INNERGEX

Renewable Energy.
Sustainable Development.

2010 ANNUAL REPORT

INNERGEX

RENEWABLE ENERGY. PURE AND SIMPLE.

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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 OUR HOST COMMUNITIES, OUR PARTNERS, AND OUR INVESTORS.

HIGHLIGHTS

FINANCIAL AND OPERATIONAL OVERVIEW

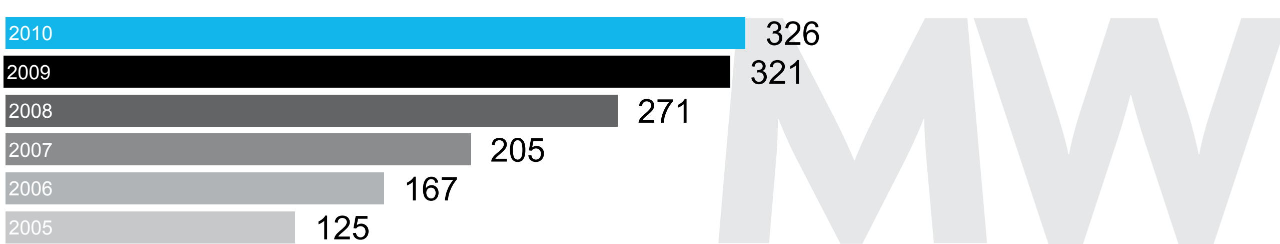
FINANCIAL OVERVIEW

FOR THE YEARS ENDED DECEMBER 31
(in thousands of Canadian dollars except as noted)

	2010	2009	2008	2007	2006
Power generated (MWh)	1,227,435	823,989	862,394	608,509	641,525
Gross operating revenues	$ 89,100	$ 58,625	$ 59,430	$ 40,372	$ 41,154
EBITDA	$ 68,098	$ 46,778	$ 47,097	$ 31,293	$ 32,427
Dividend declared - series A preferred shares	$ 1,520	$ -	$ -	$ -	$ -
Dividend declared - per preferred share	$ 0.42123	$ -	$ -	$ -	$ -
Dividend declared - common shares	$ 33,323	$ 29,404	$ 29,393	$ 24,196	$ 23,816
Dividend declared - per common share	$ 0.61	$ 0.68	$ 0.68	$ 0.66	$ 0.66
Adjusted net earnings	$ 10,777	$ 12,685	$ 12,478	$ 9,880	$ 11,763

NET INSTALLED CAPACITY

FOR THE YEARS ENDED DECEMBER 31



2010 HIGHLIGHTS

Combination of Innergex Power Income Fund with Innergex Renewable Energy Inc.

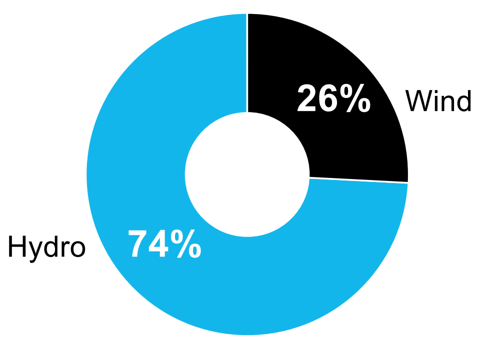
Net electricity production increased by **49%** in 2010

Operating revenues up 52% – to **$89.1 million**

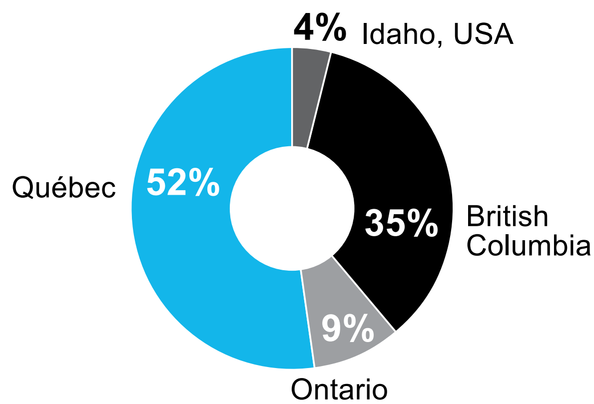
7.5 MW Fitzsimmons Creek facility starts commercial operation

Construction starts at three wind farms that will total **103 MW(net)**

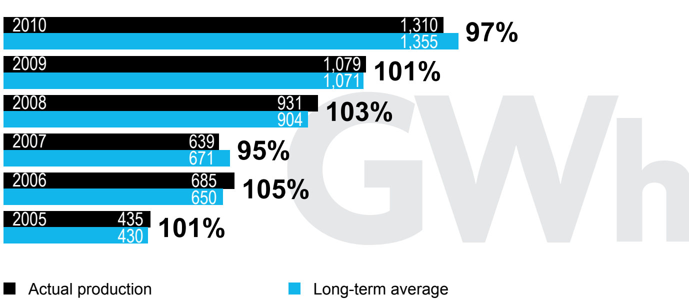
ESTIMATED PRODUCTION BY ENERGY SOURCE (in MWh)



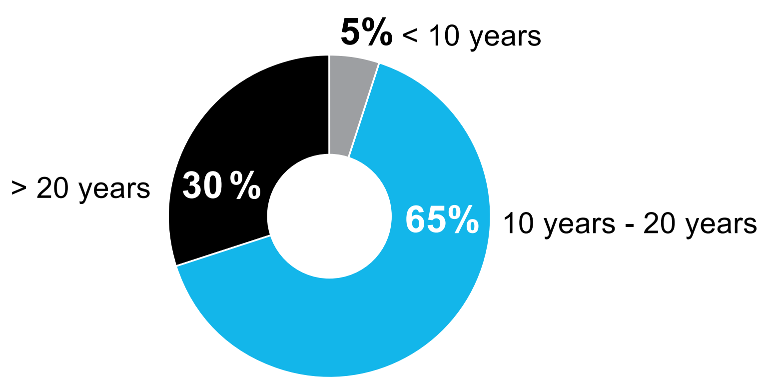
GEOGRAPHIC DIVERSIFICATION (in MWh)



PRODUCTION PREDICTABILITY



PPA REMAINING TERM



Weighted average PPA term: 17 years

Three hydroelectric projects, totalling **75 MW (net)**, awarded PPAs

Issuance of **$80.5 million** of subordinated convertible debentures **(TSX: INE.DB)**

Issuance of **$85 million** of cumulative rate reset preferred shares **(TSX: INE.PR.A)**

S&P assigns **BBB-** and **DBRS** assigns **BBB (low)** long-term corporate credit ratings to Innergex

Jean La Couture, FCA
Chairman of the Board

Michel Letellier, MBA
President and Chief Executive Officer

MESSAGE TO SHAREHOLDERS

20 YEARS OF RENEWABLE ENERGY DEVELOPMENT

"A key benefit of the merger will be a lower cost of capital and better access to funding for the new, larger corporation."
— CIBC research analyst, as cited in The Globe and Mail, February 2, 2010

"IN OUR VIEW, THE PROJECT DEVELOPER HAS ROBUST BUSINESS FUNDAMENTALS THAT A DIVERSIFIED PORTFOLIO OF LONG-LIFE AND LOW-RISK HYDROELECTRIC AND WIND FARM POWER GENERATING FACILITIES UNDERPIN."
— Standard & Poor's, August 23, 2010

"The simplified corporate entity will not only be a larger and more liquid asset for investors, it will also eliminate the trust structure and along with it any worries about the end of tax breaks that many trusts will face in 2011."
— The Globe and Mail, February 2, 2010

Fiscal 2010 has been a pivotal year for Innergex. Twenty years after the business was started in 1990, we have completed the strategic combination of Innergex Renewable Energy Inc. ("Innergex") and Innergex Power Income Fund (the "Fund") into a single large Corporation.

This strategic move propelled us into a new growth phase, fuelled by Innergex's significantly larger scale, increased financial strength, and substantially improved balance sheet. Moreover, this major transition has occurred while a dynamic market is creating business opportunities that Innergex is in a position to consider.

During 2010, as a result of the strategic combination, Innergex produced over 1.2 million megawatt hours of electricity, while revenues reached a record of $89 million, representing an increase of 52% compared to 2009. This level of production is enough to power approximately 72,000 homes with green and renewable energy.

At Innergex, we take great pride in being part of the solution to climate change and helping to reduce CO_2 emissions. We can achieve all this by investing intelligently in communities, creating jobs, and building the economy of the future for generations to come.

INNERGEX CONTINUES TO DEVELOP ITS PORTFOLIO IN BRITISH COLUMBIA

Fitzsimmons Creek begins commercial operation and Ashlu Creek completes its first full year of production

Development in the British Columbia market is a key focus of our growth strategy. We have had a place of business there for several years, along with a considerable number of operating facilities, development projects and prospective projects.

The Ashlu Creek hydroelectric facility (49.9 MW) started commercial operation on November 29, 2009, making 2010 the first full year of production for this run-of-river power plant.

Commercial operation of the Fitzsimmons Creek run-of-river hydroelectric facility (7.5 MW), located in the Resort Municipality of Whistler, began on January 26, 2010, approximately 10 months ahead of schedule, with construction costs under budget.

Three new hydroelectric development projects

Meanwhile, Innergex issued a limited notice to proceed to the Engineering, Procurement and Construction Contractors, thereby launching the construction phase of the 50 MW Kwoiek Creek hydroelectric project. Construction of this facility is expected to be completed in 2013.

We also have three new hydroelectric projects to develop. In March, Innergex signed long-term power purchase agreements with BC Hydro for our Upper Lillooet River, Boulder Creek and North Creek hydroelectric projects, representing total installed capacity of 113 MW. Innergex expects Boulder Creek to start commercial operation in 2015, with the Upper Lillooet and North Creek projects scheduled to start up in 2016. Innergex has a 66⅔% ownership interest in these three new projects.

| *Viger-Denonville*

|| *Baie-des-Sables*

||||| WIND FARM DEVELOPMENT AND CONSTRUCTION MOVING FORWARD

In the second quarter of 2010, construction began on three wind projects through Innergex's joint venture, Cartier Wind Energy.

The construction schedules and budgets established for these projects are being met, and we expect Montagne-Sèche and Gros-Morne Phase I to start commercial operation by December of 2011, with Gros-Morne Phase II following in December of 2012.

Viger-Denonville: a new wind project in Quebec

Quebec's wind power sector is growing. In December 2010, our team was awarded a power purchase agreement for the Viger-Denonville community wind farm project. This project was submitted in response to a Hydro-Québec Distribution call for tenders for 250 MW of wind-generated energy from community projects. Developed in partnership with the Rivière-du-Loup MRC, this project will have a total installed capacity of 24.6 MW, with commercial operation scheduled to begin in 2013.

The Viger-Denonville project is a great business opportunity not only for the Rivière-du-Loup region, but also for the two municipalities where the wind farm will be built. Important local benefits are anticipated, and we expect the project to be completed in an atmosphere of harmony.

||||| MAJOR TRANSACTION

The strategic combination of Innergex and the Fund was completed in March 2010 with the support of over 99% of the Fund's and Innergex's securityholders, sending a clear signal about the positive attributes of the resolution submitted by the Innergex Board of Directors and the Fund Board of Trustees.

In our opinion, this also explains the positive reaction of the stock market. In fact, the value of Innergex stock on the day after we announced the transaction proved to us that the market shares our understanding of the value of this transaction.

In its new form, Innergex will profit from the fiscal and operational synergies that have been created, and from a more focused vision and growth strategy. Furthermore, Innergex now has the benefit of an enhanced growth profile that promises increasing cash flows which should provide an attractive dividend yield for our shareholders in the long term.

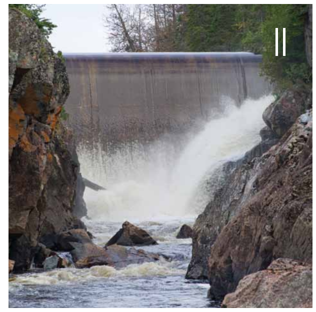
||||| LARGER CAPITALIZATION, LOWER COST OF CAPITAL

The strategic combination has provided Innergex with increased market capitalization and a larger enterprise value, as well as greater trading liquidity, which gives us more flexibility in the area of project development and helps to diversify and optimize Innergex's capital structure.

A new credit facility and two public offerings

Concurrent with the strategic combination, Innergex arranged a new three-year $170 million credit facility.

In February 2010, Innergex also entered into an agreement under which a syndicate of underwriters agreed to purchase extendible convertible unsecured subordinated debentures (TSX: INE.DB) in the aggregate principal amount of $70 million. This amount rose to $80.5 million when the previously granted over-allotment option for an additional $10.5 million principal amount was exercised by the syndicate of underwriters.



| *Cloudworks Energy Inc.*

|| *Umbata Falls*

Later in 2010, Innergex issued 3,400,000 Cumulative Rate Reset Preferred Shares, Series A, on a bought deal basis at $25 per share, for total gross proceeds of $85 million. (TSX: INE.PR.A.).

The net proceeds of these two issues completed in 2010 were used to reduce indebtedness and for general corporate purposes, giving us greater financial flexibility by lowering the cost of capital, and enhancing our financial strength in the context of financing Innergex's upcoming projects.

||||| INNERGEX RATED BY DBRS AND STANDARD & POOR'S

In August, Standard & Poor's assigned Innergex a BBB- long-term corporate credit rating. S&P also assigned a P-3 Canada scale issue-level rating to Innergex's preferred shares at the time they were issued. Concurrently, DBRS assigned an Issuer Rating of BBB (low) to Innergex and a rating of Pfd-3 (low) to Innergex's preferred shares.

These credit ratings are very meaningful. They provide outside confirmation that Innergex is on a solid footing, and that our conservative management style promotes healthy growth based on realistic objectives and tangible results.

||||| A YEAR OF ACQUISITIONS AHEAD

In 2010, Innergex studied a number of potential acquisitions offering attractive business opportunities in this fast-growing market.

With a stronger financial position and enhanced balance sheet, Innergex can actively take advantage of these opportunities. Our capitalization and financial resources make this approach both sound and feasible. Nonetheless, we applied the same level of conservatism that we would use in project development to the various project opportunities under consideration in 2010.

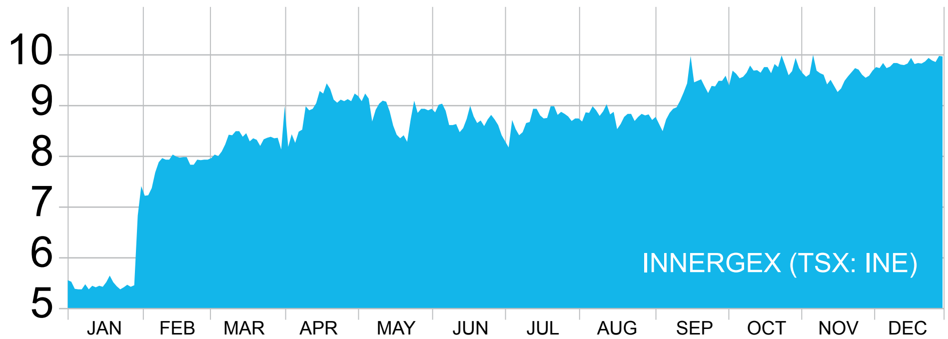
With this as a priority, one of these opportunities was sufficiently attractive to prompt Innergex to proceed with the acquisition. On February 14, 2011, Innergex announced the acquisition of Cloudworks Energy Inc., a private developer, owner and operator of run-of-river hydroelectric plants in British Columbia.

Innergex's asset portfolio grows by 23% with the acquisition of Cloudworks Energy Inc.

The Cloudworks acquisition is a significant step for Innergex, increasing Innergex's current portfolio by six new operating power stations with a total installed capacity of 150 MW (75 MW net, since Innergex holds a 50% stake in these facilities).

The acquisition also includes three new projects supported by power purchase agreements secured under BC Hydro's latest Clean Power Call, representing a total of 76 MW (in which Innergex's stake is 100%), as well as over 800 MW of potential installed capacity from prospective projects in various stages of development. As well, the Innergex team will grow, joined by thirty people bringing a wealth of local knowledge with them. These people not only possess key expertise, they share Innergex's philosophy with respect to developing and managing run-of-river hydroelectric facilities, and will be a great asset to us as we build, complete and maintain projects of a very high quality.

INNERGEX'S COMMON SHARE PRICE PERFORMANCE IN 2010
(in Canadian dollars)



INNERGEX, A FORCE IN THE RENEWABLE ENERGY INDUSTRY

With an enterprise value now approaching $1.5 billion, Innergex has become one of Canada's largest independent renewable energy producers, combining strong growth with stable returns.

To date, including the Cloudworks transaction, Innergex owns facilities with an aggregate net installed capacity of 401 MW, including 20 run-of-river hydroelectric plants with an aggregate capacity of 279.1 MW and three wind farms with an aggregate capacity of 121.4 MW. Furthermore, Innergex has projects in development or under construction, supported by power purchase agreements, totalling 279 MW, along with some 2,800 MW in prospective projects.

All of the operating facilities are covered by long-term contracts with public utilities having a weighted remaining average term of 17 years, clearly ahead of the competition.

A PROMISING FUTURE

While Innergex has recently experienced considerable growth, our mission remains the same, simple and straightforward: to increase the production of renewable energy using high-quality facilities operated in an environmentally sustainable way and in the best interests of our host communities, partners and investors.

We will continue to fulfill this mission by providing our shareholders with the returns they expect and by building exclusively on green, clean, renewable sources of energy, in a spirit of partnership with the communities where our facilities are located.

When all is said and done, our growth is solidly rooted in a long-term vision, without compromising our mission and our respect for others. After twenty years, the approach that has brought us this far is still current and, backed by the ongoing confidence of our shareholders, we fully expect to continue helping to meet the growing demand for renewable energy.

Jean La Couture, FCA
Chairman of the Board

Michel Letellier, MBA
President and Chief Executive Officer

FINANCIAL REVIEW

FOR THE YEAR ENDED DECEMBER 31, 2010

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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 Canadian generally accepted accounting principles ("GAAP") 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
Vice President
and Chief Financial Officer

Innergex Renewable Energy Inc.

Longueuil, Canada, March 23, 2011

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. and its subsidiaries, which comprise the consolidated balance sheet as at December 31, 2010 and the consolidated statements of earnings, comprehensive (loss) income, changes in shareholders'/unitholders' equity and cash flows for the year then ended, 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 Canadian generally accepted accounting principles, 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 audit. We conducted our audit 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 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. and its subsidiaries as at December 31, 2010 and its financial performance and its cash flows for the year then ended in accordance with Canadian generally accepted accounting principles.

Other matter

The financial statements of Innergex Power Income Fund, the acquirer for accounting purpose as disclosed in note 1 to the consolidated financial statements, for the year ended December 31, 2009, were audited by other auditors who expressed an unmodified opinion on those statements on February 25, 2010.

