-term economic and political imperatives that do not correspond to the reality of energy production, which must be conceived over the long term. A constant lag exists between energy supply and demand, which are anything but linear. Demand projections do not always match economic cycles, while lead times to commission new production capacity can take 3 to 5 years. Against this backdrop, we have observed that during periods of economic crisis, the only thing that matters is price, while all other considerations become secondary.

Over the years, we have witnessed firsthand this cyclicality. Today, Innergex is well positioned to face the inherent uncertainty of the energy industry, particularly of renewable energy. Fortunately, the political and economic cycles of our multiple geographic markets and our three energy sources are not synchronized. Our diversification provides us with the flexibility to react to favourable circumstances arising in one market, while we wait for conditions to improve in another.

Furthermore, a prolonged period of uncertainty or crisis creates merger and acquisition opportunities, which we are well equipped to seize. Moreover, we believe the environment will once again become top of mind for individuals and governments as economic prosperity returns.

For Innergex, choosing to produce renewable energy is choosing the long term. It's choosing to work towards energy independence and self-sufficiency, towards local job creation and economic benefits, and towards the preservation of the environment. We are very confident about the sustainable nature of our mission and strategy and we are devoting our talent and resources to continuing on the course we have set.

Michel Letellier, MBA
President and Chief Executive Officer



BIGGER, STRONGER, BETTER

JEAN PERRON, CA, CMA
Chief Financial Officer
and Senior Vice President

Jean Perron joined Innergex in December 2003 as Vice President and Treasurer. He was appointed Chief Financial Officer in 2007 and Senior Vice President in 2011. Mr. Perron is responsible for the Corporation's accounting, taxation, and budgeting processes. He also provides leadership and coordination in developing the Corporation's corporate structure in close cooperation with the legal department.

Prior to joining Innergex, Mr. Perron worked for KPMG LLP for more than 13 years, where he held positions of increasing responsibility, lastly as Senior Manager in taxation for a diversified clientele of private and public companies. Mr. Perron holds a Bachelor of Business Administration degree from Université du Québec à Montréal (1990) and has been a Chartered Accountant and a Certified Management Accountant since 1992.

JEAN PERRON, THEY SAY THE ONLY CONSTANT IS CHANGE. HOW HAS INNERGEX CHANGED OVER THE LAST YEAR?

In the last twelve months, Innergex has become a more mature, more experienced, and more well-rounded company. And the single greatest catalyst for this change has been the integration of our Cloudworks acquisition.

Over the years, we had developed substantial expertise in acquiring stand-alone projects under development and sites in operation. However, acquiring an entity with management and operation teams in place and a diversified portfolio of both sites in operation and projects under development represented uncharted territory for us. With the benefit of hindsight, it's fair to say we experienced an intense growth spurt in 2011.

Several years ago, we identified British Columbia as a major growth pole of renewable energy production, particularly of very high quality run-of-river hydroelectric facilities. We opened an office in Vancouver in 2003 and even transferred some senior members of our management team. When the opportunity arose to acquire Cloudworks, it was no mere coincidence. Not only did it bring us sizeable operations, it gave us the critical mass and the infrastructure to properly develop this attractive market. It also magnified our long-term growth prospects. Furthermore, we deepened our expertise in environmental matters – a paramount consideration on the West Coast, which we are now bringing to our development activities across the country.

We chose to approach the integration process in much the same way as we conduct our business – respectfully, collaboratively, and patiently. While virtually every facet of Innergex's activities was impacted, decisions were made on a case-by-case basis. That's why, for example, instead of consolidating the accounting department, some accounting functions were actually decentralized, in order to give the British Columbia operations more autonomy. Our Vancouver office has evolved from a satellite branch focusing on project development to a fully integrated operational entity.

We can feel that Innergex has emerged from the successful integration of Cloudworks a stronger, more mature company, well equipped to consider future acquisitions and to fulfill its long-term development potential.

Transition to IFRS

All told, the transition to IFRS will have represented more than 3,000 man-hours over a two-year period.

"More than a restatement of the numbers, it is the greater disclosure requirements and the greater transparency that IFRS confer to these numbers that are most likely to benefit the readers of our financial statements."

A BALANCE BETWEEN ECONOMIC AND SOCIAL IMPERATIVES

JEAN TRUDEL, MBA
Chief Investment Officer and
Senior Vice President – Communications

Jean Trudel joined Innergex in 2002 as Vice President – Corporate Development and was named Vice President – Finance the following year. He was appointed Chief Investment Officer and Senior Vice President – Communications in May 2011. Mr. Trudel is responsible for the execution of the Corporation's investment strategy, which includes optimizing its capital structure, financing projects under development, and leading the evaluation, negotiation, and financing process for potential acquisitions. He is also responsible for overseeing corporate communications, which includes public relations, media relations, and investor relations.

Prior to joining Innergex, from 1999 to 2002 Mr. Trudel worked for Sun Life Assurance Company of Canada (formerly Clarica) as Director, Investment Project Finance for Québec and Atlantic Canada. Prior to that, Mr. Trudel spent three years as a member of the Corporate Banking Group at Bank of Nova Scotia. Mr. Trudel holds a Bachelor of Business Administration (Finance) degree from HEC Montréal (1993) and a Master of Business Administration degree from Queen's University (1996).

JEAN TRUDEL, MANY FACTORS CONTRIBUTED TO THE SUCCESS OF INNERGEX – IS THERE ONE THAT STANDS OUT?

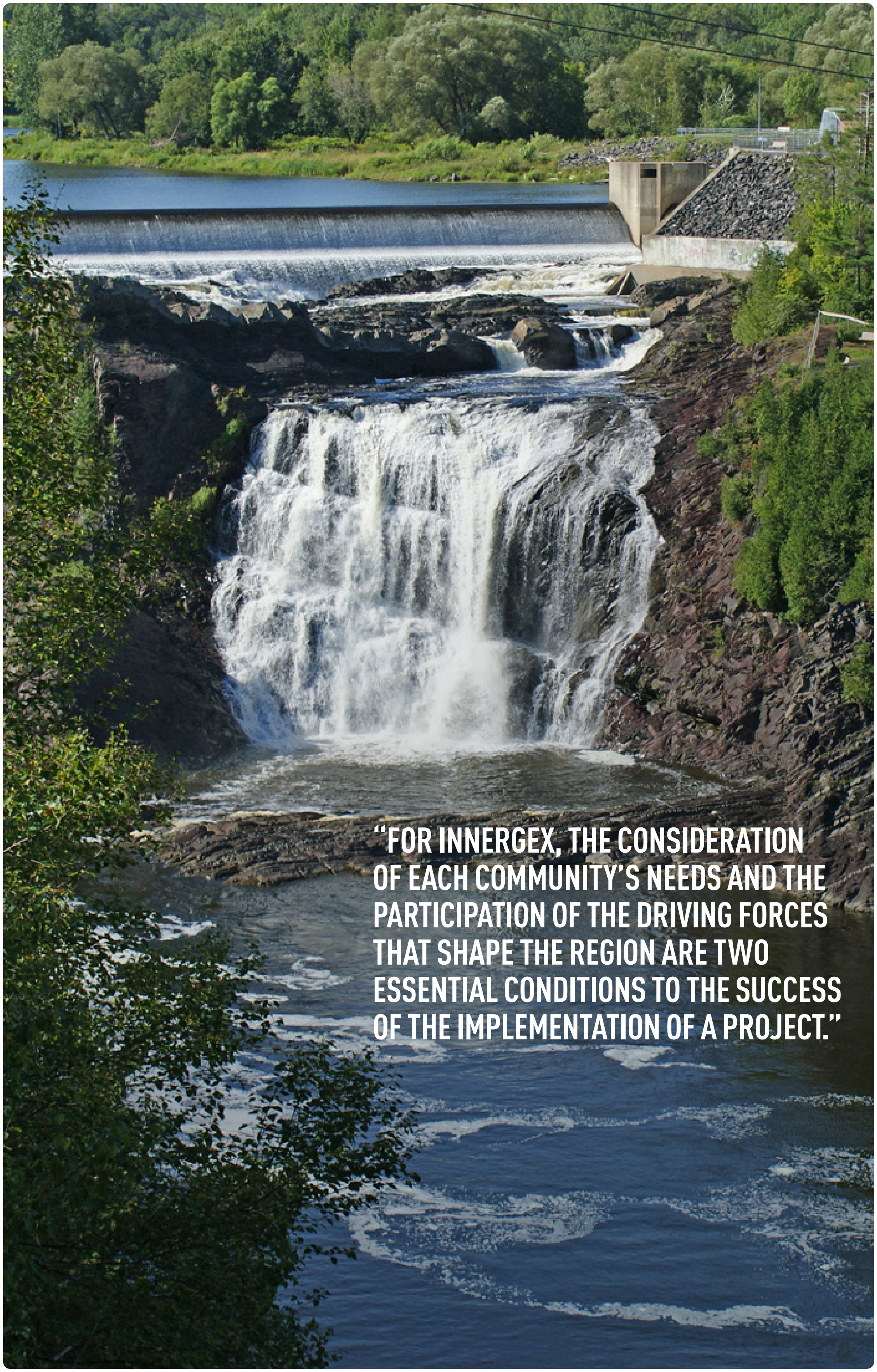
Many factors explain our success over the years. There is not one fundamental pillar of our success. Actually, there are two.

A competitive cost of capital
First, an energy project requires substantial capital expenditures. From its inception, Innergex has strived to achieve the lowest cost of capital in order to make its projects as competitive as possible, whether we sought to build them or acquire them. Today, several factors contribute to our competitive cost of capital, including: the Corporation's portfolio of high quality, long-term assets; its sound balance sheet; its conservative long-term average production forecasts; its unique business model based on derisking; and its impressive track record of delivering on its commitments, on time and on budget.

Social acceptance of our projects
Second, we are keenly aware that the resources we harness do not belong to us; we have simply acquired a right to use them. Of course, we use these resources to produce energy that is both clean and renewable. Yet, we appreciate that they also serve the needs of the local communities who live and work nearby. From its inception, Innergex has placed social acceptability at the core of its business model, as an essential precondition to the realization of its projects. Each time, we travel to the local communities and engage in a dialogue. We listen to their concerns, answer their questions, and explain both the risks and the merits of the project. The proposal we eventually submit takes into account the fruits of this consultation, whether in the form of shared ownership or revenues, local job creation, local content requirements, or other special considerations.

Here's a great example of how social acceptability has found its expression at Innergex since the very beginning.

The Chaudière run-of-river hydroelectric facility is located on public lands near the town of Lévis, Québec. This power plant was originally built in 1901 and was abandoned in the 1970s after the dam was damaged by ice pack. In the early 1990s, we submitted a proposal which explicitly reflected the needs and concerns of the Chaudière Falls community and which culminated in the complete renovation of the powerhouse and the revitalization of the surrounding nature park. Twelve years later, the Parc des Chutes-de-la-Chaudière has become a major tourist attraction, drawing more than 300,000 visitors each year. In fact, we regulate river flow rates to optimize the aesthetics of the falls throughout the tourist season. We also contribute financially to the maintenance and preservation of the park each year.


"FOR INNERGEX, THE CONSIDERATION
OF EACH COMMUNITY'S NEEDS AND THE
PARTICIPATION OF THE DRIVING FORCES
THAT SHAPE THE REGION ARE TWO
ESSENTIAL CONDITIONS TO THE SUCCESS
OF THE IMPLEMENTATION OF A PROJECT."

BEYOND THE RESOURCE, THE PEOPLE

RICHARD BLANCHET, P. ENG.,M.SC.
Senior Vice President – Western Region

Richard Blanchet joined Innergex in 2001 as Vice President – Development and was appointed Senior Vice President – Western Region in 2011. Mr. Blanchet is responsible for overseeing the Corporation's activities in Western Canada, providing leadership and guidance to the development, engineering, and construction teams.

Prior to joining Innergex, Mr. Blanchet worked as a specialist and project manager at Group RSW Inc. for more than 13 years. Mr. Blanchet holds a Master of Science degree (1989) and a Bachelor of Civil Engineering degree (1986), both from Université Laval. Mr. Blanchet has been a member of the Ordre des Ingénieurs du Québec since 1988, and a member of the Association of Professional Engineers and Geoscientists of British Columbia since 2002.

RICHARD BLANCHET, ARE SUCCESSFUL RELATIONS WITH FIRST NATIONS A REALITY OF DOING BUSINESS IN WESTERN CANADA?

In building and operating run-of-river hydroelectric facilities in remote areas of British Columbia, we are also building relations with various First Nations communities.

We cannot talk about our operations in British Columbia without talking about the acquisition of Cloudworks. This company had forged very solid relations with First Nations communities since early 2000, during the process of developing, constructing, and subsequently operating their six run-of-river hydroelectric facilities, many of which are located on native lands. Negotiations were well under way towards a new agreement for its projects under development when we announced we would acquire the company. Understandably, these First Nations chose to take a pause in the negotiations, wanting to get to know the people of Innergex and to understand the changes taking place.

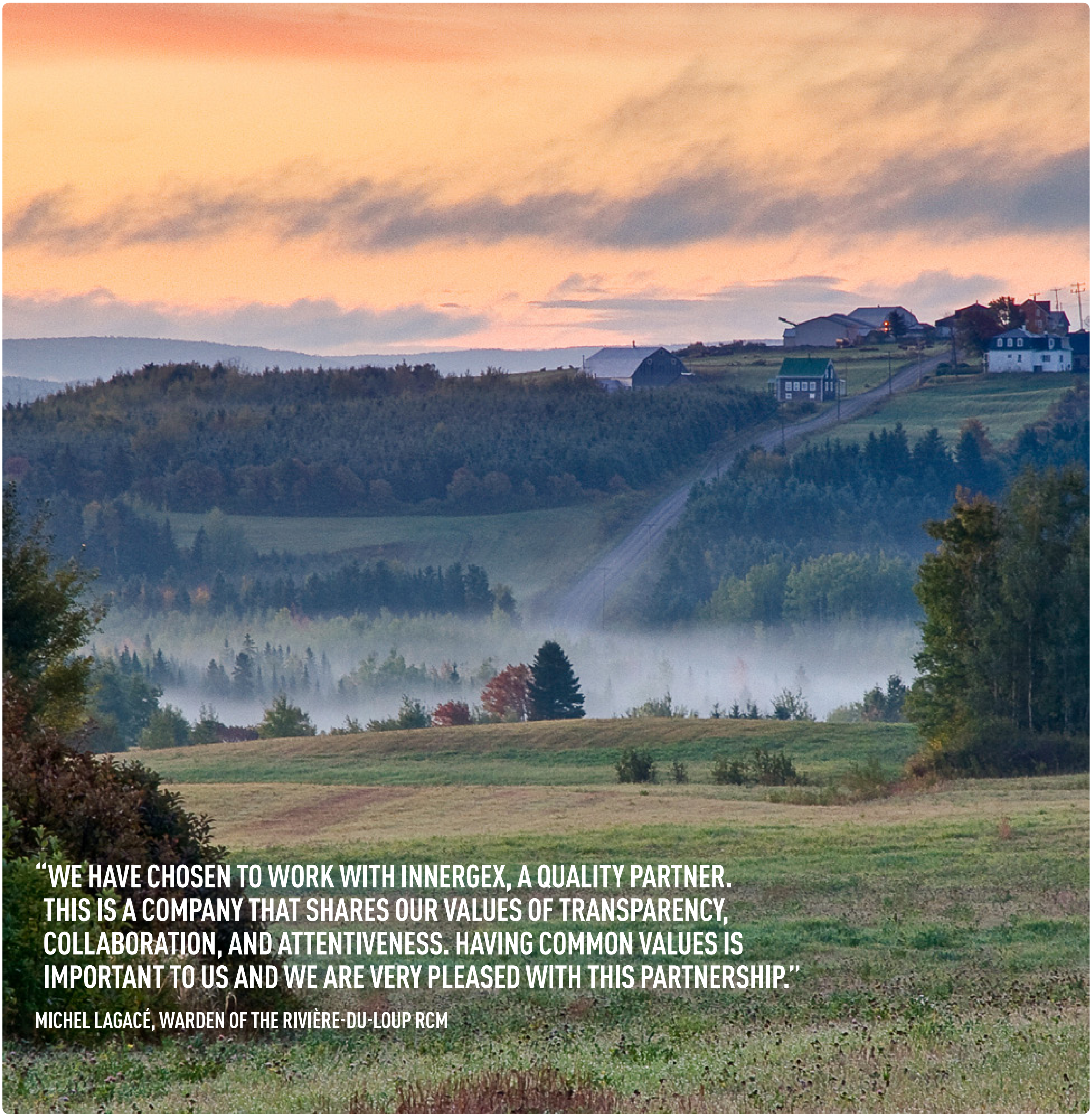
From its very beginnings, Innergex has succeeded in building strong relations with several First Nations communities in Québec, Ontario, and British Columbia. These favourable points of reference proved invaluable last year when we endeavoured to transfer the deep-rooted relations that Cloudworks had established with First Nations communities onto Innergex. But relations between a First Nation and a company inevitably boil down to the bonds of trust that form between their people. It's all about the people. We were very fortunate that the values which Cloudworks had espoused were the same as those cultivated by Innergex: transparency, collaboration, and respect. A lot of respect. So our First Nations stakeholders recognized in us the same kind of people they had been dealing with previously.

We were able to get to know each other and (re)connect. In the end, we were able to resume negotiations and conclude a new agreement.

We are very proud to participate in the well-being of these communities. Beyond the financial contributions and physical presence, we help them achieve their long-time goal of connecting to the provincial transmission grid and replacing their unreliable diesel-powered generators with renewable hydroelectric power. The local jobs and training we provide have attracted several members to return to their community, giving them an opportunity to reconnect with their ancestral values. We are guests on their land and we build our projects in consideration of their cultural heritage.

We firmly believe that our success in forging strong relations with our First Nations stakeholders lies in the fact that we share a very long-term view; we develop high-quality, long-lasting assets in order to operate them for a long, long time.

Photo: Signing Ceremony with the Douglas First Nation, October 26, 2011.


"WE HAVE CHOSEN TO WORK WITH INNERGEX, A QUALITY PARTNER. THIS IS A COMPANY THAT SHARES OUR VALUES OF TRANSPARENCY, COLLABORATION, AND ATTENTIVENESS. HAVING COMMON VALUES IS IMPORTANT TO US AND WE ARE VERY PLEASED WITH THIS PARTNERSHIP."
MICHEL LAGACÉ, WARDEN OF THE RIVIÈRE-DU-LOUP RCM

IMPROVEMENT: A CONTINUOUS PROCESS

FRANÇOIS HÉBERT
Senior Vice President – Operations and Maintenance

François Hébert joined Innergex in 1999 as Vice President – Operations and Maintenance. He was appointed Senior Vice President – Operations and Maintenance in 2011. Mr. Hébert is responsible for overseeing the operation and maintenance activities for the Corporation's hydroelectric facilities, in order to maximize their productivity and life expectancy. He also plays an active role in the design and commissioning of electromechanical equipment for hydroelectric projects under construction.

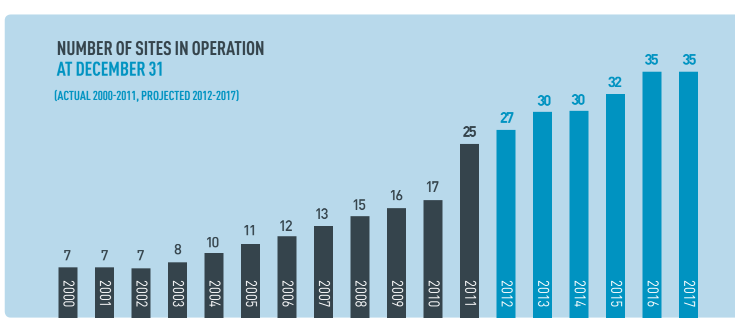
Prior to joining Innergex, Mr. Hébert worked for Alstom for 12 years, where he held positions of increasing responsibility, lastly as the automation department's Electrical Coordinator. Mr. Hébert holds a diploma in Electronics from Cégep de Sherbrooke (1986) and a diploma in instrumentation and controls from Cégep du Vieux-Montréal (1987).

FRANÇOIS HÉBERT, GROWTH AND CHANGE SEEM TO BE RECURRING THEMES – HOW DO THEY AFFECT OPERATIONS AND MAINTENANCE?

Innergex has experienced significant growth over the last ten years. From seven power plants in early 2000, we have 25 today. Understandably, having to operate and maintain so many facilities over such a large geographic area, many of which are isolated and difficult to access, constitutes an additional challenge, which few companies of our size are faced with. That's especially true from a health and safety standpoint, for example. In 2011, the acquisition of Cloudworks actually served as the catalyst to review and improve our health and safety policies.

The unusual challenges arising from the nature of our activities guide us in setting health and safety priorities. For example, the risk of avalanches is a very real issue to contend with in British Columbia, something those of us from Québec were naturally unfamiliar with. Paradoxically, it is precisely when the avalanche risk is high, there's a lot of heavy rain, and people are advised to stay off the roads that our operators must go out to make sure our power plants are operating properly; it becomes critical for us to ensure we do so in the safest, most efficient way possible. This involves analyzing each step of our procedures, and sometimes rethinking how we do things.

Our review process culminated with the publication of a new Health, Safety, and Environment Policy, as well as a comprehensive set of written procedures with respect to our practices. We are very proud of the work accomplished to date. But it's clear that the implementation of health and safety measures in the workplace is an ongoing process: standards are continuously rising; our employees must receive training that is both appropriate and recurring; and our practices and procedures are the object of continuous improvement. We look forward to pursuing our efforts in this direction in 2012 and beyond.



WORK ALONE PROCEDURE

OPERATORS AT OUR HYDRO ELECTRIC FACILITIES AND WIND FARMS OFTEN WORK ALONE IN REMOTE LOCATIONS, WHICH PRESENTS AN IMPORTANT HEALTH AND SAFETY CHALLENGE. EACH OF OUR OPERATORS IS EQUIPPED WITH A MAN-DOWN ALARM SYSTEM; IF IT DETECTS A PROLONGED ABSENCE OF MOVEMENT, IT SENDS A SIGNAL, FIRST BACK TO THE OPERATOR'S QUARTERS TO AVOID ANY FALSE ALARMS, AND THEN TO AN ALARM COMMUNICATION CENTER, WHICH WILL DISPATCH LOCAL EMERGENCY SERVICES.

WIND-FUELED GROWTH

PETER GROVER, ENG.
Senior Vice President – Project Management

Peter Grover joined Innergex in 2005 as Vice President – Project Management. He was appointed Senior Vice President – Project Management in 2011. Mr. Grover is responsible for overseeing Innergex's development activities in wind and solar energy, including the development, construction, and operation of the Corporation's co-owned wind farm projects under the Cartier Wind Energy joint venture.

Prior to joining Innergex, Mr. Grover worked for Alstom for more than 20 years, holding positions of increasing responsibility in the renewable energy sector in Canada and abroad, lastly as Director of Project Management. Mr. Grover holds a Bachelor of Electrical Engineering degree from Concordia University (1986) and has been a member of the Ordre des Ingénieurs du Québec since 1992.

PETER GROVER, INNERGEX HAS REACHED SEVERAL MILESTONES IN THE PAST YEAR. HAVE THERE BEEN ANY DEFINING ACHIEVEMENTS IN THE WIND ENERGY SECTOR?

The Corporation maintains a very high level of activity in all sectors, and wind energy is certainly no exception. In 2011, we pursued and completed the construction of Montagne Sèche and Gros-Morne I, two wind farms on the Gaspé Peninsula which were commissioned at the end of November. Work also progressed rapidly on the construction of Gros-Morne II, which is expected to begin operations in late 2012. In parallel to all of this activity, perhaps our most notable achievement has been the integration of the operations and maintenance ("O&M") activities at our Baie-des-Sables wind farm, upon expiry of the five-year O&M contract with the original equipment manufacturer of the wind turbines.

In the field, this transition began in the spring with end-of-warranty inspections and was completed in November with the addition of five new staff members at our Cartier Wind Energy joint venture. Integrating operations and maintenance activities will primarily enable us to better coordinate equipment maintenance, repair, and overhaul efforts with prevailing wind conditions, in order to maximize production levels. Our employees exhibited a great level of professionalism in orchestrating and implementing such a smooth and successful transition. An excellent precedent has been set for the integration of operations and maintenance activities at the L'Anse-à-Valleau wind farm in 2012 and at the Carleton wind farm in 2013, as their respective five-year O&M contract with the manufacturer expires.

Late last year, we also received approval from the Québec Régie de l'énergie for the power purchase agreement of the Viger-Denonville community wind farm, a new form of project structure in which the host community becomes a partner and an active participant. While we've always had great support for our wind farm projects in the Gaspé Peninsula over the years, we are witnessing firsthand how community participation takes social acceptability one step further by uniting local enthusiasm for the project, and we appreciate the work and commitment of the Rivière-du-Loup RCM.

In the year to come, we look forward to completing the integration of operations and maintenance activities at the L'anse-à-Valleau wind farm, commencing operations at the Gros-Morne II wind farm, and advancing the permitting process and construction preparations for the Viger-Denonville wind farm. We remain in a state of preparedness to respond to future requests for proposals from any of the provincial governments. At the same time, we continue to develop a very healthy pipeline of prospective wind projects across our major geographic markets, whether initiated from scratch or acquired at various stages of development. After all, it bears mentioning that each of our sites, in operation, in construction or in permitting, was at one time a prospective project.

FINANCIAL REVIEW

AT DECEMBER 31, 2011

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MANAGEMENT'S DISCUSSION AND ANALYSIS

(in thousands of Canadian dollars, except as noted, and amounts per share)

This Management's Discussion and Analysis ("MD&A") has been prepared as at March 21, 2012.

The purpose of this MD&A is to provide the reader with an overview of the financial position, operating results and cash flows of Innergex Renewable Energy Inc. ("Innergex" or the "Corporation") for the year ended December 31, 2011.

This MD&A should be read in conjunction with the audited consolidated financial statements and the accompanying notes for the year ended December 31, 2011. Historical financial statements and MD&A for periods ending in or up to 2010 were prepared in accordance with Canadian generally accepted accounting principles ("GAAP"). **The consolidated financial statements contained in this MD&A and the accompanying notes for the year ended December 31, 2011, along with the 2010 comparative figures, have been prepared in accordance with International Financial Reporting Standards ("IFRS").**

A more detailed discussion of the impact of the conversion from Canadian GAAP to IFRS can be found in the "Accounting Changes" section of this MD&A. Furthermore, the impacts of the transition from Canadian GAAP to IFRS for the year ended December 31, 2010, are presented in Note 1 of the audited consolidated financial statements for the year ended December 31, 2011.

Some amounts included in this MD&A have been rounded to make reading easier. These rounded numbers may affect some calculations.

ESTABLISHMENT AND MAINTENANCE OF DC&P AND ICFR

The President and Chief Executive Officer and the Chief Financial Officer and Senior Vice President of the Corporation have designed, or caused to be designed, under their supervision:

- Disclosure controls and procedures ("DC&P") to provide reasonable assurance that: (i) material information relating to the Corporation is accumulated and communicated by others to the President and Chief Executive Officer and the Chief Financial Officer and Senior Vice President, in a timely manner, particularly during the period in which the interim and annual filings are being prepared; and (ii) the information required to be disclosed by the Corporation in its annual filings, interim filings or other reports filed or submitted by it under applicable securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.

- Internal control over financial reporting ("ICFR") to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS applicable to the Corporation.

In accordance with *Regulation 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings*, the President and Chief Executive Officer and the Chief Financial Officer and Senior Vice President of the Corporation have evaluated the effectiveness of the Corporation's DC&P and ICFR as at December 31, 2011 and have concluded that they were effective and that there were no material weaknesses relating to the DC&P and ICFR for the year ended December 31, 2011. They have limited the scope of the Corporation's design of DC&P and ICFR to exclude the controls, policies and procedures of Cloudworks Energy Inc. ("Cloudworks"). The design and evaluation of the operating effectiveness of Cloudworks' DC&P and ICFR will be completed within a 12-month period from the date of acquisition. Cloudworks' summary unaudited financial information is presented in the "Acquisition of Cloudworks Energy Inc." section of this MD&A. During the year ended December 31, 2011, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

MANAGEMENT'S DISCUSSION AND ANALYSIS

(in thousands of Canadian dollars, except as noted, and amounts per share)

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FORWARD-LOOKING INFORMATION

In order to inform shareholders of the Corporation as well as potential investors in the Corporation's future prospects, sections of this MD&A may contain forward-looking information within the meaning of securities legislation ("Forward-Looking Information"). Forward-Looking Information can generally be identified by the use of words and phrases such as "may," "will," "estimate," "anticipate," "plans," "expects," or "does not expect," "is expected," "budget," "scheduled," "forecasts," "intends" or "believes," or variations of such words and phrases that state that certain events will occur. Forward-Looking Information represent, as of the date of this MD&A, the estimates, forecasts, projections, expectations or opinions of the Corporation relating to future events or results. Forward-Looking Information involve known and unknown risks, uncertainties and other important factors which may cause the actual results or performance to be materially different from those expressed, implied, or presented by the Forward-Looking Information. The material risks and uncertainties that may cause the actual results and developments to be materially different from the current expressed expectations are referred to in this MD&A under the "Risks and Uncertainties" heading and include the ability of the Corporation to execute its corporate strategy; the inability to access sufficient capital from internal and external sources; liquidity risks related to derivative financial instruments; general economic conditions; availability of water flows, wind and sunlight; delays in project development; uncertainty relating to the development of new power generating facilities; uncertainty relating to the amounts of power current or future operating facilities are able to generate; equipment failure; interest rate fluctuations and debt refinancing; contractual restrictions contained in instruments governing current and future indebtedness; penalties for events of default under certain power purchase agreements; the ability to retain qualified personnel and management; the performance of third-party suppliers; reliance on major customers; relationships with communities in which projects or facilities are located and joint venture partners; wind turbine and solar panel supply; obtainment of permits; changes to governmental regulatory requirements and applicable governing statutes; obtaining new power purchase agreements; securing appropriate land for projects; reliance on power purchase agreements; reliance on transmission systems; water and land rental expenses; dam safety; health, safety and environmental risks; natural disasters; foreign exchange fluctuations and sufficiency of insurance coverage. Although the Corporation believes that the expectations instigated by the Forward-Looking Information are based on reasonable and valid assumptions, there is a risk that the Forward-Looking Information may be incorrect. The reader of this MD&A is cautioned not to rely unduly on these Forward-Looking Information. Forward-Looking Information, expressed verbally or in writing by the Corporation or by a person acting on its behalf, are expressly qualified by this cautionary statement. The Forward-Looking Information contained herein are made as of the date of this MD&A and the Corporation does not undertake any obligation to update or revise any Forward-Looking Information, whether as a result of events or circumstances occurring after the date hereof, unless required by legislation.

OVERVIEW

General

The Corporation is a developer, owner and operator of renewable power-generating facilities. The Corporation's shares are listed on the Toronto Stock Exchange ("TSX") under the symbol INE. The Corporation is very active in the Canadian renewable power industry, with a focus on hydroelectric, wind power and solar photovoltaic ("PV") projects that benefit from low operating and management costs and simple proven technologies. The Corporation has been active in the renewable power industry since 1990, has developed and brought to commercial operation eleven hydroelectric and five wind power facilities, has acquired and refurbished, through various ventures, three hydroelectric facilities and has acquired six hydroelectric power facilities in commercial operation, representing a gross aggregate installed capacity of 847 megawatts ("MW"). The Corporation is rated BBB- by Standard and Poor's Rating Services ("S&P") and BBB (low) by DBRS Limited ("DBRS").

Portfolio of Assets

The Corporation's portfolio is comprised of interests in three groups of power-generating projects:

- facilities that are in commercial operation (the "Operating Facilities");
- projects for which Power Purchase Agreements ("PPA") have been secured and which are either under construction or scheduled to begin commercial operation on planned dates (the "Development Projects"); and
- projects that have secured certain land rights, for which an investigative permit application has been filed or for which a proposal has either been submitted under a Request for Proposal ("RFP") or could be submitted under a Standing Offer Program ("SOP") or Feed-In Tariff Program ("FIT Program") (collectively the "Prospective Projects").

As at the date of this MD&A, the Corporation owns interests in:

- 25 Operating Facilities with an aggregate net installed capacity of 461 MW (gross 847 MW). These consist of 20 hydroelectric facilities and five wind farms with aggregate net installed capacities of 279 MW (gross 368 MW) and 182 MW (gross 479 MW) respectively. Commissioned between November 1994 and November 2011, the facilities have a weighted average age of approximately 6.1 years. They sell the generated power under long-term PPAs that have a weighted average remaining life of 19.9 years;

- ten Development Projects with an aggregate net installed capacity of 264 MW (gross 407 MW) for which PPAs with public utilities have been secured. Construction is near completion at one of the projects and ongoing at three others. Construction is expected to begin on the remaining six projects between 2013 and 2014. The projects are expected to reach the commercial operation stage between 2012 and 2016; and

- Prospective Projects with a net capacity of 2,844 MW (gross 2,977 MW) which are at various stages of development.

The chart on the following page diagrams the Corporation's direct and indirect interests in the Operating Facilities, Development Projects and Prospective Projects.

(in thousands of Canadian dollars, except as noted, and amounts per share)

INNERGEX

Renewable Energy.
Sustainable Development.

Operating Facilities

Hydro
- 100% St-Paulin, QC (8.0 MW)
- 100% Windsor, QC (5.5 MW)
- 100% Chaudière, QC (24.0 MW)
- 100% Portneuf-1, QC (8.0 MW)
- 100% Portneuf-2, QC (9.9 MW)
- 100% Portneuf-3, QC (8.0 MW)
- 100% Montmagny, QC (2.1 MW)
- 100% Glen Miller, ON (8.0 MW)
- 49% Umbata Falls, ON (23.0 MW)
- 100% Batawa, ON (5.0 MW)
- 100% Rutherford Creek, BC (49.9 MW)
- 100% Ashlu Creek, BC (49.9 MW)
- 50% Douglas Creek, BC (27.0 MW)
- 50% Fire Creek, BC (23.0 MW)
- 50% Stokke Creek, BC (22.0 MW)
- 50% Tipella Creek, BC (18.0 MW)
- 50% Lamont Creek, BC (27.0 MW)
- 50% Upper Stave River, BC (33.0 MW)
- 66⅔% Fitzsimmons Creek, BC (7.5 MW)
- 100% Horseshoe Bend, Idaho, USA (9.5 MW)

Wind
- 38% Baie-des-Sables, QC (109.5 MW)
- 38% L'Anse-à-Valleau, QC (100.5 MW)
- 38% Carleton, QC (109.5 MW)
- 38% Gros-Morne Phase I, QC (100.5 MW)
- 38% Montagne Sèche, QC (58.5 MW)

Development Projects

Hydro
- 50% Kwoiek Creek, BC (49.9 MW)
- 100% Northwest Stave, BC (17.5 MW)
- 66⅔% Boulder Creek, BC (23.0 MW)
- 100% Tretheway Creek, BC (21.2 MW)
- 66⅔% North Creek, BC (16.0 MW)
- 66⅔% Upper Lillooet, BC (74.0 MW)
- 100% Big Silver-Shovel Creek, BC (36.9 MW)

Wind
- 38% Gros-Morne Phase II, QC (111.0 MW)
- 50% Viger-Denonville, QC (24.6 MW)

Solar
- 100% Stardale, ON (33.2 MW_{DC})

Prospective Projects

Hydro
- 48% QC Project (42.0 MW)
- 100% BC Projects (819.8 MW)
- 66⅔% BC Projects (132.0 MW)

Wind
- 100% QC Projects (836.0 MW)
- 70% QC Projects - Community (98.4 MW)
- 50% QC Projects - Community (49.2 MW)
- 100% ON Projects - FIT (440.0 MW)
- 49% ON Project - FIT (25.3 MW)
- 100% BC Projects (475.0 MW)

Solar
- 100% ON Projects - FIT (59.0 MW)

	Operating Facilities	Development Projects	Prospective Projects
Hydro			
Gross capacity:	368.3 MW	238.5 MW	993.8 MW
Net capacity[1]:	279.1 MW	175.9 MW	928.0 MW
Wind			
Gross capacity:	478.5 MW	135.6 MW	1923.9 MW
Net capacity[1]:	181.8 MW	54.5 MW	1856.9 MW
Solar			
Gross capacity:	-	33.2 MW	59.0 MW
Net capacity[1]:	-	33.2 MW	59.0 MW
Total			
Gross capacity:	846.8 MW	407.3 MW	2976.7 MW
Net capacity[1]:	460.9 MW	263.6 MW	2843.9 MW

1. Net capacity represents the proportional share of the total capacity attributable to Innergex, based on its ownership interest in these facilities and projects. The remaining capacity is attributable to the strategic partners' ownership share.

BUSINESS STRATEGY

The Corporation’s strategy for building shareholder value is to develop or acquire high-quality renewable power production facilities generating sustainable cash flows and providing a high return on invested capital, and to distribute a stable dividend.

Strategic Relationships

The Corporation often teams up with a strategic partner when bidding for projects under an RFP. When this is the case, the Corporation and the strategic partner share the ownership of such projects. Current strategic partners are TransCanada Energy Ltd. (owner of 62% of the Baie-des-Sables, L’Anse-à-Valleau, Carleton, Montagne Sèche and Gros-Morne Phase I and II wind farms), the Kanaka Bar Indian Band (owner of 50% of the Kwoiek Creek Development Project), the Ojibways of the Pic River First Nations (owner of 51% of the Umbata Falls facility), Ledcor Power Group Ltd. (owner of 33⅓% of the Fitzsimmons Creek facility, the Boulder Creek, North Creek and Upper Lillooet Development Projects and other Creek Power Inc. Prospective Projects) and the Rivière-du-Loup Regional County Municipality (“RCM”) (owner of 50% of the Viger-Denonville community wind project).

Areas of growth

Growing awareness and concern over issues such as access to clean energy, energy security, energy efficiency and the environmental impacts of conventional fossil fuels are leading the federal and provincial governments to increase their demand for and commitments to development of the renewable energy supply. Consequently, the Corporation believes that the outlook for the renewable energy industry in Canada is promising.

The Corporation is confident that RFP opportunities will continue to arise in the future, especially in Québec, British Columbia, and Ontario, as these provinces have set ambitious targets for renewable power generation. While the Corporation has historically focused its bidding activities on RFPs issued in these three provinces, where it has experienced a high level of success, it continues to monitor the situation in other provinces where opportunities may arise.

In Québec, the provincial government has indicated its intention to increase its supply of renewable energy from wind and small hydro sources through an upcoming RFP, the details of which have yet to be announced.

In Ontario, the Corporation has 453 MW (net) of wind farm projects submitted under that province’s FIT Program, four of which are ranked among the top ten projects still awaiting contracts by the Ontario Power Authority (“OPA”). In addition, the Corporation has submitted six solar photovoltaic projects totalling 59 MW (see the “Prospective Projects” section of this MD&A). Eventual award of FIT Program contracts will depend on the result of the Economic Connection Test and the subsequent implementation of transmission expansion.

As of the date of this MD&A, the Ontario government had not yet completed the first scheduled two year review of its FIT Program, which began in the fall of 2011. Recommendations are expected to include a reduction of the feed-in-tariff, especially for solar photovoltaic projects, which reduction would reflect the declining costs of raw materials and components worldwide. It is also expected that local content requirements for solar and wind projects will be maintained. FIT Review recommendations are expected to be announced around the end of the first quarter of 2012.

In British Columbia, BC Hydro revised the terms of its SOP in January 2011. Among other things, it increased the upper limit on project size (from 9.9 MW to 15.0 MW) and the electricity rates applicable to each region. The Corporation has several Prospective projects that could be eligible under this program, including at least six hydroelectric projects with a capacity of up to 15 MW each which it continues to investigate for submission.

In the United States, the Corporation’s management team will continue to assess potential opportunities, particularly in light of the Obama administration’s renewed focus on increasing renewable energy production. The White House’s *Blueprint for a Secure Energy Future* (March 30, 2011) calls for 80% of electricity generated in the US to come from a diverse set of low-carbon energy sources by 2035, “including renewable energy sources like wind, solar, biomass and hydropower”.

Diversification

The Corporation may also expand through the acquisition of prospective and development projects at varying development stages or of suitable power generating assets already in commercial operation. As a public company, the Corporation could use its equity to finance potential acquisitions. As it has done in the past, Innergex will continue to focus its efforts on developing hydroelectric, wind, and solar power generation facilities. The Corporation could also grow through expansion into other forms of clean and renewable energy production, if profitable opportunities arise. While future projects may be located in any region where opportunities exist, the Corporation expects most of its growth opportunities to come from Canada and the United States.

Key Growth Factors

The Corporation's future growth will be affected by six key factors:

i) the public's and governments' demand for renewable energy;
ii) its capacity to evaluate and secure the best prospective sites for the development of new projects in cooperation with local communities;
iii) its ability to enter into attractive PPAs and obtain the required environmental and other permits;
iv) its ability to adequately forecast total construction costs, expected revenues, and expected expenses for each project;
v) its ability to make accretive acquisitions; and
vi) the availability of financing.

Capacity for Delivering Results

As the Corporation evolves in a competitive sector, the experience and dedication of its management team are its strongest asset. Due to its careful management of the process, the team has a proven track record of completing projects by the commercial operation start date specified in its PPAs without incurring any significant cost overruns. The Corporation's employees possess the specialized knowledge and skills necessary to carry out its business. The Corporation can also rely on a network of technical, financial and legal partners, and has a proven ability to complement its internal capabilities 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. At as December 31, 2011, the Corporation employed a total of 116 persons (including Cartier Wind Energy and power plant employees).

MARKET TRENDS

Renewable power producers are involved in the generation of electricity from renewable energy sources including:

i) hydro;
ii) wind;
iii) solar;
iv) biomass (e.g. waste wood from forest products operations) and landfill gas; and
v) geothermal sources, such as heat or steam.

While traditional regulated utilities continue to dominate the North American electricity generation markets, the growing importance of the role played by independent power producers in meeting future electricity needs is now acknowledged and the benefits of their power output have increasingly been recognized by government authorities and other policymakers in recent years.

There are a number of reasons to explain the growing role played by independent power producers in supplying renewable power in North America, including:

i) the growing demand for energy;
ii) the availability of long-term renewable energy purchase contracts with high creditworthy counterparties, allowing independent power producers to develop new projects in a low-risk environment with the expectation of stable long-term contractual cash flows;
iii) the implementation of non-discriminatory access to transmission systems, providing independent power producers with access to regional electricity markets;
iv) the efficiency of independent power producers; and
v) the increase in government-sponsored incentives.

Furthermore, natural gas price has been declining over the last few years. This price variation could impact renewable power selling price included in future PPAs.

Renewable Power in Canada

Over the past few years, the significant growth in renewable power generation in Canada has resulted from: rising electricity and fossil fuel prices; the increased cost of large-scale hydroelectric sites; public concern over nuclear power generation, air quality, and greenhouse gases; improvements in renewable energy technologies; and shorter construction lead times for some 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, which are explained below. Several provinces are also expecting to make significant transmission grid investments in order to bring this power to market.

In response to the long-term trend toward stronger environmental protection policies, many provincial governments have introduced Renewable Portfolio Standards ("RPS"), which typically set a target for an increased component of renewable energy in their electricity generation supply mix, in order to reduce greenhouse gas emissions over time. These RPS typically reflect the distinct resource issues associated with electricity generation, given the provinces' respective electricity industry structure and geographical conditions. While sometimes applied and implemented as goals or targets, rather than mandatory requirements, provincial authorities or their utilities are using RPS to source renewable generation resources and, in some cases, offer PPAs through competitive bidding processes. The competitive bidding process seeks to ensure that the RPS are achieved at the lowest possible cost and with the highest probability of project completion. Several provinces have set a specific target percentage of electricity to be generated from renewable sources:

- 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 develop up to 4,500 MW of wind energy capacity by 2025;
- 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 RPS to 30% of total electricity from renewable resources by 2013;
- Québec – To develop 4,000 MW of wind energy capacity by 2015; and
- Saskatchewan – To develop 200 MW of wind energy capacity by 2015.

As a result, several provinces have recently released, revised, or are currently preparing significant new RFPs, SOPs, and FIT Programs, with the objective of procuring additional electricity generation capacity from renewable sources. By simplifying the negotiation and financing processes and decreasing the transactional costs for obtaining a long-term PPA, these mechanisms can contribute to meeting renewable energy generation goals.

Canada enjoys a unique abundance of hydrological resources. With an estimated installed hydroelectric capacity of more than 70,000 MW, it is the second largest hydroelectric energy producer in the world. Furthermore, according to the Canadian Hydropower Association, the country has an undeveloped, technically feasible potential estimated at 118,000 MW. Despite the competition for appropriate sites and the challenges associated with power transmission over great distances, the low operational costs and long project lives of these facilities suggest that hydroelectric power generation will remain a major affordable supply source for many years. Transmission corridors in Canada have traditionally run directly from major generation facilities to major demand centres, meaning that strategic investments in new transmission corridors will play an important role in the development of hydroelectric projects and other isolated renewable energy generation projects.

Over the last few years, according to the National Energy Board, wind power has become commercially viable and emerged as the fastest growing segment of the renewable power industry in Canada. The Canadian Wind Energy Association ranks Canada as the ninth largest producer of wind energy in the world, with an installed wind power capacity of 5,265 MW at the end of 2011, a 30% increase from the preceding year. In addition, more than 6,000 MW of wind energy projects are contracted to be built over the next five years. Several reasons explain the robustness of the wind energy industry, including provincial RPS, relatively short construction timelines, favourable wind resources, including vast shorelines and strong winds throughout a wide range of rural areas, and numerous renewable energy RFPs. The customary challenges of resource availability and transmission exist in Canada and, in some areas, access to transmission lines with available capacity is an economic or regulatory consideration.

A solar energy industry has emerged in Canada in recent years, especially in Ontario. According to the Canadian Solar Industries Association, the total solar photovoltaic installed capacity (grid-tied) is estimated to have reached 375 MW in 2011. While Ontario is expected to remain the dominant market for solar photovoltaic manufacturing and deployment, governments at all levels across the country are considering incentives to encourage the development of the Canadian solar industry, which should continue to post substantial growth rates over the next decade.

(in thousands of Canadian dollars, except as noted, and amounts per share)

ANNUAL DIVIDEND POLICY

The Corporation intends to distribute an annual dividend of $0.58 per common share payable quarterly. Its dividend policy is based on the long-term cash flow generating capacities of its Operating Facilities. Innergex's investments in the Development Projects and Prospective Projects are financed through excess cash flows and a combination of additional indebtedness and equity.

KEY PERFORMANCE INDICATORS

The Corporation measures its performance using key performance indicators that include or could include: power generated in megawatt-hours ("MWh") and gigawatt-hours ("GWh"), adjusted cash flows from operating activities; adjusted net earnings (loss); and EBITDA, defined as earnings before interest, provision for income taxes, depreciation and amortization and other items. These indicators are not recognized measures under IFRS and therefore may not be comparable with those presented by other issuers. The Corporation believes that these indicators are important since they provide management and the reader with additional information about its production and cash generation capabilities and facilitate the comparison of results over different periods.

SEASONALITY

The amount of energy generated by the Operating Facilities is generally dependent on the availability of water flows and wind regimes. Lower-than-expected water flows or wind regimes in any given year could have an impact on the Corporation's revenues and hence on its profitability. Innergex owns interests in 20 hydroelectric facilities, which draw on 17 watersheds and five wind farms, providing significant diversification in terms of operating revenue sources. Furthermore, given the nature of hydroelectric and wind farm production, seasonal variations are partially offset, as illustrated in the following table:

	LTA[1] (GWh and %) - Net Interest [2]								
Energy	Q1		Q2		Q3		Q4		Total
HYDRO	230.1	14%	583.3	37%	449.1	28%	333.1	21%	1,595.5
WIND	172.7	32%	116.0	21%	90.9	17%	167.4	31%	546.9
Total	402.8	19%	699.3	33%	540.0	25%	500.5	23%	2,142.4

1. Long-term average.
2. Net interest adjusted in accordance with revenue recognition accounting rules under IFRS.

(in thousands of Canadian dollars, except as noted, and amounts per share)

OPERATING FACILITIES

The Corporation currently has 25 facilities in commercial operation:

Project name and location	Ownership %	Net installed capacity[1]	COD[2]	LTA (GWh) Net Interest [3]	PPA expiry	ecoENERGY [4]
HYDRO (Québec)						
Saint-Paulin	100.0	8.0	1994	41.1	2014 [5]	No
Windsor	100.0	5.5	1996	31.0	2016 [5]	No
Chaudière	100.0	24.0	1999	116.7	2019 [5]	No
Portneuf-1	100.0	8.0	1996	40.0	2021 [6]	No
Portneuf-2	100.0	9.9	1996	69.0	2021 [6]	No
Portneuf-3	100.0	8.0	1996	42.7	2021 [6]	No
Montmagny	100.0	2.1	1996	8.0	2021 [6]	No
Subtotal		65.5		348.5		
HYDRO (Ontario)						
Glen Miller	100.0	8.0	2005	41.6	2025	No
Umbata Falls	49.0	11.3	2008	53.5	2028	Yes
Batawa	100.0	5.0	1999	32.9	2029 [7]	No
Subtotal		24.3		128.0		
HYDRO (British Columbia)						
Rutherford Creek	100.0	49.9	2004	180.0	2024	No
Ashlu Creek	100.0	49.9	2009	265.0	2039	Yes
Douglas Creek	50.0	13.5	2009	92.6	2049	Yes
Fire Creek	50.0	11.5	2009	94.2	2049	Yes
Lamont Creek	50.0	13.5	2009	105.2	2049	Yes
Stokke Creek	50.0	11.0	2009	88.0	2049	Yes
Tipella Creek	50.0	9.0	2009	70.0	2049	Yes
Upper Stave River	50.0	16.5	2009	144.4	2049	Yes
Fitzsimmons Creek	66.7	5.0	2010	33.0	2050	Yes
Subtotal		179.8		1,072.4		
HYDRO (Idaho)						
Horseshoe Bend	100.0	9.5	1995	46.8	2030	N/A
WIND (Québec)						
Baie-des-Sables [8]	38.0	41.6	2006	113.4	2026	Yes
L'Anse-à-Valleau [8]	38.0	38.2	2007	113.2	2027	Yes
Carleton [8]	38.0	41.6	2008	129.4	2028	Yes
Montagne Sèche [8]	38.0	22.2	2011	73.5	2031	No
Gros-Morne I [8]	38.0	38.2	2011	117.4	2032	No
Subtotal		181.8		546.9		
Total		460.9		2,142.6		

1. Corresponds to the Corporation's ownership share of capacity.
2. Commercial operation date.
3. Net interest adjusted in accordance with revenue recognition accounting rules under IFRS.
4. The ecoENERGY Initiative provides for an incentive payment of $10 per MWh for the first ten years of operation.
5. These PPAs are renewable at the Corporation's option for an additional term of 20 years.
6. These PPAs are renewable at the Corporation's option for an additional term of 25 years.
7. This PPA remains valid after expiry unless one of the parties to the agreement gives a one-year cancellation notice.
8. The wind farms were developed by the Corporation through the Cartier Wind Energy joint venture.

(in thousands of Canadian dollars, except as noted, and amounts per share)

2011 DEVELOPMENTS

Acquisition of Cloudworks Energy Inc.

On April 4, 2011, Innergex announced that it had finalized the acquisition of all the issued and outstanding shares of Cloudworks Energy Inc. (the "Cloudworks Acquisition"). Cloudworks' portfolio of assets consists of a 50.01% interest in six run-of-river hydroelectric facilities (the "Harrison Operating Facilities") with a combined gross installed capacity of 150 MW; full ownership of 75.6 MW of run-of-river hydroelectric projects under development with 40-year PPA; and full ownership of run-of-river hydroelectric projects in various stages of development and with a potential aggregate installed capacity of over 800 MW. As at April 4, 2011, Cloudworks' assets had increased the Corporation's installed capacity by 23% (from 326 MW to 401 MW) and Innergex's weighted average remaining PPA term from approximately 21 to 25 years (including the related Development Projects).

The consideration paid under the share purchase agreement was $191 million, which was financed with a $166 million public share issuance and a $39 million private placement of common shares.

For more information about the Cloudworks Acquisition, please refer to the "Short Form Prospectus" dated February 25, 2011 (the "Prospectus"), which is available on Innergex's website at www.innergex.com and on the SEDAR website at www.sedar.com

In accordance with IFRS, the results for the year ended December 31, 2011, include Cloudworks' contribution since April 5, 2011. Cloudworks' summary unaudited financial information included in the Corporation's audited consolidated financial statements as at December 31, 2011, is as follows:

Cloudworks' summary consolidated statement of earnings and comprehensive income

For the period from April 5, 2011 to December 31	2011
Operating revenues	46,595
Operating expenses	6,156
General and administrative expenses	1,788
Prospective projects expenses	536
EBITDA	38,115
Finance costs [1]	24,944
Other net revenues	(610)
Depreciation and amortization	13,322
Provision for income taxes	600
Net loss and comprehensive loss	(141)
Net (loss) earnings attributable to:	
Owners of the parent	(1,499)
Non-controlling interests	1,358
	(141)

1. For the year ended December 31, 2011, finance costs include compensation interest of $7.2 million.

(in thousands of Canadian dollars, except as noted, and amounts per share)

Cloudworks' summary consolidated statement of financial position

	December 31, 2011
Current assets	58,968
Reserve accounts	29,285
Other long-term assets	772,624
Total assets	860,877
Current liabilities	17,118
Long-term liabilities	564,871
Total liabilities	581,989
Equity attributable to owners	162,563
Non-controlling interests	116,325
Shareholders' equity	278,888
	860,877

Cloudworks' summary consolidated statement of cash flows

For the period from April 5, 2011 to December 31	2011
Cash flows from operating activities	20,631
Cash flows from financing activities	6,616
Cash flows used by investing activities	(30,387)
Net decrease in cash and cash equivalents	(3,140)

Acquisition of the Stardale Solar Project
On April 20, 2011, Innergex announced it had completed the acquisition of all the issued and outstanding shares of the entity owning the rights to develop the 33.2 MW_{DC} Stardale solar PV project (the "Stardale Project") located in Ontario.

Construction of the Stardale Project began in November 2010, and although the project is expected to be completed by the end of the second quarter of 2012, it is scheduled to produce electricity by the end of March 2012. The Stardale Project consists of a ground-mounted PV array system comprising a total of approximately 144,000 SolarWorld SW 230 polycrystalline PV modules. The forecast annual electric energy output is estimated at 39 GWh. All the energy delivered by the Stardale Project is covered by three Renewable Energy Standard Offer Program Contracts ("RESOP" Contracts) with the OPA, each with a 20-year term beginning on the COD.

The original consideration under the share purchase agreement was $11.1 million; it will be adjusted upward or downward when certain milestones are reached, allowing Innergex to benefit from a minimum threshold internal rate of return. The contract with the engineering, procurement and construction contractor ("EPC contractor") will be adjusted upwards or downwards based on the project's actual performance and annual energy generation using the same minimum threshold internal rate of return.

(in thousands of Canadian dollars, except as noted, and amounts per share)

Commissioning Activities

The following table presents the Operating Facilities that have been commissioned during the last 12 months:

Project name and location	Net installed capacity (MW)	Net estimated LTA (GWh)	Total project costs Estimated ($M)	Revised ($M)	As at Dec. 31, 2011 ($M)	Original estimate & actual COD	Expected year-one Revenues ($M)	EBITDA ($M)
WIND (Québec)								
Montagne Sèche	22.2	73.5	39.1 [1,2]	41.7 [2]	42.0 [2]	Q4-2011	5.3 [1,2]	4.6 [1,2]
Gros-Morne I	38.2	117.4	64.4 [1,2]	68.5 [2]	69.2 [2]	Q4-2011	8.2 [1,2]	7.1 [1,2]

1. See the "Project cost and revenue adjustments of Montagne Sèche and Gros-Morne I" paragraph below for more details.
2. Corresponding to the Corporation's 38% interest in this project.

Montagne Sèche

On November 25, 2011, Innergex announced that the Montagne Sèche wind farm ("Montagne Sèche") had begun commercial operation. This wind farm is located in the township municipality of Cloridorme and the municipality of Petite-Vallée in the Québec's Gaspé Peninsula. Montagne Sèche, in which Innergex owns a 38% interest and a 50% management stake, was built through the Cartier Wind Energy joint venture.

Montagne Sèche comprises 39 wind turbines with a total installed capacity of 58.5 MW. Its 20-year PPA with Hydro-Québec provides for an annual adjustment to the selling price based on the consumer price index ("CPI"). During the last quarter of 2011, Montagne Sèche produced 8,124 MWh.

Gros-Morne Phase I

On November 29, 2011, the Corporation announced that the Gros-Morne Phase I wind farm ("Gros-Morne I") had begun commercial operation. This wind farm is located in the municipalities of Mont-Louis and Sainte-Madeleine-de-la-Rivière-Madeleine in Québec's Gaspé Peninsula. Gros-Morne I, in which Innergex owns a 38% interest and a 50% management stake, was built through the Cartier Wind Energy joint venture.

Gros-Morne I comprises 67 wind turbines with a total installed capacity of 100.5 MW. Its 21-year PPA with Hydro-Québec provides for an annual adjustment to the selling price based on the CPI. During the last quarter of 2011, Gros-Morne I produced 106 MWh. The wind farm was not in service in December due to converters damaged after a load rejection event. Replacement of damaged components was completed in January and the wind farm was back in service as of February 11, 2012, with control modifications to mitigate further similar failures. Innergex expects to mitigate the loss of revenue partly through its business interruption insurance coverage and partly via recourse to the wind turbine supplier. The repair costs are expected to be assumed by the turbine supplier as well. The Corporation continues to work with the turbine supplier to ensure the implementation of a permanent solution to meet all the requirements of the turbine supply agreement.

Project cost and revenue adjustments of Montagne Sèche and Gros-Morne I

For each of the Montagne Sèche and Gros-Morne I wind farms, the project costs, revenues, and EBITDA are reported using current dollars. The 2004 original cost estimates previously disclosed were revised to be adjusted for the indices included in the turbine supply agreements of each wind farm. These indices include the Canadian and U.S. CPI, the USD/CAD exchange rate, and a Canadian steel index. However, each PPA provides for a corresponding adjustment to the selling price received from Hydro-Québec, which is based on similar indices. As such, the expected year-one revenues and EBITDA were also revised and adjusted accordingly. These adjustment mechanisms allow the Corporation to protect the economic value of each wind farm.

DEVELOPMENT PROJECTS

The Corporation currently has ten projects that are expected to reach the commercial operation stage between 2012 and 2016.

(in thousands of Canadian dollars, except as noted, and amounts per share)

Projects under construction

Project name and location	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA (GWh)	PPA life (years)	Total project costs: Estimated ($M)	Total project costs: Revised ($M)	Total project costs: As at Dec. 31, 2011 ($M)	Expected year-one: Revenues ($M)	Expected year-one: EBITDA ($M)
HYDRO (British Columbia)										
Kwoiek Creek	50.0	49.9	Q4 2013	215.0	40	152.1	153.2	21.3	18.2	14.8
Northwest Stave River	100.0	17.5	Q4 2013	61.9	40	69.8 [1]	91.4 [1]	21.6	7.4	5.9
WIND (Québec)										
Gros-Morne II	38.0	111.0	Q4 2012	341.1	20	68.0 [2,3]	N/A [2]	11.5 [3]	9.2 [2,3]	8.1 [2,3]
SOLAR (Ontario)										
Stardale	100.0	$33.2MW_{DC}$	Q2 2012	39.0	20	140.0	141.7	116.6	16.4	15.0

1. See the "Total project costs revision" below for more details.
2. See the "Gros-Morne Phase II" paragraph below for more details.
3. Corresponding to the Corporation's 38% interest in this project.

Total project costs revision

The estimated project costs were initially established based on direct construction costs. The Northwest Stave River, Tretheway Creek and Big-Silver-Shovel Creek project costs were revised upwards due to the purchase price allocation of the Cloudworks Acquisition. The revised Northwest Stave River project costs also include the budget increase due to the election to build the project under turn-key contracts.

HYDRO

Kwoiek Creek

The Kwoiek Creek project is a run-of-river hydroelectric power plant located at the confluence of the Kwoiek Creek and the Fraser River, approximately 14 km south of Lytton, British Columbia. The F2006 Open Call for Power under which the PPA for the Kwoiek Creek project was awarded had an adjusted bid price that ranged from $68.90 to $99.50 per MWh, with an average adjusted bid price of $87.50 per MWh. A portion equal to 30% of the electricity price is to be adjusted, based on the increase or decrease in the CPI during the preceding 12 months, beginning on January 1, 2006, and on every January 1 thereafter during the term of the PPA.

The Corporation owns 50% of the voting rights in the Kwoiek Creek project but receives a larger share of the economic value of the project through a preferred return on the Corporation's investments in the project. As at December 31, 2011, the Corporation's total investment in the project amounted to $29.5 million.

As at December 31, 2011, all permits had been granted and the EPC contractor had begun the powerhouse and penstock excavation under limited notices to proceed. During the last quarter of 2011, the turbine and powerhouse design, the transmission line design, transmission line clearing and penstock final design were done by the respective suppliers. As at the date of this MD&A, the EPC contractor had been given a full notice to proceed and agreements with the electro mechanic and transmission line suppliers had been signed.

Northwest Stave River

The Northwest Stave River project is a run-of-river hydroelectric power plant located approximately 35 km north of Mission, British Columbia. The clean power call under which the PPA for the Northwest Stave River project was awarded had a firm energy bid price that ranged from $95 to $156 per MWh, with a weighted average firm energy bid price of $139.90 per MWh. A portion equal to 50% of the electricity price is to be adjusted, based on the increase or decrease in the CPI during the preceding 12 months, beginning on January 1, 2009, and on every January 1 thereafter during the term of the PPA.

During the last quarter of 2011, the turbine supplier was selected and the EPC contractor continued engineering and preliminary construction work under limited notices to proceed. As planned, construction activities have been halted for the winter period; they will resume in the spring of 2012.

(in thousands of Canadian dollars, except as noted, and amounts per share)

WIND

Gros-Morne Phase II

The Gros-Morne Phase II project ("Gros-Morne II") is located in the municipalities of Mont-Louis and of Sainte-Madeleine-de-la-Rivière-Madeleine, Québec. It is being developed by the Corporation through the Cartier Wind Energy joint venture. Gros-Morne II is covered under the same PPA with Hydro-Québec as Gros-Morne I. The price payable by Hydro-Québec for the electricity delivered from Gros-Morne II was set at $65.58 per MWh as at January 1, 2004, and is adjusted annually, based on the CPI and certain factors specified in the PPA.

The construction of this wind farm began in the second quarter of 2010. At the end of 2011, all the foundations had been completed, all the roads had been built and the substation had been energized. As planned, construction activities have been halted for the winter period; they will resume in the spring of 2012. Innergex expects Gros-Morne II to be completed by December 1, 2012.

The 2004 original cost estimates and expected year-one revenues and EBITDA will be revised to be adjusted for the indices included in the turbine supply agreements, as they were for Montagne Sèche and Gros-Morne I, once the indices are known. For the wind farm, wind turbine costs represent approximately 65% of the total estimated project costs. Furthermore, 90% of the price of wind turbines is payable after COD. Therefore, a significant portion of the wind farm's total estimated accrued project costs will be payable following COD.

SOLAR

Stardale

The Stardale Project is located in East-Hawkesbury, Ontario. The price of electricity delivered pursuant to the three RESOP Contracts with the OPA is $420.00 per MWh.

Construction of this solar farm began in November 2010. At as December 31, 2011, 96% of inverter substation buildings and the entire substation grounding system had been completed and 24% of PV SolarWorld modules had been installed on rackings. As at the date of this MD&A, the vast majority of the PV modules had been installed on rackings and preparation for commissioning activities was under way. Although the project is expected to be completed by the end of the second quarter of 2012, it is scheduled to produce electricity by the end of March 2012.

Projects under permit phase

Project name and location	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA (GWh)	PPA life (years)	Total project costs: Estimated ($M)	Total project costs: Revised ($M)	Total project costs: As at Dec. 31, 2011 ($M)
HYDRO (British Columbia)								
Boulder Creek	66.7	23.0	2015	85.7	40	84.0	84.2	-
Tretheway Creek	100.0	21.2	2015	81.9	40	78.1 [1]	91.5 [1]	13.7
North Creek	66.7	16.0	2016	59.7	40	71.0	72.0	-
Upper Lillooet	66.7	74.0	2016	270.2	40	260.0 [1]	264.2 [1]	6.6
Big Silver-Shovel Creek	100.0	36.9	2016	147.1	40	144.9 [1]	165.4 [1]	26.0
WIND (Québec)								
Viger-Denonville	50.0	24.6	2013	67.6	20	73.3	73.3	0.1

1. See "Total project costs revision" paragraph above for more details.

HYDRO

Boulder Creek, Tretheway Creek, North Creek, Upper Lillooet, and Big Silver-Shovel Creek

Current activities include geotechnical analysis, hydrometric monitoring, environmental studies, consultation with the various stakeholders, applications for obtaining the relevant permits and preliminary engineering. As at the date of this MD&A, the applications had been submitted to the Environmental Assessment Office for the Boulder Creek, North Creek and Upper Lillooet projects. See the following paragraphs for details on each project.

Boulder Creek

The Boulder Creek project is a run-of-river hydroelectric facility located on Boulder Creek in the Lillooet River drainage basin, 56 km northwest of Pemberton, British Columbia. The Boulder Creek project has a 40-year PPA with BC Hydro for all of the power that the facility will produce. The price payable by BC Hydro for the electricity delivered is determined using a formula set out in the PPA. The Corporation owns 66⅔% of the voting rights in the Boulder Creek facility but should receive a larger share of the economic value of the facility through a preferred return on the Corporation's investments in the project. Construction of this facility is expected to begin in 2013.

Tretheway Creek
The Tretheway Creek project is a run-of-river hydroelectric facility located approximately 50 km north of Harrison Hot Springs, British Columbia. The Tretheway Creek project has a 40-year PPA with BC Hydro for all the power that the facility will produce. The price payable by BC Hydro for the electricity delivered is determined using a formula set out in the PPA. Construction of this facility is expected to start in 2013.

North Creek
The North Creek project is a run-of-river hydroelectric facility located on North Creek in the Lillooet River drainage basin, 38 km northwest of Pemberton, British Columbia. The North Creek project has a 40-year PPA with BC Hydro for all the power that the facility will produce. The price payable by BC Hydro for the electricity delivered is determined using a formula set out in the PPA. The Corporation owns 66⅔% of the voting rights in the North Creek facility but should receive a larger share of the economic value of the facility through a preferred return on the Corporation's investments in the project. Construction of this facility is expected to start in 2014.

Upper Lillooet
The Upper Lillooet project is located on the Lillooet River, a tributary of the Fraser River, approximately 70 km northwest of Pemberton, British Columbia. The Upper Lillooet project has a 40-year PPA with BC Hydro for all the power that the facility will produce. The price payable by BC Hydro for the electricity delivered is determined using a formula set out in the PPA. The Corporation owns 66⅔% of the voting rights in the Upper Lillooet facility but should receive a larger share of the economic value of the facility through a preferred return on the Corporation's investments in the project. Construction of this facility is expected to start in 2013.

Big Silver-Shovel Creek
The Big Silver-Shovel Creek project is a run-of-river hydroelectric facility located approximately 40 km north of Harrison Hot Springs, British Columbia. The Big Silver-Shovel Creek project has a 40-year PPA with BC Hydro for all the power that the facility will produce. The price payable by BC Hydro for the electricity delivered is determined using a formula set out in the PPA. Construction of this facility is expected to start in 2013.

WIND
Viger-Denonville
On November 22, 2011, the Viger-Denonville project reached an important milestone when it received approval from the Régie de l'énergie for the PPA awarded in December 2010 by Hydro-Québec with respect to the Viger-Denonville community wind farm project located in the municipalities of Saint-Paul-de-la-Croix and Saint-Épiphane located in Québec's Lower St. Lawrence region. Its 20-year PPA with Hydro-Québec provides for an annual adjustment to the selling price based on the CPI. It is being developed jointly by the Corporation and the Rivière-du-Loup RCM, each party having a 50% equity interest in the project.

The Viger-Denonville wind farm project will include 12 wind turbines. Current activities include environmental studies, consultation with the various stakeholders and applications for obtaining the relevant permits. As at the date of this MD&A, the interconnection agreement with Hydro-Québec had also been concluded. Construction of this facility is expected to begin in the spring of 2013.

Prospective Projects
All the Prospective Projects, with a combined potential net installed capacity of 2,844 MW (gross 2,977 MW), are in the preliminary development stage. Some Prospective Projects are targeted towards specific future RFPs, SOPs or FIT Programs while others will be available for future RFPs yet to be announced. There is no certainty that any Prospective Project will be realized.

During the year 2011, the Corporation submitted four applications of 10.0 MW each under the FIT Program for solar photovoltaic projects in Ontario, bringing Innergex's total number of FIT Program applications for solar photovoltaic projects to six, with a combined capacity of 59.0 MW.

Additional information about the Corporation's facilities and projects can be found in the Corporation's Annual Information Form for the year ended December 31, 2011, which is filed at www.sedar.com.

(in thousands of Canadian dollars, except as noted, and amounts per share)

2010 DEVELOPMENTS

Strategic Combination of the Fund and Innergex

On March 29, 2010, Innergex Power Income Fund (the "Fund") and Innergex announced the completion of the strategic combination of the two entities whereby the Fund acquired Innergex by way of a reverse takeover (the "Combination"), effecting at the same time the Fund's conversion to a corporation.

In accordance with IFRS, the historical results for the year ended December 31, 2010, are those of the Fund, including Innergex's contribution as of March 30, 2010.

As a result of this Combination and unless otherwise noted, the terms "Innergex Renewable Energy Inc.," "Innergex" and the "Corporation" as used in this MD&A mean the Fund with respect to the activities and results occurring prior to March 29, 2010, and the combined entities with respect to the activities and results occurring thereafter. References to "Pre-Combination Innergex" refer to Innergex Renewable Energy Inc. prior to the Combination. Certain terms, such as shareholder/unitholder and dividend/distribution, may also be used interchangeably throughout this MD&A. Prior to March 29, 2010, all distributions to unitholders were in the form of distributions on trust units.

For more information about the Combination, please refer to the "Arrangement Agreement" dated January 31, 2010, and the joint management information circular regarding the Combination and dated February 17, 2010 (the "Joint Circular"), both of which are available on Innergex's website at www.innergex.com and on the SEDAR website at www.sedar.com.

SELECTED ANNUAL INFORMATION

For the years ended December 31	2011[1]	2010[1]	2009[2]
Power generated (MWh)	1,905,426	1,227,435	823,989
Revenues	148,260	91,385	58,625
Operating and general and administrative expenses	34,591	20,903	11,847
Net (loss) earnings attributable to			
owners of the parent	(40,547)	(68,635)	26,243
($ per common share - basic)	(0.59)	(1.13)	0.61
($ per common share - diluted)	(0.59)	(1.13)	0.61
Weighted average number of common shares	75,681	55,530	42,930
Total assets	2,033,409	947,140	493,426
Long-term financial liabilities:			
Debt related to operating facilities	874,467	339,869	221,803
Debt related to projects under construction	147,441	7,086	-
Debt related to projects under development	8,129	2,476	-
Derivative financial instruments	71,158	22,597	4,795
Accrual for acquisition of long-term assets	41,267	-	-
Liability portion of convertible debentures	79,490	79,334	-
Dividends declared on Series A Preferred Shares	4,250	1,431	-
Dividends declared on common shares	43,990	33,324	29,404
Shareholders' equity	464,717	358,900	189,478

1. Prepared in accordance with IFRS.
2. Prepared in accordance with Canadian GAAP.

Comparison between 2011 and 2010

The main differences between 2011 and 2010 are attributable to the Cloudworks Acquisition. The addition of the six hydroelectric facilities for a total net installed capacity of 75 MW (gross 150 MW) is mainly responsible for the increases in revenues, expenses, assets and financial liabilities. The Cloudworks Acquisition also explains the increase in the weighted average number of shares outstanding and as such, part of the increase in shareholders' equity.

For the year ended December 31, 2011, the Corporation recorded a net loss attributable to owners of the parent of $40.5 million ($68.6 million in 2010). This favourable difference is mainly due to a $43.1 million increase in EBITDA, which is detailed in the Financial Results table, and a $51.8 million unrealized loss on unitholders' capital registered in 2010, partly offset by a $61.5 million unrealized net loss on derivative financial instruments (net loss of $20.8 million in 2010) resulting from the general decrease in benchmark interest rates in 2011. As the Corporation does not use hedge accounting, changes in the fair market value of derivative financial instruments have a direct effect on net earnings.

(in thousands of Canadian dollars, except as noted, and amounts per share)

The increase in dividends declared on common shares from 2010 to 2011 is due mainly to the increase in the weighted average number of common shares outstanding.

Comparison between 2010 and 2009

The main differences between 2010 and 2009 are attributable to the Combination. The addition of the Pre-Combination Innergex' assets, including five Operating Facilities for a total net installed capacity of 116 MW (gross 198 MW), the Development Projects and the Prospective Projects, to the Fund's assets is mainly responsible for the increases in revenues, expenses, assets and financial liabilities. The Combination also explains the increase in the weighted average number of common shares outstanding and as such, part of the increase in shareholders' equity, the other factor being the issuance of preferred shares in September 2010 for gross proceeds of $85.0 million.

For the year ended December 31, 2010, the Corporation recorded a net loss attributable to owners of the parent of $68.6 million (net earnings of $26.2 million in 2009). This difference is due mainly to a $51.8 million unrealized loss on unitholders' capital registered in 2010 and to a $20.8 million unrealized net loss on derivative financial instruments (net gain of $15.8 million in 2009) resulting from the general decrease in benchmark interest rates since December 31, 2009. As the Corporation does not use hedge accounting, changes in the fair market value of derivative financial instruments have a direct effect on net earnings.

The increase in dividends declared from 2009 to 2010 is due mainly to the increase in the weighted average number of common shares outstanding and to the issuance of preferred shares.

Adjusted Net Earnings (Loss)

The Corporation believes that adjusted net earnings (loss) represent important additional information for the reader because they provide a profitability measure that excludes certain elements that have no impact on cash on hand. Adjusted net earnings (loss) exclude unrealized net gains (loss) on derivative financial instruments, unrealized loss on unitholders' capital and unrealized net gains (loss) on foreign exchange as well as any associated deferred tax expense (income). When applicable, adjusted net earnings (loss) also exclude some non-recurring items. The Corporation calculates adjusted net earnings (loss) as shown below:

For the years ended December 31	2011	2010
Net loss	(43,704)	(68,703)
Add (deduct):		
Non-cash expense related to royalty agreement	-	983
Unrealized net loss on derivative financial instruments	61,479	20,761
Unrealized loss on unitholders' capital	-	51,761
Unrealized net gain on foreign exchange	-	(28)
Deferred recoveries for income taxes associated with the above elements	(16,599)	(5,943)
Adjusted net earnings (loss)	1,176	(1,169)

Unrealized net gains (loss) on derivative financial instruments are the most volatile of these elements. The Corporation uses derivative financial instruments to manage its exposure to the risk of increasing interest rates on its debt financing ("Derivatives"). Since several Derivatives are entered into for a term equal in length to the underlying debt amortization schedule, which can reach 30 years, a Derivative's fair market value can be very sensitive to day-to-day variations in long-term interest rates. Please refer to the "Derivative Financial instruments" and "Derivative Financial Instruments and Risk Management" sections of this MD&A for more information about Derivatives.

For the year ended December 31, 2011, the adjusted net earnings, compared to an adjusted net loss in 2010, were due mainly to an increase in EBITDA, which is detailed in the Financial Results table, offset by higher finance costs and depreciation and amortization expenses.

The unrealized loss on unitholders' capital had a significant impact in the year ended December 31, 2010, due to the conversion to IFRS. The Corporation did not record any such loss for year ended December 31, 2011, as the unitholders' capital was reclassified to share capital in equity at the Combination date. Please refer to the "Unrealized Loss on Unitholders' Capital" section of this MD&A for more information.

OPERATING RESULTS

The Corporation's operating results for the year ended December 31, 2011, are compared with the operating results for the same period in 2010. In accordance with IFRS, the results include Cloudworks' contribution since April 5, 2011. Also, due to the Combination, results of the Pre-Combination Innergex have been accounted for in the Corporation's results as of March 30, 2010.

Production

When evaluating its operating results, the Corporation compares actual electricity generation with a long-term average for each hydroelectric facility and wind farm. These long-term averages are determined carefully and prudently to allow long-term forecasting of the expected generation for each of the Corporation's facilities.

To define the long-term average of a power generating facility, the Corporation and independent engineers carry out studies that take into consideration a number of important factors: for hydroelectricity, the historically observed flows of the river, the operating head, the technology employed and the reserved aesthetic and ecological flows; and for wind energy, the historical wind and meteorological conditions and turbine technology. Also taken into account are factors such as site topography, installed capacity, energy losses, operational features and maintenance. Although production will fluctuate from year to year, over an extended period it should approach the forecast long-term average.

(in thousands of Canadian dollars, except as noted, and amounts per share)

For the years ended December 31	2011				2010			
	Production	LTA	Production as a % of LTA	Average price[1] ($/MWh)	Production	LTA	Production as a % of LTA	Average price[1] ($/MWh)
HYDRO								
Saint-Paulin [2]	52,122	41,082	127%	68.73	40,057	41,082	98%	74.22
Windsor [3]	34,589	31,000	112%	88.36	37,944	31,000	122%	84.36
Chaudière [2,3]	142,503	116,651	122%	78.75	128,064	116,651	110%	83.20
Portneuf-1	41,878	40,822	103%	76.25	40,972	40,822	100%	73.97
Portneuf-2	69,006	68,496	101%	76.25	67,119	68,496	98%	73.97
Portneuf-3	42,728	42,379	101%	76.25	42,102	42,379	99%	73.97
Montmagny [3]	7,677	8,000	96%	76.97	7,140	8,000	89%	78.99
Glen Miller [4]	43,682	41,606	105%	67.48	32,727	28,415	115%	67.25
Umbata Falls [4]	41,426	53,461	77%	83.92	27,523	45,318	61%	83.60
Batawa [5]	36,948	32,938	112%	68.72	37,039	32,938	112%	62.15
Rutherford Creek	170,404	180,000	95%	56.06	171,289	180,000	95%	55.41
Ashlu Creek [4,6]	254,049	265,000	96%	68.54	230,297	238,746	96%	67.17
Douglas Creek [4,6]	93,860	78,611	119%	84.19	-	-	-	-
Fire Creek [4,6]	88,324	75,781	117%	84.88	-	-	-	-
Lamont Creek [4,6]	99,905	87,133	115%	84.07	-	-	-	-
Stokke Creek [4,6]	70,970	74,655	95%	83.98	-	-	-	-
Tipella Creek [4,6]	67,582	60,501	112%	85.63	-	-	-	-
Upper Stave River [4,6]	131,562	127,340	103%	83.99	-	-	-	-
Fitzsimmons Creek [4,6]	21,648	33,000	66%	88.78	21,761	29,713	73%	88.28
Horseshoe Bend	41,983	46,800	90%	65.09	38,133	46,800	81%	70.33
Subtotal	1,552,846	1,505,256	103%		922,167	950,360	97%	
WIND								
Baie-des-Sables	108,353	113,360	96%	86.50	102,737	113,360	91%	86.24
L'Anse-à-Valleau	111,666	113,240	99%	86.59	110,824	113,240	98%	86.24
Carleton [4]	124,331	129,398	96%	88.62	91,707	92,099	100%	88.31
Montagne Sèche [4]	8,124	8,641	94%	73.06	-	-	-	-
Gros-Morne I [4]	106	14,636	1%	69.41	-	-	-	-
Subtotal	352,580	379,275	93%		305,268	318,699	96%	
Total	1,905,426	1,884,531	101%		1,227,435	1,269,059	97%	

1. Including all payment adjustments linked to month, day and hour of delivery; environmental attributes and ecoENERGY Initiative as applicable.
2. Under these PPAs, electricity delivered beyond the agreed maximum annual quantity is paid at a lower price adjusted annually. The reference period for the calculation of the excess quantity runs from December 1 to November 1.
3. The PPAs include a winter premium for power generated from December to March.
4. The long-term average was adjusted for the period during which the facility contributed to Innergex' results.
5. This PPA provides for a premium on power sold in the winter and during peak hours.
6. These PPAs provide for a premium (discount) on power sold during high (low) demand months and hours.

(in thousands of Canadian dollars, except as noted, and amounts per share)

The Corporation's facilities produced 1,905,426 MWh in the year ended December 31, 2011, 1% more than the adjusted long-term average of 1,884,531 MWh. Most of the facilities exceeded their LTA or were less than 5% below their LTA. The facilities that did not reach at least 95% of their LTA were:

Facilities	Explanations
Umbata Falls	Water flows lower than the LTA for most of the year except during the second quarter.
Fitzsimmons Creek	Water flows lower than the LTA for most of the year, plus an intake issue that occurred during high-flow periods. During the first quarter of 2012, work to solve the intake issue was performed.
Horseshoe Bend	Water flows lower than the LTA during the first two quarters and scheduled sand removal operations during the fourth quarter.
Gros-Morne I	Production stopped in December due to converters damaged after a load rejection event. Production resumed on February 12, 2012. See the "Commissioning Activities" section for more information.

Additional Information

Portneuf

In addition to revenue from the power generated at the three Portneuf facilities, the Corporation receives cash payments from Hydro-Québec to compensate for the partial diversion of the water flow that would have otherwise been available to the Corporation's plants. These payments are based on long-term average annual water flows over 20 years. Although these facilities are exempt from annual hydrological variations under the "virtual energy" provisions included in the long-term PPAs with Hydro-Québec, they must remain in operation in order to receive financial compensation. As such, the payments are contingent on turbine availability and maximum production with the water resources made available by Hydro-Québec.

Inflation Protection

Most of the Corporation's PPAs for Operating Facilities include a clause that mitigates the inflation fluctuation effects on revenues:

- all PPAs for hydroelectric facilities in Québec provide for a CPI based power rate increase of minimum 3% and maximum 6% per year;
- PPAs for the Glen Miller and Umbata Falls hydroelectric facilities provide for an annual power rate adjustment based on 15% of the CPI;
- all PPAs for hydroelectric facilities in British Columbia provide for an annual power rate adjustment based on 50% of the CPI; and
- all PPAs for wind farms in Québec provide for an annual power rate adjustment based on approximately 20% of the CPI.

The overall performance of the Corporation's facilities for the year ended December 31, 2011, demonstrates the benefits of geographic diversification and the complementarity of hydroelectric and wind power generation.