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

Montreal, Quebec

March 23 2011

[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 year ended December 31, 2010	For the year ended December 31, 2009
	$	$
Revenues		
Operating	89,100	58,625
Expenses		
Operating	12,357	8,241
Stock-based compensation	331	-
General and administrative	5,943	3,606
	18,631	11,847
Earnings from operations	70,469	46,778
Prospective project expenses	2,371	-
Earnings before interest, income taxes, depreciation and amortization and other items	68,098	46,778
Interests	23,193	13,187
Realized gain on derivative financial instruments	(555)	-
Realized foreign exchange loss (gain)	64	(182)
Other net revenues	(81)	(114)
Earnings before income taxes, depreciation and amortization and other items	45,477	33,887
Depreciation and amortization	31,289	21,426
Unrealized net loss (gain) on derivative financial instruments (Note 10)	20,761	(15,798)
Expense related to royalty agreement upon share exchange arrangement (Note 4 a))	983	-
Unrealized foreign exchange gain	(23)	(320)
(Loss) earnings before income taxes	(7,533)	28,579
(Recovery of) provision for income taxes (Note 15)		
Current	(2,253)	386
Future	(1,621)	1,950
	(3,874)	2,336
Net (loss) earnings	(3,659)	26,243
Weighted average number of common shares outstanding (in 000)	55,530	42,930
Basic net (loss) earnings per common share (Note 18)	(0.09)	0.61
Diluted net (loss) earnings per common share (Note 18)	(0.09)	0.61

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

CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

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

	For the year ended December 31, 2010	For the year ended December 31, 2009
	$	**$**
Net (loss) earnings	(3,659)	26,243
Other comprehensive (loss) income		
Unrealized foreign exchange loss on translation of a self-sustaining foreign subsidiary (Nil income tax)	(227)	(546)
Unrealized foreign exchange gain on the designated portion of the US$ denominated debt used as hedge on the investment in a self-sustaining foreign subsidiary (Nil income tax)	257	519
Realized gain from reduction in net investment in foreign subsidiary (Nil income tax)	135	-
	165	(27)
Comprehensive (loss) income	(3,494)	26,216

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

CONSOLIDATED BALANCE SHEETS

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

	December 31, 2010	December 31, 2009
	$	$
Assets		
Current assets		
Cash and cash equivalents	42,116	9,352
Accounts receivable (Note 5)	16,026	6,165
Current portion of reserve accounts (Note 6)	494	476
Current portion of future income taxes (Note 15)	2,133	213
Current portion of derivative financial instruments (Note 10)	1,679	1,369
Prepaid and others	4,648	1,938
	67,096	19,513
Reserve accounts (Note 6)	20,947	14,913
Property, plant and equipment (Note 7)	614,142	334,199
Intangible assets (Note 8)	186,490	119,426
Project development costs (Note 9)	9,688	-
Derivative financial instruments (Note 10)	9,534	8,779
Future income taxes (Note 15)	14,269	2,372
Goodwill (Note 11)	7,901	8,269
Other long-term assets	763	670
	930,830	508,141
Liabilities		
Current liabilities		
Dividends/distributions payable to shareholders/unitholders	10,152	2,451
Accounts payable and accrued liabilities (Note 12)	22,963	9,574
Current portion of future income taxes (Note 15)	319	-
Current portion of derivative financial instruments (Note 10)	8,543	5,422
Current portion of long-term debt (Note 13)	9,259	2,758
	51,236	20,205
Construction holdbacks	76	-
Derivative financial instruments (Note 10)	22,597	4,795
Long-term debt (Note 13)	349,431	221,803
Asset retirement obligations (Note 14)	1,591	977
Future income taxes (Note 15)	79,219	70,883
Convertible debentures (Note 16)	79,334	-
	583,484	318,663
Shareholders'/Unitholders' equity	347,346	189,478
	930,830	508,141

Commitments and contingencies (Note 22)
The accompanying notes are an integral part of these audited consolidated financial statements.

On behalf of the Board of Directors

[S] *Jean La Couture*
Jean La Couture, FCA
Chairman

[S] *Michel Letellier*
Michel Letellier, MBA
Director

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS'/UNITHOLDERS' EQUITY

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

	For the year ended December 31, 2010		For the year ended December 31, 2009	
	Shares/Units (in 000)	$	Units (in 000)	$
Unitholders' capital account – beginning	29,404	309,681	29,404	309,681
Reduction of unitholders' capital account owned by the Corporation and not converted into common shares	(4,724)	(57,165)	-	-
Adjustment to number of units to reflect the 1.46 conversion ratio	11,353	-	13,526	-
Common shareholders' capital account from common shares of the Corporation already issued prior to the share exchange arrangement	23,500	167,129	-	-
Common shareholders' capital account from expense related to royalty agreement upon share exchange arrangement	-	983	-	-
Reduction of capital on common shares	-	(420,627)	-	-
Unitholders' capital account – end	-	-	42,930	309,681
Common shareholders' capital account – end	59,533	1	-	-
Contributed surplus from reduction of capital on common shares		420,627	-	-
Series A Preferred Shares – beginning	-	-	-	-
Issued during the year (Note 17)	3,400	82,589	-	-
Series A Preferred Shares – end	3,400	82,589	-	-
Fair value of stock-based compensation accounted upon share exchange arrangement		497		-
Stock-based compensation of the year		331		-
Stock-based compensation – end		828		-
Equity portion of convertible debentures accounted upon share exchange arrangement (Notes 4a) and 16)		1,841		-
Deficit, beginning		(120,274)		(117,113)
Net (loss) earnings		(3,659)		26,243
Dividends/Distributions declared to shareholders/unitholders		(34,843)		(29,404)
Deficit, end		(158,776)		(120,274)
Cumulative other comprehensive income – beginning		71		98
Other comprehensive income		30		(27)
Realized gain from reduction in net investment in foreign subsidiary		135		-
Cumulative other comprehensive income – end		236		71
Total deficit and cumulative other comprehensive income		(158,540)		(120,203)
Shareholders'/Unitholders' Equity – end		347,346		189,478

Additional information is presented in Note 4 a).
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 year ended December 31, 2010	For the year ended December 31, 2009
	$	$
Operating activities		
Net (loss) earnings	(3,659)	26,243
Items not affecting cash:		
Depreciation of property, plant and equipment	18,341	11,546
Amortization of intangible assets	12,948	9,880
Amortization of financing fees	768	170
Accretion expense on asset retirement obligations	113	76
Stock-based compensation	331	-
Unrealized net loss (gain) on derivative financial instruments	20,761	(15,798)
Future income taxes	(1,621)	1,950
Unrealized foreign exchange gain	(23)	(320)
Expense related to royalty agreement upon share exchange arrangement (Note 4a))	983	-
Others	75	-
Effect of exchange rate fluctuations	51	(343)
	49,068	33,404
Changes in non-cash operating working capital items (Note 19)	(25,712)	1,542
	23,356	34,946
Financing activities		
Dividends paid to common shareholders	(17,454)	-
Distributions paid to former unitholders	(9,688)	(29,403)
Increase of long-term debt	134,220	-
Repayment of bank loan	(12,900)	-
Repayment of long-term debt	(205,539)	(2,733)
Net proceeds from issuance of Series A Preferred Shares (Note 17 a))	81,743	-
Deferred financing costs	(1,724)	-
	(31,342)	(32,136)

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

	For the year ended December 31, 2010	For the year ended December 31, 2009
	$	$
Investing activities		
Additions to property, plant and equipment	(29,667)	(2,223)
Additions to intangible assets	(413)	-
Additions to project development costs	(9,056)	-
Additions to other long-term assets	(365)	-
Business Acquisitions (Note 4)	83,033	636
Short-term loan to a partner in a joint venture	(1,000)	-
Proceeds from disposal of property, plant and equipment	298	-
Net funds withdrawn from the levelization reserve	570	465
Net funds invested into wind/hydro reserve	(2,081)	-
Net funds invested into major maintenance reserve accounts	(463)	(980)
	40,856	(2,102)
Translation adjustment on cash and cash equivalents	(106)	7
Net increase in cash and cash equivalents	32,764	715
Cash and cash equivalents, beginning of year	9,352	8,637
Cash and cash equivalents, end of year	42,116	9,352
Cash and cash equivalents is comprised of:		
Cash	9,965	2,789
Short-term investments	32,151	6,563
	42,116	9,352

Additional information is presented in Note 19.
The accompanying notes are an integral part of these audited consolidated financial statements.

NOTES TO THE CONSOLIDATED FINANCIAL STATEMENTS

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

1. DESCRIPTION OF BUSINESS

Innergex Renewable Energy Inc. (the "Corporation") was incorporated under the *Canada Business Corporation Act* on October 25, 2002. The Corporation is an independent developer, owner and operator of renewable power-generating facilities, essentially focused on the hydroelectric and wind power sectors.

Pursuant to the share exchange arrangement as described in Note 4 a), the Corporation acquired 100% of the issued and outstanding units of Innergex Power Income Fund ("the Fund") by issuing 36,032,606 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 Canadian Institute of Chartered Accountants (the "CICA") Handbook Section 1581. This type of share exchange is referred to as a "reverse takeover". In a reverse takeover 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, IPT and the Fund distributed all their assets and transferred all of their liabilities to the Corporation.

Results for the year 2010 include a complete year for the Fund and results since March 30, 2010 for the Corporation.

2. SIGNIFICANT ACCOUNTING POLICIES

These consolidated financial statements (the "financial statements") have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP") and include the following accounting policies:

Principles of consolidation

The consolidated financial statements include the accounts of the Corporation and its subsidiaries as well as those of the variable interest entity for which the Corporation is the primary beneficiary and the accounts of joint ventures to the extent of the Corporation's proportional interest in their respective assets, liabilities, revenues and expenses. The investments over which the Corporation has effective control are fully consolidated. All intercompany balances and transactions have been eliminated.

Consolidation of variable interest entities

Accounting Guideline 15 ("AcG-15"), *Consolidation of Variable Interest Entities* ("VIEs") outlines consolidation principles for VIEs. VIEs are entities in which equity investors do not have controlling financial interest or the equity investment at risk is not sufficient to permit the entity to finance its activities without additional subordinated financial support provided by any parties, including equity holders. AcG-15 requires the consolidation of a VIE by its primary beneficiary (i.e. the party that receives the majority of the expected residual returns and/or absorbs the majority of the entity's losses). In accordance with AcG-15, the Corporation is considered the primary beneficiary for one of its 50% investment in a joint venture and accordingly, it was consolidated.

Cash and cash equivalents

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

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

Reserve accounts

The Corporation holds three types of reserve accounts designed to help ensure its stability. The first is the hydrology/wind reserve 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 conditions or other unpredictable events. The amounts in this 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. The third is the levelization reserve which was established to level the monetary contribution from the power plants in order to make distributions or pay dividends.

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.

Property, plant and equipment

Property, plant and equipment, comprised mainly of hydroelectric and wind farm facilities, are recorded at cost. Financing costs related to the construction of property, plant and equipment and revenues derived prior to commercial operation are capitalized. 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 a period of 50 years or 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 a period of 25 years or the period for which the Corporation owns the rights to the assets. Improvements that increase or extend the service life or capacity of an asset are capitalized. Other equipments are depreciated using the straight-line method over a period extending from 3 to 5 years. Maintenance and repair costs are expensed as incurred. Property, plant and equipment are not depreciated until their commissioning date. The useful life used to calculate depreciation of property, plant and equipment is as follows:

Type of property, plant and equipment	Ending years of depreciation period	Useful life for the depreciation period
Hydroelectric facilities	2033 to 2054	25 to 49 years
Wind farm facilities	2031 to 2033	24 to 25 years

Intangible assets

Intangible assets consist of various permits, licenses and agreements. They are recorded at cost. Financing costs related to the construction period are capitalized. They are amortized using the straight-line method over a period extending from 11 to 40 years ending on the maturity date of the permits, licenses or agreements of each facility. Intangible assets are related to four categories, being hydroelectric facilities, hydroelectric facilities under construction, wind farm facilities and wind farm facilities under construction. Intangible assets related to facilities under construction are not amortized until the commissioning date of the related facilities. Intangible assets also include the cost of an extended warranty for wind farm equipments; these costs are amortized between the third and fifth year after the commissioning date of wind farms.

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 2028	19 to 20 years
Extended warranty	2011 to 2013	3 years

Project development costs

Project development costs represent costs incurred for the acquisition of prospective projects and for the development of hydroelectric and wind farm 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 long-lived assets

Long-lived assets, other than goodwill, are tested for impairment whenever events or changes in circumstances indicate that their carrying amount may not be recoverable. An impairment loss is recognized if the carrying value of an asset exceeds the future undiscounted cash flows expected to result from the asset and its expected disposal. The amount of the impairment loss is determined as the excess of the carrying amount of the asset over its fair value.

Goodwill

Goodwill represents the excess of purchase price over fair value of the net identifiable assets of acquired businesses. Goodwill is not amortized but is tested for impairment annually or more frequently when an event or circumstance occurs that indicates that goodwill might be impaired. When the carrying amount exceeds the fair value, an impairment loss is recognized in the consolidated statement of earnings in an amount equal to the excess. Goodwill is related to businesses acquired and allocated between groups of assets, being hydroelectric facilities and wind farm facilities, in operation or construction, and project under development. If an asset is transferred between a group of assets or segments, the related goodwill is also transferred.

Asset retirement obligations

The Corporation recognizes a liability for an asset retirement obligation arising from acquisitions, construction or development or in the normal course of business. An asset retirement liability is initially recognized at its fair value during the year in which the Corporation incurs a legal asset retirement obligation and when a reasonable estimate of the fair value can be made. The corresponding cost is capitalized as part of the related asset and amortized over the asset's estimated useful life. In subsequent years, this liability is adjusted for changes resulting from the passage of time and for revisions to the timing or amount of the original estimate of the undiscounted future cash flows. Any increase in the liability fair value resulting from the passage of time is charged to earnings.

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.

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. Settlement date accounting is used.

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.

The Corporation has made the following classification:

- Cash and cash equivalents, cash and cash equivalents included in reserve accounts and derivative financial instruments were classified as held for trading. These items are measured at fair value; gains or losses arising from the revaluation at the end of each period are recorded in the Consolidated statements of Earnings.

  Investment income earned on assets or liabilities designated as held for trading is included in other revenues and expenses 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.

- Accounts receivable are classified as loans and receivables and are measured at amortized cost.

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

- Accounts payable and accrued liabilities, dividends/distributions payable to shareholders/unitholders, construction holdbacks, long-term debts and convertible debentures are classified as other financial liabilities and are recorded at amortized cost.

- 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 only financial asset or liabilities measured at fair value are cash and cash equivalents, which are level 1 and derivative financial instruments, disclosed in Note 10.

Stock-based compensation

The Corporation uses the fair value method to measure compensation expense at the date of grant of stock options to employees. The fair value of options is determined using the Black-Scholes option pricing model and is amortized to earnings over the vesting period with an offset to contributed surplus. For options that are forfeited before vesting, the compensation expense that had previously been recognized in operating expenses and contributed surplus is reversed. When options are exercised, the corresponding contributed surplus and the proceeds received by the Corporation are credited to capital stock.

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 balance sheet at fair value and changes in fair value are recorded in net earnings. The Corporation does not use hedge accounting for its financial instruments.

Foreign currency translation

Foreign currency accounts and transactions
Transactions originating in foreign currencies are translated at rates in effect at the date of the transaction. Monetary assets or liabilities denominated in foreign currencies are translated at exchange rates in effect at the balance sheet dates. Unrealized gains or losses arising from the translation of monetary assets or liabilities are included in net earnings for the year.

Foreign operation
The Corporation translates the financial statements of its self-sustaining foreign operation using the current rate method. Under this method, all assets and liabilities denominated in a foreign currency are translated at the exchange rate prevailing at the balance sheet date. Revenues and expenses are translated using the average exchange rate for the year. Translation gains or losses are included in other comprehensive income. The Corporation designates a portion of its US dollar-denominated debt to hedge its investment in its self-sustaining foreign operation. Translation gains or losses on the portion of the debt designated as a hedge are included in other comprehensive income. 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 self-sustaining foreign operation.

Income taxes

The Corporation follows the liability method of accounting for income taxes. Under this method, future income taxes assets and liabilities are recognized based on the expected future tax consequences of differences between the carrying amount of balance sheet items and their corresponding tax bases. Future income taxes are computed using the enacted and substantively enacted income tax rates for the years in which the differences are expected to reverse. Future income tax assets are recognized to the extent it is more likely than not they will be realized. Following the share exchange arrangement described in Note 4 a), the Fund became liable for income taxes.

Prior to the share exchange arrangement, under the *Income Tax Act* (Canada), the Fund, as a trust, was not subject to taxes on income earned prior to 2011 insofar as its taxable income and capital gains were paid or payable to the unitholders. In addition, the Fund was contractually required to distribute to its unitholders all or virtually all of its taxable income and capital gains that would otherwise be taxable to the Fund.

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 KW-hr produced at the Ashlu Creek, Fitzsimmons Creek and Umbata Falls 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. Net EcoEnergy subsidies of $ 3,564 ($ 534 in 2009) are included in the operating revenues of the facilities.

The Corporation incurs renewable energy development expenditures, which are eligible for 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 (see Note 7) or expenses to which they relate. The prospective projects expenses were reduced by investment tax credits of $ 711 (nil in 2009).

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 and the if converted 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.

Use of estimates

The preparation of financial statements in conformity with Canadian generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those 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, future income taxes, as well as the fair value of financial assets and liabilities including derivatives. These estimates and assumptions are based on current 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.

3. CHANGES IN ACCOUNTING POLICIES

International Financial Reporting Standards

The Canadian Accounting Standards Board has announced the adoption of International Financial Reporting Standards ("IFRS") for publicly accountable enterprises in Canada. Effective January 1, 2011, companies must convert from Canadian GAAP to IFRS. Accordingly, the Corporation will adopt IFRS effective in the quarter ending March 31, 2011.

Accounting policies

The Corporation has started its detailed assessment and evaluation of the impact the IFRS will have on accounting and financial presentation as well as the various accounting policies that the Corporation could adopt. To this end, the Corporation has been assessing the various choices provided in IFRS 1, "First-time Adoption of International Financial Reporting Standards," to prepare the opening balance sheet as at January 1, 2010, and has been discussing with its auditors for that purpose. The Corporation will not elect to revaluate its property, plant and equipment at their fair market value.

The items identified as having a potentially significant impact on the opening balance sheet or on the statements of earnings are property, plant and equipment, investments in associates and joint ventures, classification of unitholders' equity, business combination and future tax.

The potential impact from property, plant and equipment comes from its disclosure in its various components, and their various useful lives. The property, plant and equipment and their useful lives components have been determined by management and will range from 15 to 75 years for hydroelectric facilities and from 15 to 25 years for wind farm facilities.

IAS 31 – Investments in Joint Ventures is currently under revision by the IASB and the new standard is not finalized yet. The effective date for the application of the revised standard is yet to be determined. It is expected that IAS 31 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 statement of financial position and the statement of operations. 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 statement of financial position and the statement of operations are expected to change significantly.

Several investments in associates and joint ventures are consolidated in Innergex under Canadian GAAP. These investments are either, fully consolidated, proportionally consolidated or consolidated as variable interest entities. Under the IAS 31 revised standard, some of these investments might have to be accounted for as investments on the balance sheet with their results recognized as share of net earnings of an entity subject to significant influence. The analysis of these differences is underway to identify which entities might be affected. As of today, the main difference identified by the Corporation is that the accounting of the Umbata Falls facility could be modified. Under Canadian GAAP, Umbata Falls L.P. is the sole proportionally consolidated entity, according to the Corporation's 49% interest in the Umbata Falls facility. Under the revised standard, Umbata Falls L.P. should be accounted for as an investment on the balance sheet with 49% of its net results recognized as share of net earnings of an entity subject to significant influence. This will decrease both total assets and liabilities on the balance sheet. Accounting for the other joint ventures should remain similar to Canadian GAAP.

Prior to the share exchange arrangement, the Fund equity was comprised of trust units issued to unitholders. The Fund was contractually required to make distributions to its unitholders for an amount at least equivalent to its taxable income. Under IFRS, the trust units will be considered as financial instruments and reclassified as liabilities with variation in fair value and distributions recognized in the Consolidated statements of Earnings.

For former business combinations, no significant immediate impact on the financial statements is anticipated on adoption of IFRS as the Corporation expects to take advantage of the IFRS 1 exemption, which avoids the requirement to retrospectively restate all business combinations prior to the date of transition to IFRS. However, a number of differences between IFRS and Canadian GAAP will affect the business acquisition realized with the share exchange arrangement. Under IFRS, all assets and liabilities of an acquired business are recorded at fair value. Estimated obligations for contingent considerations and contingencies are also recorded at fair value at the acquisition date. In addition, acquisition-related costs are expensed as incurred. Under Canadian GAAP, acquisition-related costs form part of the consideration paid for the acquisition and contingent considerations are recorded as part of the cost of the acquisition when the contingency is resolved and the consideration is issued or becomes issuable.

In transitioning to IFRS, the Corporation future tax will be impacted by the tax effects resulting from the IFRS changes discussed above.

4. BUSINESS ACQUISITIONS

a) Share exchange arrangement

On March 29, 2010, the Corporation acquired from the Fund's unitholders their equity interests in the Fund, such that the Fund became wholly-owned by the Corporation. The acquisition was effectively paid by the issuance to the Fund's unitholders of 36,032,606 common shares. After the transaction, control of the combined entity was passed to the unitholders of the Fund, and the Fund was identified as the acquirer for accounting purposes. Therefore, this transaction resulted in a reverse takeover.

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 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. 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)

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 future tax liabilities. This adjustment reflects the tax impact of recording future tax assets and liabilities for temporary differences that are reversing or settling prior to 2011 which were previously not recorded since, prior to the transaction, these temporary difference reversals were not previously expected to be taxed in the Fund.

The acquisition of the Corporation is accounted for under Section 1581 of the CICA Handbook. 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, at that time, the same percentage of ownership of the combined entity to the unitholders of the Fund.

The total purchase price has been calculated as follows:

	Estimated purchase price as at March 29, 2010	2010 adjustments	Final purchase price
Units that would have had to be issued (in 000)	16,002	-	16,002
Weighted average of the price of Fund units at the announcement date ($ per Unit)	10.44	-	10.44
Value of Fund units that would have had to be issued	167,129	-	167,129
Transaction costs	6,000	(600)	5,400
Equity portion of convertible debentures	1,841	-	1,841
Fair value of vested stock options	497	-	497
Total Purchase Price	175,467	(600)	174,867

The following table reflects the purchase price allocation:

	Preliminary allocation purchase price March 29, 2010	2010 adjustments	Revised allocation purchase price
	$	$	$
Cash and cash equivalents	88,394	-	88,394
Accounts receivable	4,082	-	4,082
Prepaid and other	781	-	781
Reserve Accounts	4,163	-	4,163
Property, plant and equipment	268,927	(1,382)	267,545
Intangible assets	69,069	11,041	80,110
Project development costs	11,397	(9,669)	1,728
Investment in the Fund, an entity subject to significant influence	57,165	-	57,165
Net future income tax assets	1,990	(411)	1,579
Derivative financial instruments	903	-	903
Other long-term assets	63	-	63
Accounts payable and accrued liabilities	(24,207)	(179)	(24,386)
Bank loan	(12,900)	-	(12,900)
Long-term debt and accrual for acquisition of long-term assets	(214,637)	-	(214,637)
Convertible debentures	(79,222)	-	(79,222)
Other long-term liabilities	(501)	-	(501)
Net assets acquired	175,467	(600)	174,867

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

The transaction expenses relating to the combination totalling $ 5,400 have been recognized as cost of the business combination in accordance with Section 1581 of the CICA Handbook. As at December 31, 2010, an amount of $ 39 remains payable. Net cash acquired amounted to $ 83,033.

The total purchase price of $ 174,867 was allocated between share capital for an amount of $ 167,129, transaction costs for an amount of $ 5,400, equity portion of convertible debentures for $ 1,841 and contributed surplus for stock options for an amount of $ 497.

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 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 balance sheet 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. 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 Canadian GAAP, 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 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.

b) Acquisition of IHI Hydro Inc. ("IHI")

During the second quarter of 2009, a $ 636 adjustment was made to the purchase price of IHI. This adjustment related to a partial reimbursement of the purchase price was due to a working capital deficiency. Accordingly, the goodwill was decreased by $ 636.

5. ACCOUNTS RECEIVABLE

	December 31, 2010	December 31, 2009
	$	$
Trade	11,938	6,097
Commodity taxes	1,587	-
Investment tax credits	869	-
Income taxes	1,341	-
Others	291	68
	16,026	6,165

Substantially all of the Corporation's trade receivables relate to electricity sold to public utilities including Hydro-Quebec, Ontario Electricity Financial Corporation, Ontario Power Authority, British Columbia Hydro and Power Authority and Idaho Power Company. Hydro-Quebec currently holds a credit rating of A+ from Standard & Poor's (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 Purchase Power Agreements to which it is a party. British Columbia Hydro and Power Authority currently holds a credit rating of AAA from S&P. Idaho Power Company currently has a credit rating of BBB from S & P.

The Corporation didn't record any allowance for doubtful accounts since, based on its experience, there is a low risk of doubtful accounts. The Corporation doesn't hold any specific guarantees for its accounts receivable. All accounts receivable are current.

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

6. RESERVE ACCOUNTS

During the year, the funds held in the levelization reserve generated investment income totalling $ 21 ($ 23 in 2009), for a weighted average global return of 2.56% (1.83% in 2009). During the same period, investments totalling $ 570 ($ 465 in 2009) held in the levelization reserve were liquidated and used as distributable cash.

During the year, the amounts held in the hydrology/wind power reserve increased from $ 10,597 to $ 16,511 and generated investment income of $ 69 ($ 39 in 2009) for an overall average weighted return of 0.49% (0.38% in 2009). The increase in this reserve, since December 31, 2009, stems mainly from the share exchange arrangement and from the initial funding of the Ashlu Creek facility's hydrology reserve during the second quarter of 2010 ($ 2,000).

In 2010, amounts held in the major maintenance reserve generated investment income of $ 19 ($ 12 in 2009), for an overall average weighted return of 0.45% (0.36% in 2009). During the year, an amount of $ 761 was invested in major maintenance reserve ($ 980 in 2009) and an amount of $ 298 (nil in 2009) has been used for repairs at the Rutherford facility.

The table below summarizes the changes in the reserve accounts:

				For the year ended December 31, 2010	**For the year ended December 31, 2009**
	Hydrology / wind power reserve	Major maintenance reserve	Levelization reserve	Total	Total
	$	**$**	**$**	**$**	**$**
Reserves – beginning of year	10,597	3,728	1,064	15,389	15,097
Reserves acquired on the share exchange arrangement (Note 4 a))	3,898	265	-	4,163	-
Investments in the reserves	4,194	761	-	4,955	980
Net withdrawals	(2,113)	(298)	(570)	(2,981)	(465)
Impact of foreign exchange fluctuations	(65)	(20)	-	(85)	(223)
Reserves – end of year	16,511	4,436	494	21,441	15,389
Less:					
Current short-term portion	-	-	(494)	(494)	(476)
	16,511	4,436	-	20,947	14,913

The Corporation used a portion of the cash held in the reserve accounts to purchase investments aimed at generating additional revenues to insure its stability. As at December 31, 2010, the carrying values and market values of these investments were as follows:

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

Reserve account investments

	Maturity	Market value	Net carrying value
		$	$
Government-backed securities	2011	1,120	1,120
Short-term investments	2011	19,327	19,327
Cash and cash equivalents		994	994
		21,441	21,441

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 $ 12,161 in the reserve accounts is restricted by credit agreements.

7. PROPERTY, PLANT AND EQUIPMENT

			December 31, 2010
	Cost	Accumulated depreciation	Net book value
	$	$	$
Land	70	-	70
Hydroelectric facilities	448,787	(44,266)	404,521
Wind farm facilities	198,108	(18,491)	179,617
Wind farm facilities under construction	29,096	-	29,096
Other equipments	1,097	(259)	838
	677,158	(63,016)	614,142

			December 31, 2009
	Cost	Accumulated depreciation	Net book value
	$	$	$
Land	74	-	74
Hydroelectric facilities	245,304	(33,406)	211,898
Wind farm facilities	133,069	(11,092)	121,977
Other equipments	560	(310)	250
	379,007	(44,808)	334,199

Property, plant and equipment include capitalized interests of $ 215 (nil in 2009). The cost of the wind farm facilities under construction were reduced by investment tax credits of $ 205 (nil in 2009).

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

8. INTANGIBLE ASSETS

The Corporation's intangible assets are related to the following assets:

			December 31, 2010
	Cost	Accumulated amortization	Net book value
	$	$	$
Hydroelectric facilities	177,737	(47,675)	130,062
Wind farm facilities	59,179	(6,371)	52,808
Extended warranties	5,766	(2,146)	3,620
	242,682	(56,192)	186,490

			December 31, 2009
	Cost	Accumulated amortization	Net book value
	$	$	$
Hydroelectric facilities	107,784	(37,030)	70,754
Wind farm facilities	51,205	(5,442)	45,763
Extended warranties	3,706	(797)	2,909
	162,695	(43,269)	119,426

A decrease of $ 433 in the carrying amount comes from the recognition in year 2010 of a future income tax asset related to a previous acquisition having resulted in an intangible asset for the excess of the purchase price over the net assets acquired.

9. PROJECT DEVELOPMENT COSTS

	December 31, 2010	December 31, 2009
	$	$
Projects under development	1,871	-
Intangibles related to projects under development	7,817	-
	9,688	-

Project development costs include capitalized interests of $ 122 (nil in 2009).

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 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 2.02% as at December 31, 2010 over the remaining terms of these agreements, discounted at a rate of 4.52%. The expected impact of a 0.1% increase in the long-term inflation rate would reduce the fair value of these financial instruments by $ 1,200; a 0.1% drop in the long-term inflation rate would increase fair value of these financial instruments by $ 1,200.

The Corporation holds swap contracts 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 21 b)). The counterparties to swap 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 $ 3,547. Conversely, a decrease in swap rates curve of 0.1% would result in a reduction of $ 3,487 of the fair value of these financial instruments.

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

	Inflation provisions (Level 3)	Interest rate swap contracts (Level 2)	Total
	$	$	$
Assets – Derivative financial instruments			
Balance as at December 31, 2008	7,628	-	7,628
Variation during 2009	2,520	-	2,520
Balance as at December 31, 2009	10,148	-	10,148
Asset acquired on the share exchange arrangement (Note 4 a))	-	903	903
Variation during the year	743	(581)	162
Balance as at December 31, 2010	10,891	322	11,213
Less:			
Current portion	(1,679)	-	(1,679)
Long-term asset balance as at December 31, 2010	9,212	322	9,534
Liabilities – Derivative financial instruments			
Balance as at December 31, 2008	-	23,495	23,495
Variation during 2009	-	(13,278)	(13,278)
Balance as at December 31, 2009	-	10,217	10,217
Variation during the year	-	20,923	20,923
Balance as at December 31, 2010	-	31,140	31,140
Less:			
Current portion	-	(8,543)	(8,543)
Long-term liability balance as at December 31, 2010	-	22,597	22,597

The increase in the interest rate swap liability mainly arises from the decrease in the benchmark interest rates, the new swap contracts entered into in 2010 and the swap contracts assumed on the share exchange arrangement (Note 4 a)).

11. GOODWILL

For the year ended December 31, 2010, the Corporation conducted an annual goodwill impairment test. The test was performed using a net present value of projects within the group of assets described in the accounting policy. Based on the result of this test, no impairment charge (nil in 2009) was required. The decrease of $ 368 in the carrying amount comes from the recognition in year 2010 of a future income tax asset related to a previous acquisition having resulted in goodwill for the excess of the purchase price over the net assets acquired.

12. ACCOUNTS PAYABLE AND ACCRUED LIABILITIES

	December 31, 2010	**December 31, 2009**
	$	$
Trade and accrued liabilities	18,419	6,149
Income taxes	1,303	2,791
Current portion of construction holdbacks	618	-
Capital tax	484	-
Interest payable	1,251	294
Commodity taxes	888	340
	22,963	9,574

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

13. LONG-TERM DEBT

	December 31, 2010	December 31, 2009
	$	$
Operating facility (a)		
LIBOR advances, US$ 13,900 renewable until March 2013	13,825	-
BDS Facility (b)		
Bankers' acceptances renewable until March 2013	27,400	-
Facility 1 (c)		
Prime rate advances renewable until May 2013 (rate of 2.38%);	-	93
Bankers' acceptances renewable until May 2013 (rate of 1.52%);	-	51,200
LIBOR advances, US$ 5,000 renewable until May 2013 (average rate of 1.38%)	-	5,255
Facility 2 (c)		
LIBOR advances, US$ 8,873 renewable until May 2013 (average rate of 1.38%)	-	9,325
Facility 3 (d)		
Bankers' acceptances renewable until May 2013 (rate of 1.52%)	-	52,600
Term loans		
Glen Miller, floating-rate term loan maturing in 2013, (e);	14,500	-
Innergex CAR, L.P., floating-rate term loan maturing in 2013, (f);	49,083	-
Umbata Falls, floating-rate term loan maturing in 2014, (g);	24,348	-
Fitzsimmons Creek, floating-rate construction loan, (h);	22,551	-
Hydro-Windsor, 8.25% fixed rate term loan maturing in 2016 (i);	5,841	6,590
Rutherford Creek, 6.88% fixed rate term loan maturing in 2024 (j);	50,000	50,000
Ashlu Creek, floating-rate term loan maturing in 2025, (k);	104,406	-
Innergex AAV, L.P., floating-rate term loan maturing in 2026, (l);	47,891	50,067
Kwoiek Creek, 20% fixed rate term loan during development phase and 14% fixed rate during construction and operation phase (m).	150	-
	359,995	225,130
Deferred financing costs	(1,305)	(569)
	358,690	224,561
Current portion of long-term debt	(9,259)	(2,758)
Long term portion	349,431	221,803

(a) Operating facility

A $ 117,400 revolving credit facility secured by a first-ranking hypothec on the Corporation's assets and by various security interests granted by some of its subsidiaries. The facility will mature in 2013 and is not amortized. Advances are made in the form of bankers' acceptances ("BA"), prime-rate advances, US base-rate advances, LIBOR rate advances or letters of credit. In all cases, interest is calculated at the prevailing benchmark rate, plus an additional margin based on the Corporation's ratio of consolidated senior debt to adjusted earnings before income taxes, depreciation and amortization.

As at December 31, 2010, a LIBOR rate advance of $ 13,825 (US$ 13,900) bearing interest at a rate of 3.04% was due under this facility and an amount of $ 20,839 was used for the issuance of letters of credit. Thus the unused and available portion of the Operating Facility amounted to $ 82,736. The carrying value of the assets of the Corporation and subsidiaries given as securities under the operating facility totals approximately $ 284,100.

(b) BDS Facility

A $ 52,600 revolving credit facility guaranteed by a security interest granted by Innergex and the Corporation's 38% interest in the BDS wind farm. The facility will mature in 2013 and is not amortized. Advances are made in the form of BA, prime-rate advances, US base-rate advances or LIBOR rate advances. In all cases, interest is calculated at the prevailing benchmark rate plus an additional margin based on Innergex's ratio of consolidated senior debt to adjusted earnings before income taxes, depreciation and amortization.

As at December 31, 2010, an amount of $ 27,400 was drawn and the loan bears interest at an average rate of 3.87%. The unused and available portion of the facility amounted to $ 25,200. The carrying value of the 38% interest in the BDS wind farm is approximately $ 81,600.

(c) Facilities 1 and 2

Facility 1 consisted of a term loan whose maturity was originally extended to May 2013. This facility was secured by first-ranking hypothecs on all IPT's assets and by a hypothec-secured guarantee granted on the assets of some of its subsidiaries. Under this facility, advances were obtained by way of bankers' acceptances ($ 51,200 as at December 31, 2009), prime rate advances ($ 93 as at December 31, 2009) or US LIBOR advances (US$ 5,000 as at December 31, 2009), each with an applicable margin based on the adjusted ratio of consolidated total debt to consolidated earnings before interest, taxes, depreciation and amortization recorded by certain IPT subsidiaries. On March 29, 2010, Facility 1 was cancelled and replaced by the Operating Facility described in (a).

Facility 2 consisted of a term loan granted to a US subsidiary of the Fund, maturing on the same date as Facility 1. This facility was guaranteed by a security interest granted by IPT and, consequently, benefits from the same collateral as Facility 1. In addition, the borrower granted a hypothec on the shares it holds in its US subsidiary. Under this facility, advances were obtained by way of US LIBOR advances ($ 9,235 (US$ 8,873) as at December 31, 2009), plus an applicable margin based on the adjusted ratio of consolidated total debt to consolidated earnings before interest, taxes, depreciation and amortization recorded by certain IPT subsidiaries. On March 29, 2010, Facility 2 was cancelled and replaced by the Operating Facility described in (a).

(d) Facility 3

Facility 3 consisted of a term loan to a Fund subsidiary to mature on the earlier of two dates: May 31, 2013 or, in the event of a default by IPT, 365 days following the date on which the lenders declare the bank credit facility and Facilities 1 and 2 payable. Facility 3 was guaranteed by a security interest granted by IPT and, consequently, benefits from the same collateral as Facilities 1 and 2, in addition to collateral on this subsidiary's assets. Under this facility, advances were obtained by way of bankers' acceptances ($ 52,600 as at December 31, 2009), plus an applicable margin based on the adjusted ratio of consolidated total debt to consolidated earnings before interest, taxes, depreciation and amortization recorded by certain IPT subsidiaries. On March 29, 2010, Facility 3 was cancelled and replaced by the BDS facility described in (b).

(e) 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 2.65% as at December 31, 2010. The term loan is repayable in quarterly installments of $ 250 and the principal repayments for 2011 will amount 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. The facility is totally used to secure one letter of credit. The long-term debt is secured by a first-ranking security interest in the amount of $ 20,400 on all the property and assets of Glen Miller Power, Limited Partnership and the equity interest in Glen Miller Power, Limited Partnership and its general partner. The carrying value of the property and assets is approximately $ 25,600.