(in thousands of Canadian dollars, except as noted, and amounts per share)

Financial results

For the years ended December 31	2011	2010
Operating revenues	148,260	91,385
Operating expenses	24,226	14,529
General and administrative expenses	10,365	6,374
Prospective projects expenses	2,473	2,371
EBITDA	111,196	68,111
Finance costs [1]	53,122	23,749
Transaction costs	1,863	5,159
Realized gain on derivative financial instruments	-	(555)
Loss on contingent considerations	1,858	-
Other net revenues	(1,028)	(17)
Depreciation and amortization	50,970	32,985
Unrealized net loss on derivative financial instruments	61,479	20,761
Unrealized loss on unitholders' capital	-	51,761
Expense related to royalty agreement	-	983
Unrealized net gain on foreign exchange	-	(28)
Recovery of income taxes	(13,364)	(5,222)
Distributions declared to unitholders	-	7,238
Net loss	(43,704)	(68,703)
Net loss attributable to:		
Owners of the parent	(40,547)	(68,635)
Non-controlling interests	(3,157)	(68)
	(43,704)	(68,703)

1. For the year ended December 31, 2011, finance costs include compensation interest of $7.2 million.

Revenues
For the year ended December 31, 2011, the Corporation recorded operating revenues of $148.3 million ($91.4 million in 2010). This increase is due mainly to additional revenues resulting from the Cloudworks Acquisition ($46.6 million), the Combination ($6.8 million) and to higher revenues from the pre-combination assets of the Fund (aggregate positive impact of $2.6 million).

Expenses
Operating expenses consist primarily of the operators' salaries, water rights, royalties, insurance premiums, property taxes, maintenance and repairs.

In 2011, the Corporation incurred $24.2 million in operating expenses related to the operation of the power-producing facilities ($14.5 million in 2010). This increase was expected and is due mainly to the Cloudworks Acquisition ($6.2 million), which resulted in the Corporation operating a greater number of facilities in 2011 than in 2010. The operating expenses from the pre-combination assets account for most of the remaining difference.

General and administrative expenses totalled $10.4 million for the year ended December 31, 2011 ($6.4 million in 2010). This increase is due to the Combination and the Cloudworks Acquisition.

Prospective projects expenses include the costs incurred for the development of Prospective Projects. Prospective projects expenses totalled $2.5 million for the year ended December 31, 2011 ($2.4 million in 2010).

Finance Costs
Finance costs include interest expenses on long-term debt and debentures, compensation interest, amortization of financing fees, amortization of the revaluation of long-term debt and debentures, accretion expense on asset retirement obligations and accretion expense on contingent considerations.

The long-term debt acquired as part of the Cloudworks Acquisition consists of fixed rate bonds and real return bonds ("RRB"). The total interest expense of a RRB is adjusted for inflation and is composed of two types of interest expense:

i) Indexed interest
The RRB repayment schedule of principal and interest is first calculated based on a zero inflation assumption over the term of the bond. When due, each scheduled repayment of principal and interest is adjusted for inflation by multiplying the repayment by an inflation ratio. This adjusted repayment constitutes the total amount paid to bondholders. The adjusted interest is called indexed interest.

ii) Compensation interest
The total interest expense equals to the premium (or spread) added to the changes in the CPI. The difference between the total interest and the indexed interest is called the compensation interest. When the total amount paid to bondholders is lower than the sum of the principal and total interest expense, the unpaid balance becomes accrued compensation interest.

During the early years of the term, the RRB repayment schedule is designed to fully cover the indexed interest and principal and to partially cover the compensation interest. This mechanism allows for deferral of a portion of the inflation-related interest during the early years of the term, thereby creating accrued compensation interest. The design of the RRB repayment schedule is such that accrued compensation interest is paid in the later years of the term.

Real return bonds' interest expense fluctuates with the CPI but, as the PPAs for the Harrison Operating Facilities provide CPI-based revenue increases, the Corporation's risk to CPI fluctuation is limited.

For the year ended December 31, 2011, finance costs totalled $53.1 million ($23.7 million in 2010). This difference is due mainly to compensation interest ($7.2 million) and to the increase in long-term debt resulting from the Cloudworks Acquisition ($17.7 million). The remaining difference is due to the issuance of Convertible Debentures and to increases in long-term debt resulting from the Combination.

During the last quarter of 2011, the Corporation amended its swap contracts related to long-term debts, resulting in fixed interest rate reductions ranging from 0.08% to 0.13%. As at December 31, 2011, 88% of the Corporation's outstanding debt, including Convertible Debentures, was fixed or hedged against interest rate movements (100% as at December 31, 2010). The difference is due to drawings on the revolving credit term facility greater than at the same date in 2010 and to drawings on the Stardale construction loan whose interest will be hedged by a swap effective September 2012. As such, the effective all-in interest rate on the Corporation's debt and Convertible Debentures was 5.99% as at December 31, 2011 (6.07% as at December 31, 2010). The decrease stems from the reduction in fixed interest rates on swap contracts, the better conditions of the revolving credit term facility following its refinancing and the lower interest rates related to debts that are not hedged by swap contracts, partly offset by the bonds acquired as part of the Cloudworks Acquisition. Please see the "Derivative Financial Instruments and Risk Management" section for more information.

Transaction Costs
Transaction costs include the costs incurred for the Combination and for acquisitions.

In the year ended December 31, 2011, the Corporation incurred transaction costs of $1.9 million as a result of the Cloudworks Acquisition and the acquisition of the Stardale Project. For the corresponding period of 2010, transaction costs of $5.2 million were related to the Combination.

Contingent Considerations
For the year ended December 31, 2011, the loss on contingent considerations totalled $1.9 million (nil in 2010). This stems from the earn-out agreements related to the Cloudworks Acquisition and to the Stardale Project acquisition.

Depreciation and Amortization
For the year ended December 31, 2011, depreciation and amortization expenses totalled $51.0 million ($33.0 million in 2010). The increase is mainly attributable to the greater asset base resulting from the Cloudworks Acquisition and from the Combination.

Derivative Financial Instruments
The Corporation uses derivative financial instruments to manage its exposure to the risk of rising interest rates on its debt financing, thereby protecting the economic value of its projects. Innergex also has derivative financial instruments embedded in some of its PPAs. The Corporation does not use hedge accounting for its derivative financial instruments nor does it own or issue financial instruments for speculative purposes.

The Corporation recorded a $61.5 million unrealized net loss on derivative financial instruments in the year ended December 31, 2011 ($20.8 million in 2010), due mainly to the decrease in benchmark interest rates since the end of 2010. This loss had no impact on the Corporation’s cash flow.

Unrealized Loss on Unitholders’ Capital
Due to the transition to IFRS, under IAS 32, the unitholders’ capital of the Fund was reclassified as a long-term liability, and variations in fair value were recognized in the statements of earnings.

Between January 1, 2010, and March 29, 2010, the fair value of the unitholders’ capital increased by $51.8 million. This variation was reflected as an unrealized loss on unitholders’ capital. The Corporation did not record any such loss for the year ended December 31, 2011, as the unitholders’ capital was reclassified to share capital in equity at the Combination date.

Expense Related to Royalty Agreement
For the year ended December 31, 2010, the Corporation recorded a $1.0 million non-recurring expense due to the deemed cancellation of a contract resulting from the Combination. The Fund had to expense the engagement it had with Innergex prior to the Combination. In 2005, a subsidiary of the Corporation sold the Rutherford Creek hydroelectric facility to the Fund. Rutherford Creek Power, Limited Partnership, which owns the assets, then agreed, following the expiry or termination of the Rutherford Creek PPA in 2024, to pay royalties to the subsidiary provided certain revenue thresholds are reached. This expense had no cash impact on the Corporation's results as it was considered to be paid for by the issuance of shares.

Provision for Income Taxes
For the year ended December 31, 2011, the Corporation recorded current income tax provisions of $0.5 million (recoveries of $1.7 million in 2010), and deferred recoveries of income taxes of $13.8 million ($3.5 million in 2010). Prior to the Combination, the Fund’s income trust structure minimized income tax. As a result of the Combination and the Fund’s conversion to a corporation, Innergex is now taxable, although it can take advantage of the Pre-Combination Innergex’s large pool of tax bases and the resulting substantial available unused capital cost allowance to minimize current income taxes.

Distributions Declared to Unitholders
Due to the transition to IFRS, the unitholders’ capital has been reclassified as a long-term liability for the period between January 1, 2010, and March 29, 2010. Accordingly, the $7.2 million in distributions declared to unitholders during the period up to the Combination on March 29, 2010, are included in the calculation of net earnings instead of being accounted for distributions.

(in thousands of Canadian dollars, except as noted, and amounts per share)

Net Earnings (Loss)

For the year ended December 31, 2011, the Corporation recorded a net loss of $43.7 million (basic and diluted net loss of $0.59 per share). For the corresponding period of 2010, Innergex recorded a net loss of $68.7 million (basic and diluted net loss of $1.13 per share). The following table outlines the main items that contributed to this favourable variation in net loss:

Item	Variation	Explanation
EBITDA	43.1	Primarily due to the Cloudworks Acquisition.
Finance costs	29.4	Primarily due to the Cloudworks Acquisition.
Transaction costs	(3.3)	Higher transaction costs in 2010 are due to the Combination.
Loss on contingent considerations	1.9	Earn-out agreements related to the Cloudworks Acquisition and to the Stardale Project acquisition.
Depreciation and amortization	18.0	Primarily due to the Cloudworks Acquisition.
Unrealized loss on the fair market value of derivative financial instruments	40.7	Primarily due to the decrease in benchmark interest rates since the end of 2010.
Unrealized loss on unitholders' capital	(51.8)	Non-recurring expense recorded in 2010 due to the reclassification of the unitholder's capital of the Fund as long-term liability.
Expense related to royalty agreement	(1.0)	Non-recurring expense recorded in 2010 due to the Combination.
Recovery for income taxes	8.1	Due to deferred taxes.
Distributions declared to unitholders	(7.2)	Non-recurring expense recorded in 2010 due to reclassification of the unitholder's capital of the Fund as long-term liability.

The basic and diluted per-share figures for the year ended December 31, 2011, are based on a weighted average number of 75,681,128 and 75,754,667 common shares outstanding respectively. As per IFRS, 1,869,420 stock options were non-dilutive during the periods concerned, as the average market price of the Corporation's common share was below the strike price. The other 808,024 stock options were dilutive as the average market price of the Corporation's common share was above the strike price. However, they were excluded from the computation of per-share figure, as the Corporation recognized a net loss for the year ended December 31, 2011. Convertible Debentures were non-dilutive, as the average market price was below the conversion price. A total of 7,558,684 common shares could potentially be issued on conversion of the Convertible Debentures.

For the corresponding period ended December 31, 2010, the basic and diluted per-share figures were based on a weighted average number of 55,529,845 common shares outstanding. All stock options were non-dilutive during this period. For the 1,842,024 stock options, the average market price of the Corporation's common share was below the strike price. Convertible Debentures were also non-dilutive, as the average market price was below the conversion price.

As at December 31, 2011, the Corporation had a total of 81,282,460 common shares, 80,500 Convertible Debentures, 3,400,000 Series A Preferred Shares and 2,677,444 stock options outstanding. As at December 31, 2010, it had 59,532,606 common shares, 80,500 Convertible Debentures, 3,400,000 Series A Preferred Shares and 1,842,024 stock options outstanding.

Non-controlling Interests

For the year ended December 31, 2011, the Corporation allocated loss of $3.2 million to non-controlling interests (not material in 2010). These non-controlling interests are mostly related to the Harrison Operating Facilities acquired as part of the Cloudworks Acquisition on April 4, 2011, the Fitzsimmons Creek Operating Facility and the Kwoiek Creek Development Project.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows from Operating Activities

For the year ended December 31, 2011, cash flows generated by operating activities totalled $43.4 million ($8.2 million in 2010). This difference is due primarily to the $43.1 million increase in EBITDA, the $3.3 million decrease in transaction costs and the non-recurrent $9.7 million in distributions paid to unitholders in 2010, partly offset by a $19.8 million increase in interest paid and a $1.9 million increase in the negative variation of non-cash working capital items. The variation in non-cash working capital items stems mainly from the negative impact of a larger increase in accounts receivable ($13.7 million) due mainly to an increase in commodity taxes, partly offset by the positive impact of a decrease in prepaid and others compared to an increase in 2010 ($1.7 million) and of a lower decrease in accounts payable and accrued liabilities ($10.1 million).

Cash Flows from Financing Activities

For the year ended December 31, 2011, cash flows generated by financing activities totalled $326.9 million ($21.7 million used in 2010). This results mainly from a $222.6 million net long-term debt increase ($84.2 million net repayment in 2010), partly offset by an amount of $45.5 million paid in dividends to preferred and common shareholders ($17.5 million in 2010). Net proceeds from issuance of common shares amounted to $155.7 million ($81.7 million in preferred shares in 2010).

Cash Flows from Investing Activities

For the year ended December 31, 2011, cash flows used by investing activities amounted to $377.2 million (inflows of $46.4 million in 2010). During this period, business acquisitions accounted for a $160.8 million outflow (nil in 2010), additions to property, plant and equipment for a $178.9 million outflow ($29.7 million in 2010), additions to project development costs for a $31.7 million outflow ($9.1 million 2010), additions to intangible assets and other long-term assets for a combined $4.2 million outflow ($0.6 million in 2010), increase in restricted cash and short-term investments for a $15.5 million outflow (nil in 2010) and net funds withdrawn from the reserves for a $8.0 million inflow (net outflows of $2.0 million in 2010). Cash acquired concurrently with the Cloudworks Acquisition accounted for a $4.9 million inflow in 2011 whereas the Combination accounted for an $88.4 million inflow in 2010.

Cash and Cash Equivalents

For the year ended December 31, 2011, the Corporation used $6.8 million in cash and cash equivalents ($32.8 million generated in 2010) as a net result of its operating, financing and investing activities.

As at December 31, 2011, the Corporation had cash and cash equivalents amounting to $35.3 million ($42.1 million as at December 31, 2010).

Dividends to Preferred Shareholders

On March 21, 2012, the Corporation declared a dividend of $0.3125 per Series A Preferred Share payable on April 16, 2012, to Series A preferred shareholders of record at the close of business on March 30, 2012.

Dividends to Common Shareholders

On March 21, 2012, the Corporation declared a dividend of $0.1450 per common share payable on April 16, 2012, to common shareholders of record at the close of business on March 30, 2012.

(in thousands of Canadian dollars, except as noted, and amounts per share)

USE OF FINANCING PROCEEDS

For the years ended December 31	2011	2010
Proceeds from issuance of long-term debt	270,117	134,220
Proceeds from issuance of share capital	155,721	81,743
Financing proceeds	425,838	215,963
Cash acquired on business acquisitions	4,943	88,394
Business acquisitions	(160,844)	-
Additions to property, plant and equipment	(178,896)	(29,667)
Additions to intangible assets	(3,469)	(413)
Additions to project developments costs	(31,726)	(9,056)
Additions to other long-term assets	(724)	(221)
Short-term loan to a partner	1,000	(1,000)
Funds invested in the hydrology reserve funded from long-term debt	-	(2,016)
Refinancing of long-term debt	-	(119,806)
Payment of deferred financing costs	(5,983)	(1,724)
Cancellation of revolving credit facility	-	(12,900)
Long-term debt repayment	(47,475)	(85,733)
Use of financing proceeds	(423,174)	(174,142)
Contribution to working capital	2,664	41,821

During the year ended December 31, 2011, the Corporation borrowed $270.1 million and issued shares for $155.7 million to pay for the Cloudworks Acquisition, the acquisition and construction of the Stardale Project, the construction of Gros-Morne I and II, and to repay long-term debt. During the corresponding period of 2010, the Corporation refinanced its credit facilities as part of the Combination and used the net cash acquired from the Pre-Combination Innergex to reduce drawings and make additions to assets.

FINANCIAL POSITION

Assets

As at December 31, 2011, the Corporation had $2,033.4 million in total assets ($947.1 million as at December 31, 2010). This increase is due primarily to the following:

- restricted cash and short-term investments of $53.4 million due to the Cloudworks Acquisition;
- accounts receivable increased from $14.7 million to $36.9 million, as explained in the "Working Capital" section below;
- reserve accounts increased from $21.4 million to $42.2 million due mainly to the Cloudworks Acquisition;
- property, plant and equipment increased from $612.3 million to $1,259.8 million due mainly to the Cloudworks Acquisition, the Stardale Project acquisition and construction, and construction of Montagne Sèche and Gros-Morne I and II;
- intangible assets increased from $210.8 million to $441.3 million due mainly to the Cloudworks Acquisition; and
- project development costs increased from $5.9 million to $98.0 million due mainly to the Cloudworks Acquisition.

Working Capital

As at December 31, 2011, working capital was positive at $50.1 million with a working capital ratio of 1.60:1.00. As at December 31, 2010, working capital was positive at $14.0 million with a working capital ratio of 1.27:1.00. The Corporation increased the working capital ratio over the preceding twelve months due mainly to the Cloudworks Acquisition.

In view of these ratios, the Corporation considers its current level of working capital to be sufficient to meet its needs. The Corporation can also use its newly increased $350.0 million revolving credit term facility if necessary. As at December 31, 2011, US$13.9 million and $164.8 million of this credit facility had been drawn as cash advances and $23.8 million had been used for issuing letters of credit.

As part of the Cloudworks Acquisition, the Corporation maintains restricted cash accounts which amounted to $53.4 million as at December 31, 2011. Of this amount, $40.0 million has been released on March 1, 2012 when the distribution conditions related to the Harrison Operating Facilities long-term debt were met.

(in thousands of Canadian dollars, except as noted, and amounts per share)

Accounts receivable increased from $14.7 million as at December 31, 2010, to $36.9 million as at December 31, 2011. The increase stems mainly from a $12.9 million increase in commodity taxes, from Hydro-Québec receivables for the reimbursement of the Montagne Sèche substation and from higher revenues in the last quarter of 2011, compared with the same period of 2010, due mainly to the Cloudworks Acquisition.

Accounts payable and accrued liabilities increased from $21.7 million as at December 31, 2010, to $26.6 million as at December 31, 2011. The increase stems mainly from interest payable related to the Cloudworks Acquisition. The trade payables and accrued liabilities are mostly related to the Stardale Project acquisition and normal operations.

Prepaid and others decreased from $4.6 million as at December 31, 2010, to $4.1 million as at December 31, 2011.

Derivative financial instruments included in current liabilities were $8.5 million as at December 31, 2010, and $20.3 million as at December 31, 2011. This difference is attributable mainly to new swap and bond forward contracts, and to a decrease in benchmark interest rates.

A total of $13.8 million of the current portion of long-term debt amounting to $19.5 million relates to the L'Anse-à-Valleau, Hydro-Windsor, Glen Miller, Umbata Falls, Carleton, Rutherford Creek, Ashlu Creek, Fitzsimmons Creek and Montagne Sèche credit facilities. The remaining $5.7 million relates to the newly acquired Harrison Operating Facilities.

Reserve Accounts

	December 31, 2011	December 31, 2010
Hydrology/wind power reserve	39,045	16,511
Major maintenance reserve	3,109	4,436
Levelization reserve	-	494
Total	42,154	21,441

The Corporation holds two types of reserve accounts designed to help ensure its stability:

i) The Hydrology/wind power reserve is established at the start of commercial operations at a facility to compensate for the variability of cash flows related to fluctuations in hydrology or wind regime and other unpredictable events. The amounts in this reserve are expected to vary from quarter to quarter according to the seasonality of cash flows. The increase in this reserve since December 31, 2010, is attributable mainly to the Cloudworks Acquisition.

ii) The Major maintenance reserve is established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity. To optimize its use of funds, the Corporation revaluated the reserve, taking into account the amount required under its credit agreements. As the reserve was overfunded, cash was withdrawn, resulting in a decrease since December 31, 2010.

As at December 31, 2010, the Corporation held an additional reserve account, the Levelization reserve, which was established to level the monetary contribution from the Funds' power plants in order to pay distributions to unitholders. As planned, this reserve was fully used in the first quarter of 2011.

The availability of funds in the Hydrology/wind power and Major maintenance reserve accounts may be restricted by credit agreements and trust indentures.

Property, Plant and Equipment

Property, plant and equipment are comprised mainly of hydroelectric facilities, wind farms and solar projects that are either in operation or under construction. They are recorded at cost less accumulated depreciation and accumulated impairment losses. They are depreciated using the straight-line method over the lesser of (i) the period for which the Corporation owns the rights to the assets or (ii) a period of 15 to 75 years for hydroelectric facilities or 15 to 25 years for wind and solar farm facilities. As required under IFRS, the Corporation adjusted the accumulated depreciation of property, plant and equipment to reflect the depreciation of significant components based on their respective estimated useful lives. The Corporation had $1,259.8 million in property, plant and equipment as at December 31, 2011, compared with $612.3 million as at December 31, 2010. This increase stems from the Cloudworks Acquisition, the new wind farms Montagne Sèche and Gros-Morne I and the construction of the Stardale Project, Gros-Morne II and the Kwoiek Creek and Northwest Stave River hydroelectric projects, and is partly offset by depreciation and amortization.

Intangible Assets

Intangible assets consist of various PPAs, permits and licences. They also include the extended warranty for the L'Anse-à-Valleau, Carleton, Montagne Sèche and Gros-Morne I wind farm turbines. The Corporation reported $441.3 million in intangible assets as at December 31, 2011, an increase from the $210.8 million reported as at December 31, 2010. This increase results from the Cloudworks Acquisition and the Stardale Project, partly offset by depreciation and amortization. Intangible assets, excluding $4.8 million related to the wind farms' extended warranty, are amortized using the straight-line method over 11- to 40-year periods that commence when the related project is commissioned or acquired. The wind farms' extended warranty is amortized using the straight-line method over the three-year extended warranty period.

Project Development Costs

Project development costs are the costs to acquire and develop Development Projects and to acquire Prospective Projects. Depending on their nature, these costs are transferred either to property, plant and equipment or to intangible assets once the project reaches the construction phase. As at December 31, 2011, the Corporation had $98.0 million in project development costs ($5.9 million as at December 31, 2010). This increase is due to the Cloudworks Acquisition and to the Development Projects in permit phase.

Goodwill

The Corporation had $8.3 million in goodwill as at December 31, 2011 (idem as at December 31, 2010). Goodwill is tested for impairment annually, or more frequently when there is indication that it may be impaired. No impairment was recognized for the year ended December 31, 2011.

Accrual for Acquisition of Long-Term Assets

Accrual for acquisition of long-term assets consists of long-term debt commitments that have been secured and will be drawn on to finance the Corporation's projects currently under construction or for which construction has been completed but costs remained to be paid. As at December 31, 2011, the Corporation had $41.3 million in accrual for acquisition of long-term assets (nil as at December 31, 2010).

Long-Term Debt

On July 28, 2011, the Corporation announced it had executed a loan agreement, consisting of a $111.7 million non-recourse term loan and a $5.6 million letter of credit facility, for the construction and long-term debt financing of the Stardale Project.

On August 9, 2011, Innergex announced that it had completed the extension and refinancing of its $170.0 million revolving credit facility with a five-year $350.0 million revolving credit term facility. In addition to increasing the availability of credit, the new facility provides the Corporation with greater flexibility and improved terms and conditions.

As at December 31, 2011, long-term debt totalled $1,049.5 million ($358.7 million as at December 31, 2010). The increase in long-term debt results mainly from the Cloudworks Acquisition, drawings under the Stardale construction loan and net drawings under the revolving credit term facility, partly offset by scheduled long-term debt repayments of $14.9 million.

(in thousands of Canadian dollars, except as noted, and amounts per share)

The Corporation had the following long-term debts outstanding as at December 31, 2011:

	Maturity		December 31, 2011	December 31, 2010
Revolving credit term facility		i)		
Prime rate advances	2016		20	-
Bankers' acceptances	2016		164,780	27,400
LIBOR advances, US$13,900	2016		14,136	13,825
Term loans				
Truck loans, fixed-rate	2012-2017	ii)	73	-
Glen Miller, floating-rate	2013	iii)	13,500	14,500
Carleton, floating-rate	2013	iv)	46,298	49,083
Umbata Falls, floating-rate	2014	v)	23,885	24,348
Fitzsimmons Creek, floating-rate	2016	vi)	22,458	22,551
Hydro-Windsor, fixed rate	2016	vii)	5,027	5,841
Montagne Sèche, floating-rate	2016	viii)	26,200	-
Rutherford Creek, fixed rate	2024	ix)	50,000	50,000
Ashlu Creek, floating-rate	2025	x)	102,669	104,406
L'Anse-à-Valleau, floating-rate	2026	xi)	45,706	47,891
Stardale, floating-rate construction loan		xii)	73,706	-
Kwoiek Creek, fixed rate subordinated term loan		xiii)	150	150
Bonds				
Harrison Hydro, real return	2049	xiv)	226,338	-
Harrison Hydro, fixed rate	2049	xv)	215,570	-
Harrison Hydro, real return	2049	xvi)	26,484	-
Deferred financing costs			(7,488)	(1,305)
			1,049,512	358,690
Current portion of long-term debt			(19,475)	(9,259)
			1,030,037	349,431

i) a $350.0 million revolving credit term facility secured by a first-ranking hypothec on Innergex assets and by various security interests granted by some of its subsidiaries. The facility will mature in 2016 and is not amortized. Advances are made in the form of bankers' acceptances ("BA"), prime-rate advances, U.S. base-rate advances, LIBOR advances or letters of credit. In all cases, interest is calculated at the prevailing benchmark rate plus an additional margin based on Innergex's ratio of adjusted consolidated senior debt to adjusted EBITDA. As at December 31, 2011, $178.9 million was due under this facility and $23.8 million was used for the issuance of letters of credit; thus the unused and available portion of the revolving credit term facility totalled $147.2 million. As at December 31, 2011, the all-in interest rate was 5.37% after accounting for the interest rate swaps;

ii) as part of the Cloudworks Acquisition, the Corporation assumed a total of $0.1 million in truck loans. The loans are secured by the trucks and are either interest-free or bear interest at a rate of 0.9%. They will mature in 2012 and 2017;

iii) as part of the Combination, the Corporation assumed a $15.3 million non-recourse term loan maturing in 2013. It is secured by the Glen Miller hydroelectric facility. The loan is amortized at the rate of $250 per quarter and bears interest at the BA rate plus an applicable credit margin. As at December 31, 2011, the all-in interest rate was 2.66%;

iv) as part of the Combination, the Corporation assumed a $50.9 million non-recourse term loan maturing in 2013. It is secured by the Corporation's 38% interest in the Carleton wind farm. The loan was accounted for at its fair market value of $51.7 million as at March 29, 2010. The loan's quarterly principal payments are based on an 18.5-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2011, the all-in effective interest rate was 4.72% after accounting for the interest rate swap;

v) as part of the Combination, the Corporation assumed a $24.8 million non-recourse term loan maturing in 2014. It is secured by the Corporation's 49% ownership interest in this facility. The loan's quarterly principal payments are based on a 25-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2011, the all-in interest rate was 5.18% after accounting for the interest rate swap;

vi) as part of the Combination, the Corporation assumed a $17.1 million non-recourse construction loan which was accounted for at its fair market value of $19.6 million as at March 29, 2010. During the second quarter of 2010, an additional $3.0 million was drawn under this construction loan. In December 2011, the loan was converted from a construction loan into a term loan maturing in 2016. The loan is secured by the Fitzsimmons Creek hydroelectric facility. The loan's monthly principal payments are based on a 30-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2011, the all-in effective interest rate was 2.52%;

vii) as part of the acquisition of the Hydro-Windsor hydroelectric facility in 2004, the Corporation assumed an $8.3 million non-recourse term loan maturing in 2016. It is secured by the Hydro-Windsor hydroelectric facility. This debt was accounted for at its fair market value of $9.9 million as at April 27, 2004. The loan is repayable by monthly blended payments of principal and interest totalling $105. The loan bears interest at an effective fixed interest rate of 8.25%;

viii) a $31.7 million non-recourse construction loan, of which $26.2 million had been drawn as at December 31, 2011. The loan is secured by the Montagne Sèche wind farm and matures in 2016. The loan's quarterly principal payments will begin on March 31, 2012 and be based on an 18.5-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2011, the all-in effective interest rate was 6.47% after accounting for the interest rate swap;

ix) as part of the acquisition of the Rutherford Creek hydroelectric facility in 2005, the Corporation assumed a $50.0 million non-recourse term loan maturing in 2024. It is secured by the Rutherford Creek hydroelectric facility. The debt will be repayable in monthly blended payments of principal and interest totalling $511 starting on July 1, 2012. Until such date, monthly interest-only payments of $286 are made. The loan bears interest at a fixed rate of 6.88%;

x) as part of the Combination, the Corporation assumed a $100.4 million non-recourse construction loan which was accounted for at its fair market value of $95.6 million as at March 29, 2010. In July 2010, the Corporation made a final draw, bringing the total drawn amount to a fair market value of $105.2 million. Concurrently with this last draw, the construction loan was converted to a term loan maturing in 2025. The loan is secured by the Ashlu Creek hydroelectric facility. The loan's quarterly principal payments are based on a 25-year amortization period. The loan bears interest at the BA rate or prime-rate plus an applicable credit margin. As at December 31, 2011, the all-in effective interest rate was 6.13% after accounting for the interest rate swaps;

xi) as part of the acquisition of a 38% interest in the L'Anse-à-Valleau wind farm in 2007, the Corporation assumed a $54.5 million non-recourse term loan maturing in 2026. It is secured by the Corporation's 38% interest in the L'Anse-à-Valleau wind farm. The loan's quarterly principal payments are based on an 18.5-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2011, the all-in interest rate was 5.83% after accounting for the interest rate swap;

xii) a $111.7 million non-recourse construction loan, of which $73.7 million had been drawn as at December 31, 2011. The loan is secured by the Stardale solar farm and will mature on June 30, 2030. The loan's quarterly principal payments will begin on September 30, 2012 and be based on an 18-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2011, the all-in effective interest rate was 3.45%;

xiii) as part of the Combination, the Corporation assumed a $0.2 million subordinated non-recourse term loan made by the Corporation's partner to Kwoiek Creek Resources Limited Partnership ("KCRLP"), the owner of the Kwoiek Creek hydroelectric project. As per the project agreements, both partners can participate in the financing of the project. The Corporation's subordinated non-recourse term loan made to KCRLP, which was eliminated in the financial statement consolidation process, amounted to $29.5 million as at December 31, 2011;

xiv) as part of the Cloudworks Acquisition, the Corporation assumed a $258.7 million senior real return bond maturing in 2049. It is secured by the Harrison Operating Facilities. This bond was accounted for at its fair market value of $223.9 million at the time of the Cloudworks Acquisition. The bond is repayable by semi-annual blended payments of principal and interest totalling $5,790 before CPI adjustment. On December 1, 2031, the payment amount decreases to $4,481 before CPI adjustment. The bond bears interest at a fixed rate adjusted by an inflation ratio and an inflation compensation interest factor. Both inflation adjustments are based on the not seasonally adjusted CPI. As at December 31, 2011, the all-in effective interest rate was 6.94%;

xv) as part of the Cloudworks Acquisition, the Corporation assumed a $244.8 million senior fixed bond maturing in 2049. It is secured by the Harrison Operating Facilities. This bond was accounted for at its fair market value of $216.4 million at the time of the Cloudworks Acquisition. The bond is repayable by semi-annual blended payments of principal and interest totalling $8,072. On December 1, 2031, the payment amount decreases to $6,724. The bond bears interest at an effective fixed interest rate of 6.67%;

xvi) as part of the Cloudworks Acquisition, the Corporation assumed a $28.7 million junior real return bond maturing in 2049. It is secured by the Harrison Operating Facilities but is second ranking to the bonds described in xiv) and xv). This bond was accounted for at its fair market value of $25.8 million at the time of the Cloudworks Acquisition. The bond is repayable by quarterly interest payments of $291 before CPI adjustment. On June 1, 2017, the quarterly payments increase to $389 before CPI adjustment and include principal repayment until maturity. The bond bears interest at a fixed rate adjusted by an inflation ratio and an inflation compensation interest factor. Both inflation adjustments are based on the not seasonally adjusted CPI. As at December 31, 2011, the all-in effective interest rate was 7.94%.

If they are not met, certain financial and non-financial covenants included in the credit agreements, trust indentures or PPAs entered into by various subsidiaries of the Corporation could limit the capacity of these subsidiaries to transfer funds to the Corporation. These restrictions could have a negative impact on the Corporation's ability to meet its obligations. Since the beginning of the 2011 fiscal year, the Corporation and its subsidiaries have met all the financial and non-financial conditions related to their credit agreements, trust indentures and PPAs.

Convertible Debentures

As part of the Combination process, the Corporation issued the Convertible Debentures for a total notional amount of $80.5 million. As at December 31, 2011, the debt portion of the Convertible Debentures was $79.5 million and the equity portion was $1.3 million ($79.3 million and $1.3 million respectively as at December 31, 2010).

The Convertible Debentures bear interest at an annual rate of 5.75% and will mature on April 30, 2017. Each Convertible Debenture is convertible into common shares of the Corporation at the option of the holder at any time prior to the earlier of April 30, 2017, and the redemption date specified by the Corporation. The conversion price is $10.65 per common share, being a conversion rate of approximately 93.8967 common shares per $ 1,000 principal amount of convertible debentures. Holders converting their Convertible Debentures will receive accrued and unpaid interest thereon for the period from the last interest payment date on their Convertible Debentures to the date of conversion.

For more information about the issuance of the Convertible Debentures, please refer to the "Short Form Prospectus" dated February 25, 2010, available on Innergex's website at www.innergex.com and on the SEDAR website at www.sedar.com.

The Convertible Debentures are subordinated to all other indebtedness of the Corporation.

Preferred Shares

On September 14, 2010, the Corporation issued a total of 3,400,000 Series A Preferred Shares at $25.00 per share for aggregate gross proceeds of $85.0 million. For the initial five-year period up to but excluding January 15, 2016, the holders of Series A Preferred Shares are entitled to receive fixed cumulative preferential cash dividends as and when declared by the Corporation's board of directors (the "Board of Directors"). The dividends are payable quarterly on the 15th day of January, April, July and October of each year at an annual rate equal to $1.25 per share.

(in thousands of Canadian dollars, except as noted, and amounts per share)

The Series A Preferred Shares are rated P-3 by S&P and Pfd-3 (low) by DBRS.

For more information about the Series A Preferred Shares, please refer to the "Short Form Prospectus" dated September 7, 2010 available on Innergex's website at www.innergex.com and on the SEDAR website at www.sedar.com.

Derivative Financial Instruments and Risk Management

The Corporation uses derivative financial instruments to manage its exposure to the risk of increasing interest rates on its debt financing. While Derivatives are entered into with major financial institutions rated BBB+ or better by S&P, recent events in Europe may have affected some of the Corporation' counterparties. The Corporation nevertheless considers the risk of illiquidity to be low, as current interest rate swap valuation results in amounts being treated as Innergex liabilities owed to the counterparties.

For a long-term debt subject to variable interest rates, Innergex will use bond forward contracts and interest rate swaps to protect the economic return of the related Operating Facility or Development Project. The Corporation does not intend to settle its Derivatives before maturity. The Corporation does not own or issue any Derivatives for speculation purposes. The Corporation does not use hedge accounting to account for its Derivatives.

Taken together, the bond forward and swap contracts shown in the following table allow the Corporation to eliminate the risk of interest rate increases in actual and planned long-term debt ($404.5 million and $259.6 million respectively). As at December 31, 2011, interest rate swaps related to outstanding debts combined with the $523.5 million in existing fixed-rate debts and the $79.5 million in Convertible Debentures mean that 88% of outstanding debts are protected from interest rate increases. Derivatives were also executed for planned long-term debt for the Kwoiek Creek and Northwest Stave River hydroelectric projects and the Stardale Project.

	Maturity	Early termination option	December 31, 2011	December 31, 2010
Bond forwards, from 2.74% to 2.85%	2012	None	137,500	-
Interest rate swaps, from 3.96% to 4.09%	2015	None	15,000	15,000
Interest rate swap, 4.27%	2016	None	3,000	3,000
Interest rate swap, 4.41%	2018	2013	30,000	30,000
Interest rate swap, 4.27%	2018	2013	52,600	52,600
Interest rate swap, from 4.83% to 4.93%, amortizing	2026	None	45,705	47,890
Interest rate swap, from 3.35% to 3.45%, amortizing	2027	2013	45,605	48,315
Forward interest rate swaps, from 3.64% to 3.75%, amortizing	2030	None	101,996	-
Interest rate swap, 4.22%, amortizing	2030	2016	31,690	31,690
Interest rate swap, 4.25%, amortizing	2031	2016	49,940	49,940
Interest rate swap, from 3.98% to 4.11%, amortizing	2034	None	23,885	24,348
Interest rate swaps, from 4.61% to 4.70%, amortizing	2035	2025	107,111	109,067
Forward interest rate swap, 2.85%, amortizing	2041	2016	20,100	-
			664,132	411,850

Derivatives had a net negative value of $91.4 million at the end of 2011 (negative $30.8 million at the end of 2010). This difference is due to a decrease in benchmark interest rates since the end of 2010, to new bond forward contracts entered into in the third and fourth quarters of 2011 for the Kwoiek Creek and Northwest Stave River projects and to new forward interest rate swaps entered into for the Stardale Project in July 2011 and for the Fitzsimmons Creek facility in December 2011.

Some interest rate swaps have imbedded early termination options that are exercisable only on their underlying debt's maturity date. The triggering of these options could pose a liquidity risk. Should the early termination option be triggered, a presumed realized loss would be offset by the savings realized on future interest expenses, as a negative swap value would be the result of an environment in which interest rates were lower than the rate embedded in the swap.

(in thousands of Canadian dollars, except as noted, and amounts per share)

The Corporation has recorded Derivatives using an estimated credit-adjusted mark-to-market valuation that is determined by increasing the swap-based discount rates used to calculate the estimated mark-to-market valuation by an estimated credit spread for the relevant term and counterparty for each Derivative. In the case of Derivatives that Innergex accounts for as assets (i.e. Derivatives for which the counterparties owe Innergex), the credit spread for the bank counterparty was added to the swap-based discount rate to determine the estimated credit-adjusted value whereas, in the case of Derivatives accounted for as liabilities (i.e. Derivatives for which Innergex owes the counterparties), Innergex's credit spread was added to the swap-based discount rate. The estimated credit-adjusted values of the Derivatives are subject to changes in credit spreads of Innergex and its counterparties.

As at December 31, 2011, the fair market value of the derivative financial instruments related to some PPAs with Hydro-Québec was positive at $10.0 million ($10.9 million as at December 31, 2010). These instruments represent the value attributed to minimum inflation clauses of 3% per year included in these PPAs.

Deferred Income Taxes

The tax impact of temporary differences may result in future tax assets or liabilities. As at December 31, 2011, the Corporation's net deferred tax liability was $116.0 million, compared with a net deferred tax liability of $69.5 million as at December 31, 2010. This increase resulted mainly from the Cloudworks Acquisition and the Stardale Project.

Off-Balance-Sheet Arrangements

As at December 31, 2011, the Corporation had issued letters of credit totalling $30.4 million to meet its obligations under its various PPAs and other agreements. Of this amount, $23.8 million was issued under its revolving credit term facility and the remainder under the projects' non-recourse credit facilities. As at that date, Innergex had also issued a total of $34.9 million in corporate guarantees to support the construction of the Montagne Sèche and Gros-Morne wind farms and some bond forward contracts.

Shareholders' Equity

As at December 31, 2011, the shareholders' equity of the Corporation totalled $579.1 million, including $114.4 million of non-controlling interests, compared with $358.9 million, including $2.6 million of non-controlling interests as at December 31, 2010. The increase in total shareholders' equity stems mainly from the Cloudworks Acquisition and the concurrent issuance of common shares. The Cloudworks Acquisition also explains the increase in non-controlling interest.

Contractual Obligations

as at December 31, 2011	Total	Under 1 year	1 to 3 years	4 to 5 years	Thereafter
Long-term debt including convertible debentures	1,203,576	20,836	123,014	246,794	812,932
Interest on long-term debt and convertible debentures	825,330	60,741	120,447	106,534	537,608
Others	18,538	1,726	2,199	2,227	12,386
Purchase (Contractual) obligations[1]	234,083	158,799	35,597	7,422	32,265
Total contractual obligations	2,281,527	242,102	281,257	362,977	1,395,191

1. Purchase obligations are derived mainly from turbine supply agreements and engineering, procurement and construction contracts.

Contingencies

Cloudworks

The Cloudworks Acquisition provides for the potential payment of additional amounts to the vendors over a period of more than 40 years, from April 4, 2011, to the 40th anniversary of the last project under development that achieved commercial operation (or to April 4, 2061 if earlier). The deferred payments are intended to provide for the potential sharing of the value created if the Harrison Operating Facilities and projects under development perform better than the Corporation's expectations, and if Prospective Projects are developed.

The maximum aggregate amount of all deferred payments under the Cloudworks Acquisition is limited to a present value, as at the acquisition date, of $35 million. For the purposes of applying such a maximum aggregate amount, the amount of any deferred payments made is discounted to its present value by applying a mutually agreed-upon discount rate per annum. At any time during the five-year period after April 4, 2011, the Corporation has the right to cancel all of its obligations to make deferred payments by making a one-time payment of the amount by which the maximum aggregate amount of deferred payments, i.e. $35 million, exceeds the present value of any deferred payments (discounted to their present value amounts by applying an agreed discount rate per annum) made prior to the exercise of such right by the Corporation.

(in thousands of Canadian dollars, except as noted, and amounts per share)

Stardale
In connection with the Stardale Project acquisition, the corporation agreed to pay contingent considerations based on future events for a period of three years beginning April 20, 2011. These contingent considerations provide for a potential sharing of the value created if the Stardale Project benefits from a return better than the Corporation's initial expectation agreed upon with the seller as at the date of acquisition.