(f) Innergex CAR, L.P.

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 2.67% as at December 31, 2010. This loan was accounted for at its fair market value of $ 51,699 as at March 29, 2010, on the share exchange arrangement (Note 4a)), for an effective interest rate of 2.11%. The term loan is repayable in quarterly installments. The principal repayments are variable and are set at $ 2,710 for 2011. 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.

The security constituted by the security documents comprises a deed of hypothec providing security for the payment and performance of all Innergex CAR, L.P.'s obligations and providing a lien on all the present and future real and personal property of Innergex CAR, L.P. and on the equity interest in Innergex CAR, L.P. and its general partner. The carrying value of the property and assets of Innergex CAR, L.P. totals approximately $ 97,900.

(g) 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 2.50% as at December 31, 2010. The term loan is repayable in quarterly instalments. The principal repayments are variable and are set at $ 945 for 2011 (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, 2010, an amount of $ 470 has been used to secure two letters of credit.

The security constituted by the security documents comprises a valid and perfect first-ranking charge and security interest upon all of the property and assets of Umbata Falls Limited Partnership and all the equity investment in Umbata Falls Limited Partnership and its general partner. The carrying value of the property and assets of Umbata Falls Limited Partnership, totals approximately $ 86,400 (the share of the Corporation is 49%).

(h) Fitzsimmons Creek

Lenders agreed to make available, for the Fitzsimmons Creek Hydro Limited Partnership project, a non recourse construction loan in a principal amount up to but not exceeding $ 24,000. The loan matures five years after conversion of the construction loan into a term loan. As at December 31, 2010, $ 20,100 was drawn. The loan advances bear interest at BA rate plus an applicable margin for an all-in rate of 4.90% as at December 31, 2010. 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 4a)), for an effective interest rate of 4.58%. Expected principal repayments for 2011 are $ 184.

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.

The payment and performance of all Fitzsimmons Creek Hydro Limited Partnership's obligations under the credit facilities are secured by a lien on all the present and future real and personal property of Fitzsimmons Creek Hydro Limited Partnership and the equity interest in Fitzsimmons Creek Hydro Limited Partnership and its general partner. The carrying value of the property and assets of Fitzsimmons Creek Hydro Limited Partnership totals approximately $ 28,100.

(i) 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 2011 will amount to $ 677. This debt is secured by all of Hydro-Windsor LP's assets, with a carrying value of approximately $ 14,700.

(j) 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. This debt is secured by all of Rutherford Creek Power Limited Partnership's assets, with a carrying value of approximately $ 91,350.

(k) Ashlu Creek

Lenders agreed to make available for the Ashlu Creek hydroelectric facility a non-recourse construction loan in a principal amount of up to but not exceeding $ 110,000. This facility was fully drawn during the third quarter of 2010 and it 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 2.83% as at December 31, 2010. The amount drawn as at March 29, 2010 was $ 100,400 and the loan term was accounted for at its fair market value of $ 95,587 as at March 29, 2010, on the share exchange arrangement (Note 4a)), for an effective interest rate of 1.74%. The term loan is repayable in quarterly installments. The principal repayments are variable and are set to $ 1,956 for 2011.

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, 2010 an amount of $ 1,779 has been used to secure one letter of credit.

This loan is secured by a demand debenture in the principal amount of $ 175,000, creating a first-priority fixed and specific mortgage, charge and assignment of, and grant of a security interest in all the rights, titles and interest of Ashlu Creek Investments Limited Partnership and its general partners in the project assets and all other assets. The loan is also secured by a security granted on the equity interest in the Ashlu Creek Investments Limited Partnership and its general partners. The carrying value of the property and assets of Ashlu Creek Investments Limited Partnership, totals approximately $ 175,100.

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

(l) Innergex AAV, L.P.

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 2010 (1.44% at December 31, 2009). The term loan is repayable in quarterly installments. The principal repayments are variable and are set at $ 2,185 for 2011. 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, 2010, an amount of $ 458 had been used to issue a letter of credit. This loan is secured by all of the assets of the borrower, Innergex AAV, L.P., by its partners' interests and by all other assets needed for project maintenance and operation, with a carrying value of approximately $ 90,000.

(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 Corporation can participate up to an amount of $ 20,000 and its partner up to an amount of $ 3,000. The loan bears interests at a rate of 20% during the development phase and 14% during the construction and operating phases. The Corporation loan made to Kwoiek Creek Resources Limited Partnership, which is eliminated in the consolidation process of the financial statements, amounts to $ 10,106. The partner loan made to Kwoiek Creek Resources Limited Partnership amounts to $ 150.

(n) Innergex MS, L.P.

On December 22, 2010, the Corporation entered into a credit agreement providing for a $ 31,700 non-recourse construction and term project financing for the 38% interest it holds in the 58.5 MW Montagne-Sèche Project. The credit agreement allows the Corporation to access the funds necessary to finalize the construction of the project. The $ 31,700 construction loan will convert into a four-year term loan, amortizing over a period of approximately 18.5 years, starting at the beginning of commercial operation. No draws have been made on this credit facility as at December 31, 2010.

(o) Principal repayments

The principal repayments for the next years, excluding the reevaluations, will be as follows:

	Principal repayments	Amortization of reevaluation	Long-term debt
	$	$	$
2011	9,175	84	9,259
2012	10,962	64	11,026
2013	105,588	41	105,629
2014	32,024	13	32,037
2015	9,817	(21)	9,796
Thereafter	193,360	(1,112)	192,248
	360,926	(931)	359,995

14. ASSET RETIREMENT OBLIGATIONS

Asset retirement obligations primarily arise from obligations to retire wind farm assets upon expiry of the site leases. The wind farms 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:

	December 31, 2010	December 31, 2009
	$	$
2031	2,990	2,990
2032	2,773	2,773
2033	3,260	-
	9,023	5,763

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

The following table presents the changes in liabilities during the reporting period:

	For the year ended December 31, 2010	For the year ended December 31, 2009
	$	$
Balance – beginning of year	977	901
Liability assumed as part of the share exchange arrangement (Note 4 a))	501	-
Accretion expenses	113	76
Balance – end of year	1,591	977

The cash flows were discounted at rates varying from 8.25% to 8.50% to determine the obligations.

15. INCOME TAXES

The provision for income taxes shows an effective income tax rate that differs from the rate computed under Canadian income tax legislation. The differences between the statutory rate and the effective rate are as follows:

	For the year ended December 31, 2010	For the year ended December 31, 2009
	$	$
(Loss) income before provision for income taxes	(7,533)	28,579
Less:		
Accounting loss (income) allocated to the unitholders	111	(19,074)
(Deductible loss) taxable income of the Corporation/Fund or their subsidiaries	(7,422)	9,505
Canadian statutory income tax rate	28.41%	31.17%
Income tax (recovery) expense calculated at the statutory rate	(2,109)	2,963
Items affecting the statutory rate:		
Non-deductible expenses	272	-
Income taxable at a higher (lower) rate than the Canadian statutory rate	250	(198)
Reduction in future income tax rates	(1,342)	(429)
Reduction in taxes related to share exchange arrangement	(751)	-
Others	(194)	-
(Recovery) provision for income taxes	(3,874)	2,336

Following the share exchange arrangement, the Fund became subject to income tax as described in Note 4 a).

The tax impact of the temporary differences and losses carryforward relating to the Corporation and giving rise to significant future income tax assets and liabilities is presented in the table below:

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

	December 31, 2010	December 31, 2009
	$	$
Future income tax assets		
Non-capital losses carry forward and minimum taxes	9,066	1,295
Accounting provision	-	14
Income tax on dividends on preferred shares	435	-
Excess of the tax basis over carrying values of:		
Property, plant and equipment	-	3,608
Project development costs	1,149	-
Financing fees	3,110	-
Derivative financial instruments	9,560	1,433
Future income tax assets before valuation allowance	23,320	6,350
Valuation allowance	(822)	(868)
Future income tax assets	22,498	5,482
Future income tax liabilities		
Non-repatriated income from foreign subsidiaries	(363)	(365)
Excess of the carrying values over tax basis of:		
Property, plant and equipment	(43,786)	(51,393)
Intangible assets	(41,133)	(19,871)
Derivative financial instruments	-	(2,151)
Investments into joint ventures	(352)	-
Future income tax liabilities	(85,634)	(73,780)
Net future income tax liabilities	(63,136)	(68,298)
Reported in the financial statements		
Current future income tax assets	2,133	213
Current future income tax liabilities	(319)	-
Long-term future income tax assets	14,269	2,372
Long-term future income tax liabilities	(79,219)	(70,883)
Net future income tax liabilities	(63,136)	(68,298)

As at December 31, 2010, the Corporation, its subsidiaries and joint ventures recorded tax losses totaling approximately $ 35,700 that may be applied against taxable income in future years. These losses expire gradually between 2011 and 2030. The Corporation and its subsidiaries recorded capital losses totaling approximately $ 7,000 that may be applied against capital gains in future years. The tax benefit arising from the capital losses was not recognized in future income tax assets.

16. CONVERTIBLE DEBENTURES

The convertible debentures were part of the assumed liabilities on the share exchange arrangement described in Note 4 a). They were accounted at their fair market value of $ 79,222 as at March 29, 2010, on the share exchange arrangement described in Note 4 a) 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.

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

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, in whole or in part from time to time. Such redemption would be done at a price equal to the principal amount thereof plus accrued and unpaid interest, provided that the volume weighted average trading price of the common shares on the Toronto Stock Exchange for the 20 consecutive trading days ending five trading days preceding the date on which the notice of redemption is given 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 in whole or in part at the option of the Corporation at a price equal to their principal amount plus accrued and unpaid interest. Subject to required regulatory approval, 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, 2010	December 31, 2009
	$	$
Debt portion of convertible debentures, at fixed rate, 5.75% (effective rate of 6.09%), maturing in April, 2017, with a face value of $ 80,500	79,334	-
Equity portion of convertible debentures	1,841	-

17. 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 4 a), the authorized capital of the Fund consisted of an unlimited number of trust units. The Fund had 29,404,276 (42,930,243 when considering the 1.46 conversion ratio) trust units outstanding.

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.

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

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, 2010	December 31, 2009
	$	$
Series A Preferred Shares		
3,400,000 shares, $ 25.00 each	85,000	-
Issuance costs	(3,257)	-
Net proceeds	81,743	-
Future income taxes	846	-
Net carrying value	82,589	-

b) 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.

The maximum aggregate number of shares that may be subject to options under the stock option plan is 2,350,000. 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.

	December 31, 2010		December 31, 2009	
	Number of options	Weighted average exercise price	Number of options	Weighted average exercise price
	(000's)	$	(000's)	$
Outstanding - beginning of year	-	-	-	-
Outstanding stock options assumed on the share exchange arrangement described in Note 4 a)	1,269	11.00	-	-
Granted	808	8.75	-	-
Exercised	-	-	-	-
Cancelled	235	11.00	-	-
Outstanding - end of year	1,842	10.02	-	-
Options exercisable - end of year	776	11.00	-	-

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

The following options were outstanding and exercisable as at December 31, 2010:

	Outstanding		Exercisable		
	Number of options	**Exercise price**	**Number of options**	**Exercise price**	**Year of maturity**
	(000's)	**$**	**(000's)**	**$**	
	1,034	11.00	776	11.00	2017
	808	8.75	-	8.75	2020
	1,842		776		

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. Stock-based compensation costs are expensed and a credit is made to contributed surplus 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	35% to 40%
Weighted average fair value per option	$ 1.02

For the purpose of compensation expense, stock-based compensation is amortized to expense on a straight-line basis over the vesting period ranging from 1.7 years to 5 years. The weighted average contractual life of the outstanding stock options is 8.0 years. Expected volatility is estimated by considering historic average share price volatility.

c) 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 4 a). The warrants were exercisable at a strike price of $ 12.50 per warrant.

18. COMPUTATION OF EARNINGS AVAILABLE TO COMMON SHAREHOLDERS

The net (loss) earnings of the Corporation are adjusted for the preferred return allocated to the preferred shares as follows:

	For the year ended December 31, 2010	**For the year ended December 31, 2009**
	$	**$**
Net (loss) earnings	(3,659)	26,243
Less:		
Dividends declared on Series A preferred shares	(1,520)	-
Net (loss) earnings available to common shareholders	(5,179)	26,243
Weighted average number of shares/units (when considering the 1.46 conversion ratio) outstanding (in 000)	55,530	42,930
Basic net (loss) earnings per share ($)	(0.09)	0.61
Weighted average number of shares/units (when considering the 1.46 conversion ratio) outstanding (in 000)	55,530	42,930
Effect of dilutive stock options (in 000)	22	-
Diluted weighted average number of shares/units (when considering the 1.46 conversion ratio) outstanding (in 000)	55,552	42,930
Diluted net (loss) earnings per share	(0.09)	0.61

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

During the period covered by the financial statements, 1,034,000 stock options (nil in 2009), 200,000 warrants and 7,558,684 shares potentially issued on conversion of convertible debenture (nil in 2009) were excluded in the calculation of diluted weighted average number of shares/units outstanding.

During the period covered by the financial statements, all of the issued convertible debentures, stock options and warrants were excluded from the calculation of diluted net (loss) earnings per share as including them would be anti-dilutive.

19. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

Changes in non-cash operating working capital items

	For the year ended December 31, 2010	For the year ended December 31, 2009
	$	$
Accounts receivable	(6,607)	1,248
Prepaid and others	(960)	2,000
Accounts payable and accrued liabilities	(18,145)	(1,706)
	(25,712)	1,542
Additional information		
Interest paid	19,219	12,843
Income taxes paid	2,153	1,104
Non-cash transactions		
(Increase) decrease of unpaid property, plant and equipment	(5,164)	925
Decrease (increase) of unpaid transaction costs	31	(670)
Increase of unpaid development costs	(1,794)	-
Increase of long-term holdbacks	76	-
Increase of unpaid intangibles assets	(8)	-
Decrease (increase) of unpaid long-term assets	(335)	-

20. RELATED PARTY TRANSACTIONS

(a) Innergex Renewable Energy Inc.

Prior to the share exchange arrangement described in Note 4 a), 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.

	For the year ended December 31, 2010	For the year ended December 31, 2009
	$	$
(i) Management agreement	536	1,892
(ii) Administration agreement	29	113
(iii) Other services	6	38
	571	2,043

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. The maximum chargeable amount for regular services in 2010 was set at $ 1,005 ($ 999 in 2009) and an amount of $ 251 was incurred by the Fund in 2010 ($ 999 in 2009). An amount of $ 101 ($ 158 in 2009) 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 year, incentive fees totalling $ 184 ($ 735 in 2009) were incurred by the Fund. The management agreement was terminated upon the share exchange arrangement described in Note 4 a).

(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. The maximum chargeable amount for 2010 was set at $ 114 ($ 113 in 2009) and an amount of $ 29 was incurred by the Fund in 2010 ($ 113 in 2009). 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 4 a).

(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 4 a), these operations became intercompany transactions and are eliminated upon consolidation of the financial statements.

21. FINANCIAL INSTRUMENTS

(a) Fair market value disclosures

Fair market 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 balance sheet 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 balance sheet 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 $ 9,700 higher than their estimated fair market values based on the swap interest curve on December 31, 2010, increased by a risk premium ranging from 1.25% to 2.21% for a total ranging from 1.75% to 5.99%. The carrying values of the fixed-rate debts and the debentures are approximately $ 9,200 less than their estimated fair market values based on the swap interest curve on December 31, 2010, increased by a risk premium ranging from 1.25% to 2.02% for a total ranging from 2.55% to 5.66%.

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

(b) Interest rate risk

The terms of the contracts reducing the Corporation's risk of interest rate fluctuations are as follows:

Swap contract notional amount	Early termination option	December 31, 2010	December 31, 2009
		$	$
Interest rate swaps, rates ranging from 3.96% to 4.09%, expiring in June 2015	None	15,000	15,000
Interest rate swap, 4.27%, expiring in November 2016	None	3,000	3,000
Interest rate swap, 4.41%, expiring in June 2018	March 2013	30,000	30,000
Interest rate swap, 4.27%, expiring in June 2018	March 2013	52,600	52,600
Interest rate swap, 4.93%, amortized until March 2026	None	47,890	50,067
Interest rate swap, 3.45%, amortized until March 2027	December 2013	48,315	-
Forward interest rate swap, 4.31%, amortized until June 2030	March 2011	31,690	-
Forward interest rate swap, 4.33%, amortized until June 2031	June 2014	49,940	-
Interest rate swap, 4.11%, amortized until June 2034 (total of $ 49,690, 49% share)	None	24,348	-
Interest rate swaps, 4.70%, amortized until June 2035	June 2025	109,067	-
		411,850	150,667

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.

On the share exchange arrangement described in Note 4 a), the Corporation took-over two interest rate swaps and one forward interest rate swap.

On April 29, 2010, the Corporation settled the $ 110,000 forward-starting amortizing interest rate swap. Concurrently, the Corporation entered into two forward-starting amortizing interest rate swaps for a total of $ 109,537, thereby fixing the interest rate at 4.70% starting on the effective date of September 30, 2010 until the end of the related long-term debt amortization schedule of June 2035.

Forward interest rate swaps related to the Montagne-Sèche and Gros-Morne wind farms were progressively put in place during the year.

(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 majorly 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 5.

The reserve accounts and related risks are described in detail in Note 6.

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.

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

Some interest rate swaps 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.

The Corporation had a positive working capital of $ 14,490 as at December 31, 2010. If necessary, the Corporation can use a bank credit facility, as described in Note 13 a) and 13 b), of which $ 107,936 was available as at December 31, 2010. 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 6) 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	10,152	-	-
Accounts payable and accrued liabilities	17,191	5,772	-
Current portion of derivative financial instruments	2,519	6,024	-
Current portion of long-term debt	2,614	6,561	-
Derivative financial instruments	-	-	22,550
Long-term debt	-	-	158,391
Interest on long-term debt and convertible debentures	4,311	14,192	71,381
Total	36,787	32,549	252,322

(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 currency translation 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 increased 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; their revenues, net of 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 subsidiary, as described in Note 2.

22. 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 2028, Hydro-Québec agreed to purchase all of the electrical energy provided by Innergex LP, Innergex Montmagny LP, Hydro-Windsor LP, Innergex BDS, L.P., Innergex AAV, L.P. and Innergex CAR, L.P., up to the agreed maximum quantity for each of the hydroelectric facilities and wind farms. In return, Innergex LP, Innergex Montmagny LP, Hydro-Windsor LP, Innergex BDS, L.P., Innergex AAV, L.P. and Innergex CAR, L.P. are required to supply a minimum quantity of electricity during each of the consecutive 12-month periods beginning on December 1 of each year for the hydroelectric facilities and beginning on January 1 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 $ 51,962 in 2010 ($ 44,134 in 2009), representing 58% of the Corporation's revenues (75% in 2009). 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 Rutherford Creek Power LP, Ashlu Creek Investments LP and Fitzsimmons Creek Hydro LP. Total revenues from British Columbia Hydro and Power Authority amounted to $ 24,356 in 2010 ($ 8,102 in 2009) representing 27% of the Corporation's revenues (14% in 2009).

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 Trent-Severn Power Corporation, Umbata Falls L.P. and Glen Miller Power L.P.

Total revenues from the Ontario facilities amounted to $ 6,528 ($ 2,474 in 2009) representing 7% of the Corporation's revenues (4% in 2009).

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 $ 2,682 in 2010 ($ 3,364 in 2009), representing 3% of the Corporation's revenues (6% in 2009).

(b) Other Commitments

Wind farm facilities

Subsidiaries or joint ventures of the Corporation entered into power purchase agreements with Hydro-Quebec. In order to fulfill its obligation under the power purchase agreements, the Corporation will need to develop and construct wind powered facilities. Collectively with TransCanada Energy Ltd. ("TransCanada") (the share of the Corporation is 38%), the Corporation entered into various agreements related to the acquisition of the turbines, the construction and the operation of the Gros-Morne and Montagne-Sèche 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 or joint ventures are also committed under options on leases for projects under development.

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 limited notice to proceeds 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

Forty 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.

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 13.

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

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

Twenty-five 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.

Operating leases

The Corporation is engaged under long-term operating leases of premises which will end between 2012 and 2018.

Summary of commitments

As at December 31, 2010, the expected schedule of commitment payments is as follows:

Contractual obligations	Hydroelectric Generation	Wind Power Generation	Site Development	Total
	$	$	$	$
2011	17,756	12,373	83,528	113,657
2012	19,182	11,846	37,035	68,063
2013	32,063	61,314	41,846	135,223
2014	41,234	5,390	8,310	54,934
2015	17,777	5,414	7,630	30,821
Thereafter	223,564	59,194	111,445	394,203
Total	351,576	155,531	289,794	796,901

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.

23. 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 $ 520 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. Finally, the Corporation has a levelization reserve account, established to levelize the net available cash for a number of years.

The Corporation's capital is composed of cash and cash equivalents, reserve accounts, long-term debts, convertible debentures and shareholders' equity. Total capital amounts to $ 848,927 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 through non-recourse long-term debt financing.

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 Operating facility and the BDS facility described in Note 13, the Corporation needs to maintain a minimum tangible net worth, a margining requirement ratio and an interests coverage ratio. If the ratios are not met, the lender has the ability to recall the facilities.

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 have changed following the share exchange arrangement. The Fund's primary objective was to ensure the stability and sustainability of the net distributable cash payable to its unitholders. Although the distribution of a stable dividend remains an objective, the Corporation also has an objective of developing or acquiring power production facilities.

24. SEGMENT INFORMATION

Reportable segments

The Corporation has three reportable segments: (a) hydroelectric generation (b) wind power generation and (c) 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, 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.

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

	Year ended December 31, 2010			
Reportable Segments	**Hydroelectric Generation**	**Wind Power Generation**	**Site Development**	**Total**
	$	**$**	**$**	**$**
Gross operating revenues from external clients	64,870	24,230	-	89,100
Expenses:				
Operating expenses	9,430	2,927	-	12,357
Stock-based compensation	127	76	128	331
General and administrative expenses	2,751	1,447	1,745	5,943
Prospective project expenses	-	-	2,371	2,371
Earnings (loss) before interest, income taxes, depreciation and amortization and other items	52,562	19,780	(4,244)	68,098
Interest on long-term debt and convertible debentures				23,193
Realized gain on derivative financial instruments				(555)
Realized foreign exchange loss (gain)				64
Other net revenues				(81)
Earnings before income taxes, depreciation and amortization and other items				45,477
Depreciation and amortization				31,289
Unrealized net loss (gain) on derivative financial instruments				20,761
Expense related to royalty agreement upon share exchange arrangement				983
Unrealized foreign exchange gain				(23)
(Loss) earnings before income taxes				(7,533)
As at December 31, 2010				
Goodwill	7,901	-	-	7,901
Total assets	599,996	254,947	75,887	930,830
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)

	Year ended December 31, 2009			
Reportable Segments	**Hydroelectric Generation**	**Wind Power Generation**	**Site Development**	**Total**
	$	**$**	**$**	**$**
Gross operating revenues from external clients	41,833	16,792	-	58,625
Expenses:				
Operating expenses	6,177	2,064	-	8,241
General and administrative expenses	2,624	982	-	3,606
Earnings before interest, income taxes, depreciation and amortization and other items	33,032	13,746	-	46,778
Interest on long-term debt and convertible debentures				13,187
Realized foreign exchange loss (gain)				(182)
Other net revenues				(114)
Earnings before income taxes, depreciation and amortization and other items				33,887
Depreciation and amortization				21,426
Unrealized net loss (gain) on derivative financial instruments				(15,798)
Unrealized foreign exchange gain				(320)
Earnings before income taxes				28,579
As at December 31, 2009				
Goodwill	8,269	-	-	8,269
Total assets	330,157	177,984	-	508,141
Acquisition of property, plant and equipment	938	360	-	1,298

25. JOINT VENTURE OPERATIONS

The Corporation’s consolidated financial statements include its 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 and its 49% proportionate share of the assets, liabilities, revenues and expenses of the joint venture of Umbata Falls.

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

The proportionate interest is as follows:	December 31, 2010	December 31, 2009
	$	$
Assets		
Current	7,217	3,434
Long term	253,914	125,855
Liabilities		
Current	9,354	1,513
Long term	25,433	1,122
Results		
Revenues	26,537	16,792
Expenses	18,752	9,092
Net earnings	7,785	7,700
Cash flow		
Operating activities	28,189	13,731
Financing activities	(329)	-
Investing activities	(27,985)	(360)

26. COMPARATIVE FIGURES

Certain comparative figures have been reclassified to conform to the current year's presentation.

27. SUBSEQUENT EVENTS

Acquisition of Cloudworks Energy Inc. and $ 165,963 Equity Offering
On February 14, 2011, the Corporation announced that it had entered into a definitive agreement with the shareholders of Cloudworks Energy Inc. ("Cloudworks") to acquire all of the issued and outstanding shares of Cloudworks (the "Acquisition"). Cloudworks will be purchased for an aggregate consideration of $185,000, approximately $ 145,700 of which will be payable in cash (the "Cash Consideration") and approximately $39,300 of which will be payable by the issuance, by way of private placement, of common shares of the Corporation at a price of $9.75 per common share.

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

To finance the Cash Consideration, the Corporation has sold subscription receipts of the Corporation through a syndicate of underwriters on a bought deal basis. The agreement with the syndicate includes the issuance of 17,750,000 subscription receipts at a price of $ 9.35 per subscription receipt to raise gross proceeds of approximately $ 165,963. The proceeds of the subscription receipt financing will be held in escrow pending the completion of the Acquisition. The subscription receipts are exchangeable on a one-for-one basis for common shares of the Corporation upon closing of the Acquisition for no additional consideration or further action.

Viger-Denonville Community Wind Project
On March 17, 2011, Hydro-Québec, the Rivière-du-Loup MRC and the Corporation executed the PPA that was previously awarded on December 20, 2010 by Hydro-Québec. The Corporation expects the 24.6 MW wind farm to start commercial operation on December 1, 2013. The Corporation owns 50% of the project with the Rivière-du-Loup MRC owning the other 50%.

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 23, 2011.

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, 2010.

This MD&A should be read in conjunction with the audited consolidated financial statements and the accompanying notes for the financial year ended December 31, 2010. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

Except for share values or where otherwise stated, the Corporation reports its results in thousands of Canadian dollars. Some amounts included in this MD&A are rounded to make reading easier. These rounded numbers may affect some calculations.

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 Canadian GAAP, the results for the year ended December 31, 2010, are those of the Fund including Innergex's contribution since March 30, 2010. Also in accordance with Canadian GAAP and Canadian securities regulations, the historical results presented in this MD&A are those of the Fund.

As a result of this Combination and unless otherwise noted, the terms "Innergex Renewable Energy Inc.," "Innergex" and the "Corporation" as used in the remainder of this MD&A shall 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" shall 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.

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.

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.

ESTABLISHMENT, MAINTENANCE AND EFFECTIVENESS OF DC&P AND ICFR

The President and Chief Executive Officer and the Vice President and Chief Financial Officer 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 Vice President and Chief Financial Officer, 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 Canadian GAAP applicable to the Corporation.

In accordance with *Multilateral Instrument 52-109 – Certification of Disclosure in Issuers’ Annual and Interim Filings*, the President and Chief Executive Officer and the Vice President and Chief Financial Officer of the Corporation have evaluated the effectiveness of the Corporation’s DC&P and ICFR as at December 31, 2010, and have concluded that they were effective and that there were no material weakness relating to the DC&P and ICFR. During the year ended December 31, 2010, there was no change to the ICFR that has materially affected, or is reasonably likely to affect, the ICFR.

FORWARD-LOOKING STATEMENTS

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 statements within the meaning of securities legislation (“Forward-Looking Statements”). Forward-Looking Statements 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 Statements 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 Statements 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 Statements. 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 and wind; 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 Statements are based on reasonable and valid assumptions, there is a risk that the Forward-Looking Statements may be incorrect. The reader of this MD&A is cautioned not to rely unduly on these Forward-Looking Statements. Forward-Looking Statements, 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 Statements 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 Statements, 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 one of the most active in the Canadian renewable power industry, with a focus on hydroelectric, wind power and solar photovoltaic projects that benefit from low operating and management costs and simple and proven technologies. The Corporation's management team, which has been active in the renewable power industry since 1990, has developed and brought to commercial operation or refurbished, through various ventures, 15 hydroelectric and three wind power facilities, representing an aggregate installed capacity of 548 megawatts ("MW"). The Corporation is rated BBB– by Standard and Poor's Rating Services ("S&P") and BBB (low) by DBRS Limited ("DBRS").

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

- 17 operating facilities with an aggregate net installed capacity of 325.5 MW (gross 537.8 MW). These consist of 14 hydroelectric facilities and three wind farms with aggregate net installed capacities of 204.1 MW (gross 218.3 MW) and 121.4 MW (gross 319.5 MW) respectively. Commissioned between November 1994 and January 2010, the facilities have a weighted average age of approximately 6.0 years. They sell the generated power under long-term Power Purchase Agreements ("PPA") that have a weighted average remaining life of 16.9 years;

- seven development projects with an aggregate net installed capacity of 202.9 MW (gross 432.9 MW) for which PPAs with public utilities have been secured. Construction began on three of these projects in June 2010. A limited notice to proceed was issued on another one at the end of 2010 and construction is expected to begin on the remaining three projects in 2013 and 2014. The projects are expected to reach the commercial operation stage between 2011 and 2016; and

- a net capacity of more than 2,000 MW (gross 2,100 MW) in prospective projects that are at various stages of development.

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 PPAs have been secured and which are either under construction or scheduled to begin commercial operation on planned dates. (the "Development Projects");

- projects that have secured certain land rights, for which an investigative permit application has been filed, for which a proposal has 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") (the "Prospective Projects").

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)
- 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)

Development Projects

Hydro
- 66⅔% Boulder Creek, BC (23.0 MW)
- 50% Kwoiek Creek, BC (49.9 MW)
- 66⅔% North Creek, BC (16.0 MW)
- 66⅔% Upper Lillooet, BC (74.0 MW)

Wind
- 38% Gros-Morne (Phase I), QC (100.5 MW)
- 38% Gros-Morne (Phase II), QC (111.0 MW)
- 38% Montagne-Sèche, QC (58.5 MW)

Prospective Projects

Hydro
- 48% QC Projects (42.0 MW)
- 100% BC Projects (19.8 MW)
- 66⅔% BC Projects (132.0 MW)

Wind
- 100% QC Projects (836.0 MW)
- 70% QC Projects - Community (98.4 MW)
- 50% Viger-Denonville, QC (24.6 MW)
- 50% QC Projects - Community (49.2 MW)
- 100% ON Projects - FIT (440.0 MW)
- 49% ON Projects - FIT (25.3 MW)
- 100% BC Projects (475.0 MW)

Solar
- 100% ON Projects - FIT (39.0 MW)

	Operating Facilities	Development Projects	Prospective Projects
Hydro			
Gross capacity:	218.3 MW	162.9 MW	193.8 MW
Net capacity[1]:	204.1 MW	100.3 MW	128.0 MW
Wind			
Gross capacity:	319.5 MW	270.0 MW	1,948.5 MW
Net capacity[1]:	121.4 MW	102.6 MW	1,869.2 MW
Solar			
Gross capacity:	-	-	39.0 MW
Net capacity[1]:	-	-	39.0 MW
Total			
Gross capacity:	537.8 MW	432.9 MW	2,181.3 MW
Net capacity[1]:	325.5 MW	202.9 MW	2,036.1 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.

OPERATING FACILITIES
The Corporation currently has 17 facilities in commercial operations.

HYDRO
Saint-Paulin
The Saint-Paulin facility is an 8.0 MW run-of-river hydroelectric power plant at Magnan Falls in the municipality of Saint-Paulin, Québec. The plant was commissioned in 1994 and its estimated yearly energy output is 41,082 megawatt-hours ("MW-hr"). The PPA for the facility entered with Hydro-Québec expires in 2014 and is renewable for an additional 20-year period. The current PPA provides for a consumer price index ("CPI") based power rate increase of between 3% and 6% per year. In 2010, the Saint-Paulin power plant generated 40,057 MW-hr of power (44,237 MW-hr in 2009) and the average price of electricity delivered to Hydro-Québec was $74.19 per MW-hr ($70.60 per MW-hr in 2009). Under the current PPA, electricity delivered beyond the agreed maximum quantity is paid at a lower price adjusted annually. In 2009, this excess quantity totalled 1,008 MW-hr (nil in 2010) and was paid at a price of $16.00 per MW-hr. This explains mainly the higher average rate in 2010. For the Saint-Paulin facility and for the other facilities located in the province of Québec, the reference period for the calculation of the excess quantity of electricity runs from December 1, to November 30. The Corporation owns 100% of this facility.

Windsor
The Windsor facility is a 5.5 MW run-of-river hydroelectric power plant located on the St. François River near the city of Windsor, Québec. The plant was commissioned in 1996 and acquired by the Corporation on April 27, 2004. Its estimated yearly energy output is 31,000 MW-hr. The PPA for the facility entered with Hydro-Québec expires in 2016 and is renewable for an additional 20-year period. The current PPA provides for a CPI-based power rate increase of between 3% and 6% per year. The current PPA also includes a winter premium for power generated from December to March. In 2010, the Windsor power plant generated 37,944 MW-hr of power (35,381 MW-hr in 2009) and the average price of electricity delivered to Hydro-Québec was $84.33 per MW-hr ($82.63 per MW-hr in 2009). The Corporation owns 100% of this facility.

Chaudière
The Chaudière facility is a 24.0 MW run-of-river hydroelectric power plant that lies on the Chaudière River in Lévis, Québec. The plant was commissioned in 1999 and its estimated yearly energy output is 116,651 MW-hr. The PPA for the facility entered with Hydro-Québec expires in 2019 and is renewable for an additional 20-year period. The current PPA provides for a CPI-based power rate increase of between 3% and 6% per year. The current PPA also includes a winter premium for power generated from December to March. For the 12 months ended December 31, 2010, the Chaudière power plant generated 128,064 MW-hr of power (145,718 MW-hr in 2009) and the average price of electricity delivered to Hydro-Québec was $83.20 per MW-hr ($73.59 per MW-hr in 2009). Under the current PPA, electricity delivered beyond the agreed maximum quantity is paid at a lower price adjusted annually. In 2009, this excess quantity totalled 16,148 MW-hr (nil in 2010) and was paid at a price of $16.00 per MW-hr. This explains mainly the higher average rate in 2010. The Corporation owns 100% of this facility.

Portneuf
The Portneuf facilities consist of three run-of-river hydroelectric power plants with a combined installed capacity of 25.9 MW, located a few kilometres apart on the Portneuf River in the municipalities of Sainte-Anne-de-Portneuf and Longue-Pointe, Québec. All were commissioned in 1996. Their estimated yearly energy output is 151,697 MW-hr. The Portneuf PPA entered with Hydro-Québec expires in 2021 and is renewable for an additional 25-year period. The current PPA provides for a CPI-based power rate increase of between 3% and 6% per year. In addition to revenue from the power generated at the Portneuf facilities, the Corporation receives cash payments from Hydro-Québec to compensate for the partial diversion of the water flow that had been available to the Corporation's plants. These payments are based on long-term average annual water flows over 20 years, but are also contingent on turbine availability and maximum production with the water resources made available by Hydro-Québec. In 2010, the three Portneuf facilities generated, or were compensated for, the equivalent of 150,193 MW-hr of power (146,856 MW-hr in 2009). The average price of electricity delivered to Hydro-Québec in 2010 was $73.97 per MW-hr ($71.87 per MW-hr in 2009). The Corporation owns 100% of these facilities.

Montmagny
The Montmagny facility is a 2.1 MW run-of-river hydroelectric power plant located on the Du Sud River in Montmagny, Québec. The plant was commissioned in 1996 and its estimated yearly energy output is 8,000 MW-hr. The PPA for the facility entered with Hydro-Québec expires in 2021 and is renewable for an additional 25-year period. The current PPA provides for a CPI-based power rate increase of between 3% and 6% per year. The current PPA also includes a winter premium for power generated from December to March. For the 12 months ended December 31, 2010, the Montmagny power plant generated 7,140 MW-hr of power (7,512 MW-hr in 2009) and the average price of electricity delivered to Hydro-Québec was $78.99 per MW-hr ($75.43 per MW-hr in 2009). The Corporation owns 100% of this facility.

Glen Miller
The Glen Miller facility is an 8.0 MW run-of-river hydroelectric power plant located on the Trent River in Trenton, Ontario. The plant was commissioned in December 2005 and acquired by the Corporation on March 29, 2010 through the Combination. Its estimated yearly energy output is 41,606 MW-hr. The PPA for the facility entered with the Ontario Power Authority ("OPA") expires in 2025. On January 1 of each year, a portion equal to 15% of the price of electricity purchased under the PPA is indexed to the percentage increase or decrease in the CPI. For the 12 months ended December 31, 2010, the Glen Miller power plant generated 45,827 MW-hr of power (49,889 MW-hr in 2009) and the average price of electricity delivered to the OPA was $67.27 per MW-hr ($67.12 per MW-hr in 2009). The Corporation owns 100% of this facility.