ADJUSTED CASH FLOWS FROM OPERATING ACTIVITIES
Adjusted cash flows from operating activities are calculated on the basis of cash flows from operating activities adjusted to eliminate the effect of changes in non-cash working capital items that are influenced by, among other things, seasonal variations and that would be financed with short-term debt. The effect of transaction costs is also eliminated, as these costs are financed by sources of capital other than cash flows from operating activities. The Corporation also adds or deducts amounts that are withdrawn from or invested in the Hydrology/wind power reserve, the Major maintenance reserve and the Levelization reserve with the exception of amounts invested at the time of a business acquisition or funded from long-term debt.

The Corporation calculates adjusted cash flows from operating activities as follows:

For the years ended December 31	2011	2010
Cash flows from operating activities	43,445	8,163
Change in non-cash working capital items	23,728	21,838
Transaction costs	1,863	5,159
Distributions paid to unitholders	-	9,688
Net funds withdrawn from (invested into) the reserve accounts (not funded from long-term debt)	7,989	42
Adjusted cash flows from operating activities	77,025	44,890

For the year ended December 31, 2011, Innergex generated $77.0 million in adjusted cash flows from operating activities ($44.9 million in 2010). This improvement reflects the increase in cash flows from operating activities attributable mainly to a $43.1 million increase in EBITDA, which was partly offset by an increase of $19.8 million in interest paid. This improvement also reflects an $8.0 million of funds withdrawn from the reserve accounts.

DIVIDENDS

For the years ended December 31	2011	2010
Dividends declared on Series A Preferred Shares	4,250	1,431
Dividends declared on common shares	43,990	33,324
Dividends declared on common shares ($ per share)	0.580	0.607

During the year ended December 31, 2011, the Corporation declared dividends of $4.3 million on its Series A Preferred Shares ($1.4 million in 2010) and $44.0 million on its common shares or $0.580 per common share ($33.3 million or $0.607 per common share in 2010).

SEGMENT INFORMATION
Geographic Segments
As at December 31, 2011, the Corporation had 19 hydroelectric facilities and five wind farms in Canada and one hydroelectric facility in the United States. For the year ended December 31, 2011, operating revenues generated by the Horseshoe Bend hydroelectric facility located in the United States totalled $2.7 million (idem in 2010), representing contributions of 1.8% (2.9% in 2010) to the Corporation's consolidated operating revenues for these periods.

Reportable Segments
The Corporation has three reportable segments: hydroelectric generation; wind power generation; and site development.

Through its hydroelectric generation and wind power generation segments, the Corporation sells electricity produced by its hydroelectric and wind farm facilities to publicly owned utilities. Through its site development segment, Innergex analyses potential sites and develops hydroelectric, wind farm and solar photovoltaic facilities up to the commissioning stage.

The accounting policies for these segments are the same as those described in the "Significant Accounting Policies" section of the Corporation's audited consolidated financial statements for the year ended December 31, 2011. The Corporation evaluates performance based on EBITDA and accounts for inter-segment and management sales at cost. Any transfers of assets from the site development segment to the hydroelectric or wind power generation segments are accounted for at cost.

(in thousands of Canadian dollars, except as noted, and amounts per share)

The operations of the Corporation's reportable segments are conducted by different teams, as each segment has different skill requirements.

There was no site development segment prior to the Combination on March 29, 2010, as the Fund was solely an operator.

	Hydroelectric Generation	Wind Power	Site Development	Total
For the year ended December 31, 2011				
Power generated (MWh)	1,552,846	352,580	-	1,905,426
Operating revenues	117,342	30,918	-	148,260
Expenses:				
Operating expenses	18,174	6,052	-	24,226
General and administrative expenses	4,297	1,987	4,081	10,365
Prospective projects expenses	-	-	2,473	2,473
Earnings before interest, income taxes, depreciation and amortization and other items	94,871	22,879	(6,554)	111,196
For the year ended December 31, 2010				
Power generated (MWh)	922,167	305,268	-	1,227,435
Operating revenues	64,870	26,515	-	91,385
Expenses:				
Operating expenses	9,430	5,099	-	14,529
General and administrative expenses	2,917	1,546	1,911	6,374
Prospective projects expenses	-	-	2,371	2,371
Earnings before interest, income taxes, depreciation and amortization and other items	52,523	19,870	(4,282)	68,111
As at December 31, 2011				
Goodwill	8,269	-	-	8,269
Total assets	1,307,949	386,343	339,117	2,033,409
Total liabilities	814,435	349,831	290,027	1,454,293
Acquisition of property, plant and equipment during the year	1,305	484	192,396	194,185
As at December 31, 2010				
Goodwill	8,269	-	-	8,269
Total assets	600,007	264,449	82,684	947,140
Total liabilities	260,267	168,126	159,847	588,240
Acquisition of property, plant and equipment during the year	1,304	318	37,224	38,846

Hydroelectric Generation Segment

For the year ended December 31, 2011, the hydroelectric generation segment produced 3% more power than the long-term average due to better-than-anticipated water flows at some of the segment's facilities, resulting in operating revenues of $117.3 million. In the corresponding period of 2010, production was below the long-term average by 3% due to lower-than-anticipated water flows at some of the segment's facilities, resulting in gross operating revenues of $64.9 million.

The contribution from the Harrison Operating Facilities is included as of April 5, 2011. For the year ended December 31, 2011, these facilities contributed $46.6 million to operating revenues.

The increase in total assets since December 31, 2010, is attributable to the Cloudworks Acquisition, partially offset by depreciation, amortization of property, plant and equipment as well as intangible assets.

The increase in total liabilities since December 31, 2010, is attributable to the Cloudworks Acquisition, partially offset by repayment of long-term debt.

Wind Power Generation Segment
For the year ended December 31, 2011, the wind power generation segment produced 7% less power than the long-term average due to lower-than-anticipated wind regime at all the wind farms, resulting in operating revenues of $30.9 million. When excluding the impact of Gros-Morne I production halt, the wind power generation segment produced 3% less power than the long-term average. In the corresponding period of 2010, production was below the long-term average by 4% due to lower-than-anticipated wind regimes at all the wind farms, resulting in gross operating revenues of $26.5 million.

Total assets have increased since December 31, 2010, due to the addition of the Montagne Sèche and Gros-Morne I facilities, partly offset by depreciation and amortization of property, plant and equipment as well as intangible assets.

The increase in total liabilities since December 31, 2010, is attributable to Montagne Sèche and Gros-Morne I facilities.

Site Development Segment
Prior to the Combination, this segment was relevant only for the Pre-Combination Innergex. As a result of the Combination, results from this segment have been recorded since March 30, 2010.

The increase in total assets since December 31, 2010, results mainly from the Cloudworks Acquisition and the construction of the Stardale Project and the Kwoiek Creek and Gros-Morne II projects.

The increase in total liabilities since December 31, 2010, is attributable mainly to the Development Projects, particularly the Stardale Project, Gros-Morne II and the Kwoiek Creek and Northwest Stave River projects.

RELATED PARTY TRANSACTIONS

As Manager of the Innergex Power Income Fund
Prior to the Combination, the Corporation provided services to the Fund and its subsidiaries under three agreements: the Management Agreement; the Administration Agreement; and the Services Agreement. The three agreements were terminated on the closing of the Combination. As a result, amounts were paid only during the first quarter of 2010. During that quarter, the Fund paid $0.6 million for services provided under these three agreements.

The Fund accounted for amounts paid under the three agreements at the amounts of the considerations paid.

Combination of the Fund and Innergex
Prior to the Combination, the Corporation was the owner of a 16.1% interest in the Fund and its manager. On March 29, 2010, the Fund and Innergex announced the completion of the strategic combination of the two entities whereby the Fund acquired Innergex by way of a reverse takeover, effecting at the same time the Fund's conversion to a corporation. The Combination resulted in the Fund's unitholders becoming Innergex shareholders as they agreed to exchange their units for Innergex shares based on an exchange ratio of 1.46 shares for each unit. The Combination also resulted in the unitholders of the Fund (other than Innergex) holding a 61% interest in Innergex with the Pre-Combination shareholders of Innergex holding the remaining 39% interest.

The total purchase price amounted to $195.2 million and was accounted for under IFRS 3. The fair value of the consideration transferred is based on the number of Fund units that would have had to be issued in order to provide the same percentage of ownership of the combined entity to the Fund's unitholders. The purchase price allocation is presented in Note 6 of the Corporation's audited consolidated financial statements for the year ended December 31, 2011.

For more information about the Combination, please refer to the "Arrangement Agreement" dated January 31, 2010, and the Joint Circular available on Innergex's website at www.innergex.com and on the SEDAR website at www.sedar.com.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with IFRS requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. During the reporting period, management made a number of estimates and assumptions pertaining primarily to the fair value calculation of the assets acquired and liabilities assumed in business acquisitions, impairment of assets, useful lives and recoverability of property, plant and equipment and intangible assets, deferred income taxes as well as the fair value of financial assets and liabilities, including derivative financial instruments. These estimates and assumptions are based on current market conditions, management's planned course of action and assumptions about future business and economic conditions. Changes in the underlying assumptions and estimates could have a material impact on the reported amounts. These estimates are reviewed periodically. If adjustments prove necessary, they are recognized in earnings in the period in which they are made. Other significant accounting policies are listed in Note 3 of the Corporation's audited consolidated financial statements for the year ended December 31, 2011.

ACCOUNTING CHANGES

FUTURE CHANGES

IAS 1 – Presentation of Items of Others Comprehensive Income

The IASB issued amendments to IAS 1 Presentation of Financial Statements to split items of other comprehensive income between those that are reclassed to earnings and those that do not. The standard is required to be adopted for periods beginning on or after July 1, 2012. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 9 – Financial instrument

As part of the project to replace IAS 39, Financial Instruments: Recognition and Measurement, this standard retains but simplifies the mixed measurement model and establishes two primary measurement categories for financial assets. More specifically, the standard:

- Deals with classification and measurement of financial assets;
- Establishes two primary measurement categories for financial assets: amortized cost and fair value;
- Prescribes that classification depends on entity's business model and the contractual cash flow characteristics of the financial asset;
- Eliminates the existing categories: held to maturity, available for sales, and loans and receivables.

Certain changes were also made regarding the fair value option for financial liabilities and accounting for certain derivatives linked to unquoted equity instruments.

The standard will be effective for annual periods beginning on or after January 1, 2015, with earlier adoption permitted.

The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 10 – Consolidated Financial Statement

The IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities. The standard is required to be adopted for periods beginning January 1, 2013. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 11 – Joint Arrangements

IFRS 11 will require investment in joint ventures to be accounted for using the equity method. This will result in significant changes in the presentation of the consolidated statements of financial position and the consolidated statements of earnings. Net earnings/loss and net assets are not expected to differ as a result of applying the equity method of accounting. However, the balances of each line item on the consolidated statements of financial position and the consolidated statements of earnings are expected to change significantly.

Several investments in associates and joint ventures are consolidated in the Corporation under IFRS. These investments are either, fully consolidated or proportionately consolidated. Under the IFRS 11 revised standard, some of these investments might have to be accounted for as investments on the consolidated statements of financial position with their results recognized as share of net earnings of a joint venture or an investee. The effective date for the application of the revised standard is January 1, 2013. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 12 – Disclosure of Interests in Other Entities
The IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires a company to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities. The standard is required to be adopted for periods beginning January 1, 2013. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 13 – Fair Value Measurement
The IASB issued IFRS 13 to provide comprehensive guidance for instances where IFRS requires fair value to be used. The standard provides guidance on determining fair value and requires disclosures about those measurements. The standard is required to be adopted for periods beginning January 1, 2013. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IAS 28 (2011) – Investments in Associates and Joint Ventures
IAS 28 was amended in 2011 to prescribe the accounting for investments in associates and set out the application of the equity method when accounting for investments in associates and joint ventures. IAS 28 is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Corporation is currently evaluating the impact of this amendment to IAS 28 on its consolidated financial statements.

CHANGES MADE IN 2011

IFRS Transition
The unaudited condensed consolidated financial statements for the year ended December 31, 2011, are the first financial statements prepared in accordance with IFRS. The Corporation applied IFRS standard for the preparation of these financial statements.

The Corporation had discussions with its lending financial institutions to ensure that adjustments related to IFRS would not have an impact on the methods of calculating financial ratios. As anticipated, there have been no issues with the existing wording of debts covenants and related agreements as a result of the conversion to IFRS.

IFRS
The Canadian Accounting Standards Board had announced the adoption of IFRS for publicly accountable enterprises in Canada. Effective January 1, 2011, companies had to convert from Canadian GAAP to IFRS. Accordingly, the Corporation has applied IFRS standard for the preparation of these audited consolidated financial statements.

The Corporation's transition date is January 1, 2010, being the date of the beginning of the comparative period. The Corporation prepared its Statement of Financial Position at that date. The closing date of the audited consolidated financial statements is December 31, 2011. The adoption date of the IFRS by the Corporation is January 1, 2011.

Under IFRS 1, the standards are applied retrospectively at the date of the transition with all adjustments to assets and liabilities taken to deficit unless certain exemptions or exceptions are applied. During the preparation of the financial statements, in conformity with IFRS 1, the Corporation elected to use allowed exemptions to other IFRS standards while applying exceptions to retrospective application for other IFRS standards.

The Corporation applied the following exemptions from other standards:

Business Combination
The Corporation applied the exemption allowed by the IFRS 1 on business combination. Business combinations that occurred before the transition date have not been restated in compliance with IFRS 3. The same classification as determined under Canadian GAAP has been kept. The assets and liabilities that were acquired or assumed in past business combinations were recognized at the IFRS transition date since they qualified for recognition under IFRS. The March 29, 2010, share exchange arrangement which occurred after the transition date is not comprised in the exemption's scope.

Deemed Cost of Property, Plant and Equipment and Intangible Assets
As allowed under IFRS 1, the Corporation used the values determined at the Fund's initial public offering on July 4, 2003, as its deemed cost of property, plant and equipment and intangible assets for IFRS and retrospectively recalculated accumulated depreciation and amortization since July 4, 2003 in regards of significant parts in accordance with International Accounting Standards ("IAS") 16, *Property, Plant and Equipment*.

Arrangements containing leases
IFRS 1 allows entities to determine whether an arrangement contains a lease in accordance with International Financial Reporting Interpretations Committee ("IFRIC") 4, *Determining whether an Arrangement contains a Lease* based on the facts and circumstances at the transition date rather than at the lease inception date. On transition, the Corporation has elected not to reapply the criteria for determining whether an arrangement contains a lease on the date of transition, given the same determination was made in accordance with Canadian GAAP.

The Corporation applied the following mandatory exception to the retrospective application of other IFRS:

- **Estimates**
  Hindsight was not used to create or revise estimates and accordingly the estimates in accordance with IFRS are consistent with the ones made with Canadian GAAP.

The following section presents the impact on the results of the conversion from Canadian GAAP to IFRS.

Revenues
The Corporation is entitled to subsidies under the ecoENERGY Initiative. The subsidies are equal to $10 per MWh produced at various facilities. As per the PPAs, the Corporation must transfer 75% of the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms ecoENERGY payments to Hydro-Québec.

Under Canadian GAAP, the Corporation netted ecoENERGY payments under operating revenues.

Under IAS-18, gross ecoENERGY payments are included in the facilities' revenues and a corresponding adjustment for the 75% transfer to Hydro-Québec is included in the facilities' operating expenses.

Accretion Expense on Asset Retirement Obligation
Under Canadian GAAP, asset retirement liability was initially recognized at its fair value by discounting the estimated future cash flows with a rate determined at the time the Corporation incurred a legal asset retirement obligation and when a reasonable estimate of the fair value could be made. The unwinding of the discounting was recognized as an accretion expense accounted for as an operating expense.

Under IAS 37, accretion expenses on asset retirement obligations must be adjusted to reflect the obligation by discounting the estimated future cash flows at an appropriate rate determined as at the statement of financial position date and must be accounted for as a financial expense.

Share-based Payment
Under Canadian GAAP, the Corporation recognized its share-based payment expense on a straight-line basis.

Under IFRS 2, entities are required to treat each vesting instalment as a separate share option grant because each instalment has a different vesting period.

Transaction Costs
Under Canadian GAAP, the Corporation capitalized transaction costs incurred in a business combination.

Under IFRS 3, transaction costs incurred in a business combination must be expensed in the period in which they are incurred.

Depreciation
Under Canadian GAAP, depreciation is based on the estimated useful lives of the assets.

Under IAS 16, depreciation is adjusted to reflect the depreciation of significant components based on their respective estimated useful lives.

Amortization
Under Canadian GAAP and IFRS, amortization is based on the estimated useful life of the intangible assets.

Under IAS 36, all the assets were subject to an impairment test as of January 1, 2010. The Corporation performed the impairment test and accordingly the carrying amounts of some intangible assets were impaired and this resulted in a lower amortization expense.

Under Canadian GAAP, the measurement date for issued equity is a few days before and after terms are agreed to and announced, and the Corporation recorded the non-controlling interests percentage of net assets acquired at their existing carrying values.

Under IFRS 3, the measurement date for issued equity is the acquisition date, and the non-controlling interests were measured at the non-controlling interests’ proportionate share of the net assets acquired at the share exchange arrangement date. For the Corporation, it resulted in a different purchase price allocation, which had an impact on the intangible assets and the related amortization.

Unrealized Loss on Unitholders’ Capital
Under Canadian GAAP, the Fund equity was comprised of trust units issued to unitholders.

Under IFRS, the trust units are considered as financial instruments and reclassified as liabilities whose variation in fair value is recognized in the consolidated statement of earnings.

Current Tax Expenses
Under Canadian GAAP, current tax expenses related to dividends declared on preferred shares were accounted along with the dividends. Under IAS 12, current tax related to dividends declared on preferred shares must be accounted for in the statement of earnings.

Deferred Income Taxes
Under Canadian GAAP, when a deferred tax asset related to a previous business combination is recognized, the benefit first reduces goodwill and then reduces unamortized intangible assets.

Under IAS 12, the recognition of a deferred tax asset related to a previous acquisition must be accounted for in the statement of earnings.

Under IAS 12, deferred tax related to dividends declared on preferred shares must be accounted for in the statement of earnings.

Adjustments made to the carrying values of property, plant and equipment, intangible assets, asset retirement obligations, long-term debt and convertible debentures have an impact on deferred taxes as well.

Distributions declared to unitholders
Under Canadian GAAP, distributions declared to unitholders were accounted for as distributions in the equity.

Under IAS 32, the unitholders’ capital is reclassified as a long-term liability and as such, distributions declared to unitholders are included in the net loss.

RISKS AND UNCERTAINTIES

The Corporation is exposed to various business risks and uncertainties and has outlined below those it considers material. However, additional risks and uncertainties that are not presently known to the Corporation or that are currently believed to be immaterial may adversely affect the Corporation's business. Additional risks and uncertainties are discussed in the “Risk Factors” section of the Corporation’s Annual Information Form for the year ended December 31, 2011.

Execution of Strategy
The Corporation’s strategy for building shareholder value is to develop or acquire high-quality renewable power production facilities generating sustainable cash flows and providing a high return on invested capital, and 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, 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.

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.

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
Holders of Common Shares and Series A 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.

ADDITIONAL INFORMATION AND UPDATES
Additional and updated information on the Corporation is available through its regular press releases, quarterly financial statements and Annual Information Form, which can be found on the Corporation's website at www.innergex.com and on the SEDAR website at www.sedar.com. Information contained in or otherwise accessible through our website does not form part of this MD&A and is not incorporated into the MD&A by reference.

QUARTERLY FINANCIAL INFORMATION

(in millions of dollars, unless otherwise stated)	For the three-month periods ended Dec. 31, 2011	Sept. 30, 2011	June 30, 2011	Mar. 31, 2011
Power generated (MWh)	403,920	666,009	595,317	240,180
Operating revenues	33.1	50.5	43.8	20.8
EBITDA	21.8	40.1	34.6	14.7
Net (loss) earnings attributable to owners of the parent	(13.9)	(26.2)	(6.5)	6.0
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(0.18)	(0.34)	(0.09)	0.08
Adjusted net earnings (loss)	(6.7)	8.0	1.1	(1.3)
Dividends declared on Series A Preferred Shares	1.1	1.1	1.1	1.1
Dividends declared on common shares	11.8	11.8	11.8	8.6
Dividends declared on common shares ($ per share)	0.145	0.145	0.145	0.145

(in millions of dollars, unless otherwise stated)	For the three-month periods ended Dec. 31, 2010	Sept. 30, 2010	June 30, 2010	Mar. 31, 2010
Power generated (MWh)	343,754	356,262	369,753	157,666
Operating revenues	26.8	25.2	25.4	14.0
EBITDA	18.9	19.7	18.8	10.7
Net earnings (loss) attributable to owners of the parent	14.9	(11.6)	(7.0)	(64.9)
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.23	(0.20)	(0.12)	(1.33)
Adjusted net earnings (loss)	3.4	3.2	3.3	(11.0)
Dividends declared on Series A Preferred Shares	1.4	-	-	-
Dividends declared on common shares	8.6	8.6	8.8	7.2
Dividends declared on common shares ($ per share)	0.145	0.145	0.148	0.169

Comparing the results for the most recent quarters makes apparent the seasonality that is characteristic of the Corporation's assets, i.e. that power generated, operating revenues and EBITDA vary from quarter to quarter. As the Corporation's total average long-term production is 74% hydroelectric, this seasonality can be explained by water flows that are normally at their highest in the second quarter due to the snow melt season and at their lowest in the first quarter due to the cold temperatures, which limit precipitation in the form of rain. However, premiums for the electricity generated during the coldest months of the year included in some PPAs of the Corporation's hydroelectric facilities attenuate this seasonality. The production of the wind farms also partially compensates for this seasonality experienced by hydroelectric facilities, as wind regimes are generally best in the first quarter of a typical year.

By excluding non-recurring items, readers would expect that the net earnings (loss) and net earnings (loss) per share reflect this seasonality characteristic of run-of-river hydroelectric plants and of wind farms. However, other factors also influence net earnings (loss) and net earnings (loss) per share, some of which have a relatively stable quarter-to-quarter impact while others are more variable. For the Corporation, the factor that causes the largest fluctuations in net earnings (loss) attributable to owners of the parent and net earnings (loss) attributable to owners of the parent per share is change in the market value of derivative financial instruments. As a result of the transition to IFRS, another factor impacting only the first quarter of 2010 is the $51.8 million unrealized loss on unitholders' capital. Historical analysis of net earnings (loss) attributable to owners of the parent and net earnings (loss) attributable to owners of the parent per share should therefore take these factors into account. It is important to bear in mind that changes in the market value of derivative financial instruments result from interest rate and inflation rate fluctuations and do not have an impact on the Corporation's EBITDA, finance costs or adjusted net earnings (loss).

FOURTH QUARTER RESULTS

Operating Facilities

During the fourth quarter of 2011, the Corporation's Operating Facilities produced 403,920 MWh (343,754 MWh in 2010). This increase is essentially due to the Cloudworks Acquisition.

Compared with the estimated long-term average, the Corporation produced 13% less energy than expected due mainly to lower-than-anticipated water flows at all British Columbia facilities during the last two months of 2011 and to lower-than-anticipated wind regimes at all wind farms during the month of December 2011.

Revenues

Revenues from operating activities totalled $33.1 million in the fourth quarter of 2011 ($26.8 million in 2010). This performance is due to additional revenues resulting from the Cloudworks Acquisition ($8.8 million), partly offset by lower revenues from the Saint-Paulin, Chaudière, Umbata Falls and Ashlu Creek facilities.

Expenses

In the fourth quarter of 2011, the Corporation incurred $8.0 million in operating expenses ($4.7 million in 2010) related to the operation of the power producing facilities. This increase is mainly the result of the Cloudworks Acquisition ($2.1 million) and the sand removal operation at the Horseshoe Bend facility.

The Corporation also incurred general and administrative expenses of $2.5 million during the period ($2.1 million in 2010). This increase is due to the Corporation's larger scale as a result of the Cloudworks Acquisition.

Prospective projects expenses totalled $0.9 million during the fourth quarter of 2011 ($1.2 million in 2010).

The Corporation incurred $15.3 million in finance costs during the last quarter of 2011 ($7.0 million in 2010). This increase is due mainly to the increase in long-term debt resulting from the Cloudworks Acquisition.

The depreciation and amortization expense totalled $14.3 million in the fourth quarter of 2011 ($9.2 million in 2010). The difference is attributable mainly to the greater asset base resulting from the Cloudworks Acquisition.

For the last quarter of 2011, the Corporation recorded a $19.6 million unrealized net loss on derivative financial instruments due mainly to the decrease in benchmark interest rates since September 30, 2011. For the corresponding quarter of 2010, Innergex recorded an unrealized net gain on derivative financial instruments of $15.5 million due to an increase in benchmark interest rates since September 30, 2010.

For the quarter ended in December 31, 2011, the provision for current income taxes totalled $1.4 million (recovery of $0.4 million in 2010). Innergex is able to minimize current income taxes due to its young pool of property, plant and equipment, which results in a substantial available unused capital cost allowance.

The Corporation recorded a future income tax recovery of $6.9 million in the fourth quarter of 2011 stemming primarily from an unrealized loss on derivative financial instruments. For the corresponding period in 2010, the Corporation recorded a provision for future income tax of $4.0 million.

Net Earnings (Loss)

The Corporation posted net loss and net loss attributable to the owners of the parent of $21.0 million and $13.9 million respectively (basic and diluted net loss of $0.18 per share) for the fourth quarter of 2011. For the corresponding period in 2010, net earnings and net earnings attributable to the owners of the parent totalled $14.7 million and $14.9 million respectively (basic and diluted net earnings of $0.23 per share). This $35.7 million negative variation in net earnings (loss) is attributable mainly to a $35.1 million negative variation in the fair market value of derivative, an $8.3 million increase in finance costs, and a $5.0 million increase in depreciation and amortization. These negative elements were offset by a $2.9 million increase in EBITDA and a $9.0 million favourable variation in income tax.

The basic and diluted per-share figures for the three-month period ended December 31, 2011, are based on a weighted average number of 81,282,460 and 81,368,057 commons shares respectively. 1,869,420 stock options were non-dilutive during the period concerned, as the average market price of the Corporation's common share was below the strike price. The other 808,024 options were dilutive as the average market price of the Corporation's common share was above the strike price. However, they were excluded from the computation of per-share figure, as the Corporation recognized a net loss for the three-month period ended December 31, 2011. Convertible Debentures were non-dilutive as the average market price was below the conversion price.

As at March 21, 2012, and December 31, 2011, the Corporation had a total of 81,282,460 common shares, 80,500 Convertible Debentures, 3,400,000 Series A Preferred Shares and 2,677,444 stock options outstanding. As at December 31, 2010, it had 59,532,606 common shares, 80,500 Convertible Debentures, 3,400,000 Series A Preferred Shares and 1,842,024 stock options outstanding.

SUBSEQUENT EVENTS

Execution of engagement letter

Kwoiek Creek

On February 2, 2012, the Corporation executed an engagement letter for an up to $160 million non-recourse term loan for the construction and long-term debt financing of the Kwoiek Creek project.

Northwest Stave River

On February 14, 2012, the Corporation executed an engagement letter for an up to $85 million non-recourse term loan for the construction and long-term debt financing of the Northwest Stave River project.

RESPONSIBILITY FOR FINANCIAL REPORTING

The consolidated financial statements of Innergex Renewable Energy Inc. (the “Corporation”) accompanying this annual report and all of the information herein concerning the Corporation are the responsibility of Management.

These consolidated financial statements were prepared by Management in accordance with **International Financial Reporting Standards (“IFRS”)** by applying the detailed accounting policies set out in the notes to the financial statements. Management is of the opinion that the consolidated financial statements were prepared based on reasonable and material criteria and using justifiable and reasonable estimates. The Corporation’s financial information, presented elsewhere in the annual report, is consistent with what is presented in the financial statements.

Management maintains efficient and high-quality internal accounting and management control systems while ensuring that costs are reasonable. These systems provide assurance that the financial information is relevant, accurate and reliable, and that the Corporation’s assets are correctly accounted for and adequately protected.

The Board of Directors of the Corporation is responsible for ensuring that Management fulfils its financial reporting responsibilities. In addition, the Board of Directors is ultimately responsible for reviewing and approving the Corporation’s consolidated financial statements. The Board of Directors fulfils this responsibility through its Audit Committee.

The Audit Committee is appointed by the Board of Directors and all of its members are external non-related Directors.

The Audit Committee meets with Management and the external auditors for the purposes of discussing internal controls relating to the financial reporting process, audit of financial information and other financial issues, and to make sure that each party is properly fulfilling its responsibilities. In addition, the Audit Committee reviews the annual report, the consolidated financial statements and the external auditors’ report. The Audit Committee submits its finding to the Board of Directors for review and for approval of the consolidated financial statements prior to their presentation to the shareholders. The Audit Committee also determines whether to retain the services of external auditors and to renew their mandate, which is subject to Board review and shareholders’ approval.

These financial statements were approved by the Corporation’s Board of Directors. The Corporation’s financial statements were audited by its external auditors, Samson Bélair/Deloitte & Touche s.e.n.c.r.l., in accordance with **Canadian generally accepted auditing standards** and on the shareholders’ behalf. Samson Bélair/Deloitte & Touche s.e.n.c.r.l. enjoy full and unrestricted access to the Audit Committee.

[s] Michel Letellier
Michel Letellier, MBA
President
and Chief Executive Officer

[s] Jean Perron
Jean Perron, CA, CMA
Chief Financial Officer and
Senior Vice President

Innergex Renewable Energy Inc.

Longueuil, Canada, March 21, 2012

Deloitte.

Independent Auditor's Report

To the Shareholders of Innergex Renewable Energy Inc.

We have audited the accompanying consolidated financial statements of Innergex Renewable Energy Inc. , which comprise the consolidated statements of financial position as at December 31, 2011, December 31, 2010 and January 1, 2010, and the consolidated statements of earnings, consolidated statements of comprehensive income (loss), consolidated statements of changes in shareholders' equity and consolidated statements of cash flows for the years ended December 31, 2011 and December 31, 2010, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Innergex Renewable Energy Inc. as at December 31, 2011, December 31, 2010 and January 1, 2010 and its financial performance and its cash flows for the years ended December 31, 2011 and December 31, 2010 in accordance with International Financial Reporting Standards.

Samson Bélair/Deloitte & Touche s.e.n.c.r.l.[1]

Montreal, Quebec
March 21, 2012

[1] Chartered accountant auditor permit No. 15452

CONSOLIDATED STATEMENTS OF EARNINGS

(in thousands of Canadian dollars except as noted and amounts per share)

For the years ended December 31	Notes	2011	2010
Revenues			(Note 1.4.3)
Operating		148,260	91,385
Expenses			
Operating		24,226	14,529
General and administrative		10,365	6,374
Prospective projects expenses		2,473	2,371
Earnings before interest, income taxes, depreciation and amortization and other items		111,196	68,111
Finance costs	22	53,122	23,749
Transaction costs		1,863	5,159
Realized gain on derivative financial instruments		-	(555)
Loss on contingent considerations		1,858	-
Other net revenues		(1,028)	(17)
Earnings before income taxes, depreciation and amortization and other items		55,381	39,775
Depreciation		31,177	19,358
Amortization		19,793	13,627
Unrealized net loss on derivative financial instruments		61,479	20,761
Unrealized loss on unitholders' capital		-	51,761
Expense related to royalty agreement upon share exchange arrangement	6	-	983
Unrealized net gain on foreign exchange		-	(28)
Loss before income taxes and distributions		(57,068)	(66,687)
(Recovery) provision for income taxes			
Current		464	(1,731)
Deferred		(13,828)	(3,491)
		(13,364)	(5,222)
Net loss before distributions declared to unitholders		(43,704)	(61,465)
Distributions declared to unitholders		-	7,238
Net loss		(43,704)	(68,703)
Net loss attributable to:			
Owners of the parent		(40,547)	(68,635)
Non-controlling interests		(3,157)	(68)
		(43,704)	(68,703)
Weighted average number of common shares outstanding (in 000)	23	75,681	55,530
Basic net loss per share	23	(0.59)	(1.13)
Diluted weighted average number of common shares outstanding (in 000)	23	75,755	55,530
Diluted net loss per share	23	(0.59)	(1.13)

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in thousands of Canadian dollars except as noted and amounts per share)

For the years ended December 31	2011	2010 (Note 1.4.3)
Net loss	(43,704)	(68,703)
Other items of comprehensive income (loss)		
Foreign exchange gain (loss) on translation of a self-sustaining foreign subsidiary (including $15 of income tax recovery, $113 of income tax expense in 2010)	100	(221)
Foreign exchange (loss) gain on the designated portion of the US$ denominated debt used as hedge on the investment in a self-sustaining foreign subsidiary (net of $16 of income tax recovery, nil in 2010)	(110)	251
Realized gain from reduction in net investment in foreign subsidiaries (nil income tax)	-	135
	(10)	165
Comprehensive loss	(43,714)	(68,538)
Total comprehensive loss attributable to:		
Owners of the parent	(40,557)	(68,470)
Non-controlling interests	(3,157)	(68)
	(43,714)	(68,538)

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

(in thousands of Canadian dollars except as noted and amounts per share)

As at	Notes	Dec. 31, 2011	Dec. 31, 2010	Jan. 1, 2010
Assets			(Note 1.4.2)	(Note 1.4.1)
Current assets				
Cash and cash equivalents		35,279	42,116	9,352
Restricted cash and short-term investments	7	53,415	-	-
Accounts receivable	8	36,894	14,685	6,164
Reserve accounts	9	-	494	477
Income tax receivable	14	1,664	2,200	-
Derivative financial instruments	10	1,791	1,679	1,369
Prepaid and others		4,074	4,648	1,938
		133,117	65,822	19,300
Reserve accounts	9	42,154	20,947	14,913
Property, plant and equipment	11	1,259,834	612,310	332,164
Intangible assets	12	441,262	210,838	107,360
Project development costs	13	98,042	5,908	-
Derivative financial instruments	10	8,248	9,534	8,779
Deferred tax assets	14	24,485	13,178	2,641
Goodwill	15	8,269	8,269	8,269
Other long-term assets		17,998	334	-
		2,033,409	947,140	493,426
Liabilities				
Current liabilities				
Dividends/distribution payable to shareholders/unitholders		12,848	10,064	2,451
Accounts payable and accrued liabilities	16	26,616	21,747	6,784
Income tax liabilities	14	2,835	2,164	2,790
Derivative financial instruments	10	20,287	8,543	5,422
Long-term debt	17	19,475	9,259	2,758
Contingent considerations	19	983	-	-
		83,044	51,777	20,205
Construction holdbacks		2,081	76	-
Derivative financial instruments	10	71,158	22,597	4,795
Accrual for acquisition of long-term assets		41,267	-	-
Long-term debt	17	1,030,037	349,431	221,803
Liability portion of convertible debentures	18	79,490	79,334	-
Contingent considerations	19	2,904	-	-
Asset retirement obligations	20	3,858	2,384	1,185
Deferred tax liabilities	14	140,454	82,641	66,973
Unitholders' capital		-	-	270,535
		1,454,293	588,240	585,496
Shareholders' equity (deficiency)				
Common share capital	6,21	1	5,720	-
Preferred shares	21 a)	82,589	82,589	-
Contributed surplus from reduction of capital on common shares	21 b)	656,281	453,793	-
Share-based payment		1,361	928	-
Equity portion of convertible debentures	18	1,340	1,340	-
Deficit		(277,083)	(188,296)	(92,143)
Accumulated other comprehensive income		228	238	73
Equity (deficiency) attributable to owners		464,717	356,312	(92,070)
Non-controlling interests		114,399	2,588	-
Total shareholders' equity (deficiency)		579,116	358,900	(92,070)
		2,033,409	947,140	493,426

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

(in thousands of Canadian dollars except as noted and amounts per share)

For the year ended December 31, 2011	Number of common shares (In 000's)	Common share capital account	Preferred shares	Contributed surplus from reduction of capital on common shares	Share-based payment	Equity portion of convertible debentures (Note 18)	Deficit	Accumulated other comprehensive income	Equity attributable to owners	Non-controlling interests	Shareholders' equity
Balance January 1, 2011	59,533	5,720	82,589	453,793	928	1,340	(188,296)	238	356,312	2,588	358,900
Common shares issued on April 4, 2011 (Note 5 a) :											
- public offering	17,750	163,527							163,527		163,527
- private placement	3,999	39,018							39,018		39,018
- issuance fees (Net of $2,030 of deferred income taxes)		(5,776)							(5,776)		(5,776)
Business acquisition (Note 5 a)									-	114,968	114,968
Reduction of capital on common shares (Note 21 b)		(202,488)		202,488					-		-
Net loss							(40,547)		(40,547)	(3,157)	(43,704)
Other items of comprehensive loss								(10)	(10)		(10)
Comprehensive loss	-	-	-	-	-	-	(40,547)	(10)	(40,557)	(3,157)	(43,714)
Share-based payment					433				433		433
Dividends declared on common shares							(43,990)		(43,990)		(43,990)
Dividends declared on preferred shares							(4,250)		(4,250)		(4,250)
Balance December 31, 2011	81,282	1	82,589	656,281	1,361	1,340	(277,083)	228	464,717	114,399	579,116

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENT OF CHANGES IN SHAREHOLDERS' EQUITY

(in thousands of Canadian dollars except as noted and amounts per share)

For the year ended December 31, 2010	Number of common shares/units (In 000's)	Common share/unit capital account	Preferred shares	Contributed surplus from reduction of capital on common shares	Share-based payment	Equity portion of convertible debentures (Note 18)	Deficit	Accumulated other comprehensive income	Equity attributable to owners	Non-controlling interests	Shareholders' equity
Balance January 1, 2010	-	-	-	-	-	-	(92,143)	73	(92,070)	-	(92,070)
Note 6:											
- Unitholders' value upon share exchange arrangement	29,404	322,296							322,296		322,296
- Reduction of unitholders' capital account owned by the Corporation and not converted into common shares	(4,724)	(57,165)							(57,165)		(57,165)
- Adjustment to number of units to reflect the 1.46 conversion ratio	11,353	-							-		-
- Common shareholders' capital account from common shares of the Corporation already issued prior to the share exchange arrangement	23,500	193,399							193,399		193,399
- Balances accounted upon share exchange arrangement		983			497	1,340			2,820	2,656	5,476
Reduction of capital on common shares (Note 21 b))		(453,793)		453,793					-		-
Series A preferred shares issued on September 14, 2010 (Note 21 a))			82,589						82,589		82,589
Net loss							(68,635)		(68,635)	(68)	(68,703)
Other items of comprehensive income								165	165		165
Comprehensive income	-	-	-	-	-	-	(68,635)	165	(68,470)	(68)	(68,538)
Share-based payment					431				431		431
Dividends declared on common shares							(26,086)		(26,086)		(26,086)
Dividends declared on preferred shares							(1,432)		(1,432)		(1,432)
Balance December 31, 2010	59,533	5,720	82,589	453,793	928	1,340	(188,296)	238	356,312	2,588	358,900

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands of Canadian dollars except as noted and amounts per share)

For the years ended December 31	Notes	2011	2010
Operating activities			(Note 1.4.4)
Net loss		(43,704)	(68,703)
Items not affecting cash:			
Depreciation of property, plant and equipment		31,177	19,358
Amortization of intangible assets		19,793	13,627
Unrealized net loss on derivative financial instruments		61,479	20,761
Compensation interest	22	7,199	-
Amortization of financing fees	22	231	768
Amortization of revaluation of long-term debt and convertible debenture	22	1,084	(7)
Accretion expense on asset retirement obligations	22	330	556
Accretion expenses on contingent considerations	22	177	-
Share-based payment		433	431
Unrealized loss on unitholders' capital		-	51,761
Unrealized foreign exchange gain		-	(28)
Deferred income taxes recovery		(13,828)	(3,491)
Expense related to royalty agreement upon share exchange arrangement	6	-	983
Others		100	82
Effect of exchange rate fluctuations		(296)	51
Interest in long-term debt and convertible debentures	22	44,101	22,432
Interest paid		(42,035)	(22,246)
Loss on contingent considerations		1,858	-
Contingent considerations paid		(1,147)	-
Provision for current income taxes (recovery)		464	(1,731)
Income taxes paid		(243)	(2,153)
Distributions declared to unitholders		-	7,238
Distributions paid to unitholders		-	(9,688)
		67,173	30,001
Changes in non-cash operating working capital items	25	(23,728)	(21,838)
		43,445	8,163
Financing activities			
Dividends paid on common shares		(40,836)	(17,454)
Dividends paid on preferred shares		(4,620)	-
Increase of long-term debt		270,117	134,220
Repayment of bank loan		-	(12,900)
Repayment of long-term debt		(47,475)	(205,539)
Payment of deferred financing costs		(5,983)	(1,724)
Net proceeds from issuance of common share capital	5 a)	155,721	-
Net proceeds from issuance of Serie A preferred shares		-	81,743
		326,924	(21,654)

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands of Canadian dollars except as noted and amounts per share)

For the years ended December 31	Notes	2011	2010
Investing activities			(Note 1.4.4)
Cash acquired on business acquisitions	5, 6	4,943	88,394
Business acquisitions	5	(160,844)	-
Additions to property, plant and equipment		(178,896)	(29,667)
Additions to intangible assets		(3,469)	(413)
Additions to project development costs		(31,726)	(9,056)
Additions to other long-term assets		(724)	(221)
Increase of restricted cash and short-term investments		(15,531)	-
Short-term loan to a partner		1,000	(1,000)
Proceeds from disposal of property, plant and equipment		28	298
Net funds withdrawn from the levelization reserve		494	570
Net funds withdrawn from (invested into) the hydrology/wind power reserve		5,933	(2,081)
Net funds withdrawn from (invested into) the major maintenance reserve		1,562	(463)
		(377,230)	46,361
Effects of exchange rate changes on cash and cash equivalents		24	(106)
Net (decrease) increase in cash and cash equivalents		(6,837)	32,764
Cash and cash equivalents, beginning of year		42,116	9,352
Cash and cash equivalents, end of year		35,279	42,116
Cash and cash equivalents is comprised of:			
Cash		22,940	9,965
Short-term investments		12,339	32,151
		35,279	42,116

Additional information is presented in Note 25.