Umbata Falls
The Umbata Falls facility is a 23.0 MW run-of-river hydroelectric power plant located on the White River, a tributary of Lake Superior, approximately 30 kilometres southeast of Marathon, Ontario. The plant was commissioned on November 12, 2008 and acquired by the Corporation on March 29, 2010 through the Combination. Its estimated yearly energy output is 109,102 MW-hr. The PPA for the facility entered with the OPA expires in 2028. On January 1 of each year, a portion equal to 15% of the price of electricity purchased under the PPA is indexed to the percentage increase or decrease in the CPI. For the 12 months ended December 31, 2010, the Umbata Falls power plant generated 35,953 MW-hr of power (62,377 MW-hr in 2009), which corresponds to the Corporation's interest. The average price of electricity delivered to the OPA in 2010 was $83.60 per MW-hr ($83.40 per MW-hr in 2009), including payments received from the Federal government's ecoENERGY Initiative intended to support renewable energy in Canada. The ecoENERGY Initiative provides a $10 per MW-hr incentive payment for the facility's first ten years of operation. The Corporation owns a 49% interest in this facility.

Batawa
The Batawa facility is a 5.0 MW run-of-river hydroelectric power plant located on the Trent-Severn waterway near Trenton, Ontario. The power plant was commissioned in 1999 and its estimated yearly energy output is 32,938 MW-hr. The PPA for the facility entered into with the Ontario Electricity Financial Corporation ("OEFC") expires in 2029 and will subsequently remain valid unless one of the parties to the agreement gives a one-year cancellation notice. The PPA provides for a premium on power sold in the winter and during peak hours, as opposed to production sold in the summer or during off-peak hours. In 2010, the Batawa power plant generated 37,039 MW-hr of power (39,888 MW-hr in 2009) and the average price of electricity delivered to the OPA was $62.15 per MW-hr ($62.03 per MW-hr in 2009). The Corporation owns 100% of this facility.

Rutherford Creek
The Rutherford Creek facility is a 49.9 MW run-of-river hydroelectric power plant located near Pemberton, British Columbia ("B.C."). The power plant was commissioned in 2004 and acquired by the Corporation on December 15, 2005. Its estimated yearly energy output is 180,000 MW-hr. The PPA entered into with British Columbia Hydro and Power Authority ("BC Hydro") expires in 2024 and provides for an annual power rate adjustment based on 50% of the CPI. In 2010, the Rutherford Creek power plant generated 171,289 MW-hr of power (147,183 MW-hr in 2009) and the average price of electricity delivered to BC Hydro was $55.41 per MW-hr ($55.05 per MW-hr in 2009). The Corporation owns 100% of this facility.

Ashlu Creek
The Ashlu Creek facility is a 49.9 MW run-of-river hydroelectric power plant located on Ashlu Creek, a tributary of the Squamish River, approximately 35 kilometres northwest of Squamish, B.C. The power plant was commissioned on November 29, 2009 and acquired by the Corporation on March 29, 2010 through the Combination. Its estimated yearly energy output is 265,000 MW-hr. The PPA entered into with BC Hydro expires in 2039 and provides for a premium on power sold in the winter and during peak hours, as opposed to production sold in the summer or during off-peak hours. On January 1 of each year, a portion equal to 50% of the price of electricity purchased under the PPA is indexed to the percentage increase or decrease in the CPI. For the 12 months ended December 31, 2010, the Ashlu Creek power plant generated 256,073 MW-hr of power (12,210 MW-hr from November 29, 2009, to December 31, 2009). The average price of electricity delivered to BC Hydro in 2010 was $67.93 per MW-hr ($74.74 per MW-hr from November 29, 2009, to December 31, 2009), including payments of $10 per MW-hr received from the ecoENERGY Initiative. The Corporation owns 100% of this facility.

Fitzsimmons Creek
The Fitzsimmons Creek facility is a 7.5 MW run-of-river hydroelectric power plant located on Fitzsimmons Creek, between the Whistler and Blackcomb mountains in the Resort Municipality of Whistler, B.C. The plant was commissioned on January 26, 2010 and acquired by the Corporation on March 29, 2010 through the Combination. Its estimated yearly energy output is 33.000 MW-hr. The PPA entered into with BC Hydro expires in 2050 and provides for a premium on power sold in the winter and during peak hours, as opposed to production sold in the summer or during off-peak hours. On January 1 of each year, a portion equal to 50% of the price of the electricity purchased under the PPA is indexed to the percentage increase or decrease in the CPI. The facility is also entitled to receive a payment equivalent to $3.10 per MW-hr of the electricity purchased under the PPA as compensation for BC Hydro's receiving the benefits of the environmental attributes associated with the energy generated. This payment of $3.10 per MW-hr is fully indexed to the percentage increase or decrease in the CPI. For the 12 months ended December 31, 2010, the Fitzsimmons Creek power plant generated 21,914 MW-hr of power. The average price of electricity delivered to BC Hydro from January 26, 2010 to December 31, 2010 was $88.35 per MW-hr, including payments of $10 per MW-hr received from the ecoENERGY Initiative. The Corporation owns 66⅔% of the voting rights in the Fitzsimmons Creek facility but receives a larger share of the economic value of the facility through a preferred return of 12.5% on the Corporation's investments in the project of a total of $8.3 million.

Horseshoe Bend
The Horseshoe Bend facility is a 9.5 MW run-of-river hydroelectric power plant located in the city of Horseshoe Bend on the Payette River in the state of Idaho in the USA. The plant was commissioned in 1995 and acquired by the Corporation on December 31, 2004. Its estimated yearly energy output is 46,800 MW-hr. The PPA entered into with the Idaho Power Company expires in 2030. The selling price under this PPA has a fixed component per MW-hr that fluctuates seasonally and corresponds to approximately 85% of the total selling price plus a variable component that is set each year by the Idaho State Public Utility Commission and corresponds to nearly 15% of the total selling price. In 2010, the Horseshoe Bend power plant generated 38,133 MW-hr of power (43,460 MW-hr in 2009) and the average price of electricity delivered to the Idaho Power Company was C$70.33 per MW-hr (C$77.45 per MW-hr in 2009). The Corporation owns 100% of this facility.

WIND
Baie-des-Sables ("BDS")
The Baie-des-Sables facility is a 109.5 MW wind farm located in Baie-des-Sables and Métis-sur-Mer, Québec. It was developed jointly by the Corporation through the Cartier Wind Energy joint venture. The wind farm was commissioned in November 2006 and acquired by the Corporation on December 6, 2007. Its estimated yearly energy output is 298,317 MW-hr. The PPA entered into with Hydro-Québec expires in 2026. The PPA provides for an annual power rate adjustment based on approximately 18% of the CPI. In 2010, the BDS wind farm generated 102,737 MW-hr of power (107,762 MW-hr in 2009), which corresponds to the Corporation's interest. The average price of electricity delivered to Hydro-Québec in 2010 was $78.76 per MW-hr ($78.66 per MW-hr in 2009), including net payments received from the ecoENERGY Initiative. As stipulated in the PPA, Hydro-Québec Distribution ("HQD") is entitled to 75% of the payments received by the Baie-des-Sables wind farm under the ecoENERGY Initiative. The Corporation owns 38% of this facility.

L'Anse-à-Valleau ("AAV")
The L'Anse-à-Valleau facility is a 100.5 MW wind farm located in the city of Gaspé, Québec. It was developed jointly by the Corporation through the Cartier Wind Energy joint venture. The wind farm was commissioned in November 2007 and acquired by the Corporation on December 6, 2007. Its estimated yearly energy output is 298,000 MW-hr. The PPA entered into with Hydro-Québec expires in 2027. The PPA provides for an annual power rate adjustment based on approximately 18% of the CPI. In 2010, the AAV wind farm generated 110,824 MW-hr of power (105,992 MW-hr in 2009), which corresponds to the Corporation's interest. The average price of electricity delivered to Hydro-Québec in 2010 was $78.76 per MW-hr ($78.46 per MW-hr in 2009), including net payments received from the ecoENERGY Initiative. As stipulated in the PPA, HQD is entitled to 75% of the payments received by the L'Anse-à-Valleau wind farm under the ecoENERGY Initiative. The Corporation owns 38% of this facility.

Carleton ("CAR")
The Carleton facility is a 109.5 MW wind farm located in the Town of Carleton-sur-Mer and the Regional County Municipality ("RCM") of Bonaventure, Québec. It was developed jointly by the Corporation through the Cartier Wind Energy joint venture. The wind farm was commissioned on November 22, 2008 and acquired by the Corporation on March 29, 2010 through the Combination. Its estimated yearly energy output is 340,523 MW-hr. The PPA entered into with Hydro-Québec expires in 2028. The PPA provides for an annual power rate adjustment based on approximately 18% of the CPI. In 2010, the CAR wind farm generated 126,913 MW-hr of power (130,179 MW-hr in 2009), which corresponds to the Corporation's interest. The average price of electricity delivered to Hydro-Québec in 2010 was $80.81 per MW-hr ($80.59 per MW-hr in 2009), including net payments received from the ecoENERGY Initiative. As stipulated in the PPA, HQD is entitled to 75% of the payments received by the Carleton wind farm under the ecoENERGY Initiative. The Corporation owns 38% of this facility.

DEVELOPMENT PROJECTS
The Corporation currently has seven projects that are expected to reach the commercial operation stage between 2011 and 2016.

HYDRO
Boulder Creek Project
The Boulder Creek project is a run-of-river hydroelectric power plant with a potential installed capacity of 23.0 MW and an estimated yearly energy output of 85,720 MW-hr. It is located on Boulder Creek in the Lillooet River drainage basin, 56 kilometres northwest of Pemberton, B.C. The Boulder Creek project has a PPA with BC Hydro for all of the power that the facility will produce; the PPA will expire 40 years after the facility's commercial in-service date, which is planned for 2015. 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 of 12.5% on the Corporation's investments in the project.

Kwoiek Creek Project
The Kwoiek Creek project is a run-of-river hydroelectric power plant with a potential installed capacity of 49.9 MW and an estimated yearly energy output of 215,000 MW-hr. It is located at the confluence of the Kwoiek Creek and the Fraser River, approximately 14 kilometres south of Lytton, B.C. In the latter part of 2010, a limited notice to proceed was issued to the engineering, procurement and construction ("EPC") contractor. The facility is expected to reach commercial operations in 2013. The Kwoiek Creek project has a PPA with BC Hydro for all of the power that the facility will produce; the PPA will expire 40 years after the facility's commercial in-service date. The price of electricity delivered pursuant to the PPA is $87.98 per MW-hr. 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, starting on January 1, 2006 and on every January 1 thereafter during the term of the PPA.

BC Hydro is entitled to terminate the PPA in the event that commercial operation of the Kwoiek Creek Project has not commenced by May 5, 2011, subject to any extensions for force majeure as provided in the PPA. Consent to an extension will be requested from BC Hydro as the beginning of commercial operations is currently planned for 2013. The Corporation anticipates that such an extension will be granted, given that the PPA selling price is below the price in BC Hydro's recent PPAs.

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. Under the development agreement, the Corporation can invest up to $20.0 million and its partner up to $3.0 million in interest-bearing or preferential equity instruments for the development of the facility. These instruments bear interest or preferential return at a rate of 20% during the development phase and 14% during the construction and operating phases. As at December 31, 2010, the Corporation's total investment in the project amounted to $10.1 million.

North Creek Project
The North Creek project is a run-of-river hydroelectric power plant with a potential installed capacity of 16.0 MW and an expected yearly energy output of 59,725 MW-hr. It is located on North Creek in the Lillooet River drainage basin, 38 kilometres northwest of Pemberton, B.C. The North Creek project has a PPA with BC Hydro for all of the power that the facility will produce; the PPA will expire 40 years after the facility's commercial in-service date, which is planned for 2016. 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 of 12.5% on the Corporation's investments in the project.

Upper Lillooet Project
The Upper Lillooet project is a run-of-river hydroelectric power plant with a potential installed capacity of 74.0 MW and an expected yearly energy output of 270,160 MW-hr. It is located on the Lillooet River, a tributary of the Fraser River, approximately 70 kilometres northwest of Pemberton, B.C. The Upper Lillooet project has a PPA with BC Hydro for all of the power that the facility will produce; the PPA will expire 40 years after the facility's commercial in-service date, which is planned for 2016. 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 of 12.5% on the Corporation's investments in the project.

WIND

Gros Morne Project – Phase I

The Gros Morne Phase I project is a 100.5 MW wind farm located in the Municipality of Mont-Louis and the Municipality of Sainte-Madeleine-de-la-Rivière-Madeleine, Québec. It is being developed jointly by the Corporation through the Cartier Wind Energy joint venture. It has an expected yearly energy output of 312,535 MW-hr. It is expected that this project will commence commercial operations by December 1, 2011. The Gros Morne Phase I and Phase II projects are covered under a single PPA entered into with Hydro-Québec—expiring 21 years after the start of commercial operations of the Gros Morne Phase I project—for all of the electricity produced by the two projects. The price payable by Hydro-Québec for the electricity delivered from the Gros Morne Phase I and II projects was set at $65.58 per MW-hr as at January 1, 2004, and is adjusted annually, based on the CPI and certain factors specified in the PPA. The Corporation owns a 38% interest in the project.

Gros Morne Project – Phase II

The Gros Morne Phase II project is a 111.0 MW wind farm located in the Municipality of Mont-Louis and the Municipality of Sainte-Madeleine-de-la-Rivière-Madeleine, Québec. It is being developed jointly by the Corporation through the Cartier Wind Energy joint venture. It has an expected yearly energy output of 345,188 MW-hr. It is expected that the project will commence commercial operations by December 1, 2012. The Gros Morne Phase I and Phase II projects are covered by the same PPA with Hydro-Québec for all the electricity produced by the projects. Please refer to the preceding paragraph for details about the PPA. The Corporation owns a 38% interest in the project.

Montagne-Sèche Project

The Montagne-Sèche project is a 58.5 MW wind farm located in the Municipality of the Canton of Cloridorme, Québec. It is being developed jointly by the Corporation through the Cartier Wind Energy joint venture. It has an expected yearly energy output of 182,743 MW-hr. The Montagne-Sèche project is expected to commence commercial operations by December 1, 2011. The project has a PPA with Hydro-Québec for all of the electricity that the facility will produce; the PPA will expire 20 years after the start of commercial operations. The price payable by Hydro-Québec for the electricity delivered is determined using a formula set out in the PPA. This formula is based on the price as at January 1, 2004, specifically $68.80 per MW-hr, and is adjusted annually, based on the CPI and certain factors specified in the PPA. The Corporation owns a 38% interest in this project.

PROSPECTIVE PROJECTS

All of the Prospective Projects, with a combined potential net installed capacity of more than 2,000 MW (gross 2,100 MW), are in the preliminary development stage. Some Prospective Projects are targeted towards specific future RFPs, SOPs or FIT programs and others will be available for future RFPs yet to be announced. There is no certainty that any Prospective Project will be realized.

On December 20, 2010, the Corporation's Viger-Denonville Prospective Project located in Québec was selected for a PPA award. The PPA was executed on March 17, 2011 and will now be submitted to the Régie de l'énergie for approval. The project is a 24.6 MW wind farm being developed jointly by the Corporation and the Rivière-du-Loup RCM, each party having a 50% equity interest in the project. The Corporation expects the wind farm to start commercial operation on December 1, 2013; the PPA will expire 20 years after the start of commercial operation.

In the last quarter of 2010, the Corporation submitted two applications under the FIT Program for solar photovoltaic projects in Ontario. The two projects amount to a total of 19.0 MW. Since the beginning of 2011, Innergex has submitted two additional applications under the FIT Program for solar photovoltaic projects in Ontario for a total of 20.0 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, 2010, which is filed at www.sedar.com.

BUSINESS STRATEGY

The Corporation’s strategy for building shareholder value 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. As an independent clean power producer, the Corporation aims to generate value from renewable energy sources.

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 partners are TransCanada Energy Ltd. (owner of 62% of the Baie-des-Sables, L’Anse-à-Valleau and Carleton wind farms and of the Montagne-Sèche and Gros-Morne wind projects), the Kanaka Bar Indian Band (owner of 50% of the Kwoiek Creek 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, of the Boulder Creek, North Creek and Upper Lillooet projects and other Creek Power Inc. projects) and the Rivière-du-Loup RCM (owner of 50% of the Viger-Denonville community wind project). The Corporation’s capacity measured on an ownership-weighted basis corresponds to (i) 325.5 MW out of the 537.8 MW capacity of its Operating Facilities, (ii) 202.9 MW out of the 432.9 MW capacity of its Development Projects and (iii) more than 2,000 MW out of the 2,100 MW capacity of its Prospective Projects.

Areas of Growth

The Corporation is confident that future RFP opportunities will continue to arise, especially in Québec, British Columbia and Ontario, as these provinces continue to increase their targets for renewable power generation. The Corporation has historically focused its bidding activities on RFPs issued in these three provinces, where it has experienced a high level of success.

On November 30, 2009, the Corporation submitted several wind farm projects during the Ontario FIT Program launch period. On December 21, 2010, the OPA released priority ranking for 242 projects that have not received contracts. According to this ranking, four of the Corporation’s projects, totalling 440 MW, are ranked fourth to ninth in their respective areas. Eventual award of FIT Program contracts will depend on the result of the Economic Connection Test (“ECT”) and the subsequent implementation of transmission expansion.

As presented in the “Prospective Projects” section of this MD&A, the Corporation executed a PPA for the Viger-Denonville Prospective Project. The PPA will now be submitted to the Régie de l’énergie for approval. Also mentioned in the same section, the Corporation submitted two applications under the FIT Program for solar photovoltaic projects in Ontario in the last quarter of 2010 and has submitted two additional solar photovoltaic projects since the beginning of 2011. The four projects total 39.0 MW.

On January 25, 2011, BC Hydro released its revised SOP. Among other things, BC Hydro has increased the upper limit on project size (from 9.9 MW to 15.0 MW) and the electricity rates applicable to each region. Innergex is currently evaluating the impact of this announcement, as some of its Prospective Projects could be eligible under the program.

The Corporation’s management team views the U.S. as an attractive market and will continue to assess the opportunities it offers, particularly in light of the Obama administration’s focus on increasing renewable energy production. The Global Wind Energy Council has reported that the U.S. wind industry built 5,115 MW of capacity in 2010 and that U.S. industry entered 2011 with more than 5,600 MW of capacity under construction.

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, the Corporation will continue to focus on hydroelectric and wind power generation facilities, although it has now added the solar industry to its focus areas. Innergex may also seek to grow through expansion into other forms of renewable energy production if profitable opportunities arise. Future projects may be located in any region where such profitable opportunities exist, although the Corporation expects that they will mostly be located in Canada and the United States. While the Corporation intends to continue focusing on the sale of power through long-term PPAs, it may also consider entering into the merchant wholesale power market if profitable opportunities are identified.

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) the Corporation's 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 acquisition; and
(vi) the availability of financing.

In view of the threat posed by global warming and governments' growing recognition of and support for the need to protect the environment, the Corporation believes that the future of the renewable energy industry is promising.

Capacity for Delivering Results
As it evolves in a competitive sector, the Corporation's best asset is its management team's experience and dedication. The Corporation employs approximately 75 persons. This team has a proven track record of completing projects by the commercial operations start date provided in its PPAs, without incurring any significant cost overruns, due to its careful management of the construction process. 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 capacity with an efficient use of external consultants, when required. In addition, the Corporation uses the services of several independent engineering firms to assist it with the feasibility analysis of its projects.

MARKET TRENDS
Renewable power producers are involved in the generation of electricity from renewable energy sources including:
(i) water;
(ii) wind;
(iii) the sun;
(iv) certain waste products, such as 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 has increasingly been recognized by government authorities and other policymakers in recent years.

The trend towards increased reliance on independent power producers for the supply of renewable power in North America is explained by a number of reasons, including:
(i) the increase in government-sponsored incentives;
(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; and
(iv) the efficiency of independent power producers.

Renewable Power in Canada
Significant recent growth in renewable power generation in Canada has been influenced by rising electricity and fossil fuel prices; certain competitive provincial markets; 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 investment tax credits, accelerated depreciation and Renewable Portfolio Standards ("RPS"). Several provinces are also making the necessary transmission grid investments and focusing on conservation and reduction in demand.

Canada enjoys an abundance of hydrological resources unique in the world. 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.

The National Energy Board reports that wind power generation in Canada has reached the commercial development stage and is now the fastest growing source of renewable energy in the country. According to the Canadian Wind Energy Association (CanWEA), wind energy capacity grew by an average 46 percent per year in Canada between 2005 and 2010. CanWEA also reports that the total installed wind power capacity at the end of 2010 was about 4,000 MW and that 1,000 MW of new wind capacity is expected for 2011. Installed wind power capacity in Canada has increased substantially in each of the past five years, due largely to provincial RPSs, relatively short construction timelines, favourable wind resources including vast shorelines and strong winds throughout a wide range of rural areas, and numerous RFPs for renewable energy. The customary challenges of resource availability and transmission exist in Canada and, in certain areas, access to transmission lines with available capacity is an economic or regulatory consideration. Nevertheless, if all the provinces continue to bring wind energy onto their grids, CanWEA believes Canada will reach a total installed capacity of 12,000 MW by 2015.

In response to the long-term trend toward stronger environmental protection policies, many provincial governments have introduced RPSs, which are generally being applied and implemented as goals or targets rather than mandatory requirements. These RPSs typically reflect the distinct resource issues associated with electricity generation, given the provinces' respective electricity industry structures and geographical conditions. RPSs typically set a target for an increased component of renewable energy generation in the electricity generation supply mix in order to reduce greenhouse gas emissions over time. To meet these targets, RFPs have been developed by provincial authorities or their utilities in order to source renewable generation resources and, in some cases, offer PPAs through competitive bidding processes. The competitive bidding process seeks to ensure that the RPSs are achieved at the lowest possible cost and with the highest probability of project completion. SOPs and FIT Programs have also been implemented or are planned in some provinces, as a mechanism whereby projects can contribute to meeting renewable energy generation goals by simplifying the negotiation and financing processes, and decreasing the transactional costs for obtaining a long-term PPA.

Several provinces have recently released, or are currently preparing, significant new RFPs, SOPs and FIT Programs, with the objective of procuring additional installed electricity generation capacity from renewable sources. Through provincial RPSs, several provinces have set a target capacity or percentage of electricity to be generated from renewable sources. The current provincial targets for clean or renewable energy within their supply mix include: British Columbia's requiring renewable or clean energy to continue accounting for at least 93% of total generation; Saskatchewan's aiming to acquire up to 175 MW of wind power by 2015; Ontario's targeting 9,000 MW of hydroelectric power and 10,700 MW of wind, solar and bioenergy power by 2030; Quebec's pursuing 4,000 MW of installed wind generation capacity by 2015; New Brunswick's setting a goal of 10% renewable power generation by 2016 and 4,500 MW of wind energy production by 2025; Nova Scotia's aiming for 25% renewable power generation by 2015, and 40% by 2020; Prince Edward Island's requiring 500 MW of wind energy production by 2013 and 30% renewable power generation by 2016; and Manitoba's pursuing 1,000 MW of installed wind generation by 2016.

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.

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

KEY PERFORMANCE INDICATORS

The Corporation measures its performance using key performance indicators that include or could include: power generated in MW-hr and gigawatt-hours ("GW-hr"); 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 Canadian GAAP and therefore may not be comparable to 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 the wind regime. 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 14 hydroelectric facilities, which draw on 11 watersheds and three 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.

Operating Facilities – Estimated Long-Term Averages

Project name	Electricity purchaser	PPA expiry	Net installed capacity[1] (MW)	Average long-term production (GW-hr) (Net interest)[2]				
				Q1	Q2	Q3	Q4	Total
HYDRO								
St-Paulin	HQ[3]	2014[4]	8.0	7.4	15.5	8.0	10.1	41.1
Windsor	HQ[3]	2016[4]	5.5	9.7	7.8	5.6	7.9	31.0
Chaudière	HQ[3]	2019[4]	24.0	26.0	40.8	17.6	32.2	116.7
Portneuf-1	HQ[3]	2021[5]	8.0	4.3	14.9	11.5	10.1	40.8
Portneuf-2	HQ[3]	2021[5]	9.9	10.0	20.1	19.3	19.1	68.5
Portneuf-3	HQ[3]	2021[5]	8.0	4.4	15.6	11.9	10.4	42.4
Montmagny	HQ[3]	2021[5]	2.1	1.4	3.2	1.0	2.3	8.0
Glen Miller	OPA[6]	2025	8.0	13.5	11.9	4.5	11.7	41.6
Umbata Falls	OPA[6]	2028	11.3	8.3	18.5	10.4	16.2	53.5
Batawa	OEFC[7]	2029	5.0	10.8	8.9	3.7	9.5	32.9
Rutherford Creek	BC Hydro[8]	2024	49.9	11.0	63.7	80.0	25.3	180.0
Ashlu Creek	BC Hydro[8]	2039	49.9	26.9	92.0	95.1	51.0	265.0
Fitzsimmons Creek	BC Hydro[8]	2050	5.0	3.3	10.9	13.3	5.4	33.0
Horseshoe Bend	IPC[9]	2030	9.5	7.9	17.0	16.7	5.2	46.8
Subtotal			204.1	145.1	340.8	298.9	216.5	1,001.2
WIND								
Baie-des-Sables	HQ[3]	2026	41.6	35.7	25.0	18.6	34.1	113.4
L'Anse-à-Valleau	HQ[3]	2027	38.2	38.2	22.9	16.5	35.7	113.2
Carleton	HQ[3]	2028	41.6	38.1	28.2	24.1	39.0	129.4
Subtotal			121.4	112.0	76.0	59.2	108.8	356.0
Total		16.9 years[10]	325.5	257.0	416.9	358.1	325.2	1,357.2

1. Net capacity represents the proportional share of the total capacity attributable to Innergex based on its ownership interest in these facilities. The remaining capacity is attributable to the strategic partners' ownership share.
2. Net interest adjusted in accordance with revenue recognition accounting rules under Canadian GAAP.
3. Hydro-Québec.
4. These PPAs are renewable at the Corporation's option for an additional term of 20 years.
5. These PPAs are renewable at the Corporation's option for an additional term of 25 years.
6. Ontario Power Authority.
7. Ontario Electricity Financial Corporation.
8. British Columbia Hydro and Power Authority.
9. Idaho Power Company.
10. Remaining weighted average life of PPAs, before consideration of renewal options.

MANAGEMENT'S DISCUSSION AND ANALYSIS

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

OVERALL PERFORMANCE

Highlights	For the year ended December 31, 2010	For the year ended December 31, 2009
	$	$
Power generated (MW-hr) [1]	1,227,435	823,989
Gross operating revenues	89,100	58,625
EBITDA	68,098	46,778
Net (loss) earnings	(3,659)	26,243
Adjusted cash flows from operating activities	49,110	32,889
Dividends declared on Series A Preferred Shares	1,520	-
Dividends declared on common shares	33,323	29,404
Dividends declared on common shares ($ per share)	0.607	0.685

1. In accordance with Canadian GAAP, the power generated for the year ended December 31, 2010, is that of the Fund including Innergex's contribution since March 30, 2010.

The Combination accounts for the main differences between 2010 and 2009. The addition of the Pre-Combination Innergex's five Operating Facilities (total net installed capacity of 115.8 MW) to the Fund's 12 Operating Facilities (total net installed capacity of 209.7 MW) is mainly responsible for the increases in power generated, revenues, EBITDA and adjusted cash flows from operating activities. The Combination also had a positive impact on net earnings, albeit one that was more than offset by unrealized net losses on derivative financial instruments. For the Corporation, unrealized net gains/losses on derivative financial instruments are causing the largest fluctuations to net earnings.

Adjusted Net Earnings

The Corporation believes that adjusted net earnings 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 exclude unrealized gains/losses on derivative financial instruments and unrealized foreign exchange gains/losses as well as any associated future income tax. When applicable, adjusted net earnings also exclude some non-recurring items. The Corporation calculates adjusted net earnings as shown below:

Adjusted Net Earnings	For the year ended December 31, 2010	For the year ended December 31, 2009
	$	$
Net (loss) earnings	(3,659)	26,243
Add (deduct):		
Non-cash expense related to royalty agreement	983	-
Unrealized net loss (gain) on derivative financial instruments	20,761	(15,798)
Unrealized foreign exchange gain	(23)	(320)
Future income taxes associated with the above elements	(5,943)	2,989
Decrease in future income tax rates	(1,342)	(429)
Adjusted net earnings	10,777	12,685

Unrealized gains/losses 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 25 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 Risk Management" section of this MD&A for more information about Derivatives.

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

Financing Activities
As part of the Combination, Innergex refinanced the Fund's $133.9 million bank credit facility and its $40.0 million revolving credit facility with a new three-year $170.0 million credit facility comprised of a $117.4 million revolving facility (the "Operating Credit Facility") and a $52.6 million term loan (the "BDS Credit Facility"). For more information about this refinancing, please refer to the "Use of Financing Proceeds" and "Long-Term Debt" sections of this MD&A.

The Corporation also issued $80.5 million in principal amount of subordinated convertible debentures (the "Convertible Debentures") as part of the Combination process. The Convertible Debentures are traded on the TSX under the symbol INE.DB. For more information about this issuance, please refer to the "Convertible Debentures" section of this MD&A.

On September 14, 2010, the Corporation issued a total of 3,400,000 cumulative rate reset non-voting preferred shares, Series A (the "Series A Preferred Shares") at $25.00 per share for aggregate gross proceeds of $85.0 million. The Series A Preferred Shares are traded on the TSX under the symbol INE.PR.A. For more information about this issuance, please refer to the "Preferred Shares" section of this MD&A.

On September 30, 2010, the Corporation amended the BDS Credit Facility, thereby converting this $52.6 million credit facility from a term loan to a revolving credit facility. This enhances the Corporation's cash management flexibility.

On December 22, 2010, the Corporation completed the long-term debt financing for the 58.5 MW Montagne-Sèche project by entering into a construction and four-year term loan with National Bank of Canada as the sole lender.

Commissioning Activities
The following table presents the Operating Facility that has been commissioned during the last 12 months.

Operating Facility Commissioned During the Last 12 Months

Project name and location	Installed capacity (MW)	Estimated long-term average production (GW-hr)	Total construction costs		Commercial in-service date ("COD")		Expected year-one	
			Estimated ($M)	As at Dec. 31, 2010 ($M)	Original estimate	Actual	Revenues ($M)	EBITDA ($M)
HYDRO								
Fitzsimmons Creek, BC[1]	7.5	33.0	33.2	31.2	Q4 2010	Q1 2010	3.2	2.4

1. The Corporation owns 66 ⅔% of this project

Fitzsimmons Creek
The facility began commercial operations on January 26, 2010. During the second quarter of 2010, Innergex was informed by the BC Ministry of Environment and by the Department of Fisheries and Ocean Canada that the in-stream flow requirement at the intake had to be increased from 0.1 cubic meter per second ("CMS") to 0.4 CMS until further environmental monitoring is completed. Innergex evaluates that this reduces the facility's annual budgeted production, revenues and EBITDA by 4 GW-hr, $0.4 million and $0.3 million, respectively. Innergex expects the agencies to complete their review by the end of 2011.

On April 23, 2010, the Fitzsimmons Creek facility received its EcoLogo certification, thereby confirming that the facility will receive incentive payments under the ecoENERGY Initiative of the Federal government. These payments correspond to $10 per MW-hr for the first ten years of operation.

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

Development Projects
The Corporation owns eight Development Projects. Of these, construction of the Montagne-Sèche and Gros-Morne Phase I and Phase II wind farm projects began in June 2010, pre-engineering and mobilization for the Kwoiek Creek hydroelectric project began in the fourth quarter of 2010 and the remaining wind farm and three hydroelectric projects began the permit phase. The two tables below provide an overview of these Development Projects.

Development Projects (under construction)

Project name and location	Installed capacity (MW)	Estimated long-term average production (GW-hr)	Total construction costs		Expected COD	Expected year-one	
			Estimated ($M)	As at Dec 31, 2010 ($M)		Revenues ($M)	EBITDA ($M)
WIND							
Montagne-Sèche, QC[1]	58.5	193.4	103.0	11.1[2]	Q4 2011	4.8[2]	4.3[2]
Gros-Morne – Phase I, QC[1]	100.5	308.9	348.5	25.1[2]	Q4 2011	7.8[2]	6.9[2]
Gros-Morne – Phase II, QC[1]	111.0	341.1	for both phases	for both phases	Q4 2012	8.6[2]	7.5[2]

1. The Corporation owns 38% of this project.
2. Representing the Corporation's 38% interest in this project.

Montagne-Sèche
On June 1, 2010, Innergex issued a notice to proceed to the turbine supplier and the balance-of-plant contractor, thereby launching the construction phase of this wind farm. At the end of 2010, more than half of the roads were built, the substation was 50% completed and 12 out of the 39 foundations were completed. As planned, construction activities have been halted for the winter period; they will resume in the spring of 2011.

On December 22, 2010, the Corporation completed the long-term debt financing for the 58.5 MW Montagne-Sèche project by entering into a credit agreement with National Bank of Canada as the sole lender. Innergex expects the Montagne-Sèche project to be completed by December 1, 2011.

Gros-Morne, Phase I and II
On June 1, 2010, Innergex issued a notice to proceed to the turbine supplier and the balance-of-plant contractor, thereby launching the construction phase of these two wind farms. At the end of 2010, more than 65% of roads were built, the substation was 53% completed and 32 out of the 67 foundations planned for Phase I were completed. As planned, construction activities have been halted for the winter period; they will resume in the spring of 2011.

Following the issuance of the Series A Preferred Shares, Innergex has elected to finance these projects with cash flows generated from operations, cash on hand and its revolving credit facilities. Innergex expects the 100.5 MW Gros-Morne Phase I project to be completed by December 1, 2011, and the Gros-Morne Phase II project to be completed by December 1, 2012.

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

Development Projects (permit phase)

Project name and location	Installed capacity (MW)	Total construction costs Estimated ($M)	As at Dec. 31, 2010 ($M)	Expected COD
HYDRO				
Kwoiek Creek, BC[1]	49.9	152.1	14.1	2013
Boulder Creek, BC[2]	23.0	84.0	0.1	2015
North Creek, BC[2]	16.0	71.0	0.3	2016
Upper Lillooet, BC[2]	74.0	260.0	3.6	2016

1. The Corporation owns 50% of this project.
2. The Corporation owns 66 ⅔% of this project.

Kwoiek Creek
In December 2010, the Corporation issued a limited notice to proceed to the EPC contractor. Construction of this facility is expected to be completed in 2013.

Boulder Creek, North Creek and Upper Lillooet
On March 11, 2010, BC Hydro announced that the Boulder Creek, North Creek and Upper Lillooet hydroelectric projects, totalling 113 MW and submitted under the 2008 BC Hydro Clean Power Call RFP, had been selected for PPA awards, subject to the British Columbia Utilities Commission's approval. On June 3, 2010, the BC government's Clean Energy Act was passed by the BC Legislature, thereby approving these three PPAs. The PPAs have allowed the Corporation to enter the development phase for these projects. Current activities are focused around consultation with the various stakeholders; applications for obtaining the relevant permits; geotechnical analysis for the transmission line and tunnel and preliminary engineering. The Corporation expects Boulder Creek to start commercial operation in 2015 and North Creek and Upper Lillooet to start commercial operation in 2016.

Prospective Projects
All of the Prospective Projects, with a combined potential net installed capacity of more than 2,000 MW (gross 2,100 MW), are in the preliminary development stage. Some Prospective Projects are targeted toward specific future RFPs and others will be available for future RFPs, SOPs or FITs yet to be announced. There is no certainty that any Prospective Project will be realized.

On December 20, 2010, Hydro-Québec announced that the Corporation's Viger-Denonville Prospective Project had been selected for a PPA award. The PPA was executed on March 17, 2011 and will now be submitted to the Régie de l'énergie for approval. Once approved, the PPA will allow the Corporation to enter the development phase for this project. The Corporation expects the 24.6 MW wind farm to start commercial operation on December 1, 2013.

On January 25, 2011, BC Hydro released its revised SOP. Among other things, BC Hydro has raised the upper limit on project size (from 9.9 MW to 15.0 MW) and the electricity rates applicable to each region. Innergex is currently evaluating the impact of this announcement, as some of its Prospective Projects could be eligible under the program.

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, 2010, and in 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.

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

SELECTED ANNUAL INFORMATION

Selected Annual Information	For the year ended December 31, 2010	For the year ended December 31, 2009	For the year ended December 31, 2008
	$	$	$
Revenues	89,100	58,625	59,430
Operating and general and administrative expenses	18,300	11,847	12,333
Net (loss) earnings	(3,659)	26,243	(3,238)
($ per common share - basic)	(0.09)	0.61	(0.08)
($ per common share - diluted)	(0.09)	0.61	(0.08)
Weighted average number of common shares outstanding	55,530	42,930	42,930
Total assets	930,830	508,141	530,008
Long-term financial liabilities:			
Debt related to operating facilities	350,837	226,598	245,770
Debt related to projects under construction	10,727	-	-
Debt related to projects under development	2,476	-	-
Others	9,579	977	901
Dividends declared on Series A Preferred Shares	1,520		
Dividends declared on common shares	33,323	29,404	29,393
Shareholders' equity	347,346	189,478	192,666

Comparison between 2010 and 2009
The main differences between 2010 and 2009 are attributable to the Combination. The addition of the Pre-Combination Innergex's assets, including five Operating Facilities for a total net installed capacity of 115.8 MW (gross 197.9 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 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 last year, the Corporation recorded a net loss of $3.7 million (net earnings of $26.2 million in 2009). This difference is mainly due 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 long-term benchmark interest rates in 2010. 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 mainly due to the increase in the weighted average number of shares outstanding.

Comparison between 2009 and 2008
In 2009, gross operating revenue fell $0.8 million from 2008 due to less favourable hydrologic conditions in Québec and British Columbia and less favourable wind conditions at the BDS wind farm.

In 2009, the Corporation recorded net earnings of $26.2 million (net loss of $3.2 million in 2008). This improvement is mainly due to a $15.8 million unrealized gain on derivative financial instruments (loss of $21.2 million in 2008) resulting from the general increase in long-term benchmark interest rates in 2009.