The accompanying notes are an integral part of these audited consolidated financial statements.

DESCRIPTION OF BUSINESS

Innergex Renewable Energy Inc. (the "Corporation") was incorporated under the *Canada Business Corporation Act* on October 25, 2002. The Corporation is a developer, owner and operator of renewable power-generating facilities, essentially focused on the hydroelectric, wind power and solar photovoltaic sectors. The head office of the Corporation is located at 1111, St-Charles Street West, East Tower, Suite 1255, Longueuil, Qc, J4K 5G4, Canada.

On March 29, 2010, pursuant to the share exchange arrangement as described in Note 6, the Corporation acquired 100% of the issued and outstanding units of Innergex Power Income Fund ("the Fund") by issuing 36,033 thousands common shares of the Corporation. The Fund was an unincorporated open-ended trust established on October 25, 2002 under the laws of the Province of Quebec. The Fund, which began operations on July 4, 2003, was established to indirectly acquire and own interests in renewable power generating facilities. Legally, the Corporation became the parent of the Fund. However, as a result of the transaction, control of the combined entity was passed to the unitholders of the Fund, and the Fund is identified as the acquirer for accounting purposes in accordance with International Financial Reporting Standards ("IFRS"). This type of share exchange is referred to as a "reverse acquisition". In a reverse acquisition situation, the legal parent is deemed to be a continuation of the acquiring enterprise, i.e., the legal subsidiary. As a result, the consolidated financial statements are a continuation of the consolidated financial statements of the Fund. The capital stock represents the authorized and issued share of the legal parent and the dollar amount of shareholders' equity is that of the Fund.

Prior to the share exchange arrangement, the Corporation administered the Fund and managed Innergex Power Trust ("IPT"), a wholly owned subsidiary of the Fund; IPT indirectly owned the Fund's assets and investments. The Corporation was also providing management services to the operators of the Fund's facilities.

Following the share exchange arrangement, the Fund distributed all its assets and transferred all of its liabilities to the Corporation.

These consolidated financial statements were approved by the Board of Directors on March 21, 2012.

The impact of the transition from the previous Canadian Generally Accepted Accounting Principles ("GAAP") to IFRS is presented in Notes 1 and 2.

These consolidated financial statements have been prepared in accordance with the accounting policies described in Note 3.

(in thousands of Canadian dollars except as noted and amounts per share)

Principal subsidiaries

The following provides information about the principal subsidiaries of the Corporation as at December 31, 2011. All subsidiaries reside in Canada except the Horseshoe Bend Hydroelectric Company that resides in the USA.

Subsidiaries	Voting rights owned (1) %	Accounting method used
Innergex, L.P.	100	Consolidation
Innergex Montmagny, L.P.	100	Consolidation
Hydro-Windsor, L.P.	100	Consolidation
Trent-Severn Power, L.P.	100	Consolidation
Horseshoe Bend Hydroelectric Company	100	Consolidation
Rutherford Creek Power L.P.	100	Consolidation
Innergex AAV, L.P. (2)	100	Consolidation
Innergex BDS, L.P. (2)	100	Consolidation
Innergex CAR, L.P. (2)	100	Consolidation
Innergex GM, L.P. (2)	100	Consolidation
Innergex MS, L.P. (2)	100	Consolidation
Glen Miller Power, L.P.	100	Consolidation
Ashlu Creek Investments, L.P.	100	Consolidation
Cloudworks Energy Inc. (3)	100	Consolidation
Stardale Solar L.P. (4)	100	Consolidation
Northwest Stave River Hydro L.P.	100	Consolidation
Fitzsimmons Creek Hydro, L.P.	66.67	Consolidation with non-controlling interest
Creek Power Inc.	66.67	Consolidation with non-controlling interest
Douglas Creek Project L.P. (3)	50.01	Consolidation with non-controlling interest
Fire Creek Project L.P. (3)	50.01	Consolidation with non-controlling interest
Lamont Creek Project L.P. (3)	50.01	Consolidation with non-controlling interest
Stokke Creek Project L.P. (3)	50.01	Consolidation with non-controlling interest
Tipella Creek Project L.P. (3)	50.01	Consolidation with non-controlling interest
Upper Stave Project L.P. (3)	50.01	Consolidation with non-controlling interest
Kwoiek Creek Resources, L.P.	50	Consolidation with non-controlling interest
Viger-Denonville, L.P.	50	Proportionate consolidation
Umbata Falls, L.P.	49	Proportionate consolidation

(1) % of ownership and % of voting rights held are the same except for Kwoiek Creek project where the Corporation owns more than 50% of the economic interest.
(2) Undivided owner of a 38% stake in the l'Anse-à-Valleau, Baie-des-Sables, Carleton, Gros-Morne and Montagne Sèche wind farms.
(3) Results are consolidated since the acquisition on April 4, 2011.
(4) Results are consolidated since the acquisition on April 20, 2011.

1. FIRST TIME ADOPTION OF THE INTERNATIONAL FINANCIAL REPORTING STANDARDS

1.1 IFRS 1 Application

The consolidated financial statements of the Corporation for the year ended December 31, 2011 are the first annual financial statements prepared in accordance with IFRS. The Corporation applied IFRS 1 standard for the preparation of these financial statements.

The transition date of the Corporation is January 1, 2010, being the date of the beginning of the comparative period. The Corporation prepared its Statement of Financial Position at that date. The closing date of the audited consolidated financial statements is December 31, 2011. The adoption date of the IFRS by the Corporation is January 1, 2011.

Under IFRS 1 the standards are applied retrospectively at the date of transition with all adjustments to assets and liabilities taken to deficit unless certain exemptions or exceptions are applied. During the preparation of the consolidated financial statements, in conformity with IFRS 1, the Corporation elected to use allowed exemption to other IFRS standards while applying exceptions to retrospective application for other IFRS standards.

The Company completed an impairment test of its assets at January 1, 2010 and concluded that some of the assets were impaired in accordance with IFRS as described in Note 1.4.1.

1.2 Exemptions from other IFRS's

The Corporation applied the following exemptions from other standards:

a) Business combination

The Corporation applied the exemption allowed by the IFRS 1 on business combinations. Business combinations that occurred before January 1, 2010, the date of transition to IFRS's, have not been restated in compliance with IFRS 3. The same classification as determined under Canadian GAAP has been kept. The assets and liabilities that were acquired or assumed in past business combinations were recognized at the date of transition to IFRS since they qualified for recognition under IFRS. The March 29, 2010 share exchange arrangement which occurred after the date of transition is not part of the scope of the exemption.

b) Deemed cost of property, plant and equipment and intangible assets.

As allowed under IFRS 1, the Corporation used the values determined at the Initial Public Offering of the Fund, on July 4, 2003, as its deemed cost of property, plant and equipment and intangible assets for IFRS and retrospectively recalculated accumulated depreciation and amortization since July 4, 2003 in regards of significant parts in accordance with International Accounting Standards ("IAS") 16, *Property, Plant and Equipment*.

c) Arrangements containing leases

IFRS 1 allows entities to determine whether an arrangement contains a lease in accordance with International Financial Reporting Interpretations Committee ("IFRIC") 4, *Determining whether an Arrangement contains a Lease* based on the facts and circumstances at the transition date rather than at the lease inception date. On transition, the Corporation has elected not to reapply the criteria for determining whether an arrangement contains a lease on the date of transition, given the same determination was made in accordance with Canadian GAAP.

1.3 Exception to the retrospective application of other IFRS

The Corporation applied the following mandatory exception to the retrospective application of other IFRS:

a) Estimates

Hindsight was not used to create or revise estimates and accordingly, the estimates in accordance with IFRS are consistent with the ones made in accordance with Canadian GAAP.

1. FIRST TIME ADOPTION OF THE INTERNATIONAL FINANCIAL REPORTING STANDARDS (CONTINUED)

1.4 Reconciliation between IFRS and Canadian GAAP

The following reconciliations detail the transitional effect to the IFRS:

- Financial position as at January 1, 2010 (Note 1.4.1)
- Financial position as at December 31, 2010 (Note 1.4.2)
- Statement of Earnings and comprehensive income for the year ended December 31, 2010 (Note 1.4.3)
- Statement of cash flows for the year ended December 31, 2010 (Note 1.4.4)

(in thousands of Canadian dollars except as noted and amounts per share)

1.4.1 Reconciliation of financial position as at January 1, 2010

Consolidated statement of financial position	Canadian GAAP	Notes	IFRS transition effect	IFRS
Assets				
Current assets				
Cash and cash equivalents	9,352			9,352
Accounts receivable	6,164			6,164
Reserve accounts	477			477
Deferred tax assets	213	a)	(213)	-
Derivative financial instruments	1,369			1,369
Prepaid and others	1,938			1,938
	19,513		(213)	19,300
Reserve accounts	14,913			14,913
Property, plant and equipment	334,199	b)	(2,035)	332,164
Intangible assets	119,426	c)	(12,066)	107,360
Derivative financial instruments	8,779			8,779
Deferred tax assets	2,372	a)	213	
		a)	56	2,641
Goodwill	8,269			8,269
Other long-term assets	670	d)	(670)	-
	508,141		(14,715)	493,426
Liabilities				
Current liabilities				
Distribution payable to unitholders	2,451			2,451
Accounts payable and accrued liabilities	9,574	e)	(2,790)	6,784
Income tax liabilities	-	e)	2,790	2,790
Derivative financial instruments	5,422			5,422
Long-term debt	2,758			2,758
	20,205		-	20,205
Derivative financial instruments	4,795			4,795
Long-term debt	221,803			221,803
Asset retirement obligations	977	f)	208	1,185
Deferred tax liabilities	70,883	a)	(838)	
		a)	(3,072)	66,973
Unitholders' capital	-	g)	270,535	270,535
	318,663		266,833	585,496
Unitholders' equity (Deficiency)				
Unitholders' capital	309,681	g)	(309,681)	-
Deficit	(120,274)	a)	895	
		a)	3,072	
		b)	(2,038)	
		c)	(12,066)	
		d)	(670)	
		f)	(208)	
		g)	39,146	(92,143)
Accumulated other comprehensive income	71	a)	(1)	
		b)	3	73
Equity (Deficiency) attributable to owners	189,478		(281,548)	(92,070)
	508,141		(14,715)	493,426

1.4.1 Reconciliation of Financial position as at January 1, 2010 (continued)

a) Deferred tax assets / liabilities

Under IAS 1, deferred tax assets or liabilities should not be classified as current assets or liabilities. Accordingly, the $213 current portion of deferred tax assets has been reclassified with the long-term deferred tax assets.

Adjustments made to the carrying value of Property, plant and equipment and to Accretion expenses on asset retirement obligations explain an increase of $56 in deferred tax assets and a decrease of $838 in deferred liabilities. These elements have corresponding entries of $895 and $1 into deficit and accumulated other comprehensive income, respectively.

Adjustments made to the intangible assets following the impairment test as at January 1, 2010 explain $3,072 of the reduction in deferred tax liabilities with a corresponding entry into deficit.

b) Property, plant and equipment

Under IAS 16, accumulated depreciation of property, plant and equipment is adjusted to reflect the depreciation of significant components based on their respective estimated useful lives. The accumulated depreciation of property, plant and equipment is increased resulting in a lower carrying value of $2,035 with corresponding entries in the deficit increased by $2,038 and the accumulated other comprehensive income increased by $3.

c) Intangible assets

The Corporation performed an impairment test, as of January 1, 2010, and accordingly the carrying amounts of intangible assets were impaired by an amount of $12,066 with a corresponding entry in the deficit.

d) Other long-term assets

Under IFRS 3, transaction costs incurred in a business combination must be expensed in the period they are incurred, whereas they were capitalized under section 1581 of the Canadian Institute of Chartered Accountant (“CICA”) Handbook. As a result, the transaction costs of $670 incurred for the share exchange arrangement described in Note 6, have been derecognized with a corresponding entry to the deficit account.

e) Income tax liabilities

Under IAS 1, the Corporation must present the income tax liabilities of $2,790 separately from other liabilities.

f) Asset retirement obligations

Under IAS 37, accretion expense must be adjusted to reflect the obligation by discounting the estimated future cash flows with an appropriate rate determined as at the statement of financial position date. The rate at which the cash flows have been discounted was adjusted resulting in an increase in asset retirement obligations of $208 with a corresponding entry in the deficit.

g) Unitholders’ capital

Under IAS 32, the unitholders’ capital of the Fund is reclassified as a long-term liability and accounted for as a financial instrument at fair value. As at January 1, 2010, the unitholders’ capital is reduced by $309,681. The fair value of the unitholders’ capital was estimated at $270,535 and reclassified as a long-term liability. An adjustment of $39,146 has been recorded in the deficit to reflect the excess of the carrying value of the unitholders’ capital under Canadian GAAP over the value of the liability.

(in thousands of Canadian dollars except as noted and amounts per share)

1.4.2 Reconciliation of financial position as at December 31, 2010

Consolidated statement of financial position	Canadian GAAP	Notes	IFRS transition effect	IFRS
Assets				
Current assets				
Cash and cash equivalents	42,116			42,116
Accounts receivable	16,026	a)	(1,341)	14,685
Reserve accounts	494			494
Deferred tax assets	2,133	b)	(2,133)	-
Income tax receivable	-	a)	2,200	2,200
Derivative financial instruments	1,679			1,679
Prepaid and others	4,648			4,648
	67,096		(1,274)	65,822
Reserve accounts	20,947			20,947
Property, plant and equipment	614,142	c)	(3,718)	
		c)	1,886	612,310
Intangible assets	186,490	d)	(11,378)	
		d)	433	
		d)	35,293	210,838
Project development costs	9,688	e)	(3,780)	5,908
Derivative financial instruments	9,534			9,534
Deferred tax assets	14,269	b)	(1,157)	
		b)	66	13,178
Goodwill	7,901	f)	368	8,269
Other long-term assets	763	g)	(429)	334
	930,830		16,310	947,140
Liabilities				
Current liabilities				
Dividends / distribution payable to shareholders / unitholders	10,152	h)	(88)	10,064
Accounts payable and accrued liabilities	22,964	h)	(1,217)	21,747
Income tax liabilities	-	a)	859	
	-	h)	1,305	2,164
Deferred tax liabilities	319	b)	(319)	-
Derivative financial instruments	8,543			8,543
Long-term debt	9,259			9,259
	51,237		540	51,777
Construction holdbacks	76			76
Derivative financial instruments	22,597			22,597
Long-term debt	349,431			349,431
Liability portion of convertible debentures	79,334			79,334
Asset retirement obligations	1,591	i)	793	2,384
Deferred tax liabilities	79,219	b)	(2,971)	
		j)	6,393	82,641
	583,485		4,755	588,240

(in thousands of Canadian dollars except as noted and amounts per share)

1.4.2 Reconciliation of financial position as at December 31, 2010 (continued)

Consolidated statement of financial position	Canadian GAAP	Notes	IFRS transition effect	IFRS
Shareholders' equity				
Common share capital	1	k)	5,719	5,720
Preferred shares	82,589		-	82,589
Contributed surplus from reduction of capital on common shares	420,627	k)	20,551	
		l)	12,615	453,793
Share-based payment	828	m)	100	928
Equity portion of convertibles debentures	1,841	n)	(501)	1,340
Deficit	(158,777)	c)	24	
		c)	(3,079)	
		d)	(11,378)	
		d)	433	
		d)	(1,367)	
		f)	368	
		g)	(5,829)	
		i)	(651)	
		j)	4,602	
		l)	(12,615)	
		m)	(100)	
		o)	68	
		p)	5	(188,296)
Accumulated other comprehensive income	236	c)	12	
		p)	(10)	238
Equity attributable to owners	347,345		8,967	356,312
Non-controlling interests	-	o)	2,588	2,588
Total shareholders' equity	347,345		11,555	358,900
	930,830		16,310	947,140

a) Income tax receivable

Under IAS 1, the Corporation must present the current tax assets separately from other assets. Consequently, an amount of $859 was reclassified from Accounts receivable to Income tax liabilities and an amount of $2,200 was reclassified from Accounts receivable to Income tax receivable.

b) Deferred tax assets

Under IAS 1, deferred tax assets or liabilities should not be classified as current assets or liabilities. Accordingly, the $2,133 current portion of deferred tax assets and the $319 current portion of deferred tax liabilities have been reclassified amongst deferred tax assets (reduction of $1,157) and deferred tax liabilities (reduction of $2,971).

Those four elements resulted in a net increase in deferred tax assets of $66:

- Adjustments made to the carrying values of Property, plant and equipment and to the accretion expense on the Asset retirement obligations explain the increase of $58 in deferred tax assets.

- In addition, a deferred tax liability was recognized on a difference resulting from the initial recognition of intangible properties in the course of a business combination. It resulted in a decrease in the deferred tax assets of $314.

1.4.2 Reconciliation of financial position as at December 31, 2010 (continued)

- Furthermore, IAS 12 contains guidance on calculating deferred tax in relation to compound financial instruments. According to these rules, a decrease of $303 was made to the deferred tax assets.
- Additionally, IAS 12 and the deferred tax recognition principle relating to temporary differences are based on recovering or settling the carrying amount of the asset or liability at the reporting date. According to that principle, adjustments were made to the deferred tax assets booked on long-term debt. It was increased by $625.

c) Property, plant and equipment

Under IAS 16, accumulated depreciation of property, plant and equipment is adjusted to reflect the depreciation of significant components based on their respective estimated useful lives. The accumulated depreciation of property, plant and equipment is increased resulting in a lower carrying value of $3,718 with corresponding entries in the deficit of $3,079, the accumulated other comprehensive income of $12 and the intangible assets of $651. The later amount is included in the $35,293 adjustment in Note 1.4.2 d).

Under IFRS 3, the measurement date for equity issued is different than under section 1581 of the CICA Handbook and the non-controlling interest were measured at fair value of the net assets acquired on the share exchange arrangement. This resulted into a net increase in fair value of property, plant and equipment of $1,862 and the depreciation expense was decreased by $24. The total adjustment on property, plant and equipment is $1,886 and the later amount is included in the $20,551 adjustment in Note 1.4.2 k).

d) Intangible assets

The Corporation performed an impairment test as at January 1, 2010, using discounted cash flows as required under IAS 36 and, accordingly, the carrying amounts of intangible assets were impaired by an amount of $12,066. The impact of the impairment test resulted in a lower amortization expense by an amount of $688. The net adjustment on intangible assets is $11,378 with a corresponding entry in the deficit.

Under IAS 12, the recognition of a deferred income tax asset related to a previous acquisition must be accounted for in the statement of earnings. A reversal of the $433 decrease in the carrying amount of the intangible assets that was accounted for under Section 3465 of the CICA handbook is accounted with a corresponding entry to the deficit account.

Under IFRS 3, the measurement date for equity issued is different than under section 1581 of the CICA Handbook and the non-controlling interests were measured at the non-controlling interests' proportionate share of the net assets acquired on the share exchange arrangement. This resulted into an increase in fair value of $36,660 and the amortization expense was increased by $1,367. The net adjustment to intangible assets is $35,293.

e) Project development costs

Under IFRS 3, the measurement date for equity issued is different than under section 1581 of the CICA Handbook and the non-controlling interests were measured at the non-controlling interests' proportionate share of the net assets acquired on the share exchange arrangement. This resulted into a decrease in project development costs' fair value of $3,780.

f) Goodwill

Under IAS 12, the recognition of a deferred tax assets related to a previous acquisition must be accounted for in the statement of earnings. A reversal of the $368 decrease in the carrying amount of the goodwill that was accounted for under Section 3465 of the CICA handbook is accounted with a corresponding entry to the deficit account.

g) Other long-term assets

Under IFRS 3, transaction costs incurred in a business combination must be expensed in the period they are incurred, whereas they were capitalized under section 1581 of the CICA handbook. As a result, the transaction costs of $429 related to the acquisition of Cloudworks Energy inc. described in Note 5 a) and the transaction costs of $5,400 incurred in view of the March 2010 share arrangement described in Note 6, have been derecognized with a corresponding total entry to the deficit account of $5,829.

1.4.2 Reconciliation of financial position as at December 31, 2010 (continued)

h) Income tax liabilities

Under IAS 1, the Corporation must present the income tax liabilities separately from other liabilities. An amount of $1,305 was reclassified from Accounts payable and other liabilities to Income tax liabilities and an amount of $88 was reclassified from Dividends/distribution payable to shareholders/unitholders to Income tax liabilities.

i) Asset retirement obligations

Under IAS 37, accretion expense must be adjusted to reflect the obligation by discounting the estimated future cash flows with an appropriate rate determined as at the statement of financial position date. The rate at which the cash flows have been discounted was adjusted resulting in an increase in asset retirement obligations of $793 with a corresponding increase of the deficit by $651 and a corresponding decrease of $142 in the intangible assets. This later amount is included in the $35,293 adjustment in Note 1.4.2 d).

j) Deferred tax liabilities

Those five elements resulted in a net increase in deferred tax liabilities of $6,393:

- Adjustments made to the carrying values of Property, plant and equipment and to the accretion expense on the Asset retirement obligations explain a decrease of $1,183 in deferred tax liabilities.

- Adjustments made to the carrying values of Intangibles assets explain a decrease of $3,129 in the deferred tax liabilities.

- A deferred income tax liability was recognized on differences resulting from the initial recognition of intangible assets in the course of a business combination. It resulted in an increase in the deferred tax liabilities of $662.

- Since under IFRS 3 the measurement date for equity issued is different and the non-controlling interest must be measured at fair value of the net assets acquired on the share exchange arrangement, it resulted in an increase in fair value of most of the assets accounted for. Accordingly, it created, at the date of the share exchange arrangement, an additional deferred tax liability. These adjustments explain $9,031 of increase in the deferred tax liabilities.

- Additionally, IAS 12 and the deferred tax recognition principle relating to temporary differences are based on recovering or settling the carrying amount of the asset or liability at the reporting date. According to that principle, adjustments were made to the deferred tax liabilities booked on long-term debt. It was increased by $1,012.

Adjustments made to the deferred tax liabilities of $895 and $3,072 described in 1.4.1 a) and adjustment made to deferred tax expense of $635 described in note 1.4.3 j) resulted in a net decrease of the deficit account of $4,602.

k) Common share capital

Under section 1581 of the CICA Handbook, the measurement date for equity interests issued on a reversed acquisition is when terms of the transaction are agreed upon and announced. Under IFRS 3, the measurement date for equity interests issued is the acquisition date. The difference in these method resulted in an increase of $26,270 in the fair value of Fund units that would have had to be issued in order to provide the same percentage of ownership of the combined entity to the unitholders of the Fund. This increase is recognized in common share capital and contributed surplus for $5,719 and $20,551 respectively.

l) Contributed surplus

Under IAS 32, the unitholders' capital is accounted for as a financial instrument at fair value and reclassified as a long-term liability. As at January 1, 2010, the unitholders' capital was reduced by $309,681. Upon the share exchange arrangement, the fair value of the unitholders' capital classified as a long-term liability was estimated at $322,296 and was reclassified into common share capital. This resulted in a net total adjustment of $12,615 that was subsequently reclassified into contributed surplus upon the legal reduction of the stated capital by an amount of $453,793. A corresponding entry of $12,615 was made to the deficit.

1.4.2 Reconciliation of financial position as at December 31, 2010 (continued)

m) Share-based payment

Under IFRS 2, entities are required to treat each vesting installment as a separate share option grant because each installment has a different vesting period. The expense was increased by $100 with a corresponding entry into deficit.

n) Equity portion of convertible debentures

Under Canadian GAAP, temporary differences between the liability component of convertible debentures and the underlying tax basis are not recognized as deferred tax. Under IFRS, deferred tax is recognized for such temporary differences. Accordingly, the Corporation recognized an amount of $501 of deferred tax with a corresponding entry in the deferred tax liabilities. The later amount is included in the $6,393 adjustment in Note 1.4.2 j).

o) Non-controlling interests

Under IFRS 3, for each business combination, at the acquisition date, the acquirer is required to measure components of non-controlling interests in the acquiree that have an ownership interest and entitle their holders to a proportionate share of the entity's net assets at fair value. Therefore, the Corporation recognized an amount of $2,656 as non-controlling interests in the share exchange arrangement. For the year ended December 31, 2010, a loss of $68 was allocated to the non-controlling interest. The net adjustment to the non-controlling interests is $2,588.

p) Unrealized foreign exchange loss (gain)

Adjustments made to the foreign subsidiaries regarding the depreciation and the deferred tax resulted in a net adjustment of $5 into the deficit and $10 into the accumulated other comprehensive income.

(in thousands of Canadian dollars except as noted and amounts per share)

1.4.3 Reconciliation of statement of earnings and comprehensive income for the year ended December 31, 2010

Consolidated statement of earnings	Canadian GAAP	Notes	IFRS transition effect	IFRS
Revenues				
Operating	89,100	a)	2,285	91,385
Expenses				
Operating	12,357	a)	2,285	
		b)	(113)	14,529
General and administrative	6,274	c)	100	6,374
Prospective projects expenses	2,371			2,371
Earnings before interest, income taxes, depreciation and amortization and other items	68,098		13	68,111
Finance costs	23,193	b)	556	23,749
Transaction costs	-	d)	5,159	5,159
Realized loss on derivative financial instruments	(555)			(555)
Other net revenues	(17)			(17)
Earnings before income taxes, depreciation and amortization and other items	45,477		(5,702)	39,775
Depreciation	18,341	f)	1,017	19,358
Amortization	12,948	g)	679	13,627
Unrealized net loss on derivative financial instruments	20,761			20,761
Unrealized loss on unitholders' capital		h)	51,761	51,761
Expense related to royalty agreement upon share exchange arrangement	983			983
Unrealized foreign exchange gain	(23)	e)	(5)	(28)
Loss before income taxes and distributions	(7,533)		(59,154)	(66,687)
(Recovery) provision for income taxes				
Current	(2,253)	i)	522	(1,731)
Deferred	(1,621)	j)	(1,870)	(3,491)
	(3,874)		(1,348)	(5,222)
Net loss before distributions declared to unitholders	(3,659)		(57,806)	(61,465)
Distributions declared to unitholders	-	k)	7,238	7,238
Net loss	(3,659)		(65,044)	(68,703)
Net loss attributable to:				
Owners of the parent	(3,659)		(64,976)	(68,635)
Non-controlling interests	-		(68)	(68)
	(3,659)		(65,044)	(68,703)

(in thousands of Canadian dollars except as noted and amounts per share)

1.4.3 Reconciliation of statement of earnings and comprehensive income for the year ended December 31, 2010 (continued)

Consolidated statement of comprehensive income (loss)	Canadian GAAP	Notes	IFRS transition effect	IFRS
Net loss	(3,659)		(65,044)	(68,703)
Other items of comprehensive income (loss)				
Foreign exchange loss on translation of a self-sustaining foreign subsidiary	(227)	l)	6	(221)
Foreign exchange gain on the designated portion of the US$ denominated debt used as hedge on the investment in a self-sustaining foreign subsidiary	257	l)	(6)	251
Realized gain from reduction in net investment in foreign subsidiaries	135			135
	165		-	165
Comprehensive loss	(3,494)		(65,044)	(68,538)
Total comprehensive loss attributable to:				
Owners of the parent	(3,494)		(64,976)	(68,470)
Non-controlling interests	-		(68)	(68)
	(3,494)		(65,044)	(68,538)

a) EcoEnergy program

Under IAS 18, gross revenues must be presented. The Corporation is entitled to subsidies under the EcoEnergy program. The subsidies are equal to 1 cent per KWh produced at various facilities, including the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms, for the first 10 years following commissioning of each facility. As per the electricity purchase agreements, the Corporation must transfer 75% of the Carleton, Baie-des-Sables and l'Anse-à-Valleau wind farms subsidy to Hydro-Québec. Net EcoEnergy subsidies were included in the operating revenues of the facilities. Gross EcoEnergy subsidies are now included in the operating revenues of the facilities resulting in an increase of $2,285. A corresponding adjustment for the 75% transfer to Hydro-Québec is included in operating expenses of the facilities.

b) Accretion expense on asset retirement obligations

Under IAS 37, accretion expense on asset retirement obligations must be adjusted to reflect the obligation by discounting the estimated future cash flows with an appropriate rate determined as at the statement of financial position date and must be accounted for as financial expense. The rate at which the cash flows have been discounted was adjusted resulting in an increase of $443 in the Accretion expense for a total expense of $556. The $113 Accretion expense on asset retirement obligations accounted for under Canadian GAAP was reclassified from the Operating expenses to the Finance costs.

c) Share-based payment

Under IFRS 2, entities are required to treat each vesting installment as a separate share option grant because each installment has a different vesting period. This resulted in an increase of $100 of the Share-based payment included in General and administrative costs.

1.4.3 Reconciliation of statement of earnings and comprehensive income for the year ended December 31, 2010 (continued)

d) Transaction costs

Under IFRS 3, transaction costs incurred in a business combination must be expensed in the period they are incurred whereas they were capitalized under section 1581 of the CICA Handbook. As a result, the transaction costs of $4,730 related to the Share exchange arrangement described in Note 6 and an amount of $429 related to Cloudworks Energy inc.'s acquisition described in Note 5 a) for a total of $5,159 were expensed as incurred.

e) Unrealized foreign exchange gain

Adjustments made to the foreign subsidiaries regarding the depreciation resulted in a net adjustment of $5 to the deficit.

f) Depreciation

These two elements resulted in a net increase in depreciation of $1,017:

- Under IAS 16, depreciation of Property, plant and equipment is adjusted to reflect the depreciation of significant components based on their respective estimated useful lives which resulted in an increase in depreciation of $1,041.

- Under IFRS 3, the measurement date for equity issued in a business combination is different than under Section 1581 of the CICA Handbook and the non-controlling interests were measured at the non-controlling interests' proportionate share of the net assets acquired on the Share exchange arrangement which resulted in a different purchase price allocation. The depreciation expense was decreased by $24 resulting from a lower allocation to the Property, plant and equipment.

g) Amortization

These two elements resulted in a net increase of amortization of $679:

- Under IAS 1, the Corporation performed an impairment test as at January 1, 2010, and, accordingly, the carrying amounts of intangibles were impaired and this resulted in a lower amortization expense by an amount of $688.

- Under IFRS 3, the measurement date for equity issued in a business combination is different than under Section 1581 of the CICA Handbook and the non-controlling interests were measured at the non-controlling interests' proportionate share of the net assets acquired on the Share exchange arrangement which resulted in a different purchase price allocation. The amortization expense was increased by $1,367 resulting from a higher allocation to the Intangible assets.

h) Unrealized loss on unitholders' capital

Under IAS 32, the unitholders' capital of the Fund is reclassified as a long-term liability with variations in fair value recognized in the consolidated statement of earnings. The unrealized loss on unitholders' capital was adjusted to reflect the fair value increase of the unitholders' capital of $51,761 between January 1, 2010 and March 29, 2010. At that date, the unitholders' capital was reclassified in share capital as part of the Share exchange arrangement, as described in Note 6.

i) Current tax expense

Under IAS12, current tax related to dividends should be accounted for in the statement of earnings. An amount of $522 was reclassified from the dividends declared on preferred shares.

1.4.3 Reconciliation of statement of earnings and comprehensive income for the year ended December 31, 2010 (continued)

j) Deferred tax expense

These three elements resulted in a net adjustment of $1,870:

- Under IAS 12, the recognition of a deferred tax asset related to a previous acquisition must be accounted for in the statement of earnings. Amounts of $433 that was accounted for as a reduction of Intangible assets under Canadian GAAP and $368 that was accounted for as a reduction of Goodwill under Canadian GAAP, totaling $801, are accounted for in the provision for deferred tax.

- Under IAS 12, deferred tax related to preferred dividends should be accounted for in the statement of earnings. An amount of $434 of tax recovery was reclassified from the preferred dividends.

- Adjustments made to elements identified in the consolidated statement of earnings for the year ended December 31, 2010 explain the increase in deferred tax recovery of $635.

k) Distributions declared to unitholders

Under IAS 32, the unitholders' capital is reclassified as a long-term liability. Accordingly, distributions declared to unitholders in an amount of $7,238 were included in the net loss instead of being accounted as distributions.

l) Comprehensive income

The effect of the adjustments to depreciation and deferred tax expenses of the foreign subsidiaries resulted in a net adjustment of nil to the comprehensive income.

(in thousands of Canadian dollars except as noted and amounts per share)

1.4.4 Reconciliation of statement of cash flows for the year ended December 31, 2010

Consolidated statement of cash flows	Canadian GAAP	Notes	IFRS transition effect	IFRS
Operating activities				
Net loss	(3,659)	a)	(65,044)	(68,703)
Items not affecting cash:				
Depreciation of property, plant and equipment	18,341	b)	1,017	19,358
Amortization of intangible assets	12,948	c)	679	13,627
Unrealized net loss on derivative financial instruments	20,761			20,761
Amortization of financing fees	768			768
Amortization of reevaluation of long-term debt and convertible debenture	(7)			(7)
Accretion expenses on asset retirement obligations	113	d)	443	556
Share-based payment	331	e)	100	431
Unrealized loss on unitholders' capital	-	f)	51,761	51,761
Unrealized foreign exchange gain	(23)	h)	(5)	(28)
Deferred income tax (recovery)	(1,621)	g)	(1,870)	(3,491)
Expense related to royalty agreement upon share exchange arrangement (Note 6)	983			983
Others	82			82
Effect of exchange rate fluctuations	51			51
Interest on long-term debt and convertible debentures	-	i)	22,432	22,432
Interest paid	-	i)	(22,246)	(22,246)
Current income taxes recovery	-	j)	(1,731)	(1,731)
Income taxes paid	-	j)	(2,153)	(2,153)
Distributions declared to unitholders	-	k)	7,238	7,238
Distributions paid to unitholders	-	l)	(9,688)	(9,688)
	49,068		(19,067)	30,001
Changes in non-cash operating working capital items	(25,712)	m)	522	
		n)	(346)	
		i)	(186)	
		j)	3,884	(21,838)
	23,356		(15,193)	8,163
Financing activities				
Dividends paid on common shares	(17,454)			(17,454)
Distributions paid to unitholders	(9,688)	l)	9,688	-
Increase of long-term debt	134,220			134,220
Repayment of bank loan	(12,900)			(12,900)
Repayment of long-term debt	(205,539)			(205,539)
Payment of deferred financing costs	(1,724)			(1,724)
Net proceeds from issuance of Serie A preferred shares	81,743			81,743
	(31,342)		9,688	(21,654)

(in thousands of Canadian dollars except as noted and amounts per share)

1.4.4 Reconciliation of statement of cash flows for the year ended December 31, 2010 (continued)

Consolidated statement of cash flows	Canadian GAAP	Notes	IFRS transition effect	IFRS
Investing activities				
Cash acquired on business acquisitions (Note 5)	83,033	n)	5,361	88,394
Additions to property, plant and equipment	(29,667)			(29,667)
Additions to intangible assets	(413)			(413)
Additions to project development costs	(9,056)			(9,056)
Additions to other long-term assets	(365)	n)	144	(221)
Short-term loan to a partner	(1,000)			(1,000)
Proceeds from disposal of property, plant and equipment	298			298
Net funds withdrawn from the levelization reserve	570			570
Net funds invested into the hydrology/ wind power reserve	(2,081)			(2,081)
Net funds invested into major maintenance reserve	(463)			(463)
	40,856		5,505	46,361
Effects of exchange rate changes on cash and cash equivalents	(106)			(106)
Net increase in cash and cash equivalents	32,764		-	32,764
Cash and cash equivalents, beginning of year	9,352			9,352
Cash and cash equivalents, end of year	42,116		-	42,116

a) Net loss

See Note 1.4.3 for details about the IFRS transition effects.

b) Depreciation

These two elements resulted in a net increase in depreciation of $1,017:

- Under IAS 16, depreciation of Property, plant and equipment is adjusted to reflect the depreciation of significant components based on their respective estimated useful lives which resulted in an increase in depreciation of $1,041.

- Under IFRS 3, the measurement date for equity issued in a business combination is different than under Section 1581 of the CICA Handbook and the non-controlling interests were measured at the non-controlling interest proportionate share of the net assets acquired on the Share exchange arrangement which resulted in a different purchase price allocation. The Depreciation expense was decreased by $24 resulting from a lower allocation to the Property, plant and equipment.

c) Amortization

These two elements resulted in a net increase of amortization of $679:

- Under IAS 1, the Corporation performed an impairment test as at January 1, 2010, and, accordingly, the carrying amounts of intangibles were impaired and this resulted in a lower amortization expense by an amount of $688.

1.4.4 Reconciliation of statement of cash flows for the year ended December 31, 2010 (continued)

- Under IFRS 3, the measurement date for equity issued is different than under Section 1581 of the CICA Handbook and the non-controlling interest were measured at the non-controlling interest proportionate share of the net assets acquired on the Share exchange arrangement which resulted in a different purchase price allocation. The amortization expense was increased by $1,367 resulting from a higher allocation to the Intangible assets.

d) Accretion expense on asset retirement obligations

Under IAS 37, accretion expense on asset retirement obligations must be adjusted to reflect the obligation by discounting the estimated future cash flows with an appropriate rate determined as at the statement of financial position date and must be accounted for as financial expense. The rate at which the cash flows have been discounted was adjusted resulting in an increase of $443 in the accretion expense for a total expense of $556.

e) Share-based payment

Under IFRS 2, entities are required to consider each vesting installment as a separate share option grant because each installment has a different vesting period. This resulted in an increase of $100 in the share-based payment expense.

f) Unrealized loss on unitholders' capital

Under IAS 32, the unitholders' capital of the Fund is reclassified as a long-term liability with variations in fair value recognized in the consolidated statement of earnings. The unrealized loss on unitholders' capital was adjusted to reflect the fair value increase of the unitholders' capital of $51,761 between January 1, 2010, and March 29, 2010. At that date, the unitholders' capital was reclassified in share capital as part of the share exchange arrangement, as described in Note 6.

g) Deferred tax expense

These two elements resulted in a net adjustment of $1,870:

- Under IAS 12, the recognition of a deferred tax asset related to a previous acquisition must be accounted for in the statement of earnings. Amounts of $433 that was accounted as a reduction of Intangible assets under GAAP and $368 that was accounted as a reduction of Goodwill under GAAP, totaling $801, are accounted for in the provision for deferred tax recovery.

- Adjustments made to elements identified in the consolidated statement of earnings for the year ended December 31, 2010 explain the increase in deferred tax provision recovery of $1,069.

h) Unrealized foreign exchange gain

Adjustments made to the foreign subsidiaries regarding the depreciation resulted in a net adjustment of $5 in the deficit.

i) Interest paid

Under IAS 7, an entity must present separately the interest expense of $22,432 and the interest paid of $22,246. This resulted in adjustments to changes in non-cash operating working capital items for a total amount of $186.

j) Current income taxes paid

Under IAS 7, an entity must present separately the current income tax recovery of $1,731 and the current income taxes paid of $2,153. This resulted in adjustments to changes in non-cash operating working capital items for a total amount of $3,884.

k) Distributions declared to unitholders

Under IAS 32, the unitholders' capital is reclassified as a long-term liability. Accordingly, distributions declared to unitholders in an amount of $7,238 were included in the net loss instead of being accounted for as distributions.

1.4.4 Reconciliation of statement of cash flows for the year ended December 31, 2010 (continued)

l) Distributions paid to unitholders

Under IAS 32, the unitholders' capital is reclassified as a long-term liability. Accordingly, distributions paid to unitholders in an amount of $9,688 were included in operating activities instead of financing activities.

m) Current tax expense

Under IAS12, current tax related to dividends should be accounted for in the statement of earnings. An amount of $522 was reclassified from the dividends declared on preferred shares.

n) Transaction costs

Under IFRS 3, transaction costs incurred in a business combination must be expensed in the period they are incurred whereas they were capitalized under section 1581 of the CICA Handbook. As a result, the transaction costs totaling $5,159 described in Note 1.4.3 d) and an amount related to other business acquisitions were expensed as incurred, resulting in adjustments of $5,361 and $144 respectively to the investing activities. These three elements resulted in adjustments to changes in non cash operating working capital items for a total amount of $346.

2. BASIS OF PRESENTATION AND STATEMENT OF COMPLIANCE

These consolidated financial statements have been prepared using accounting policies consistent with IFRS as issued by International Accounting Standards Board ("IASB"). These consolidated financial statements are the Corporation's first IFRS consolidated annual financial statements.

Previously to 2011, the Corporation prepared its consolidated annual and consolidated interim financial statements in accordance with Canadian GAAP.

IFRS 1 requires disclosures that explain how the transition from Canadian GAAP to IFRS's affected the Corporation's reported financial position, financial performance and cash flows. This information will not be required for fiscal year 2012 and beyond.

The consolidated financial statements have been prepared on a historical cost basis, except for certain financial instruments that are measured at fair values as described in the significant accounting policies.

3. SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation

The consolidated financial statements include the accounts of the Corporation, and the subsidiaries that it controls. Control exists where the Corporation has the power to govern the financial and operating policies of the subsidiaries so as to obtain benefits from its activities. Subsidiaries are fully consolidated from the effective date of acquisition up to the effective date of disposal.

Joint ventures

A joint venture is a contractual agreement whereby the Corporation and other parties undertake an economic activity that is subject to joint control, arising when the strategic financial and operating policy decisions relating to the activities of the joint venture require the unanimous consent of the parties sharing control.

Joint venture arrangements that involve the establishment of a separate entity in which each venturer has an interest are referred to as jointly controlled entities.

The Corporation reports its interests in jointly controlled entities using proportionate consolidation, The Corporation's share of the assets, liabilities, income and expenses of jointly controlled entities is combined with the equivalent items in the consolidated financial statements on a line-by-line basis.

3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Business combinations

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The cost of the acquisition is measured at the aggregate of the fair values, at the acquisition date, of assets given, liabilities incurred or assumed, and equity instruments issued by the Corporation in exchange for control of the acquiree. Acquisition-related costs are recognized in the statement of earnings as incurred. Where appropriate, the cost of acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition-date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition when they qualify as measurement period adjustments. All other subsequent changes in the fair value of contingent consideration classified as an asset or liability are accounted for in accordance with relevant IFRSs and reflected through net earnings. Changes in the fair value of contingent consideration classified as equity are not recognized.

Non-controlling interests

Non-controlling interests in the net assets of consolidated subsidiaries are identified separately from the Corporation's equity therein. The interest of non-controlling shareholders may be initially measured either at fair value or at the non-controlling interest's proportionate share in the recognized amounts of the acquiree's identifiable net assets. The choice of measurement basis is made on an acquisition by acquisition basis. Subsequent to acquisition, non-controlling interests consist of the amount attributed to such interests at initial recognition and the non-controlling interest's share of changes in equity since the date of the acquisition.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, bank balances and short-term investments with original maturities of three months or less, net of bank overdrafts whenever they are an integral part of the Corporation's cash management process.

Restricted cash and short-term investments

The Company holds restricted cash and short-term investments designed to help ensure its stability.

The restricted cash accounts and short-term investments are currently invested in cash or in short-term investments having maturities of three months or less.

The availability of funds in the restricted cash and short-term investments accounts may be restricted by credit agreements.

Reserve accounts

The Corporation holds two types of reserve accounts designed to help ensure its stability. The first is the hydrology/wind reserve established at the start of commercial operations of a facility to compensate for the variability of cash flows related to fluctuations in hydrology or wind conditions or other unpredictable events. The amounts in the reserve are expected to vary from quarter to quarter according to the seasonality of cash flows. The second is the major maintenance reserve established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity.

As at December 31, 2010, the Corporation held an additional reserve account. The levelization reserve was established to level the monetary contribution from the power plants, in order to make distributions or pay dividends. This reserve was extinguished in the first quarter of 2011.

The reserve accounts are currently invested in cash or in short-term investments having maturities of three months or less as well as in bonds fully guaranteed by the governments.

The availability of funds in the reserve accounts may be restricted by credit agreements.

(in thousands of Canadian dollars except as noted and amounts per share)

3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Property, plant and equipment

Property, plant and equipment are comprised mainly of hydroelectric, wind farm facilities and solar facilities that are either in operation or under construction. They are recorded at cost less accumulated depreciation and accumulated impairment losses. Depreciation of hydroelectric power generating facilities is based on the estimated useful lives of the assets using the straight-line method over the lesser of (i) a period of 15 to 75 years or (ii) the period for which the Corporation owns the rights to the assets. Depreciation of wind farm facilities is based on the estimated useful lives of the assets using the straight-line method over the lesser of (i) a period of 15 to 25 years or (ii) the period for which the Corporation owns the rights to the assets. Depreciation of solar facilities is based on the estimated useful lives of the assets using the straight-line method over the lesser of (i) a period of 20 to 25 years or (ii) the period for which the Corporation owns the rights to the assets. Others equipment are depreciated using the straight-line method over a period extending from 3 to 10 years. Improvements that increase or extend the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred. Property, plant and equipment are not depreciated until they are ready for their intended use.

The estimated useful lives, residual values and depreciation method are reviewed at the end of each reporting period, with the effect of any changes in estimate accounted for on a prospective basis.

An item of Property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on the disposal or retirement of an item of property, plant and equipment is determined as the difference between the sale proceeds and the carrying amount of the asset and is recognized in earnings.

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale. The total costs of those assets, including the addition of borrowing costs, shall not exceed the recoverable amount of the assets.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalization.

All other borrowing costs are recognized in earnings in the period in which they are incurred.

The useful life used to calculate depreciation is as follows:

Type of property, plant and equipment	Ending years of depreciation period	Useful life for the depreciation period
Hydroelectric facilities	2019 to 2079	15 to 75 years
Wind farm facilities	2021 to 2036	15 to 25 years
Solar facilities	-	20 to 25 years

Leases

Leases where the lessor retains substantially all the risks and rewards of ownership are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to income on a straight line basis over the term of the lease.

Intangible assets

Intangible assets with finite useful lives are carried at cost less accumulated amortization and accumulated impairment losses.

(in thousands of Canadian dollars except as noted and amounts per share)

3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Intangible assets consist of various permits, licenses and agreements. They are recorded at cost less accumulated amortization and accumulated impairment losses. Amortization starts when the related facility becomes ready for its intended use. They are amortized using the straight-line method over a period of 11 to 40 years ending on the maturity date of the permits, licenses or agreements of each facility. Intangible assets related to facilities under construction are not amortized until the related facilities are ready for their intended use. Intangible assets also include the cost of an extended warranty for wind farm equipments; these costs are amortized over the three-year warranty period.

The estimated useful life and amortization method are reviewed at the end of each reporting period, with the effect of any changes in estimate being accounted for on a prospective basis.

The useful life used to calculate amortization is as follows:

Intangible assets related to :	Ending years of amortization period	Useful life for the amortization period
Hydroelectric facilities	2014 to 2050	11 to 40 years
Wind farm facilities	2026 to 2032	19 to 20 years
Solar facilities	2032	20 years
Extended warranty for wind turbines	2011 to 2016	3 years

Project development costs

Project development costs represent costs incurred for the acquisition of prospective projects and for the development of hydroelectric, wind farm and solar sites. These costs are transferred to property, plant and equipment or intangible assets when construction starts. Current costs for prospective projects are expensed as incurred and costs of a project under development are written off in the year if the project is abandoned. Interest costs incurred to finance acquisition and development are capitalized as project development costs.

Impairment of tangible and intangible assets other than goodwill

At the end of each reporting period, the Corporation reviews the carrying amounts of its tangible and intangible assets to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). Where it is not possible to estimate the recoverable amount of an individual asset, the Corporation estimates the recoverable amount of the cash-generating unit to which the asset belongs. Where a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual cash-generating units, or otherwise they are allocated to the smallest group of cash-generating units for which a reasonable and consistent allocation basis can be identified.

Intangible assets not yet available for use are tested for impairment at least annually, and whenever there is an indication that the asset may be impaired.

Recoverable amount is the greater of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (or cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognized immediately in earnings.

Where an impairment loss subsequently reverses, the carrying amount of the asset (or a cash-generating unit) is increased to the revised estimate of its recoverable amount, but so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset (or cash-generating unit) in prior years. A reversal of an impairment loss is recognized immediately in earnings.

3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Goodwill

Goodwill is measured as the excess of the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree and the fair value of the acquirer's previously held equity interest in the acquiree (if any) over the net of the amount of the identifiable assets acquired and the liabilities assumed at the date of acquisition. If, after reassessment, the net amount of the identifiable assets acquired and liabilities assumed exceeds the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree and the fair value of the acquirer's previously held interest in the acquiree (if any), the excess is recognized immediately in profit or loss as a bargain purchase gain.

For the purposes of impairment testing, goodwill is allocated to each of the Corporation's cash-generating unit (or groups of cash-generating units) that is expected to benefit from the synergies of the combination.

A cash-generating unit to which goodwill has been allocated is tested for impairment annually, or more frequently when there is indication that the unit may be impaired. If the recoverable amount of the cash-generating unit is less than its carrying amount, the impairment loss is allocated first to reduce the goodwill of the unit. Any impairment loss for goodwill is recognized directly in earnings in the consolidated statement of earnings. An impairment loss recognized for goodwill is not reversed in subsequent periods.

Accrual for acquisition of long-term assets

The accrual for acquisition of long-term assets is defined as long-term debt commitments that have been secured and that will be drawn upon to finance the Corporation's projects currently under construction.

Provision and asset retirement obligations

A provision is a liability of uncertain timing or amount. Provisions are recognized when the Corporation has a present obligation (legal or constructive) as a result of a past event, it is probable that the Corporation will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation, or other operation of law. A constructive obligation arises from an entity's actions whereby, through an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, at each period end, of the expenditures required to settle the present obligation considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk adjusted interest rate.

Asset retirement obligations are recorded as liabilities when those obligations are incurred and are measured as the present value , if a reasonable estimate of the expected costs to settle the liability can be determined, discounted at a current pre-tax rate specific to the liability. The liability is accreted up to the date the liability will be incurred with a corresponding charge to operating expenses. The carrying amount of the asset retirement obligations is reviewed quarterly to reflect current estimates and charges in the discount rate.

Financial Instruments

Financial assets and liabilities are initially recorded at fair value and their subsequent measurement is dependent on their classification as described below. The classification depends on the purpose for which the financial instruments were purchased or issued, their characteristics and their designation by the Corporation.

All financial instruments are classified into one of the five categories: held-for-trading, loans and receivables, other financial liabilities, held-to-maturity investments or available-for-sale financial assets.

Transaction costs related to held for trading financial assets are expensed as incurred. Transaction costs related to available-for-sale financial assets, held-to-maturity financial assets, other liabilities and loans and receivables are added to the carrying value of the asset or are netted against the carrying value of the liability and are then recognized over the expected life of the instrument using the effective interest method.

3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

The Corporation has made the following classification:

- Derivative financial instruments were classified as held for trading and thus are measured at fair value through net profit or loss.

  Investment income earned on assets or liabilities designated as held for trading is included in other net revenues in the consolidated statements of earnings.

  Net gains or losses on assets or liabilities classified as held for trading are included into gain (loss) on derivative financial instruments in the consolidated statements of earnings. These net gains or losses do not include any investment income.

- Cash and cash equivalents, restricted cash and short-term investments, cash and cash equivalents included in reserve accounts and accounts receivable are classified as loans and receivables and are measured at amortized cost, using effective interest rate method.

- Short-term investments and Government-backed securities included in Reserve accounts are classified as assets held to maturity and recorded at amortized cost, using effective interest rate method.

- Accounts payable and accrued liabilities, dividends payable to shareholders, construction holdbacks, accrual for acquisition of long-term assets, long-term debt, convertible debentures and contingent considerations are classified as other financial liabilities and are recorded at amortized cost, using effective interest rate method.

- The Corporation does not hold any available-for-sale financial assets.

Financial instruments recognized at fair value are classified in fair value hierarchy levels as follows:

Level 1 valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;

Level 2 valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices);

Level 3 valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value.

The financial assets or liabilities measured at fair value are cash and cash equivalents, restricted cash and short-term investments and cash and cash equivalents included in reserve accounts which are level 1 and derivative financial instruments which are level 3 for inflation provision and level 2 for interest rate swap and bond forward contracts.

Hedging relationships

Derivative financial instruments are utilized by the Corporation to manage its interest rate exposure on debt financing. The Corporation's policy is not to utilize derivative financial instruments for trading or speculative purposes.

Derivatives used as economic hedges that do not qualify for hedge accounting are recognized on the statement of financial position at fair value and changes in fair value are recorded in net earnings. The Corporation does not use hedge accounting for its derivative financial instruments.

Revenue recognition

Revenue is recognized on an accrual basis upon delivery of electricity at rates provided for under the Power Purchase Agreements entered into with the purchasing utilities.

3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Government assistance

Government assistance in the form of subsidies or refundable investment tax credit are recorded in the financial statements when there is reasonable assurance that the Corporation complied with all conditions necessary to obtain the assistance.

The Corporation is entitled to subsidies under the EcoEnergy program. The subsidies are equal to 1¢ per KWh produced at the Ashlu Creek, Fitzsimmons Creek, Douglas Creek, Fire Creek, Stokke Creek, Tipella Creek, Lamont Creek, Upper Stave River and Umbata Falls hydro facilities and at the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms for the first 10 years following commissioning of each facility. As per the electricity purchase agreements, the Corporation must transfer 75% of the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms subsidy to Hydro-Quebec. Gross EcoEnergy subsidies of $12,136 ($5,848 in 2010) are included in the operating revenues and the 75% payable to Hydro-Québec for the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms are included in the operating expenses.

The Corporation incurs renewable energy development expenditures, which are eligible for refundable investment tax credits. The recorded investment tax credits are based on management's estimates of amounts expected to be recovered and are subject to an audit by the taxation authorities. Investment tax credits for renewable energy development expenditures are reflected as a reduction in the cost of the assets or expenses to which they relate.

Share-based payment

The Corporation measures equity-settled stock option awards using the fair value method. Expense is measured at the grant date at the fair value of the award and is recognized over the vesting period based on the Corporation's estimate of the number of options that will eventually vest. Each equity-settled stock option award that vests in installments is accounted for as a separate award with its own distinct fair value measurement. The fair value of options is amortized to earnings over the vesting period with an offset to share-based payment in equity. For options that are forfeited before vesting, the compensation expense that had previously been recognized and the offset to share-based payment in equity are reversed. When options are exercised, the corresponding share-based payment in equity and the proceeds received by the Corporation are credited to share capital.

Foreign currency translation

The Corporation, its subsidiaries companies, and joint ventures each determine their functional currency based on the currency of the primary economic environment in which they operate. The Corporation's functional currency is the Canadian dollar. Transactions denominated in a currency other than the functional currency of an entity are translated at the exchange rate in effect on the transaction date. The resulting exchange gains and losses are included in each entity's net earnings in the period in which they arise.

The Corporation's foreign operations are translated to the Corporation's presentation currency, which is the Canadian dollar, for inclusion in the consolidated financial statements. Foreign denominated monetary and non-monetary assets and liabilities of foreign operations are translated at exchange rates in effect at the end of the reporting period and revenue and expenses are translated at exchange rate in effect on the transaction date. The resulting translation gains and losses are included in other comprehensive income with the cumulative gain or loss reported in Accumulated other comprehensive income. Amounts previously recognized in Accumulated Other Comprehensive Income are recognized in net earnings when there is a reduction in the net investment.

The Corporation designates a portion of its US dollar-denominated debt to hedge its investment in its US functional currency foreign operations. Translation gains or losses on the portion of the debt designated as a hedge are included in other comprehensive income and accumulated in the foreign currency translation reserve. The gain or loss relating to the portion of the debt in excess of the investment in the foreign subsidiaries is recognized immediately in earnings. Gains and losses on the hedging instrument relating to the effective portion of the hedge accumulated in the foreign currency translation reserve are reclassified to earnings in the same way as exchange differences relating to the foreign operations. The Corporation formally documents this hedge. On a quarterly basis, the Corporation reviews the hedge to ensure that it effectively offsets the translation gains or losses arising from its investment in its US functional currency foreign operation.

3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Income taxes

Current tax and deferred tax are recognized in earnings except to the extent that it relates to a business combination, or items recognized directly in equity or in other comprehensive income.

Current tax is the expected tax on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date.

Deferred tax is not recognized in respect of subsidiaries for the temporary differences between the carrying amounts of the investments and the tax basis, unless such differences are expected to result in income tax in the foreseeable future.

Deferred tax assets are recognized to the extent that it is probable that taxable profits will be available against which the deductible temporary differences can be utilized.

Earnings per share

Basic earnings per share are computed by dividing net earnings available to common shareholders by the weighted average number of shares outstanding during the year. All share and per share amounts presented herein have been adjusted to reflect the conversion ratio of 1.46 shares for each unit for all years presented.

The Corporation uses the treasury stock method for calculating diluted earnings per share. Diluted earnings per share are computed similarly to basic earnings per share except that the weighted average shares outstanding are increased to include additional shares from the assumed conversion of convertible debentures and the exercise of stock options and warrants, if dilutive. The number of additional shares is calculated by assuming that convertible debentures were converted and that outstanding stock options and/or warrants were exercised and that the proceeds from such exercises were used to acquire shares at the average market price during the year.

Significant estimates and assumptions

The preparation of financial statements in conformity with IFRS requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. During the reporting period, management made a number of estimates and assumptions pertaining primarily to the fair value calculation of the assets acquired and liabilities assumed in business acquisitions, impairment of assets, useful lives and recoverability of property, plant and equipment and intangible assets, deferred income taxes, asset retirement obligations, as well as the fair value of financial assets and liabilities including derivatives. These estimates and assumptions are based on current market conditions, management's planned course of action and assumptions about future business and economic conditions. Changes in the underlying assumptions and estimates could have a material impact on the reported amounts. These estimates are reviewed periodically. If adjustments prove necessary, they are recognized in earnings in the period in which they are made.

Critical judgments and estimates

Fair Value of Financial Instruments

Certain financial instruments, such as derivative financial instruments, are carried in the consolidated statements of financial position at fair value, with changes in fair value reflected in net earnings. Fair values of some financial instruments are estimated by using valuation techniques using several assumptions such as interest rate, credit spread and risk.

3. SIGNIFICANT ACCOUNTING POLICIES (CONTINUED)

Useful Lives of Property, Plant and Equipment

Property, plant and equipment represent a significant proportion of the Corporation's total assets. The Corporation reviews estimates of the useful lives of Property, plant and equipment on an annual basis and adjust depreciation on a prospective basis, if necessary.

Goodwill Impairment

The Corporation makes a number of estimates when calculating the recoverable amount of goodwill using discounted future cash flows or other valuation methods. These estimates include the assumed growth rates for future cash flows, the numbers of years used in the cash flow model, and the discount rate.

Property, plant and equipment and Intangible assets impairment

The Corporation makes a number of estimates when calculating fair value using discounted future cash flows or other valuation methods. These estimates include the assumed growth rates for future cash flows, the number of years used in the cash flow model, and the discount rate.

Business acquisition fair value

The Corporation makes a number of estimates when allocating fair values to the assets and liabilities acquired in a business acquisition. Fair values are estimated by using valuation techniques using several assumptions such as production, earnings and expenses, interest rate and discount rate.

Income Taxes

The calculation of income taxes requires judgment in interpreting tax rules and regulations. The Corporation's tax filings are also subject to audits, the outcome of which could change the amount of current and deferred tax assets and liabilities. The Corporation believes that it has sufficient amounts accrued for outstanding tax matters based on the information that currently is available. Deferred tax assets and liabilities require management's judgment in determining the amounts to be recognized. In particular, judgment is required when assessing the timing of reversal of temporary differences to which future income tax rates are applied. Further, the amount of deferred tax assets, which is limited to the amount that is probable to be realized, is estimated with consideration given to the timing, sources and amounts of future taxable profit.

4. FUTURE CHANGES IN ACCOUNTING POLICIES

IAS 1 - Presentation of Items of Other comprehensive income

The IASB issued amendments to IAS 1 Presentation of Financial Statements to split items of other comprehensive income between those that are reclassified to earnings and those that do not.

The standard is required to be adopted for periods beginning on or after July 1, 2012. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 9 – Financial instrument

As part of the project to replace IAS 39, Financial Instruments: Recognition and Measurement, this standard retains but simplifies the mixed measurement model and establishes two primary measurement categories for financial assets. More specifically, the standard:

- Deals with classification and measurement of financial assets;
- Establishes two primary measurement categories for financial assets: amortized cost and fair value;
- Prescribes that classification depends on entity's business model and the contractual cash flow characteristics of the financial asset;
- Eliminates the existing categories: held to maturity, available for sales, and loans and receivables.

4. FUTURE CHANGES IN ACCOUNTING POLICIES (CONTINUED)

Certain changes were also made regarding the fair value option for financial liabilities and accounting for certain derivatives linked to unquoted equity instruments.

The standard will be effective for annual periods beginning on or after January 1, 2015, with earlier adoption permitted. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 10 – Consolidated Financial Statements

The IASB issued IFRS 10 which provides additional guidance to determine whether an investee should be consolidated. The guidance applies to all investees, including special purpose entities.

The standard is required to be adopted for periods beginning January 1, 2013. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 11 – Joint arrangements

IFRS 11 will require investment in joint ventures to be accounted for using the equity method. This will result in significant changes in the presentation of the consolidated statements of financial position and the consolidated statements of earnings. Net earnings/loss and net assets are not expected to differ as a result of applying the equity method of accounting. However, the balances of each line item on the consolidated statements of financial position and the consolidated statements of earnings are expected to change significantly.

Several investments in associates and joint ventures are consolidated in the Corporation under IFRS. These investments are either, fully consolidated or proportionately consolidated. Under the IFRS 11 revised standard, some of these investments might have to be accounted for as investments on the consolidated statements of financial position with their results recognized as share of net earnings of a joint venture or an investee.

The effective date for the application of the revised standard is January 1, 2013. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 12 – Disclosure of Interests in Other Entities

The IASB issued IFRS 12 which aggregates and amends disclosure requirements included within other standards. The standard requires a company to provide disclosures about subsidiaries, joint arrangements, associates and unconsolidated structured entities.

The standard is required to be adopted for periods beginning January 1, 2013. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IFRS 13 – Fair Value Measurement

The IASB issued IFRS 13 to provide comprehensive guidance for instances where IFRS requires fair value to be used. The standard provides guidance on determining fair value and requires disclosures about those measurements.

The standard is required to be adopted for periods beginning January 1, 2013. The Corporation is evaluating the impact that this standard may have on its results of operations and financial position.

IAS 28 (2011) – Investments in Associates and Joint Ventures

IAS 28 was amended in 2011 to prescribe the accounting for investments in associates and sets out the application of the equity method when accounting for investments in associates and joint ventures. IAS 28 is effective for annual periods beginning on or after January 1, 2013. Earlier application is permitted. The Corporation is currently evaluating the impact of this amendment to IAS 28 on its results of operations and financial position.

(in thousands of Canadian dollars except as noted and amounts per share)

5. BUSINESS ACQUISITIONS

a) Acquisition of Cloudworks Energy Inc.

On April 4, 2011, the Corporation finalized the acquisition of all the issued and outstanding shares of Cloudworks Energy Inc. ("Cloudworks") (the "Cloudworks Acquisition"). The aggregate consideration was $191,083, $149,669 of which was payable in cash (the "Cash Consideration"), $39,018 of which was payable by the issuance, by way of a private placement, of common shares of the Corporation at a price of $9.75 per common share, and $2,396 which is payable by way of contingent considerations based on the performance of the Cloudworks portfolio of assets.

Cloudworks' portfolio of assets consists of a 50.01% interest in six run-of-river hydroelectric facilities (the "Harrison Operating Facilities") with a combined gross installed capacity of 150 megawatts; full ownership of 76 MW of run-of-river hydroelectric projects under development with 40-year Power Purchase Agreements ("PPAs"); and full ownership of run-of-river hydroelectric projects in various stages of development with a potential aggregate installed capacity of over 800 MW.

All power generated from the operating facilities is sold to British Columbia Hydro and Power Authority under 40-year PPAs.

Additional cash flows generated from the assets acquired are expected to further increase the Corporations liquidity and flexibility to fund the development of future projects. By adding the recently commissioned low-risk hydroelectric facilities to its portfolio of assets, the Corporation believes it is improving the stability of its cash flows and the sustainability of its dividend. Also, the transaction is expected to be accretive to the Corporation's upon commissioning of three run-of-river hydroelectric projects under development with 40-year power purchase agreements with a potential installed capacity of 76 MW. Furthermore, through the transaction, the Corporation is significantly expanding its footprint in British Columbia.

To finance the Cash Consideration, the Corporation sold subscription receipts of the Corporation through a syndicate of underwriters on a bought-deal basis. The agreement with the syndicate included the issuance of 17,750,000 subscription receipts at a price of $9.35 per subscription receipt to raise gross proceeds of $165,963. The proceeds of the subscription receipt financing were held in escrow pending the completion of the Cloudworks Acquisition. The subscription receipts have therefore been exchanged on a one-for-one basis for common shares of the Corporation upon the closing of the Cloudworks' acquisition for no additional consideration.

i. The net proceeds from the subscriptions receipts along with the private placement was determined as follows:

	Subscriptions receipts	Private placement	Total
Shares issued (in 000's)	17,750	3,999	21,749
Price of shares ($ per share)	9.35	9.7549	9.42
Value of shares that have been issued	165,963	39,018	204,981
Issuance fees	(7,806)		(7,806)
Dividend equivalent payment refunded to subscriptions holders	(2,436)		(2,436)
Net proceeds	155,721	39,018	194,739

From the net proceeds of $194,739 a total of $188,687 was used for the acquisition of Cloudworks. The balance was used by the Corporation to enhance its financial flexibility, to reduce indebtness and for general corporate purposes.

ii. The total estimated purchase price has been calculated as follows:

Purchase price to vendors	188,687
Contingent considerations	2,396
Total purchase price	191,083

(in thousands of Canadian dollars except as noted and amounts per share)

5. BUSINESS ACQUISITIONS (CONTINUED)

iii. The following table reflects the revised purchase price allocation, which is subject to a final valuation:

	Preliminary purchase price allocation	Subsequent Adjustments	Revised purchase price allocation
Cash and cash equivalents	4,942		4,942
Restricted cash and short-term investments	37,693		37,693
Accounts receivable	3,080		3,080
Prepaid and others	211		211
Reserve Accounts	28,601		28,601
Property, plant and equipment	438,541		438,541
Intangible assets	225,573	4,611	230,184
Project development costs	100,746		100,746
Deferred tax assets	1,654		1,654
Other long-term assets	2,936		2,936
Accounts payable and accrued liabilities	(12,810)	(1,581)	(14,391)
Current portion of long-term debt	(6,963)		(6,963)
Long-term debt	(459,273)		(459,273)
Deferred tax liabilities	(58,880)	(3,030)	(61,910)
Non-controlling interests	(114,968)		(114,968)
Net assets acquired	191,083	-	191,083

The estimated purchase price and purchase price allocation remains subject to the completion of the valuation of the property, plant and equipment, intangible assets, project development costs, deferred tax, non-controlling interest and consequential adjustments.

The transaction costs relating to the Acquisition have been expensed as transaction costs of the business combination in accordance with IFRS 3.

iv. The share purchase agreement provides for the potential contingent considerations of additional amounts to the vendors over a period of more than 40 years. The fair market value of the contingent considerations to be paid was estimated at $2,396. See Note 19 for more details.

v. If the acquisition had taken place on January 1, 2011, the consolidated revenues and loss for the year ended December 31, 2011 would have been $154,650 and $50,675 respectively.

The amounts of revenue and net loss of Cloudworks Energy Inc. since April 4, 2011 included in the consolidated statement of earnings are $46,595 and $141 respectively for the 271 days ended December 31, 2011.

b) Acquisition of Stardale Solar Project

On April 20, 2011, the Corporation finalized the acquisition of all the issued and outstanding shares of Solaris Energy Partners Inc. (“Solaris”). The aggregate consideration, subject to certain adjustments, is approximately $11,778 of which $11,175 was payable in cash and $603 is payable by way of contingent considerations. Solaris owns the rights to develop the 33.2 MW_{DC} Stardale Photovoltaic Solar Project (the “Stardale Project”), located in Ontario, Canada.

All energy generated will be sold to Ontario Power Authority under 20-year PPAs.

With the acquisition of the Stardale project, the Corporation positions itself in a new sector. The solar technology is proven, reliable and simple, and the Corporation believes that the construction and operational risks are minimal. In addition, the sun provides for a very stable and predictable resource which for the Corporation believes will result in the Stardale Project generating a stable stream of cash flows for the next 20 years and beyond.

(in thousands of Canadian dollars except as noted and amounts per share)

5. BUSINESS ACQUISITIONS (CONTINUED)

The total estimated purchase price has been calculated as follows:

Purchase price to vendors	11,175
Contingent considerations	603
Total purchase price	11,778

The following table reflects the revised purchase price allocation which is subject to a final valuation:

	Preliminary purchase price allocation	Subsequent Adjustments	Revised purchase price allocation
Cash and cash equivalents	1		1
Accounts receivable	59		59
Property plant and equipment	3,722		3,722
Intangible assets	8,844	694	9,538
Other long-term assets	600		600
Deferred tax liabilities	(1,448)	(694)	(2,142)
	11,778	-	11,778

The estimated purchase price and purchase price allocation remains subject to the completion of the valuation of the property, plant and equipment, intangible assets, deferred tax and consequential adjustments.

The transaction costs relating to the acquisition have been expensed as transaction costs of the business combination in accordance with IFRS 3.

The share purchase agreement provides for the potential contingent considerations of additional amounts to the vendors over a period of 3 years. The fair market value of the contingent considerations to be paid was estimated at $603. See Note 19 for more details.

If the acquisition had taken place on January 1, 2011, the consolidated revenues and net loss for the year ended December 31, 2011 would have been similar as the project is under construction and costs are capitalized.

The amounts of revenues and earnings of Stardale Solar Project since April 20, 2011 included in the consolidated statement of earnings are nil for the 255 days ended December 31, 2011.

6. SHARE EXCHANGE ARRANGEMENT

On March 29, 2010, the Corporation acquired from the Fund's unitholders their entire equity interests in the Fund, such that the Fund became wholly-owned by the Corporation, which was effectively paid by the issuance to the Fund's unitholders of 36,033,000 common shares. The Fund was an unincorporated open-ended trust established on October 25, 2002 under the laws of the Province of Québec. The Fund, which began operations on July 4, 2003, was established to indirectly acquire and own interests in renewable power generating facilities. After the transaction, the Corporation fell under the control of the unitholders of the Fund. Therefore, this transaction resulted in a reverse acquisition.

As a result, for accounting purposes, the Corporation is required to be accounted for as though it was a continuation of the Fund but with its share capital reflecting the exchange of the Corporation shares for Fund's units. Therefore certain terms such as shareholder/unitholder, dividend/distribution and share/unit may be used interchangeably throughout these consolidated financial statements. For the periods reported up to the effective date of the share exchange arrangement, all payments to unitholders were in the form of distributions, and after that date all payments to shareholders are in the form of dividends.

(in thousands of Canadian dollars except as noted and amounts per share)

6. SHARE EXCHANGE ARRANGEMENT (CONTINUED)

Comparative figures presented in the consolidated financial statements of the Corporation include all amounts previously reported by the Fund.

As a result of the share exchange arrangement, the Corporation also recorded an adjustment to deferred tax liabilities. This adjustment reflects the tax impact of recording deferred tax assets and liabilities for temporary differences that were reversing or settling prior to 2011 and which were not previously recorded since prior to the transaction these temporary difference reversals were not previously expected to be taxed in the Fund.

For the Fund, the anticipated benefits of the acquisition will be a significantly larger scale with increased financial strength. It will enjoy significant internal cash flow generation and enhanced access to capital markets. Improved financial strength is also expected to lower its cost of capital, facilitate and accelerate project development and enhance its anticipated return on equity.

The reverse acquisition was accounted for under IFRS 3. The fair value of the consideration transferred is based on the number of Fund units that would have had to be issued in order to provide the same percentage of ownership of the combined entity to the unitholders of the Fund.

The total purchase price has been calculated as follows:

Units that would have had to be issued (in 000)		16,015
Weighted average of the price of Fund units at the closing date ($ per unit)		12.08
Value of Fund units that would have had to be issued	$	193,399
Equity portion of convertible debentures (net of a $501 deferred tax)		1,340
Fair value of vested stock options		497
Total Purchase Price	$	195,236

Under IFRS, transaction costs related to the share exchange arrangement are expensed as incurred.

The following table reflects the purchase price allocation:

Cash and cash equivalents	88,394
Accounts receivable	4,082
Prepaid and others	781
Reserve Accounts	4,163
Property, plant and equipment	266,704
Intangible assets	116,770
Investment in the Fund, an entity subject to significant influence	57,165
Derivative financial instruments	903
Other long-term assets	63
Current liabilities	(24,384)
Bank loan	(12,900)
Long-term debt and accrual for acquisition of long-term assets	(214,637)
Net deferred tax liabilities	(9,347)
Convertible debentures	(79,222)
Asset retirement obligations	(643)
Non-controlling interests	(2,656)
Net assets acquired	195,236

(in thousands of Canadian dollars except as noted and amounts per share)

6. SHARE EXCHANGE ARRANGEMENT (CONTINUED)

The 16.1% investment of the Corporation in the Fund, an entity subject to significant influence held before the transaction, for an amount of $57,165 was eliminated since the Fund's and the Corporation's results are consolidated.

The portion of the unit capital of the Fund, not held by the Corporation before the transaction was reclassified from unit capital to common share capital to account for the reverse take-over of the Corporation by the Fund.

The share capital and deficit of the Corporation were eliminated upon consolidation of the statement of financial position as the transaction was accounted for as a reverse take-over of the Corporation by the Fund.

On March 29, 2010, the 200,000 warrants of the Corporation remained outstanding but were adjusted to their fair value which was estimated to be nil. The 705,000 stock options of the Corporation that were vested were also adjusted to their fair values of $497. On August 29, 2010, the warrants expired.

On March 29, 2010, the Corporation recorded an expense related to royalty agreement upon share exchange arrangement of $983 due to the deemed cancellation of a contract resulting from the combination. As per IFRS, the Fund had to expense the engagement it had with the Corporation prior to the combination. In 2005, a subsidiary of the Corporation, sold the Rutherford Creek hydroelectric facility to the Fund. Rutherford Creek Power, Limited Partnership, which owns the assets, then agreed, following the expiry or termination of the Rutherford Creek Power Purchase Agreement in 2024, to pay royalties to the subsidiary provided certain revenue thresholds are reached. This expense had no cash impact on the Corporation's results as it was considered to be paid for by the issuance of shares.

Following the reverse take-over, the Corporation and the Fund were combined and refinanced. It is not possible to segregate and identify the revenues and earnings of each of the former entities.

The transaction costs relating to the combination totalling $ 5,400 have been recognized as cost of the business combination in accordance with IFRS 3. As at December 31, 2010, an amount of $39 remained payable. Net cash acquired amounted to $ 88,394.

7. RESTRICTED CASH AND SHORT-TERM INVESTMENTS

	December 31, 2011	December 31, 2010	January 1, 2010
Restricted chequing accounts	22,820	-	-
Proceeds account	24,056	-	-
Senior Debt Service Payment account	6,429	-	-
Junior Debt Service Payment account	110	-	-
	53,415	-	-

As part of the Cloudworks Acquisition, the Corporation maintains some restricted cash accounts:

In accordance with the terms of a trust indenture, the balance of the loan proceeds is held in restricted trust accounts managed by the Bank of New York as trustee and will be released once the covenants under the trust indenture are met.

Other restricted accounts required under the terms of the trust indenture are as follows:

Senior Debt Service Payment Account – requires a monthly transfer equal to one-sixth of the next semi-annual bond payments required on the outstanding senior bonds issued by Harrison Hydro Finance Inc. ("HHFI"). These amounts mirror the loan payments required by the Senior LP Credit Agreement to HHFI with the addition of an interest spread charged by HHFI. Senior loan payments are taken from this account on their due dates.

Junior Debt Service Payment Account – requires a monthly transfer equal to one-third of the next quarterly bond payment required on the outstanding junior bonds issued by HHFI. These amounts mirror the loan payments required by the Junior LP Credit Agreement to HHFI with the addition of an interest spread charged by HHFI. The junior loan payments are taken from this account on their due dates.

(in thousands of Canadian dollars except as noted and amounts per share)

8. ACCOUNTS RECEIVABLE

	December 31, 2011	December 31, 2010	January 1, 2010
Trade	15,643	11,938	6,096
Commodity taxes	14,445	1,587	-
Investment tax credits	1,497	869	-
Payment receivable for property, plant			-
and equipment	4,130	-	-
Others	1,179	291	68
	36,894	14,685	6,164

Substantially all of the Corporation's trade receivables relate to electricity sold to public utilities including Hydro-Quebec, British Columbia Hydro, Ontario Electricity Financial Corporation, Ontario Power Authority, and Idaho Power Company. Hydro-Quebec currently holds a credit rating of A+ from Standard & Poor's (S&P). British Columbia Hydro and Power Authority currently holds a credit rating of AAA from S&P. The Ministry of Energy of the Province of Ontario has stated that the Province of Ontario, which currently holds a credit rating of AA- from S&P, will honor Ontario Electricity Financial Corporation and Ontario Power Authority obligations under the Power Purchase Agreements to which it is a party. Idaho Power Company currently has a credit rating of BBB from S&P.

The payment receivable for property, plant and equipment is also receivable from Hydro-Québec and is related to the Montagne-Sèche wind farm. Commodity taxes and investment tax credits are receivable from the federal or provincial governments, following the development and construction of projects.

The Corporation did not record any allowance for doubtful accounts since, based on its experience, there is a low risk of bad debts. The Corporation does not hold any specific guarantees for its accounts receivable. All accounts receivable are current.

9. RESERVE ACCOUNTS

During the year, the amounts held in the hydrology/wind power reserve increased from $ 16,511 to $39,045 and generated investment income of $398 ($69 in 2010) for an overall average weighted return of 1.10% (0.49% in 2010).

In 2011, amounts held in the major maintenance reserve generated investment income of $38 ($19 in 2010), for an overall average weighted return of 0.90% (0.45% in 2010). During the year, an amount of $810 was invested in major maintenance reserve ($761 in 2010) and an amount of $563 ($298 in 2010) has been used for repairs at the Rutherford and Horseshoe Bend facilities.

During the year, the funds held in the levelization reserve generated no investment income ($21 in 2010), for a weighted average global return of 2.56% in 2010. During the same period, investments totalling $494 ($570 in 2010) held in the levelization reserve were liquidated and used as distributable cash.

(in thousands of Canadian dollars except as noted and amounts per share)

9. RESERVE ACCOUNT (CONTINUED)

The table below summarizes the changes in the reserve accounts:

				December 31, 2011
	Hydrology / wind power reserve	Major maintenance reserve	Levelization reserve	Total
Reserves – beginning of year	16,511	4,436	494	21,441
Reserved acquired on business acquisition (Note 5)	28,376	225	-	28,601
Investments in the reserves	2,481	810	-	3,291
Net withdrawals	(8,414)	(2,372)	(494)	(11,280)
Impact of foreign exchange fluctuations	91	10	-	101
Reserves – end of year	39,045	3,109	-	42,154
Less:				
Current portion	-	-	-	-
	39,045	3,109	-	42,154

				December 31, 2010
	Hydrology / wind power reserve	Major maintenance reserve	Levelization reserve	Total
Reserves – beginning of year	10,598	3,728	1,064	15,390
Reserves acquired on the share exchange arrangement (Note 6)	3,898	265	-	4,163
Investments in the reserves	4,194	761	-	4,955
Net withdrawals	(2,113)	(298)	(570)	(2,981)
Impact of foreign exchange fluctuations	(66)	(20)	-	(86)
Reserves – end of year	16,511	4,436	494	21,441
Less:				
Current portion	-	-	(494)	(494)
	16,511	4,436	-	20,947

The Corporation used a portion of the cash held in the reserve accounts to purchase investments aimed at generating additional revenues to provide more stability. As at December 31, 2011, the carrying values and market values of these investments were as follows:

Reserve account investments	Maturity	Market value	Net carrying value
Government-backed securities	2012	635	635
Short-term investments	2012	11,844	11,844
Cash and cash equivalents		29,675	29,675
		42,154	42,154

(in thousands of Canadian dollars except as noted and amounts per share)

9. RESERVE ACCOUNT (CONTINUED)

The market value of the securities backed by the Canadian government, the US government or a provincial government is determined by referring directly to the published active market prices. Short-term investments are held at major financial institutions. The Corporation recorded no impairment of these financial instruments since the counterparties have high credit ratings.

The availability of $42,154 in the reserve accounts is restricted by credit agreements.

10. DERIVATIVE FINANCIAL INSTRUMENTS

The Corporation records embedded derivatives separately from the host contracts. These financial instruments relate to provisions establishing minimum inflation rate at 3% of the selling prices provided for under some of the power purchase agreements entered into with Hydro-Québec. The Corporation does not anticipate any payment defaults from the counterparty. The fair value of these financial instruments is based on revenue estimates based on long-term production averages estimated for each facility. It varies based on the difference between the 3% minimum inflation rate and the long-term inflation rate, which is estimated at 2% as at December 31, 2011 over the remaining terms of these agreements, discounted at a rate of 3.37%. The expected impact of a 0.1% increase in the long-term inflation rate would reduce the fair value of these financial instruments by $981; a 0.1% drop in the long-term inflation rate would increase fair value of these financial instruments by $976.

The Corporation holds swap contracts, forward interest rate swap contracts and bond forwards contracts (“Interest hedging instruments”) that enable it to eliminate its exposure to the floating interest rates payable on the portion of its long-term debt, which is hedged by such contracts (Note 29 b)). The counterparties to the contracts are major financial institutions; the Corporation does not anticipate any payment defaults on their part. The estimated impact of an increase in swap rates curve of 0.1% would increase the fair value of these financial instruments by $7,822. Conversely, a decrease in swap rates curve of 0.1% would result in a reduction of $7,965 of the fair value of these financial instruments.

	Inflation provisions (Level 3)	Interests hedging instruments (Level 2)	Total
Assets – Derivative financial instruments			
Balance as at December 31, 2009	10,148	-	10,148
Asset acquired on the share exchange arrangement (Note 6)	-	903	903
Change in fair value during 2010	743	(581)	162
Balance as at December 31, 2010	10,891	322	11,213
Change in fair value during the year	(852)	(322)	(1,174)
Asset balance as at December 31, 2011	10,039	-	10,039
Liabilities – Derivative financial instruments			
Balance as at December 31, 2009	-	10,217	10,217
Change in fair value during 2010	-	20,923	20,923
Balance as at December 31, 2010	-	31,140	31,140
Change in fair value during the year	-	60,305	60,305
Liability balance as at December 31, 2011	-	91,445	91,445

(in thousands of Canadian dollars except as noted and amounts per share)

10. DERIVATIVE FINANCIAL INSTRUMENTS (CONTINUED)

Reported in the financial statements

	December 31, 2011	December 31, 2010	January 1, 2010
Current assets – derivative financial instruments	1,791	1,679	1,369
Long-term asset – derivative financial instruments	8,248	9,534	8,779
Current liability – derivative financial instruments	(20,287)	(8,543)	(5,422)
Long-term liability – derivative financial instruments	(71,158)	(22,597)	(4,795)
	(81,406)	(19,927)	(69)

The increase in the interest hedging instruments liability mainly arises from the decrease in the benchmark interest rates and the new contracts entered into in 2011.

(in thousands of Canadian dollars except as noted and amounts per share)

11. PROPERTY, PLANT AND EQUIPMENT

	Land	Hydroelectric facilities	Wind Farm facilities	Facilities under construction	Other equipment	Total
Cost						
As at January 1, 2011	70	447,778	197,456	31,148	1,917	678,369
Additions	-	1,305	484	190,999	1,397	194,185
Business Acquisitions	1,815	437,185	-	1,907	1,356	442,263
Transfer of assets upon commissioning	-	-	105,161	(105,161)	-	-
Transfer from projects under development	-	-	-	42,346	-	42,346
Dispositions	-	(224)	-	-	(20)	(244)
Net foreign exchange differences	2	119	-	-	-	121
As at December 31, 2011	1,887	886,163	303,101	161,239	4,650	1,357,040
Accumulated depreciation						
As at January 1, 2011	-	(43,600)	(21,838)	-	(621)	(66,059)
Depreciation	-	(20,226)	(10,080)	-	(871)	(31,177)
Dispositions	-	53	-	-	7	60
Net foreign exchange differences	-	(30)	-	-	-	(30)
As at December 31, 2011	-	(63,803)	(31,918)	-	(1,485)	(97,206)
Net value as at December 31, 2011	1,887	822,360	271,183	161,239	3,165	1,259,834

All of the property, plant and equipment are given as securities under the respective project financing or for the corporate financing.

Property, plant and equipment includes capitalized financing costs of $2,795 as at December 31, 2011 ($607 at December 31, 2010) incurred prior to their intended use or sale.

The financing costs related to a specific project financing are entirely capitalized to the specific property, plant and equipment. Financing costs related to corporate financing are capitalized for the portion of the financing actually used for a specific property, plant and equipment.

The cost of the wind farm facilities under construction were reduced by investment tax credits of $352 ($205 in 2010).

(in thousands of Canadian dollars except as noted and amounts per share)

11. PROPERTY, PLANT AND EQUIPMENT (CONTINUED)

	Land	Hydroelectric facilities	Wind Farm facilities	Facilities under construction	Other equipment	Total
Cost						
As at January 1, 2010	74	245,304	133,069	-	560	379,007
Additions	-	941	318	31,148	635	33,042
Business Acquisitions	-	201,832	64,069	-	803	266,704
Dispositions	-	-	-	-	(80)	(80)
Net foreign exchange differences	(4)	(299)	-	-	(1)	(304)
As at December 31, 2010	70	447,778	197,456	31,148	1,917	678,369
Accumulated depreciation						
As at January 1, 2010	-	(33,402)	(13,131)	-	(310)	(46,843)
Depreciation	-	(10,260)	(8,707)	-	(391)	(19,358)
Dispositions	-	-	-	-	80	80
Net foreign exchange differences	-	62	-	-	-	62
As at December 31, 2010	-	(43,600)	(21,838)	-	(621)	(66,059)
Net value as at December 31, 2010	70	404,178	175,618	31,148	1,296	612,310

(in thousands of Canadian dollars except as noted and amounts per share)

12. INTANGIBLE ASSETS

The Corporation's intangible assets are related to the following assets:

	Hydroelectric facilities	Wind farm facilities	Facilities under construction	Total
Cost				
As at January 1, 2011	189,191	77,094	-	266,285
Additions	415	3,050	-	3,465
Business Acquisitions	230,184	-	9,538	239,722
Transfer from projects under development	-	-	7,000	7,000
Net exchange differences	44	-	-	44
As at December 31, 2011	419,834	80,144	16,538	516,516
Accumulated amortization				
As at January 1, 2011	(45,979)	(9,468)	-	(55,447)
Amortization	(14,181)	(5,612)	-	(19,793)
Net exchange differences	(14)	-	-	(14)
As at December 31, 2011	(60,174)	(15,080)	-	(75,254)
Net value as at December 31, 2011	359,660	65,064	16,538	441,262

	Hydroelectric facilities	Wind farm facilities	Facilities under construction	Total
Cost				
As at January 1, 2010	107,784	41,421	-	149,205
Additions	421	-	-	421
Business Acquisitions	81,097	35,673	-	116,770
Net exchange differences	(111)	-	-	(111)
As at December 31, 2010	189,191	77,094	-	266,285
Accumulated amortization				
As at January 1, 2010	(37,030)	(4,815)	-	(41,845)
Amortization	(8,974)	(4,653)	-	(13,627)
Net exchange differences	25	-	-	25
As at December 31, 2010	(45,979)	(9,468)	-	(55,447)
Net value as at December 31, 2010	143,212	67,626	-	210,838

(in thousands of Canadian dollars except as noted and amounts per share)

13. PROJECT DEVELOPMENT COSTS

	December 31, 2011	December 31, 2010	January 1, 2010
Cost			
Beginning of year	5,908	-	-
Additions	40,734	5,908	-
Business aquisition	100,746	-	-
Transfer to property, plant and equipment	(42,346)	-	-
Transfer to intangible assets	(7,000)	-	-
End of year	98,042	5,908	-

Project development costs include capitalized interests of $347 ($122 in 2010).

14. INCOME TAXES

a) Income tax recognized in profit or loss

	December 31, 2011	December 31, 2010
Current tax		
Current tax expense (recovery) in respect of the current year	349	(1,390)
Adjustments recognized in the current year in relation to the current tax expense (recovery) of prior years	115	(341)
	464	(1,731)
Deferred tax		
Deferred tax recovery recognized in the current year	(13,395)	(1,596)
Adjustments to deferred tax attributable to changes in tax rates and laws	(433)	(1,895)
	(13,828)	(3,491)
Total income tax recovery recognized in the current year	(13,364)	(5,222)

(in thousands of Canadian dollars except as noted and amounts per share)

14. INCOME TAXES (CONTINUED)

The total income tax expense (recovery) for the year can be reconciled to the accounting profit as follows:

	December 31, 2011	December 31, 2010
Loss before provision for tax expense	(57,068)	(66,687)
Less:		
Accounting loss allocated to the unitholders	-	111
Loss allocated to minority interests on non-taxable entities	3,157	68
Deductible loss of the Corporation	(53,911)	(66,508)
Canadian statutory income tax rate	27.50%	28.41%
Income tax recovery calculated at the statutory rate	(14,826)	(18,895)
Items affecting the statutory rate		
Income that is exempt from taxation	(187)	(30)
Non-deductible expenses	1,642	15,618
Effect of previously unrecognized and unused tax losses and deductible temporary differences now recognized as deferred tax assets	(897)	-
Income taxable at a higher rate than the Canadian statutory rate	482	1,237
Reduction in taxes related to share exchange arrangement	-	(738)
Reduction in deferred income tax rates	(433)	(1,895)
Increase (reduction) in taxable temporary differences in relation to investments in subsidiaries, branches and associates	696	(48)
Income tax on dividends on preferred shares	260	88
Others	(216)	(218)
Adjustments recognized in the current year in relation to the current tax of prior years	115	(341)
Income tax recovery recognized in profit or loss relating to continuing operations	(13,364)	(5,222)

The tax rate used for 2011 and 2010 reconciliations above is the average combined corporate tax rate payable by corporate entities in Canada on taxable profits under federal and provincials' tax laws. There have been decreases in the Federal, British Columbia and Ontario tax rates applicable to year 2011.

b) Income tax recognized directly in equity

	December 31, 2011	December 31, 2010
Deferred tax		
Arising on transactions with owners		
Share issue expenses deductible over 5 years	(2,029)	(846)
Others	-	(2)
Total income tax recognized directly in equity	(2,029)	(848)

(in thousands of Canadian dollars except as noted and amounts per share)

14. INCOME TAXES (CONTINUED)

c) Income tax recognized in other comprehensive income

	December 31, 2011	December 31, 2010
Current tax		
Arising on income and expenses recognized in other comprehensive income		
Translation of foreign operations	4	(10)
Total current tax recognized directly in other comprehensive income	4	(10)
Deferred tax		
Arising on income and expenses recognized in other comprehensive income		
Translation of foreign operations	(19)	123
Fair value remeasurement of hedging instruments entered into for a hedge of a net investment in a foreign operation	(16)	-
Total deferred tax recognized directly in other comprehensive income	(35)	123
Total income tax recognized directly in other comprehensive income	(31)	113

d) Current tax assets and liabilities

	December 31, 2011	December 31, 2010	January 1, 2010
Current tax assets			
Benefit of tax losses to be carried back to recover taxes paid in prior periods	1,650	2,186	-
Tax refund receivable	14	14	-
	1,664	2,200	-
Current tax liabilities			
Income tax payable	2,835	2,164	2,790

e) Deferred tax balances

The following is the analysis of deferred tax assets (liabilities) presented in the consolidated statements of financial position:

	December 31, 2011	December 31, 2010	January 1, 2010
Deferred tax assets	24,485	13,178	2,641
Deferred tax liabilities	(140,454)	(82,641)	(66,973)
	(115,969)	(69,463)	(64,332)

(in thousands of Canadian dollars except as noted and amounts per share)

14. INCOME TAXES (CONTINUED)

	As at January 1, 2011	Recognized in earnings	Recognized in other comprehensive income	Recognized directly in equity	Acquisitions / disposals	As at December 31, 2011
Deferred tax assets (liabilities) in relation to:						
Investment into subsidiaries and on entity subject to significant influence	(352)	(666)	(15)	-	(1,877)	(2,910)
Property, plant and equipment	(43,788)	(16,983)	26	-	(1,696)	(62,441)
Project development costs	3,486	10,255	-	-	(22,330)	(8,589)
Intangible assets	(49,925)	9,348	(9)	-	(34,704)	(75,290)
Derivative financial instruments	9,559	15,316	-	-	-	24,875
Debentures	(303)	41	-	-	-	(262)
Financing fees	3,109	(2,454)	-	2,029	1,425	4,109
Debts	(388)	226	-	-	(8,263)	(8,425)
Income tax on dividends on preferred shares	435	(435)	-	-	-	-
Non-repatriated income from foreign subsidiaries	(363)	(36)	-	-	-	(399)
	(78,530)	14,612	2	2,029	(67,445)	(129,332)
Tax losses and minimum taxes	9,067	(784)	33	-	5,047	13,363
	(69,463)	13,828	35	2,029	(62,398)	(115,969)

As at December 31, 2011, the Corporation, its subsidiaries and joint ventures have non-capital losses totaling approximately $67,000 that may be applied against future taxable income. These non-capital losses expire gradually between 2012 and 2031. The Corporation and its subsidiaries recorded capital losses totaling approximately $8,500 that may be applied against capital gains in future years.

The Corporation recognized a deferred tax asset on tax non-capital and capital losses because it is probable that taxable profit and taxable capital gains will be available against which the deductible temporary difference can be utilized.

(in thousands of Canadian dollars except as noted and amounts per share)

14. INCOME TAXES (CONTINUED)

	As at January 1, 2010	Recognized in earnings	Recognized in other comprehensive income	Recognized directly in equity	Acquisitions / disposals	As at December 31, 2010
Deferred tax assets (liabilities) in relation to:						
Investment into subsidiaries and on entity subject to significant influence	-	38	-	-	(390)	(352)
Accounting provision	14	(14)	-	-	-	-
Property, plant and equipment	(47,759)	4,105	(124)	-	(10)	(43,788)
Project development costs	-	(2,092)	-	-	5,578	3,486
Intangible assets	(16,799)	(9,196)	31	2	(23,963)	(49,925)
Derivative financial instruments	(718)	6,040	-	-	4,237	9,559
Debentures	-	199	-	-	(502)	(303)
Financing fees	-	106	-	846	2,157	3,109
Debts	-	(106)	-	-	(282)	(388)
Income tax on dividends on preferred shares	-	435	-	-	-	435
Non-repatriated income from foreign subsidiaries	(365)	2	-	-	-	(363)
	(65,627)	(483)	(93)	848	(13,175)	(78,530)
Tax losses and minimum taxes	1,295	3,974	(30)	-	3,828	9,067
	(64,332)	3,491	(123)	848	(9,347)	(69,463)

(in thousands of Canadian dollars except as noted and amounts per share)

14. INCOME TAXES (CONTINUED)

f) Unrecognized deductible temporary differences, unused tax losses and unused tax credits

	December 31, 2011	December 31, 2010
Tax losses - revenue in nature	3,747	3,403
Tax losses- capital in nature	569	7,177
Transaction costs	2,032	1,354
	6,348	11,934

The unrecognized tax losses will expire gradually between 2023 and 2030.

15. GOODWILL

Allocation of Goodwill to each cash-generating unit is as follows:

	December 31, 2011	December 31, 2010	January 1, 2010
St-Paulin	935	935	935
Portneuf	4,166	4,166	4,166
Chaudière	3,168	3,168	3,168
Total Goodwill	8,269	8,269	8,269

For the year ended December 31, 2010 and 2011 and at the transition date, the Corporation conducted an annual goodwill impairment test. Based on the result of these tests, no impairment charge was required.

The recoverable amount of each cash-generating unit is determined based on a value in use calculation which uses cash flow projections based on financial budgets approved by management covering a period extending to the lesser of 50 years or the period for which the Corporation owns its rights on the site and a discount rate of 6.5% in 2011.

Assumptions used to determine the recoverable amount of assets are the following:

- The discount rate is a weighted average between the consolidated cost of debt and the consolidated cost of equity to which a risk premium is added for each cash-generating unit.
- A cash-generating unit is an individual hydroelectric facility or an individual wind farm.
- The future expected cash flows are based on the budgets before debt service and income tax of each cash-generating unit. The budgets have been built using long-term averages of water flows and wind. These long-term averages approximate actual results.

16. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31, 2011	December 31, 2010	January 1, 2010
Trade and accrued liabilities	18,334	18,506	6,150
Current portion of construction holdbacks	373	618	-
Capital tax	351	484	-
Interest payable	6,517	1,251	294
Commodity taxes	1,041	888	340
	26,616	21,747	6,784

(in thousands of Canadian dollars except as noted and amounts per share)

17. LONG-TERM DEBT

	December 31, 2011	December 31, 2010	January 1, 2010
Revolving credit term facility (a)			
Prime rate advances renewable until August 2016 (average rate of 3.60%, nil in 2010)	20	-	93
Bankers' acceptances renewable until August 2016 (average weighted rate of 2.84%, 3.87% in 2010)	164,780	27,400	103,800
LIBOR advances, US$13,900 renewable until August 2016 (rate of 2.10%, 3.04% in 2010)	14,136	13,825	14,580
Term loans			
Truck loans maturing in 2012 and 2017 (rates between 0% and 0.9%) (b)	73	-	-
Glen Miller, floating-rate term loan maturing in 2013 (rate of 2.66%, 2.65% in 2010) (c)	13,500	14,500	-
Carleton, floating-rate term loan maturing in 2013 (rate of 2.57%, 2.67% in 2010) (d)	46,298	49,083	-
Umbata Falls, floating-rate term loan maturing) in 2014 (rate of 2.42%, 2.50% in 2010) (e)	23,885	24,348	-
Fitzsimmons Creek, floating-rate term loan maturing in 2016 (rate of 2.52%, 4.90% in 2010) (f)	22,458	22,551	-
Hydro-Windsor, 8.25% fixed rate term loan maturing in 2016 (g)	5,027	5,841	6,590
Montagne-Sèche, floating-rate construction loan maturing in 2016 (rate of 3.47%, nil in 2010) (h)	26,200	-	-
Rutherford Creek, 6.88% fixed rate term loan maturing in 2024 (i)	50,000	50,000	50,000
Ashlu Creek, floating-rate term loan maturing in 2025 (rate of 2.63%, 2.83% in 2010) (j)	102,669	104,406	-
L'Anse-à-Valleau, floating-rate term loan maturing in 2026 (rate of 2.30%, same in 2010) (k)	45,706	47,891	50,067
Stardale, floating-rate construction loan (rate of 3.45%, nil in 2010) (l)	73,706	-	-
Kwoiek Creek, 20% fixed rate term loan during development phase and 14% fixed rate during construction and operation phase (m)	150	150	-
Bonds			
Harrison Operating Facilities, senior real return bond maturing in 2049 (rate of 6.94%) (n) (q)	226,338	-	-
Harrison Operating Facilities, senior fixed rate bond maturing in 2049 (rate of 6.67%) (o) (q)	215,570	-	-
Harrison Operating Facilities, junior real return bond maturing in 2049 (rate of 7.94%) (p) (q)	26,484	-	-
	1,057,000	359,995	225,130
Deferred financing costs	(7,488)	(1,305)	(569)
	1,049,512	358,690	224,561
Current portion of long-term debt	(19,475)	(9,259)	(2,758)
Long-term portion	1,030,037	349,431	221,803

17. LONG-TERM DEBT (CONTINUED)

(a) Revolving credit term facility

On August 9, 2011, the Corporation amended its $170,000 revolving credit facility for a five-year $350,000 revolving credit facility.

As at December 31, 2011, a LIBOR rate advance of $14,136 (US$13,900) bearing interest at a rate of 2.10% and Bankers' Acceptances ("BA") rate advances totaling $164,780 bearing interest at a weighted average rate of 2.84% were due under this facility.

An amount of $23,846 was used to secure letters of credit. Thus, the unused and available position of the facility was $147,218. The carrying value of assets of the Corporation and subsidiaries given as securities under this facility total approximately $582,000.

(b) Truck loans

As part of the Cloudworks Acquisition, the Corporation assumed truck loans for a total of $110. They are secured by the trucks. These loans are either interest-free or bear interest at a rate of 0.9%. They mature in 2012 and 2017.

(c) Glen Miller

The term loan consists of a 5-year term loan, amortized over a 17-year period starting July 1, 2008 with a final maturity date in December 2025. The loan bears interest at BA rate plus an applicable margin for an all-in rate of 2.66% as at December 31, 2011. The term loan is repayable in quarterly installments of $250 and the principal repayments for 2012 are set to $1,000. The lender also agreed to make available to Glen Miller Power, Limited Partnership a letter of credit facility in an amount of $ 160. This debt is secured by all of Glen Miller Power, Limited Partnership's assets with a carrying value of approximately $26,600.

(d) Carleton

The loan consists in a 5-year term loan, amortized over a 18.5-year period which started on December 31, 2008 with a final maturity in March 2027. The loan bears interest at BA rate plus an applicable margin for an all-in rate of 2.57% as at December 31, 2011. This loan was accounted for at its fair market value of $51,699 as at March 29, 2010, on the share exchange arrangement (Note 6), for an effective interest rate of 2.11%. The term loan is repayable in quarterly instalments. The principal repayments are variable and are set at $2,813 for 2012. The lenders also agreed to make available a letter of credit facility in an amount not to exceed $833. An amount of $499 has been used to secure one letter of credit. This debt is secured by all Innergex CAR, LP's assets with a carrying value of approximately $97,500.

(e) Umbata Falls

The loan consists of a 5-year term loan, amortized over a 25-year period starting in September 2009 with a final maturity in August 2034. The term loan bears interest at BA rate plus an applicable margin for an all-in total of 2.42% as at December 31, 2011. The term loan is repayable in quarterly instalments. The principal repayments are variable and are set to $1,007 for 2012 (the share of the Corporation is 49%). The lender also agreed to make available a letter of credit facility in a principal amount not exceeding $500 until five years after completion, which is defined as beginning six months after commissioning. As at December 31, 2011, an amount of $470 has been used to secure two letters of credit. This debt is secured by all of Umbata Falls LP's assets with a carrying value of approximately $84,100 (the share of the Corporation is 49%).

17. LONG-TERM DEBT (CONTINUED)

(f) Fitzsimmons Creek

Lenders agreed to make available, for the Fitzsimmons Creek hydroelectric facility, a non recourse term loan. This facility was converted into a term loan in December 2011. The loan matures five years after conversion, amortized over a 30-year period. The loan advances bear interest at BA rate plus an applicable margin for an all-in rate of 2.52% as at December 31, 2011. The amount drawn as at March 29, 2010 was $17,100 and the loan term was accounted for at its fair market value of $19,617 as at March 29, 2010, on the share exchange arrangement (Note 6), for an effective interest rate of 4.67%. The principal repayments are variable and are set to $247 for 2012.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $750 until six months after commissioning and thereafter in an amount not to exceed $150 until five years after completion. An amount of $150 has been used to secure two letters of credit. This debt is secured by all of Fitzsimmons Creek Hydro Limited Partnership assets with a carrying value of approximately $27,300

(g) Hydro-Windsor

The loan consists of a 20-year term loan starting in December 1996 amortized over a 20-year period maturing in December 2016. The loan bears interest at a fixed rate of 11.7% and was accounted for at its fair market value of $9,883 as at April 27, 2004, for an effective interest rate of 8.25%; it is repayable by monthly blended payments of principal and interest totalling $105. The principal repayments for 2012 will amount to $760. The loan is secured by Hydro-Windsor LP's assets, with a carrying value of approximately $12,400.

(h) Montagne-Sèche

Lenders agreed to make available, for the Montagne-Sèche wind farm facility, a non recourse construction loan in a principal amount up to but not exceeding $31,700. The loan matures on June 30, 2016. As at December 31, 2011, $26,200 was drawn. The loan advances bear interest at BA rate plus an applicable margin for an all-in rate of 3.47% as at December 31, 2011. The principal repayments are variable and set to $1,679 for 2012.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $445. As at December 31, 2011, an amount of $445 has been used to secure one letter of credit. The loan is secured by Innergex Montagne-Sèche, LP's assets with a carrying value of approximately $41,000.

(i) Rutherford Creek

The loan consists of a 20-year fixed rate term loan bearing interest at 6.88% starting in July 2004 and amortized over a 12-year period effective July 1, 2012 with a final maturity in June 2024. Meanwhile, this debt is repayable by monthly interest payments of $286. The principal repayments for 2012 are set to $1,366. The loan is secured by Rutherford Creek Power Limited Partnership's assets, with a carrying value of approximately $88,100.

(j) Ashlu Creek

Lenders agreed to make available for the Ashlu Creek hydroelectric facility a non-recourse construction loan. This facility was converted into a term loan on July 9, 2010. The loan consists of a 15-year term loan, amortized over a 25-year period starting in September 2010 with a final maturity date in June 2035. The loan bears interest at BA rate plus an applicable margin for an all-in rate of 2.63% as at December 31, 2011. The amount drawn as at March 29, 2010 was $100,400 and the term loan was accounted for at its fair market value of $95,587 as at March 29, 2010, on the share exchange arrangement (Note 6), for an effective interest rate of 1.74%. The term loan is repayable in quarterly instalments. The principal repayments are variable and are set to $2,080 for 2012.

The lenders also agreed to make available a letter of credit facility, on a revolving basis by way of letters of credit in the principal amount not exceeding $3,000 until the final maturity date, which is the fifteenth anniversary of the term conversion date as defined in the credit agreement. As at December 31, 2011 an amount of $1,718 has been used to secure one letter of credit. The loan is secured by Ashlu Creek hydroelectric facility's assets with a carrying value of approximately $183,700.

17. LONG-TERM DEBT (CONTINUED)

(k) L'Anse-à-Valleau

The loan consists of a 18.5-year term loan starting in December 2007 and amortized over a 18.5-year period maturing in March 2026. The loan bears interests at BA rate plus an applicable margin, for an all-in rate of 2.30% as at December 2011. The term loan is repayable in quarterly installments. The principal repayments are variable and are set at $2,191 for 2012. Innergex AAV, L.P. lender has made available to it a credit facility of $1,200 in order to secure letters of credit. As at December 31, 2011, an amount of $423 had been used to secure one letter of credit. The loan is secured by Innergex AAV, LP's assets with a carrying value of approximately $75,900.

(l) Stardale, construction loan

The project entered into a $111,700 non recourse construction loan agreement. At the end of 2011, $73,706 was drawn under this construction loan. The loan will mature 18 years after conversion of the construction loan into a term loan. The loan's quarterly principal payments will begin upon conversion and be based on an 18-year amortization period. For 2012, the principal repayments are variable and set to $1,070 for 2012. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2011, the effective interest rate was 3.45%.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $5,600. As at December 31, 2011, this facility had not been used. The loan is secured by Stardale L.P.'s assets with a carrying value of approximately $121,400.

(m) Kwoiek Creek

The Kwoiek Creek Resources Limited Partnership's long-term debt consists of a loan made by the partner of the Corporation in the Kwoiek Creek Project. As per the agreements related to the project, both partners can participate in the financing of the project. The loan bears interests at a rate of 20% during the development phase and 14% during the construction and operating phases. The partner loan made to Kwoiek Creek Resources Limited Partnership amounts to $150.

(n) Harrison Operating Facilities, Senior real return bond

As part of the Cloudworks Acquisition, the Corporation assumed a $258,685 Senior Real Return bond with interest accruing at 2.96% adjusted by an inflation ratio as well as an inflation compensation interest factor for an all-in rate of 6.94% as at December 31, 2011. Both inflation adjustments are based on the All-items Consumer Price Index for Canada ("CPI"), not seasonally adjusted. Payments on this bond are due semi-annually and the bond matures on June 1, 2049. This bond was accounted for at its fair market value of $223,883 on the Cloudworks Acquisition, for an effective interest rate of 4.04%. Semi-annual payments are $5,790 before CPI adjustment. On December 1, 2031, the payment amount decreases to $4,481 before CPI adjustment where it remains until maturity. Principal repayment started June 1, 2011. For 2012, the principal repayments are set to $4,848. The bond is secured by the Harrison Operating Facilities from the Cloudworks acquisition.

(o) Harrison Operating Facilities, Senior fixed rate bond

As part of the Cloudworks Acquisition, the Corporation assumed a $244,771 Senior Fixed Rate bond with interest accruing at 6.67%. This bond was accounted for at its fair market value of $216,433 on the Cloudworks Acquisition, for an effective interest rate of 6.66%. Payments on this bond are due semi-annually with the bond maturing on September 1, 2049. Semi-annual payments are $8,072 until September 1, 2030 when they decrease to $6,724 for the remainder of the term loan. Principal repayment started March 1, 2011. For 2012, the principal repayments are set to $2,632. The bond is secured by the Harrison Operating Facilities from the Cloudworks acquisition.

(in thousands of Canadian dollars except as noted and amounts per share)

17. LONG-TERM DEBT (CONTINUED)

(p) Harrison Operating Facilities, Junior real return bond

As part of the Cloudworks Acquisition, the Corporation assumed a $28,743 Junior Real Return Rate bond with interest accruing at 4.27% adjusted by an inflation ratio as well as an inflation compensation interest factor for an all-in rate of 7.94% as at December 31, 2011. This bond was accounted for at its fair market value of $25,810 on the Cloudworks Acquisition for an effective rate of 5.04%. Both inflation adjustments are based on the CPI, not seasonally adjusted. Payments on this bond are due quarterly and the bond matures on September 1, 2049. Quarterly payments are $291 before CPI adjustment until June 1, 2017 when the amount increases to $389 before CPI adjustment until maturity. Principal repayment does not commence until June 1, 2017. The bond is secured by the Harrison Operating Facilities from the Cloudworks acquisition.

(q) Summary of Harrison Operating Facilities

The bonds are secured by the Harrison Operating Facilities from the Cloudworks acquisition. The carrying value of the property and assets of the Harrison Operating Facilities totals approximately $737,000.

	Senior Real Return Bond	Senior Fixed Rate Bond	Junior Real Return Bond	Total
Balance – April 4, 2011	223,883	216,433	25,810	466,126
Inflation compensation interest	6,476	-	723	7,199
Principal repayment	(4,685)	(1,263)	-	(5,948)
Amortization of revaluation	664	400	(49)	1,015
Balance – December 31, 2011	226,338	215,570	26,484	468,392

The increase in compensation interest is a result of the CPI rate change over the reference period.

(r) Principal repayments

The principal repayments for the next years, excluding the reevaluations, will be as follows:

	Principal repayments	Amortization of reevaluation	Long-term debt
2012	20,836	(1,361)	19,475
2013	77,395	(1,398)	75,997
2014	45,619	(1,439)	44,180
2015	24,027	(1,486)	22,541
2016	222,767	(1,540)	221,227
Thereafter	732,432	(58,852)	673,580
	1,123,076	(66,076)	1,057,000

(in thousands of Canadian dollars except as noted and amounts per share)

18. CONVERTIBLE DEBENTURES

The convertible debentures were part of the assumed liabilities on the share exchange arrangement described in Note 6. They were accounted for at their fair market value of $79,222 as at March 29, 2010 on the share exchange arrangement described in Note 6, for an effective interest rate of 6.09%. Interest is payable semi-annually on April 30 and October 31, of each year commencing on October 31, 2010.

The convertible debentures bear interest at an annual rate of 5.75% and will mature on April 30, 2017. Each convertible debenture is convertible into common shares of the Corporation at the option of the holder at any time prior to the earlier of April 30, 2017 and the redemption date specified by the Corporation. The conversion price is $10.65 per common share (the “Conversion Price”), being a conversion rate of approximately 93.8967 common shares per $1,000 principal amount of convertible debentures. Holders converting their convertible debentures will receive accrued and unpaid interest thereon for the period from the last interest payment date on their convertible debentures to the date of conversion.

The convertible debentures may not be redeemed by the Corporation on or before April 30, 2013 except in certain limited circumstances following a change of control. After April 30, 2013, and prior to April 30, 2015, the convertible debentures may be redeemed by the Corporation. Such redemption would be done, provided that the trading price of the common shares on the Toronto Stock Exchange is not less than 125% of the Conversion Price. On or after April 30, 2015 and prior to April 30, 2017, the convertible debentures may be redeemed at the option of the Corporation at a price equal to their principal amount. Subject to required regulatory approval, the Corporation may, at its option, elect to satisfy its obligation to pay the principal amount of the convertible debentures on redemption or at maturity, in whole or in part, through the issuance of freely tradable common shares upon prior notice, by delivering that number of common shares obtained by dividing the principal amount of the convertible debentures by 95% of the current market price. Any accrued or unpaid interest will be paid in cash.

The convertible debentures are subordinated to all other indebtedness of the Corporation.

The liability portion is being accreted such that the liability at maturity will equal the face value less prior conversions if any.

	December 31, 2011	December 31, 2010	January 1, 2010
Debt portion of convertible debentures, at fixed rate, 5.75% (effective rate of 6.09%), maturing on April 30, 2017, with a face value of $80,500	79,490	79,334	-
Equity portion of convertible debentures	1,340	1,340	-

19. CONTINGENT CONSIDERATIONS

	December 31, 2011	December 31, 2010	January 1, 2010
Balance at beginning of the year	-	-	-
Liability assumed as part of the business acquisitions (Note 5)	2,999	-	-
Liability incurred	1,858	-	-
Contingent consideration paid	(1,147)	-	-
Accretion expense on contingent consideration (included in Finance costs)	177	-	-
Balance at the end of the year	3,887	-	-
Current portion of contingent consideration	(983)	-	-
Non current contingent consideration	2,904	-	-

(in thousands of Canadian dollars except as noted and amounts per share)

19. CONTINGENT CONSIDERATIONS (CONTINUED)

Cloudworks

The Cloudworks Acquisition described in Note 5 a) provides for the potential payment of additional amounts to the vendors over a period of more than 40 years from the April 4, 2011 to the 40th anniversary of the last project under development to achieve commercial operation (or the 50 years after April 4, 2011 if that date is earlier). Such potential deferred payments are divided into four categories: (i) deferred operating facilities payments; (ii) deferred development projects payments; (iii) deferred terminal value payment; and (iv) deferred prospective projects payments. The deferred payments are effectively intended to provide for a potential sharing of the value created if the projects perform better than the Corporation's expectations and would result in incremental accretion to the Corporation, net of these payments.

The maximum aggregate amount of all deferred payments under the Cloudworks acquisition is limited to a present value amount of $35,000, and for the purpose of applying such maximum aggregate payment amount, the amount of any deferred payment made is discounted to its present value amount by applying a mutually agreed upon discount rate per annum. The Corporation has the right, at any time during the five-year period after April 4, 2011, to extinguish all its obligations to make deferred payments by making a one-time payment of the amount by which the maximum aggregate amount of deferred payments of $35,000 exceeds the present value of any deferred payments (discounted to their present value amounts by applying an agreed discount rate per annum) made prior to the exercise of such right by the Corporation.

Stardale Project

In connection with the Stardale acquisition described in Note 5 b), the Corporation agreed to pay contingent considerations based upon future events for a period of 3 years after April 20, 2011. These contingent considerations provide for the sharing of the potential value created if the Stardale project benefits from a better return than the Corporation's expectations and would result in incremental accretion to the Corporation, net of these payments. No maximum applies to the potential sharing.

20. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations primarily arise from obligations to retire wind farms upon expiry of the site leases. The wind farm facilities were constructed on sites held under leases expiring 25 years after the signing date. The Corporation estimates that the undiscounted value of the payments required for settling the obligations over a 25-year period will be as follows:

Year of expected payments	
2031	2,592
2032	2,466
2033	2,748
2036	4,191
	11,997

The change in the liability during the year is as follows:

For the years ended December 31	2011	2010
Beginning of year	2,384	1,185
Liability assumed as part of the share exchange arrangement (note 6)	-	643
Liability recorded upon commissionning of facilities	1,144	-
Accretion expense (included in Finance costs)	330	556
End of year	3,858	2,384

The cash flows were discounted at rates between 5.25% to 5.33% as at December 31, 2011 (5.6% in 2010) to determine the obligations.

(in thousands of Canadian dollars except as noted and amounts per share)

21. SHAREHOLDERS' CAPITAL

a) Share capital

Authorized

The authorized capital of the Corporation consists of an unlimited number of common shares and an unlimited number of preferred shares, non-voting, retractable and redeemable. On September 14, 2010, the authorized capital was modified to included up to 3,400,000 Cumulative Rate Reset Preferred Shares, Series A (the "Series A Preferred Shares") and up to 3,400,000 Cumulative Floating Rate Preferred Shares, Series B (the "Series B Preferred Shares").

Prior to the share exchange arrangement described in Note 6, the authorized capital of the Fund consisted of an unlimited number of trust units. The Fund had 29,404,276 trust units outstanding (42,930,243 when considering the 1.46 conversion ratio).

Preferred Shares

On September 14, 2010, the Corporation issued a total of 3,400,000 Series A Preferred Shares at $25.00 per share for aggregate gross proceeds of $85,000. For the initial five-year period to, but excluding January 15, 2016 (the "Initial Fixed Rate Period"), the holders of Series A Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Corporation's board of directors (the "Board of Directors"). The dividends will be payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to $1.25 per share. The initial dividend of $0.42123 per share was paid on January 17, 2011.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of the Series A Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board of Directors. The dividends will be payable quarterly in an annual amount per Series A Preferred Share, equal to the sum of the yield on a Government of Canada bond with a term to maturity of five years on the applicable fixed rate calculation date, plus 2.79%, applicable to such Subsequent Fixed Rate Period multiplied by $25.00.

Each holder of Series A Preferred Shares will have the right, at its option, to convert all or any of its Series A Preferred Shares into the Series B Preferred Shares of the Corporation on the basis of one Series B Preferred Share for each Series A Preferred Share converted, subject to certain conditions, on January 15, 2016 and on January 15 every five years thereafter. The holders of Series B Preferred Shares will be entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board of Directors. The dividends will be payable quarterly in an annual amount per Series B Preferred Share equal to the Treasury Bills rate for the preceding quarterly period, plus 2.79%, per annum determined on the 30th day prior to the first day of the applicable quarterly floating rate period multiplied by $25.00.

The Series A Preferred Shares and the Series B Preferred Shares will not be redeemable by the Corporation prior to January 15, 2016.

	December 31, 2011	December 31, 2010	January 1, 2010
Series A Preferred Shares			
3,400,000 shares, $ 25.00 each	85,000	85,000	-
Issuance costs	(3,257)	(3,257)	-
Net proceeds	81,743	81,743	-
Deferred tax	846	846	-
Net carrying value	82,589	82,589	-

b) Reductions of the Stated Capital Account of the common shares

Special resolutions to approve the reduction of the legal stated capital account maintained in respect of the common shares of the Corporation, without any payment or distribution to the shareholders were adopted on May 10, 2011. This resulted in a decrease of $202,488 ($453,793 in 2010) of the Shareholders' capital account and an increase of $202,488 ($453,793 in 2010) of the Contributed surplus from reduction of capital on common shares account.

(in thousands of Canadian dollars except as noted and amounts per share)

21. SHAREHOLDERS' CAPITAL (CONTINUED)

c) Stock option plan

The Corporation has a stock option plan providing for the granting of options by the Board of Directors to employees, officers, directors and certain consultants of the Corporation and its subsidiaries to purchase common shares. Options granted under the stock option plan will have an exercise price of not less than the market price of the common shares at the date of grant of the option, calculated as the volume weighted average trading price of the common shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant.

On May 10, 2011, during the Annual and special meeting of shareholders of the Corporation, the special resolution to increase the maximum number of common shares of the Corporation available for issuance pursuant to options granted under the stock option plan from 2,350,000 to 4,064,123 was adopted. Any common shares subject to an option that expires or terminates without having been fully exercised may be subject to a further option. The number of common shares issuable to non-executive directors of the Corporation under the stock option plan cannot at any time exceed 1% of the issued and outstanding common shares.

Options must be exercised during a period established by the Board of Directors, which may not be greater than ten years after the date of grant. Options granted under the stock option plan vest in equal amounts on a yearly basis over a period of four to five years following the grant date.

For the years ended December 31	2011		2010	
	Number of options (000's)	Weighted average exercise price ($)	Number of options (000's)	Weighted average exercise price ($)
Outstanding - beginning of year	1,842	10.02	-	-
Outstanding stock options assumed on the share exchange arrangement described in Note 6	-	-	1,269	11.00
Granted during the year	835	9.88	808	8.75
Exercised during the year	-	-	-	-
Cancelled during the year	-	-	235	11.00
Outstanding - end of year	2,677	9.97	1,842	10.02
Options exercisable - end of year	1,196	10.70	776	11.00

The following options were outstanding and exercisable as at December 31, 2011:

	Outstanding		Exercisable		
	Number of options (000's)	Exercise price ($)	Number of options (000's)	Exercise price ($)	Year of maturity
	1,034	11.00	1,034	11.00	2017
	835	9.88	-	9.88	2018
	808	8.75	162	8.75	2020
	2,677		1,196		

(in thousands of Canadian dollars except as noted and amounts per share)

21. SHAREHOLDERS' CAPITAL (CONTINUED)

The Corporation applies the fair value method of accounting for options granted to senior management, which is estimated using the Black-Scholes option-pricing model. Share-based payments are expensed and a credit is made to the share-based payment account in the equity of the Corporation to account for the options outstanding. The following assumptions were used to estimate the fair value of the options issued to grantees:

Risk-free interest rate	0.1% to 2.7%
Expected annual dividend	$0.58
Expected life of options	0.1 to 6 years
Expected volatility	20% to 40%

For the purpose of compensation expense, stock-based compensation is amortized to expense on a straight-line basis over the vesting period of a maximum of 5 years. The weighted average contractual life of the outstanding stock options is 7 years. Expected volatility is estimated by considering historic average share price volatility.

d) Warrants

On August 29, 2010, the 200,000 warrants granted by the Corporation expired. The warrants were assumed on the share exchange arrangement described in Note 6. The warrants were exercisable at a strike price of $ 12.50 per warrant.

22. FINANCE COSTS

For the years ended December 31	2011	2010
Interest on long-term debt and on convertible debentures	44,101	22,432
Compensation interest	7,199	-
Amortization of financing fees	231	768
Amortization of revaluation of long-term debt and of convertible debentures	1,084	(7)
Accretion expense on asset retirement obligations	330	556
Accretion expense on contingent considerations	177	-
	53,122	23,749

(in thousands of Canadian dollars except as noted and amounts per share)

23. COMPUTATION OF EARNINGS AVAILABLE TO COMMON SHAREHOLDERS

The net loss of the Corporation is adjusted for the preferential dividend on the preferred shares as follows:

	December 31, 2011	December 31, 2010
Net loss attributable to owners of the parent	(40,547)	(68,635)
Add:		
Distributions declared to unitholders (a)	-	7,238
Less:		
Dividends declared on Series A preferred shares	(4,250)	(1,432)
Net loss available to common shareholders	(44,797)	(62,829)
Weighted average number of common shares/units (when considering the 1.46 conversion ratio) outstanding (in 000)	75,681	55,530
Basic net loss per share ($)	(0.59)	(1.13)
Weighted average number of common shares/units (when considering the 1.46 conversion ratio) outstanding (in 000)	75,681	55,530
Effect of dilutive stock options (in 000) (b)	74	-
Diluted weighted average number of common shares/units (when considering the 1.46 conversion ratio) outstanding (in 000)	75,755	55,530
Diluted net loss per share ($) (c)	(0.59)	(1.13)

(a) For the year ended December 31, 2010, net loss per share has been calculated using an adjusted net loss amount. The distribution to unitholders has been reclassified and excluded from the net loss for the purpose of the net loss per share calculation in order to make the calculation consistent with the current year.

(b) During the year, 1,869,420 stock options (1,842,024 as at December 31, 2010), nil warrants (200,000 prior to August 29, 2010) and 7,558,684 shares potentially issued on conversion of convertible debentures (same as at December 31, 2010) were excluded in the calculation of diluted weighted average number of shares/units outstanding as the exercise price was above the average market price of ordinary shares during the period.

(c) During the year, 808,024 stock options were excluded from the calculation of diluted net loss per share as it was anti-dilutive due to a net loss available to common shareholders.

(in thousands of Canadian dollars except as noted and amounts per share)

24. DIVIDENDS

The following are the dividends paid by the Corporation during the year.

Common shares

Date of announcement	Record date	Payment date	Dividends per share ($)	Shares outstanding (000's)	Total payment ($)
08/11/2010	31/12/2010	17/01/2011	0.1450	59,533	8,632
23/03/2011	31/03/2011	15/04/2011	0.1450	59,533	8,632
07/06/2011	30/06/2011	15/07/2011	0.1450	81,282	11,786
10/08/2011	30/09/2011	17/10/2011	0.1450	81,282	11,786
			0.5800		40,836

Preferred shares

Date of announcement	Record date	Payment date	Dividends per share ($)	Shares outstanding (000's)	Total payment ($)
08/11/2010	31/12/2010	17/01/2011	0.4212	3,400	1,431
23/03/2011	31/03/2011	15/04/2011	0.3125	3,400	1,063
07/06/2011	30/06/2011	15/07/2011	0.3125	3,400	1,063
10/08/2011	30/09/2011	17/10/2011	0.3125	3,400	1,063
			1.3587		4,620

25. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a) Changes in non-cash operating working capital items

	December 31, 2011	December 31, 2010
Accounts receivable	(19,479)	(5,747)
Prepaid and others	784	(960)
Accounts payable and accrued liabilities	(5,033)	(15,131)
	(23,728)	(21,838)

b) Additional information

	December 31, 2011	December 31, 2010
Interest paid (including $2,957 capitalized interest ($218 in 2010))	44,992	22,464
Non-cash transactions		
in unpaid property, plant and equipment	28,204	5,164
in unpaid transaction costs	-	(31)
in unpaid development costs	9,008	1,794
in unpaid intangibles assets	(4)	8
in unpaid long-term assets	(50)	335
in unpaid financing fees	(4)	6

(in thousands of Canadian dollars except as noted and amounts per share)

26. RELATED PARTY TRANSACTIONS

(a) Innergex Renewable Energy Inc.

Prior to the share exchange arrangement described in Note 6, the Corporation was administering and managing the Fund. The following expenses were included in General and administrative expenses in the Consolidated statements of Earnings of the Fund, except for a total of $71 included in business acquisition costs.

	December 31, 2011	December 31, 2010
(i) Management agreement with:		
Subsidiaries	-	536
	-	536
(ii) Administration agreement with:		
Subsidiaries	-	29
	-	29
(iii) Other services	-	6
	-	571

All of the amounts were determined based on the cash consideration exchanged.

(i) Management agreement

Under the management agreement, the Corporation provided various services to the Fund. The Corporation was entitled to be reimbursed for regular operating expenses incurred in carrying out its duties, up to a maximum annual amount indexed to the consumer price index (CPI) inflation rate. An amount of $ 251 was incurred by the Fund in 2010. An amount of $101 was also invoiced for additional services not covered by the management agreement.

The Corporation was also entitled to receive an annual incentive fee based on increases in distributable cash per trust unit. The incentive fee corresponded to 25% of the annual distributable cash per trust unit in excess of $0.925 per trust unit. The fee was intended to provide the Corporation with an incentive to maximize distributable cash per trust unit. During the 2010 year, incentive fees totalling $184 were incurred by the Fund. The management agreement was terminated upon the share exchange arrangement described in Note 6.

(ii) Administration agreement

Under the administration agreement, the Corporation provided various administrative and support services to the Fund. All operating expenses incurred by the Corporation in connection with the provision of these services were payable by the Fund up to a maximum annual amount, which was indexed to the CPI inflation rate. An amount of $29 was incurred by the Fund in 2010. The Corporation was also entitled to reimbursement for reasonable expenses incurred on the Fund’s behalf, including legal and auditing fees. The administration agreement was terminated upon the share exchange arrangement described in Note 6.

(iii) Other services

The Corporation also provided services to the operators of the wind farms. The services are associated with construction monitoring and wind farm operation. The amounts shown are equal to the portion of 38% that was belonging to the Fund. Since the share exchange arrangement described in Note 6, these operations became intercompany transactions and are eliminated upon consolidation of the financial statements.

(in thousands of Canadian dollars except as noted and amounts per share)

27. KEY MANAGEMENT PERSONAL COMPENSATION

The following are the expenses that the Corporation recognized for its key management personnel. The members of the Board of Directors as well as the President and all the Vice-Presidents are key management personnel of the Corporation.

	December 31, 2011	December 31, 2010
Salaries and short-term benefits	4,437	2,311
Attendance fees for members of the Board of Directors	526	597
Termination benefits	390	443
Share-based payment	433	431
	5,786	3,782

28. EMPLOYEE BENEFITS

The following are the expenses that the Corporation recognized for its employee benefits. The expenses were included in the following accounts:

	December 31, 2011	December 31, 2010
Operating expenses	2,487	1,697
General and administrative	4,584	3,490
Prospective projects expenses	1,933	1,706
Transaction costs	929	392
Charged to partners	493	85
Capitalized in Property, plant and equipment	1,950	712
Capitalized in Project development costs	1,950	686
	14,326	8,768

29. FINANCIAL INSTRUMENTS

(a) Fair value disclosures

Fair value estimates are made at specific points in time using available information about the financial instrument in question. These estimates are subjective in nature and often cannot be determined precisely.

As at the statement of financial position date, the Corporation determined that the carrying values of its current financial assets and liabilities approximated their fair values due to these instruments' short term maturity.

As at the statement of financial position date, the Corporation determined that the carrying values of its Short-term investments and Government-backed securities included in Reserve accounts approximated their fair values due to these instruments short-term maturity.

The carrying values of the floating-rate long-term debts are approximately $13,300 higher than their estimated fair values based on the swap interest curve on December 31, 2011, increased by a risk premium ranging from 0.55% to 2.72% for a total ranging from 1.84% to 5.32%. The carrying values of the fixed-rate debts, the bonds and the debentures are approximately $64,400 less than their estimated fair market values based on the swap interest curve on December 31, 2011, increased by a risk premium ranging from 0.55% to 4.04% for a total ranging from 1.84% to 6.58%.

(in thousands of Canadian dollars except as noted and amounts per share)

29. FINANCIAL INSTRUMENTS (CONTINUED)

(b) Interest rate risk

The terms of the contracts reducing the Corporation's risk of interest rate fluctuations are as follows:

			Notional Amounts	
Contract	Maturity	Early termination option	December 31, 2011	December 31, 2010
Bond forwards, from 2.74% to 2.85%	2012	None	137,500	-
Interest rate swaps, from 3.96% to 4.09%	2015	None	15,000	15,000
Interest rate swap, 4.27%,	2016	None	3,000	3,000
Interest rate swap, 4.41%,	2018	2013	30,000	30,000
Interest rate swap, 4.27%,	2018	2013	52,600	52,600
Interest rate swap, from 4.83% to 4.93%, amortizing	2026	None	45,705	47,890
Interest rate swap, from 3.35% to 3.45%, amotizing	2027	2013	45,605	48,315
Forward Interest rate swaps, from 3.64% to 3.75%, amortizing	2030	None	101,996	-
Interest rate swap, 4.22%, amortizing	2030	2016	31,690	31,690
Interest rate swap, 4.25%, amortizing	2031	2016	49,940	49,940
Interest rate swap, 3.98% to 4.11%, amortizing	2034	None	23,885	24,348
Interest rate swaps, from 4.61% to 4.70%, amortizing	2035	2025	107,111	109,067
Forward interest rate swap, 2.85%, amortizing	2041	2016	20,100	-
			664,132	411,850

The Corporation entered into hedge agreements to mitigate the risk of fluctuations in the interest rates on its long-term debt. Rates on contracts represent the interest rate, excluding the applicable margin.

(c) Credit risk

Credit risk relates to the possibility that a loss may occur from a party's failure to comply with contractual requirements.

Cash and cash equivalents are mainly held at large Canadian financial institutions and, to a lesser degree, at major US financial institutions.

The Corporation's accounts receivable and related risks are described in detail in Note 8.

The reserve accounts and related risks are described in detail in Note 9.

The financial derivatives and related risks are described in detail in Note 10.

(d) Liquidity risk

Liquidity risk relates to the capacity of the Corporation to meet liabilities as they become due. Certain covenants of long-term borrowing contracts could prevent the Corporation from repatriating funds from certain subsidiaries.

Some interest rate hedging instruments have embedded early termination options that are exercisable only on their underlying debt's maturity date. The triggering of these options could pose a liquidity risk. Should the early termination option be triggered, a presumed realized loss would be offset by the savings realized on future interest expenses, as a negative swap value would be the result of an environment in which interest rates were lower than the rate embedded in the swap.

(in thousands of Canadian dollars except as noted and amounts per share)

29. FINANCIAL INSTRUMENTS (CONTINUED)

The Corporation had a positive working capital of $50,073 as at December 31, 2011. If necessary, the Corporation can use its revolving credit term facility, as described in Note 17 a), of which $147,218 was available as at December 31, 2011. In addition, in the event of lower revenue due to a decline in production or to a major equipment breakdown, the Corporation has available reserve accounts (as described in note 9) and is covered by insurance plans. Accordingly, the Corporation believes its current working capital to be sufficient to meet all of its needs.

The following table presents the maturities of the financial liabilities:

Maturities of financial liabilities

	Less than 3 months	Between 3 months and 1 year	Between 1 year and 5 years
Dividends payable to shareholders	12,848	-	-
Accounts payable and accrued liabilities	19,081	7,535	-
Income tax liabilities	1,648	1,187	-
Current portion of derivative financial instruments	11,727	8,560	-
Current portion of long-term debt	3,696	15,779	-
Derivative financial instruments	-	-	57,289
Long-term debt	-	-	362,333
Contingent considerations	-	983	1,791
Total	49,000	34,044	421,413

(e) Market risk

Market risk is related to fluctuations in the fair value or future cash flows of a financial instrument because of market price variations. Market risk includes foreign exchange and interest rate risks, described under separate headings, and other price risks.

The sale of electricity is made pursuant to long-term agreements where the offtakers are committed to take and pay for the total production, up to certain annual limits. The inflation clauses of the sale price of electricity are normally allowing the Corporation to cover its increase of variable operation expenses. The inflation clauses included in some of the electricity purchasing contracts with Hydro-Québec are limited to 6% per year.

(f) Foreign exchange risk

The foreign exchange risk relates to fluctuations in the US dollar against the Canadian dollar. The Corporation has subsidiaries in the United States; for which the revenues, net of the expenses incurred, are partly repatriated to Canada. A portion of the Corporation’s debts is denominated in US dollars. Repatriated funds that are not used to service the US dollar-denominated debt are converted into Canadian dollars at the exchange rate in effect on the conversion date. The Corporation’s net risk is estimated to be $10,000 for each 1% increase in the value of the Canadian dollar against the US dollar.

The Corporation uses a portion of its US dollar-denominated debt to hedge its investment in its subsidiaries, as described in Note 3.

30. COMMITMENTS AND CONTINGENCIES

(a) Power Purchase Agreements

Quebec facilities

Under power purchase agreements with terms varying from 20 to 25 years and expiring between 2014 and 2032, Hydro-Québec agreed to purchase all of the electrical energy provided by the facilities located in the Province of Quebec, up to the agreed maximum quantity for each of the hydroelectric facilities and wind farms. In return, the facilities are required to supply a minimum quantity of electricity during each of the consecutive 12-month periods beginning on December 1st of each year for the hydroelectric facilities and beginning on January 1st of each year for the wind farms. These agreements are renewable for identical periods at the option of the Corporation's subsidiaries, except for the wind farms.

Total revenues from Hydro-Québec amounted to $57,637 in 2011 ($51,962 in 2010), representing 39% of the Corporation's revenues (58% in 2010). The Corporation is economically dependent on Hydro-Québec given the size of its revenues.

British Columbia facilities

Under power purchase agreements with terms varying from 20 to 40 years and expiring between 2024 and 2050, British Columbia Hydro and Power Authority agreed to purchase all of the electrical energy provided by the facilities located in the Province of British-Columbia. Total revenues from British Columbia Hydro and Power Authority amounted to $67,204 in 2011 ($24,356 in 2010) representing 45% of the Corporation's revenues (27% in 2010). The Corporation is economically dependent on British Columbia Hydro and Power Authority given the size of its revenues.

Ontario facilities

Under power purchase agreements with terms varying from 20 to 30 years and expiring between 2025 and 2029, Ontario Electricity Financial Corporation and Ontario Power Authority agreed to purchase all of the electrical energy provided by the facilities located in Ontario.

Total revenues from the Ontario facilities amounted to $8,549 ($6,528 in 2010) representing 6% of the Corporation's revenues (7% in 2010).

Idaho facility

Under a power purchase agreement with a 35-year term and expiring in 2030, Idaho Power Company agreed to purchase all of the electricity provided by Horseshoe Bend Hydroelectric Corporation. Total revenues from Idaho Power Company amounted to $2,733 in 2011 ($2,682 in 2010), representing 2% of the Corporation's revenues (3% in 2010).

(b) Other Commitments

Wind farm facilities

Subsidiaries or joint ventures of the Corporation entered into power purchase agreements with Hydro-Québec. In order to fulfill its obligation under the power purchase agreements, the Corporation will need to develop and construct wind powered facilities. Collectively with partners, the Corporation entered into various agreements related to the acquisition of the turbines, the construction and the operation of the wind farms.

The Corporation and its subsidiaries entered into purchase obligation contracts, royalties and other commitments related to amounts to set aside for the dismantling of wind farm components and commitments to surrounding municipalities.

The subsidiaries and/or joint ventures are also committed under options on leases for projects under development.

30. COMMITMENTS AND CONTINGENCIES (CONTINUED)

Stardale Solar LP

Construction contracts

Stardale Solar LP has entered into an engineering procurement and construction contract for the construction of a solar farm.

Service agreement

Stardale Solar LP has also entered into a contract for the operations and maintenance of the solar farm.

Ashlu Creek facility

First Nations agreements

Pursuant to an agreement with Ashlu Creek Investments Limited Partnership, the Squamish First Nation is entitled to a royalty based on revenues of the Ashlu Creek Project since the beginning of operations. 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 Project to be transferred to the Squamish First Nation for a nominal price after 40 years of commercial operation.

Kwoiek Creek facility

Construction contracts

Kwoiek Creek Resources LP entered into various contracts in view of the construction of an hydroelectric power-generating facility.

Construction agreement

Following a satisfactory result from the interconnection study, the Corporation will pay to Kwoiek Creek Resources Inc., a non-related company, compensation on the first day of the second year of the construction phase.

Royalty agreement

Kwoiek Creek Resources Limited Partnership entered into an agreement to pay to Kwoiek Creek Resources Inc. an annual 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 operations of the Kwoiek Creek Project and an increased royalty for the 20 years thereafter.

For the first 20 years of the operating phase, the partnership will not pay any interest on its subordinated debt nor any distribution on the preferred units, which are owned by the Corporation or the other Partner, unless the royalty has been paid.

Dissolution of the partnership

40 years after the beginning of the operations, Kwoiek Creek Resources Limited Partnership will be dissolved (unless otherwise dissolved at an earlier date). Upon the dissolution, the property and assets shall be distributed to the other Partner.

30. COMMITMENTS AND CONTINGENCIES (CONTINUED)

Rutherford Creek facility

Rutherford L.P. agreed to make payments to the former owners, following the expiry of the Rutherford Creek power purchase agreement. This payment is based on the difference between the then selling price of electricity and the last selling price of electricity under the agreement, adjusted annually following the expiry of the agreement by 50% of the increase or decrease in the CPI over the previous twelve months. This amount will correspond to 35% of the gross revenues attributable to the difference for the 20-year period following the expiry of the power purchase agreement. It will accrue annually and be paid quarterly during the following year. After the 20-year period, that portion of the payment will correspond to 30% of the gross revenues attributable to the difference. This commitment is secured by the Rutherford L.P. facility but is subordinated to the $50,000 term loan described in Note 17 i).

Creek Power facility

Creek Power Inc. entered into several contracts in view of the expected construction of hydroelectric power-generating facilities.

Glen Miller facility

Lease agreement

Glen Miller Power, Limited Partnership entered into a thirty-year lease agreement ending in December 2035 for the site that is in commercial operation. The lease has a 15-year extension option upon terms and conditions to be negotiated.

Glen Miller Power, Limited Partnership is committed to remit the facility to the lessor of the site, at the end of the lease agreement, for no consideration.

Umbata Falls facility

Dissolution of the Partnership

25 years after the beginning of the operations, the Partnership will be dissolved. Upon the dissolution of the Partnership, the property and assets of the Partnership shall be transferred to the other partner for no consideration.

North West Stave facility

Construction contracts

North West Stave River Hydro LP, entered into various contracts in view of the construction of a hydroelectric power-generated facility. During construction, North West Stave has to pay a fixed amount to Douglas First Nations.

Royalties

North West Stave River Hydro LP, entered into an agreement to pay Douglas First Nations an annual royalty based on a percentage of the gross revenues starting after the date of commencement of commercial operations of the North West Stave project. This percentage will increase every 20 years for the 60 years of the project. An additional royalty will be payable if the average price per megawatt hour is greater than an agreed amount.

(in thousands of Canadian dollars except as noted and amounts per share)

30. COMMITMENTS AND CONTINGENCIES (CONTINUED)

Operating leases

The Corporation is engaged under long-term operating leases of premises which will expire between 2012 and 2018.

Summary of commitments

As at December 31, 2011, the expected schedule of commitment payments is as follows:

Contractual obligations	Hydroelectric Generation	Wind Power Generation	Site Development	Total
2012	48,851	16,238	177,013	242,102
2013	61,043	55,084	56,967	173,094
2014	70,152	10,596	27,415	108,163
2015	47,388	10,516	25,969	83,873
2016	66,134	20,234	192,736	279,104
Thereafter	1,093,903	91,769	209,519	1,395,191
Total	1,387,471	204,437	689,619	2,281,527

The Corporation is subject to various claims that arise in the normal course of business. Management believes that adequate provisions have been made in the accounts where required. Although it is not possible to estimate the extent of potential costs and losses, if any, management believes that the ultimate resolution of such contingencies will not have an adverse effect on the financial position of the Corporation.

31. CAPITAL DISCLOSURES

The Corporation's strategy in managing its capital is: (i) to develop or acquire 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.

The Corporation seeks to achieve its objectives by:

- Maintaining the generating capacity and enhancing the operation of its hydroelectric facilities and wind farms; and
- Acquiring and developing new electricity-generating facilities.

The Corporation maintains its generating capacity by investing the necessary funds to maintain and continually upgrade its equipment. The Corporation also invests approximately $1,000 on an annual basis in a major maintenance reserve account in order to fund any major maintenance of hydroelectric facilities or wind farms which may be required to preserve the Corporation's generating capacity.

The Corporation determines the amount of capital required, and its allocation between debt and equity, for the acquisition and development of new electricity-generating facilities by considering the specific characteristics of stability and growth of each facility. This determination is made in order to distribute a stable dividend while maintaining an acceptable level of indebtedness.

The Corporation has a hydrology/wind reserve account. This account could be used in the event that the net available cash for any given year is less than expected, due to normal changes in hydrology or wind conditions or other unpredictable factors.

The Corporation's capital is composed of long-term debt, convertible debentures and shareholders' equity. Total capital amounts to $1,708,118 at year end.

The Corporation uses equity primarily to finance the development of projects. The Corporation uses long-term debt to finance the construction of its facilities. The Corporation expects to finance 70% to 85% of its construction costs mostly through non-recourse long-term debt financing.

(in thousands of Canadian dollars except as noted and amounts per share)

31. CAPITAL DISCLOSURES (CONTINUED)

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, borrowings and/or issuance 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 investment to construct new or maintain existing project facilities will be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund further development or expansion.

Under the terms of the Revolving credit term facility described in Note 17, the Corporation needs to maintain, a margining requirement ratio and an interest coverage ratio. If the ratios are not met, the lender has the ability to recall the facility.

Regarding the respective non-recourse projects financing, the subsidiaries of the Corporation need to maintain minimum debt coverage ratios. If the ratios of a particular project financing are not met, the lenders could have the ability to recall the particular debt. Certain financial restrictive clauses could prevent the subsidiaries from making distributions to the Corporation.

All debt covenants are monitored on a regular basis by the Corporation.

During the year, the Corporation and its subsidiaries met all the financial and non-financial conditions related to their credit agreements.

The Corporation's capital management objectives, policies and procedures are to ensure the stability and sustainability of the dividend payable to its shareholders and the development or acquisition of power production facilities. The objectives were identical in prior years.

32. SEGMENTED INFORMATION

Geographic Segments

The Corporation has 19 hydroelectric facilities and 5 wind farms in Canada and one hydroelectric facility in the United States. For the year ended December 31, 2011, operating revenues generated by the Horseshoe Bend hydroelectric facility located in the United States totalled $2,733, ($2,682 in 2010), representing a contribution of 2%, for the year ended December 31, 2011 (3% for 2010) to the Corporation's consolidated operating revenues for this year.

Major customers

A major customer is defined as an external customer whose transaction with the Corporation amount to 10 per cent or more of the Corporation's annual revenues. The Corporation has identified 2 major customers whose sales are the following:

For the years ended December 31		2011	2010
Major customer	Segment		
Hydro-Québec	Hydroelectric and wind power generation	57,637	51,962
British Columbia Hydro and Power authority	Hydroelectric generation	67,204	24,356
		124,841	76,318

Reportable segments

The Corporation has three reportable segments: (a) hydroelectric generation (b) wind power generation and (c) site development.

(in thousands of Canadian dollars except as noted and amounts per share)

32. SEGMENTED INFORMATION (CONTINUED)

Through its hydroelectric generation and wind power generation segments, the Corporation sells electricity produced by its hydroelectric and wind farm facilities to publicly owned utilities. Through its site development segment, it analyses potential sites and develops hydroelectric, wind farms and solar facilities up to the commissioning stage.

The accounting policies for these segments are the same as those described in the summary of significant accounting policies. The Corporation evaluates performance based on earnings (loss) before interest, income taxes, depreciation and amortization and other items. The Corporation accounts for inter-segment and management sales at cost. Any transfers of assets from the site development segment to the hydroelectric or wind power generation segments are accounted for at cost.

The operations of the Corporation's reportable segments are conducted by different teams, as each segment has different skill requirements.

There was no site development segment prior to the share exchange arrangement on March 29, 2010, as the Fund was solely an operator.

For the year ended December 31, 2011

Reportable Segments	Hydroelectric Generation	Wind Power Generation	Site Development	Total
Operating revenues	117,342	30,918	-	148,260
Expenses:				
Operating	18,174	6,052	-	24,226
General and administrative	4,297	1,987	4,081	10,365
Prospective projects expenses	-	-	2,473	2,473
Earnings before interest, income taxes, depreciation and amortization and others items	94,871	22,879	(6,554)	111,196
Finance costs				53,122
Transaction costs				1,863
Loss on contingent considerations				1,858
Other net revenues				(1,028)
Earnings before income taxes, depreciation and amortization and other items				55,381
Depreciation				31,177
Amortization				19,793
Unrealized net loss on derivative financial instruments				61,479
Loss before income taxes				(57,068)

As at December 31, 2011

	Hydroelectric Generation	Wind Power Generation	Site Development	Total
Goodwill	8,269	-	-	8,269
Total assets	1,307,949	386,343	339,117	2,033,409
Total liabilities	814,435	349,831	290,027	1,454,293
Acquisition of property, plant and equipment	1,305	484	192,396	194,185

(in thousands of Canadian dollars except as noted and amounts per share)

32. SEGMENTED INFORMATION (CONTINUED)

For the year ended December 31, 2010

Reportable Segments	Hydroelectric Generation	Wind Power Generation	Site Development	Total
Operating revenues	64,870	26,515	-	91,385
Expenses:				
Operating	9,430	5,099	-	14,529
General and administrative	2,917	1,546	1,911	6,374
Prospective projects expenses	-	-	2,371	2,371
Earnings before interest, income taxes, depreciation and amortization and other items	52,523	19,870	(4,282)	68,111
Finance costs				23,749
Transaction costs				5,159
Realized gain on derivative financial instruments				(555)
Other net revenues				(17)
Earnings before income taxes, depreciation and amortization and other items				39,775
Depreciation				19,358
Amortization				13,627
Unrealized net loss on derivative financial instruments				20,761
Unrealized loss on unitholders' capital				51,761
Expense related to royalty agreement upon share exchange arrangement				983
Unrealized net gain on foreign exchange				(28)
Loss before income taxes and distribution				(66,687)

As at December 31, 2010

	Hydroelectric Generation	Wind Power Generation	Site Development	Total
Goodwill	8,269	-	-	8,269
Total assets	600,007	264,449	82,684	947,140
Total liabilities	260,267	168,126	159,847	588,240
Acquisition of property, plant and equipment	1,304	318	37,224	38,846

(in thousands of Canadian dollars except as noted and amounts per share)

33. JOINT VENTURE OPERATIONS

The Corporation's has the following significant interests in joint ventures:

a) A 38% proportionate share of the assets, liabilities, revenues and expenses of the joint venture of Baie-des-Sables, L'Anse-à-Valleau and since the share exchange arrangement, of the Carleton, Gros-Morne and Montagne-Sèche wind farms;

b) A 49% proportionate share of the assets, liabilities, revenues and expenses, since the share exchange arrangement, of the joint venture of Umbata Falls;

c) A 50% proportionate share of the assets, liabilities, revenues and expenses of the joint venture of Viger-Denonville.

The following amounts are included in the Corporation consolidated financial statements as a result of the proportionate consolidation of entities described in a), b) and c):

	December 31, 2011	December 31, 2010	January 1, 2010
The proportionate interest is as follows:			
Assets			
Current	30,500	7,217	3,434
Non-current	383,084	250,057	123,816
Total assets	413,584	257,274	127,250
Liabilities			
Current	4,140	9,354	1,513
Non-current	53,024	26,226	1,330
Total liabilities	57,164	35,580	2,843

	December 31, 2011	December 31, 2010	January 1, 2010
The proportionate interest is as follows:			
Results			
Revenues	34,407	28,822	16,792
Expenses	26,333	22,788	11,339
Net earnings	8,074	6,034	5,453

34. SUBSEQUENT EVENTS

a) Dividends on Series A preferred Shares

On March 21, 2012, the Corporation declared a dividend of $0.3125 per Series A preferred share payable on April 16, 2012 to Series A preferred shareholders of record at the close of business on March 30, 2012.

b) Dividends on Common Shares

On March 21, 2012, the Corporation declared a dividend of $0.145 per common share payable on April 16, 2012, to common shareholders of record at the close of business on March 30, 2012.

34. SUBSEQUENT EVENTS (CONTINUED)

c) Execution of engagement letter

Kwoiek Creek
On February 2, 2012, the Corporation executed an engagement letter for up to $160,000 non-recourses term loan for the construction and long-term debt financing of the Kwoiek Creek project.

Northwest Stave River
On February 14, 2012, the Corporation executed an engagement letter for up to $85,000 non-recourse term loan for the construction and long-term debt financing of the Northwest Stave River project.

BOARD OF DIRECTORS

JOHN A. HANNA*

Residence: Toronto, Ontario
Principal occupation: Corporate Director
Innergex Director since: 2003

Innergex chair and committees:
Chair of the Audit Committee

Education:
_Bachelor of Commerce (Accounting), Loyola University (now Concordia University)
_Fellow of the Certified General Accountants Association

Other boards and affiliations:
_Director of Uni-Sélect Inc.
_Member of the independent audit committee of Transport Canada and Infrastructure Canada

LISE LACHAPELLE*

Residence: Île des Sœurs, Québec
Principal occupation: Corporate Director and Consultant
Innergex Director since: 2003

Innergex chair and committees:
Chair of the Corporate Governance Committee

Education:
Bachelor of Business Administration, HEC Montréal

Other boards and affiliations:
_Director of Russel Metals Inc
_Director of Industrial Alliance Insurance and Financial Services Inc.

JEAN LA COUTURE*

Residence: Montreal, Québec
Principal occupation: President, Huis Clos Limitée
Innergex Director since: 2003

Innergex chair and committees:
_Chairman of the Board
_Chair of the Nominating Committee
_Member of the Human Resources Committee
_Member of the Audit Committee
_Member of the Corporate Governance Committee

Education:
_Bachelor of Business Administration (Accounting), HEC Montréal
_Fellow of the Québec institute of Chartered Accountants

Other boards and affiliations:
_President of the Regroupement des assureurs de personnes à charte du Québec (RACQ)
_President of the Institute of Corporate Directors – Québec Chapter
_Chairman of the Board of Pomerleau
_Chairman of the Board of Maestro Group
_Chair of the Audit Committee of Québecor Inc.
_Director of JEVCO Insurance Company

RICHARD LAFLAMME*

Residence: L'Ancienne-Lorette, Québec
Principal occupation:
General Manager, Université du Québec Pension Fund
Innergex Director since: 2003

Innergex chair and committees:
_Chair of the Human Resources Committee
_Member of the Corporate Governance Committee
_Member of the Nominating Committee

Education:
Bachelor of Business Administration (Accounting), Université Laval

Other boards and affiliations:
_Independent member of the retirement committee of the policemen and policewomen of Québec City
_Independent member of the retirement committee of the manual workers of Québec City
_Director of various non-profit organizations

DANIEL L. LAFRANCE*

Residence: Kirkland, Québec
Principal occupation: Senior Vice President Finance and Procurement, CFO and Secretary, Lantic Inc., wholly owned by Rogers Sugar Inc.
Innergex Director since: 2003

Innergex chair and committees:
_Member of the Audit Committee
_Member of the Human Resources Committee

Education:
_Bachelor of Business Administration (Accounting), University of Ottawa
_Member of the Canadian Institute of Chartered Accountants

Other boards and affiliations:
_Director of the Canadian Sugar Institute

WILLIAM A. LAMBERT

Residence: Toronto, Ontario
Principal occupation: Corporate Director
Innergex Director since: 2007

Innergex chair and committees:
_Member of the Corporate Governance Committee
_Member of the Nominating Committee

Education:
_Master of Business Administration, York University
_Bachelor of Science (Electrical Engineering), Massachusetts Institute of Technology

Other boards and affiliations:
_Director of Ag Growth International Inc.
_Director of BIOX Corporation

MICHEL LETELLIER*

Residence: Candiac, Québec
Principal occupation: President and Chief Executive Officer of the Corporation
Innergex Director since: 2002

Education:
_Master of Business Administration, Université de Sherbrooke
_Bachelor of Commerce (Finance), Université du Québec à Montréal

SUSAN M. SMITH

Residence: Toronto, Ontario
Principal occupation: Corporate Director
Innergex Director since: 2007

Innergex chair and committees:
_Member of the Corporate Governance Committee
_Member of the Nominating Committee

Education:
_Master of Business Administration, University of Western Ontario
_Bachelor of Arts, Dalhousie University

Other boards and affiliations:
_Director and Chair of the Audit Committee of Optosecurity Inc.
_Director of CARE Canada

*John A. Hanna, Lise Lachapelle, Jean La Couture, Richard Laflamme, Daniel L. Lafrance et Michel Letellier were appointed directors of the Corporation on March 29, 2010 upon completion of the strategic combination of Innergex Power Income Fund and Innergex Renewable Energy Inc. Prior to the strategic combination, they had all been trustees of Innergex Power Income Fund since 2003.

INFORMATION FOR SHAREHOLDERS

STOCK EXCHANGE LISTING

Common shares of Innergex Renewable Energy Inc. are listed on the Toronto Stock Exchange (TSX) under the symbol INE. Series A preferred shares of the Corporation are listed on the TSX under the symbol INE.PR.A. Convertible debentures of the Corporation are listed on the TSX under the symbol INE.DB.

Innergex Renewable Energy Inc. is a constituent of the following market indices:

- S&P/TSX SmallCap Index
- S&P/TSX Clean Technology Index

PREFERRED SHARES (TSX: INE.PR.A)

Innergex Renewable Energy Inc. currently has 3.4 million Series A preferred shares outstanding, with a nominal value of $25 and a fixed cumulative preferential cash dividend of $1.25 per share, payable quarterly on the 15th day of January, April, July, and October. Series A preferred shares are not redeemable by the Corporation prior to January 15, 2016. They are rated P-3 by Standard & Poor's and Pfd-3 (low) by DBRS.

CONVERTIBLE DEBENTURES (TSX: INE.DB)

Innergex Renewable Energy Inc. currently has convertible debentures outstanding for a total notional amount of $80.5 million, which bear interest at an annual rate of 5.75% and mature on April 30, 2017. Each convertible debenture is convertible into common shares of the Corporation at a price of $10.65 per share at the holder's option at any time prior to the earlier of April 30, 2017 and the redemption date specified by the Corporation (no earlier than April 30, 2013, except in certain limited circumstances). The convertible debentures are subordinated to all other indebtedness of the Corporation.

CREDIT RATINGS

	STANDARD & POOR'S	DBRS
Innergex Renewable Energy Inc.	BBB-	BBB (low)
Series A Preferred Shares	P-3	Pfd-3 (low)
Convertible Debentures	-	-

TRANSFER AGENT AND REGISTRAR

For information concerning share certificates, dividend payments, a change of address, or electronic delivery of shareholder documents (such as quarterly and annual reports and proxy circulars), please contact our transfer agent and registrar:

Computershare Trust Company of Canada
1500 University Street, Suite 700
Montreal, Québec, Canada H3A 3S8
Phone: 1-800-564-6253 or 514-982-7555
Email: service@computershare.com
Website: computershare.com

Ce rapport annuel est disponible en français. Pour la version numérique, visitez notre site Web à www.innergex.com. Pour la version papier, communiquez avec la directrice – Relations avec les investisseurs.

Electronic Delivery: Shareholders may elect to receive Innergex Renewable Energy Inc.'s documents (such as the quarterly and annual reports and the proxy circular) in electronic form via the Internet rather than in printed form by mail. Shareholders wishing to use this service should contact Computershare Trust Company of Canada.

AUDITORS

Samson Bélair/Deloitte & Touche s.e.n.c.r.l.

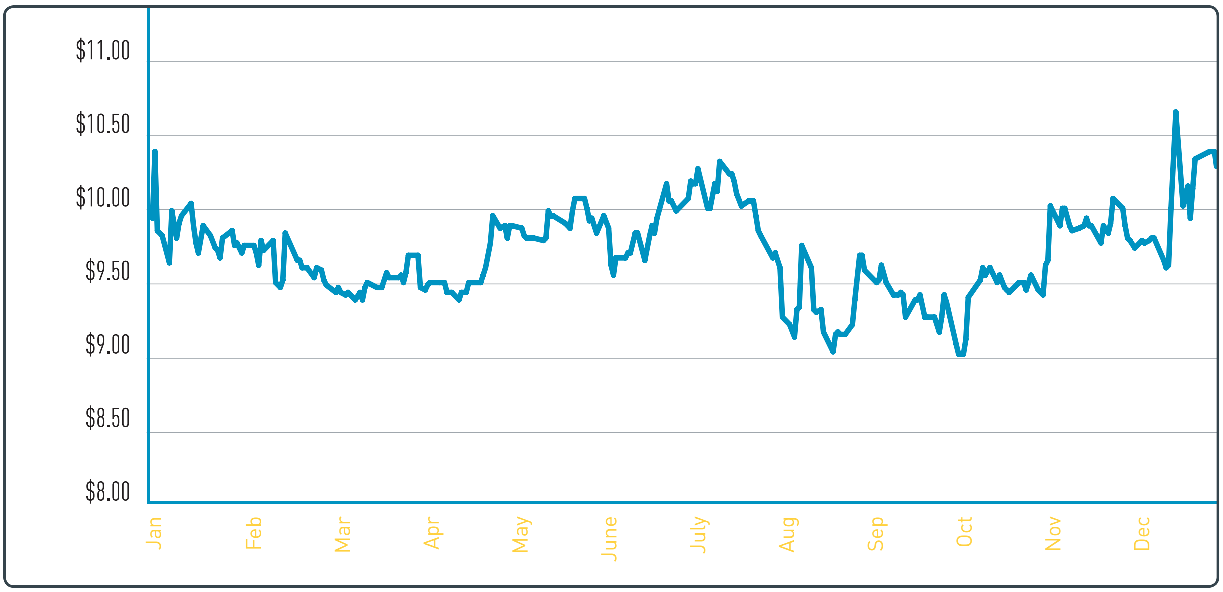
COMMON SHARE DIVIDEND POLICY

As publicly disclosed, Innergex Renewable Energy Inc. intends to pay an annual dividend of $0.58 per common share, payable on a quarterly basis.

PAYMENT HISTORY

PAYMENT HISTORY	2011	2010 [1]
First Quarter	$0.145	—
Second Quarter	$0.145	$0.14818
Third Quarter	$0.145	$0.145
Fourth Quarter	$0.145	$0.145

1 The Corporation adopted its common share dividend policy in March 2010, upon completion of the strategic combination by plan of arrangement of Innergex Power Income Fund and Innergex Renewable Energy Inc. The dividend declared for the second quarter of 2010 was prorated to reflect the adoption of an annual dividend of $0.58 per share.



INNERGEX'S STOCK PRICE PERFORMANCE IN 2011

INVESTOR RELATIONS

To obtain additional financial information, company updates, or recent news releases and investor presentations, please contact:

Marie-Josée Privyk, CFA
Director – Investor Relations
Tel.: 450-928-2550
mjprivyk@innergex.com

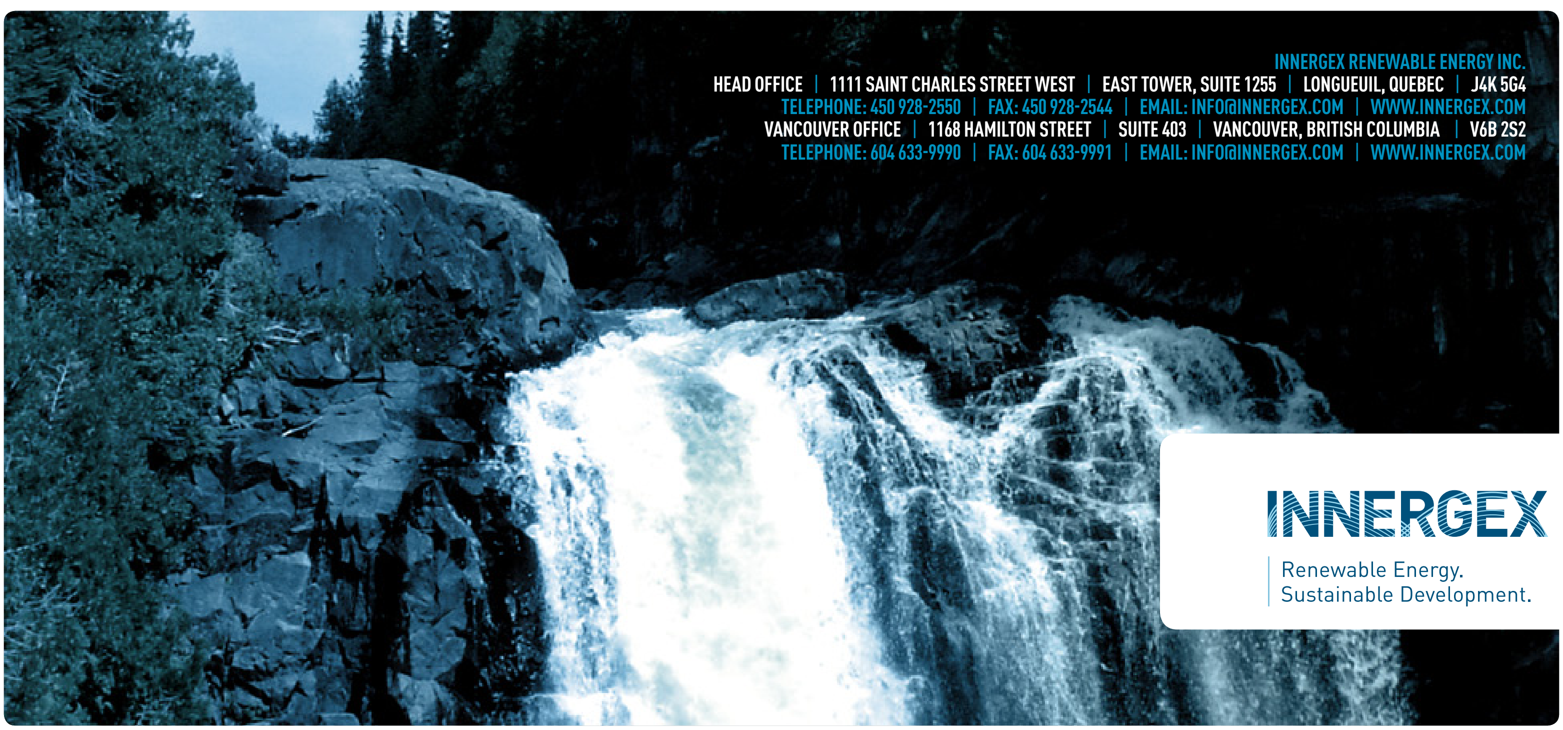
Or visit us at
www.innergex.com

ANNUAL SHAREHOLDERS' MEETING

The annual shareholders' meeting will be held on
Monday, May 14, 2012, at 16:00 ET
At the Hotel Omni Mont-Royal
1050 Sherbrooke Street West, Salon Printemps
Montreal (Québec)

Innergex Renewable Energy Inc.'s *Notice of Annual Meeting of Shareholders and Management Information Circular – Solicitation of Proxies* will be available as of April 18, 2012 on the Investors page of our Website, under Continuous Disclosure Documents.
Hard copies will be available upon request.


INTEGRITY,
RESPONSIBILITY,
TRANSPARENCY,
COLLABORATION,
LONGEVITY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Sustainable Development.