As at December 31, 2009, the Corporation's total assets amounted to $508.1 million ($530.0 million in 2008). This decrease is due to the depreciation of property, plant and equipment and to the amortization of intangible assets

The decrease in long-term financial liabilities in 2009 is due to planned repayments of the long-term debt and the decrease in liabilities related to derivative financial instruments. The latter stems from the general increase in long-term benchmark interest rates.

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

OPERATING RESULTS

The Corporation's operating results for the year ended December 31, 2010, are compared with the operating results for the same period in 2009. As a result of the Combination, the operations of the Pre-Combination Innergex have been accounted for in the Corporation's results since March 30, 2010.

Nevertheless, for the benefit of the reader, the following 12-month production results have been adjusted to include the electricity production of Glen Miller, Umbata Falls, Ashlu Creek, Fitzsimmons Creek and Carleton for the full 12-month period.

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 and the reserved aesthetic and ecological flows; for wind energy, the wind conditions. Also taken into account are the site topography, installed capacity, energy losses, operational features, maintenance, etc. Although production will fluctuate from year to year, over an extended period it should approach the forecast long-term average.

Production	**Operating period January 1 to December 31, 2010**		**Operating period January 1 to December 31, 2009**	
	Production (MW-hr)	Long-term average (MW-hr)	Production (MW-hr)	Long-term average (MW-hr)
HYDRO				
Saint-Paulin	40,057	41,082	44,237	41,082
Windsor	37,944	31,000	35,381	31,000
Chaudière	128,064	116,651	145,718	116,651
Portneuf-1	40,972	40,822	39,732	40,822
Portneuf-2	67,119	68,496	66,141	68,496
Portneuf-3	42,102	42,379	40,983	42,379
Montmagny	7,140	8,000	7,512	8,000
Glen Miller[1]	45,827	41,606	49,889	41,606
Umbata Falls[1,2]	35,953	53,461	62,377	53,461
Batawa	37,039	32,938	39,888	32,938
Rutherford Creek	171,289	180,000	147,183	180,000
Ashlu Creek[1,5]	256,073	265,000	12,210	12,117
Fitzsimmons Creek[3,6]	21,914	30,605	-	-
Horseshoe Bend	38,133	46,800	43,460	46,800
Subtotal	969,626	998,840	734,711	715,352
WIND				
Baie-des-Sables[4]	102,737	113,360	107,762	113,360
L'Anse-à-Valleau[4]	110,824	113,240	105,992	113,240
Carleton[1,4]	126,913	129,398	130,179	129,398
Subtotal	340,474	355,998	343,933	355,998
Total	1,310,100	1,354,838	1,078,644	1,071,350

1. Adjusted to include the full 12-month period
2. Representing the Corporation's 49% interest in this facility.
3. Representing the Corporation's 66⅔% interest in this facility.
4. Representing the Corporation's 38% interest in this wind farm.
5. The 2009 long-term average was adjusted for the period during which the facility was in commercial operation as commissioning occurred on November 29, 2009.
6. The 2010 long-term average was adjusted for the period during which the facility was in commercial operation as commissioning occurred on January 26, 2010.

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

For the year ended December 31, 2010, the Corporation's facilities produced 1,310,100 MW-hr, 3% less than the long-term average of 1,354,838 MW-hr. This production level is due mainly to:

- hydrologic conditions lower than the long-term average at the Umbata Falls, Rutherford Creek, Fitzsimmons Creek and Horseshoe Bend facilities;
- the tunnel inspection and subsequent corrective measures implemented at the Ashlu Creek facility, which meant that the facility was stopped from February 28, 2010, to April 17, 2010;
- the 14-day shutdown of the three Portneuf facilities in November and December 2010 due to transmission line work carried out by Hydro-Québec;
- wind conditions lower than the long-term average at the Baie-des-Sables wind farm; and
- a five-day shutdown of the L'Anse-à-Valleau and Carleton wind farms in January 2010 caused by ice accumulation on the Hydro-Québec transmission line, which required corrective measures by Hydro-Québec.

These conditions were partially offset by favourable hydrologic conditions at the Windsor, Chaudière, Glen Miller and Batawa facilities.

Although the three Portneuf 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. These provisions have been implemented to compensate for the partial diversion by Hydro-Québec of the water flow that had historically been available to these three facilities.

The overall performance of the Corporation's facilities for the year ended December 31, 2010, demonstrates the benefits of geographic diversification and the complementarity of hydroelectric and wind power generation since no single asset represents more than 20% of the total annual forecast production.

Operating Results	**For the year ended December 31, 2010**	**For the year ended December 31, 2009**
	$	**$**
Gross operating revenues	89,100	58,625
Operating expenses	12,357	8,241
Stock-based compensation	331	-
General and administrative expenses	5,943	3,606
Prospective projects expenses	2,371	-
EBITDA	68,098	46,778
Interests	23,193	13,187
Realized gain on derivative financial instruments	(555)	-
Realized foreign exchange loss (gain)	64	(182)
Other net revenues	(81)	(114)
Depreciation and amortization	31,289	21,426
Unrealized net loss (gain) on derivative financial instruments	20,761	(15,798)
Expense related to royalty agreement	983	-
Unrealized foreign exchange gain	(23)	(320)
(Recovery of) provision for income taxes	(3,874)	2,336
Net (loss) earnings	(3,659)	26,243

Revenues
For the year ended December 31, 2010, the Corporation recorded gross operating revenues of $89.1 million ($58.6 million in 2009). This increase is due to additional revenues resulting from the Combination ($29.3 million) and higher revenues from the pre-combination assets of the Fund (positive impact of $1.2 million). As specified earlier in this MD&A, revenues from the assets of the Pre-Combination Innergex have been included as of March 30, 2010.

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

In 2010, the Corporation recorded $12.4 million in operating expenses related to the operation of the power-producing facilities ($8.2 million in 2009). This increase was expected and is the result of the Combination which means that the Corporation operated a greater number of facilities in 2010 than in 2009.

Stock-based compensation relates to the amortization of the fair value of options granted concurrently with the Initial Public Offering of the Pre-Combination Innergex in December 2007 and options also granted in June 2010. Non-cash stock-based compensation was $0.3 million for year ended December 31, 2010 (nil in 2009).

General and administrative expenses totalled $5.9 million for the year ended December 31, 2010 ($3.6 million in 2009). This increase is due to the Corporation's larger size as a result of the Combination.

Prospective project expenses include the costs incurred for the development of Prospective Projects. Prior to the Combination, such expenses were not incurred by the Fund. Accordingly, prospective projects expenses totalled $2.4 million for the year ended December 31, 2010 (nil in 2009).

Interests
For the year ended December 31, 2010, interest expenses rose to $23.2 million ($13.2 million in 2009). This difference is due to the issuance of Convertible Debentures, to the increase in long-term debt resulting from the Combination and to a writeoff of $0.6 million of deferred financial costs for the refinancing of the Fund's bank credit facility.

As at December 31, 2010, the Corporation's entire actual debt, including Convertible Debentures and part of its future planned drawings, was fixed or hedged against interest rate movements (92% as at December 31, 2009). As such, the effective all-in interest rate on the Corporation's debt and Convertible Debentures was 6.07% as at that date (5.67% as at December 31, 2009). The increase stems from the Combination and from the swap related to the Ashlu long-term debt taking effect on September 30, 2010. Please see the "Derivative Financial Instruments and Risk Management" section for more information.

Derivative Financial Instruments
The Corporation uses derivative financial instruments (primarily bond forward contracts and interest rate swaps) to manage its exposure to the risk of rising interest rates on its long-term debt, 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. It does not own or issue financial instruments for speculative purposes.

For the year ended December 31, 2010, the Corporation recorded a $0.6 million realized gain on derivative financial instruments (nil in 2009) due to the settlement on April 29, 2010, of a $110.0 million forward-starting amortizing interest rate swap related to the Ashlu Creek facility.

For the year ended December 31, 2010, the Corporation recorded a $20.8 million unrealized net loss on derivative financial instruments (unrealized net gain of $15.8 million in 2009) due mainly to the decrease in benchmark interest rates for long-term maturities since the end of 2009. This loss had no cash impact on the Corporation's results.

Depreciation and Amortization
For the year ended December 31, 2010, depreciation and amortization expenses totalled $31.3 million ($21.4 million in 2009). The differences are mainly attributable to the greater asset base resulting from the Combination and to the amortization of the extended warranty of the AAV wind farm, which became effective in December 2009.

Expense Related to Royalty Agreement
For the year ended December 31, 2010, the Corporation recorded an expense of $1.0 million (nil in 2009) due to the deemed cancellation of a contract resulting from the Combination. As per Canadian GAAP, the Fund had to expense the engagement it had with the Pre-Combination Innergex since 2005. In that year, 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 that 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, 2010, Innergex recorded an income tax recovery of $3.9 million (provision of $2.3 million in 2009). Prior to the Combination, the Fund's income trust structure minimized income taxes. 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.

Net Earnings
For the year ended December 31, 2010, the Corporation recorded a net loss of $3.7 million (basic and diluted net loss of $0.09 per share). For the corresponding period of 2009, Innergex recorded net earnings of $26.2 million (basic and diluted net earnings of $0.61 per share). This difference is attributable mainly to:

- a $21.3 million increase in EBITDA; and
- a $6.2 million favourable difference in income taxes.

These were more than offset by:

- a $36.6 million negative variation in the fair market value of derivative financial instruments;
- a $10.0 million increase in interests;
- a $9.9 million increase in depreciation and amortization;
- a $1.0 million expense related to royalty agreement.

The basic and diluted per-share figures for the year ended December 31, 2010, are based on a weighted average number of 55,529,845 common shares outstanding. As per Canadian GAAP, all stock options were non-dilutive during this period. For 1,034,000 stock options, the average market price of the Corporation's common share was below the strike price. For the other 808,024 stock options, their inclusion would have resulted in a lower loss per common share amount. Convertible Debentures were also non-dilutive. For the year ended December 31, 2009, per-share figures were based on a weighted average number of 42,930,243 common shares outstanding. No Convertible Debentures or stock options were outstanding during this period.

As at December 31, 2010, the Corporation had a total of 59,532,606 common shares, 80,500 Convertible Debentures, 3,400,000 Series A Preferred Shares and 1,842,024 stock options outstanding. As at December 31, 2009, it had 42,930,243 common shares outstanding.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows from Operating Activities

For the year ended December 31, 2010, cash flows generated by operating activities totalled $23.4 million ($34.9 million in 2009). This difference is due primarily to the $27.3 million decrease in the variation of non-cash working capital items and to the $10.0 million increase in interests, partly offset by the $21.3 million increase in EBITDA. The variation in non-cash working capital items stems mainly from the Combination, which resulted in negative impacts from increases in accounts receivable ($7.9 million) and prepaid and others ($3.0 million) and a decrease in accounts payable and accrued liabilities ($16.4 million) compared with the same period of 2009. Upon the Combination, the Pre-Combination Innergex had $88.4 million of cash and cash equivalent that it used partly to pay down accounts payable and accrued liabilities due by the Pre-Combination Innergex entities.

Cash Flows from Financing Activities

For the year ended December 31, 2010, cash flows used by financing activities totalled $31.3 million ($32.1 million in 2009). This results from the issuance of the Series A Preferred Shares for net proceeds of $81.7 million (nil in 2009), net long-term debt repayments of $73.0 million ($2.7 million in 2009), a $12.9 million repayment of the bank loan (nil in 2009), $17.5 million in dividends paid to common shareholders (nil in 2009) and $9.7 million in distributions paid to former unitholders ($29.4 million in 2009).

The $73.0 million net decrease in long-term debt (net of deferred financing fees) stems from the issuance of the Series A Preferred Shares, the Combination and the refinancing of the Fund's bank credit facility and facilities 1, 2 and 3 and of the Pre-Combination Innergex's revolving credit facility. For more information about this refinancing, please refer to the "Use of Financing Proceeds" and "Long-Term Debt" sections of this MD&A.

Cash Flows from Investing Activities

For the year ended December 31, 2010, the Corporation's cash flows from investing activities amounted to total net cash inflows of $40.9 million (outflows of $2.1 million in 2009). Cash acquired concurrently with the Combination accounted for an $83.0 million inflow. For the corresponding period of 2009, net cash related to business acquisition accounted for a $0.6 million inflow. During 2010, net additions to property, plant and equipment also accounted for a $29.7 million outflow ($2.2 million in 2009), additions to project development costs for a $9.1 million outflow (nil in 2009), additions to intangible assets and other long-term assets for a combined $0.8 million outflow (nil in 2009), increases in a short-term loan to a partner for a $1.0 million outflow (nil in 2009) and net investments in the reserves for a $2.0 million outflow ($0.5 million in 2009).

Cash and Cash Equivalents

For the year ended December 31, 2010, the Corporation generated $32.8 million in cash and cash equivalents ($0.7 million in 2009), mainly as a result of the Combination and the issuance of the Series A Preferred Shares.

As at December 31, 2010, the Corporation had cash and cash equivalents amounting to $42.1 million ($9.4 million as at December 31, 2009).

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

Dividends to Preferred Shareholders
On March 23, 2011, the Corporation declared a dividend of $0.3125 per Series A Preferred Share payable on April 15, 2011, to preferred shareholders of record at the close of business on March 31, 2011.

Dividends to Common Shareholders
On March 23, 2011, the Corporation declared a dividend of $0.1450 per common share payable on April 15, 2011, to common shareholders of record at the close of business on March 31, 2011.

USE OF FINANCING PROCEEDS

Use of Financing Proceeds	For the year ended December 31, 2010	For the year ended December 31, 2009
	$	$
Proceeds from issuance of preferred shares	85,000	-
Proceeds from issuance of long-term debt	134,220	-
Financing proceeds	219,220	-
Net cash acquired on business acquisition:		
IHI Hydro Inc.	-	636
Pre-Combination Innergex	83,033	-
Additions to property, plant and equipment	(29,667)	(2,223)
Additions to intangible assets	(413)	-
Additions to project developments costs	(9,056)	-
Additions to other long-term assets	(365)	-
Short-term loan to a partner	(1,000)	-
Funds invested in the hydrology reserve funded from long-term debt	(2,016)	-
Refinancing of long-term debt	(119,806)	-
Financing and issuance fees	(4,981)	-
Cancellation of revolving credit facility	(12,900)	-
Long-term debt repayment	(85,733)	(2,733)
Use of financing proceeds	(182,904)	(4,320)
Contribution to (reduction of) working capital	36,316	(4,320)

During the year ended December 31, 2010, the Corporation issued the Series A Preferred Shares for aggregate gross proceeds of $85.0 million. For more information about this issuance, please refer to the "Preferred Shares" section of this MD&A. The Corporation also borrowed $134.2 million in 2010. These proceeds were used mainly to finance the ongoing construction and development of power generating projects (total of $39.5 million), to fund the hydrology reserve of the Ashlu Creek facility ($2.0 million) and to repay long-term debt ($85.7 million).

As part of the Combination, the Corporation refinanced the Fund's bank credit facility and facilities 1, 2 and 3, from which $119.8 million was drawn, and cancelled its revolving credit facility, from which $12.9 million was drawn by putting in place the Operating Credit Facility (commitment of $117.4 million) and the BDS Credit Facility (commitment of $52.6 million) for a total amount of $170.0 million. The Corporation used the $83.0 million in net cash acquired from the Pre-Combination Innergex to reduce its drawings.

During the year ended December 31, 2009, the purchase price for IHI Hydro Inc. was adjusted by $0.6 million. The Corporation also invested $2.2 million in property, plant and equipment and repaid $2.7 million in long-term debt.

FINANCIAL POSITION

Assets

As at December 31, 2010, the Corporation had $930.8 million in total assets ($508.1 million as at December 31, 2009). This increase results mainly from the Combination and to the ongoing capital expenditures related to the Development Projects. The following items were the most affected:

- property, plant and equipment increased from $334.2 million to $614.1 million; and
- intangible assets increased from $119.4 million to $186.5 million.

Working Capital

As at the end of year 2010, working capital was positive at $15.9 million with a working capital ratio of 1.31:1.00. As at the end of 2009, working capital was negative at $0.7 million with a working capital ratio of 0.97:1. The improvement in the working capital ratio over the last year stems mainly from an increase in cash and cash equivalents due to the issuance of the Series A Preferred Shares and Convertible Debentures and from an increase in accounts receivable. These items are partly offset by increases in accounts payable and accrued liabilities, in dividends payable to shareholders and in the current portion of the long-term debt resulting from the Combination.

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 Operating Credit Facility and its BDS Credit Facility. As at December 31, 2010, US$13.9 million and $27.4 million of these credit facilities had been drawn as cash advances and $20.8 million had been used for issuing letters of credit. The combined unused and available portion of the Operating Credit Facility and BDS Credit Facility was therefore $107.9 million as at that date.

Accounts receivable increased from $6.2 million as at December 31, 2009, to $16.0 million as at December 31, 2010, as a result of the Combination. They are comprised mainly of receivables from public utilities for the sale of electricity.

Accounts payable and accrued liabilities increased from $9.6 million as at December 31, 2009, to $23.0 million as at the end of 2010 due to the Combination. They are comprised mainly of trade payables related, among other things, to the Montagne-Sèche, Gros-Morne, Ashlu Creek and Kwoiek Creek projects.

Derivative financial instruments included in current liabilities increased from $5.4 million as at December 31, 2009, to $8.5 million as at December 31, 2010. This difference is due mainly to the Combination.

The current portion of long-term debt totalling $9.3 million relates to the L'Anse-à-Valleau, Hydro-Windsor, Glen Miller, Umbata Falls, Carleton, Ashlu Creek and Fitzsimmons Creek credit facilities.

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

Reserve Accounts

Reserve Accounts Breakdown	December 31, 2010	December 31, 2009
	$	$
Hydrology/wind power reserve	16,511	10,597
Major maintenance reserve	4,436	3,728
Levelization reserve	494	1,064
Total	21,441	15,389

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

1) The Hydrology/wind power reserve, which 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 conditions or 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, 2009, results mainly from the Combination and from the initial funding of the Ashlu Creek facility's hydrology reserve during the second quarter of 2010 ($2.0 million).

2) The Major maintenance reserve, which is established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity. The increase in this reserve since December 31, 2009, results mainly from the Combination and from the annual contributions paid by the Corporation.

3) The Levelization reserve, which was established to level the monetary contribution from the power plants in order to pay dividends.

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

Property, Plant and Equipment
Property, plant and equipment are comprised mainly of hydroelectric and wind farm projects that are either in operation or under construction. They are recorded at cost and depreciated using the straight-line method based on their estimated useful lives upon commissioning. The Corporation had $614.1 million in property, plant and equipment as at December 31, 2010, compared with $334.2 million as at December 31, 2009. This increase stems mainly from the Combination and from the construction of the Montagne-Sèche and Gros Morne wind farm projects.

Intangible Assets
Intangible assets consist of various PPAs, permits and licences. They also include the extended warranty for the BDS, AAV and CAR wind farm turbines. The Corporation reported $186.5 million in intangible assets as at December 31, 2010, an increase from the $119.4 million reported as at December 31, 2009; this increase results from the Combination. Intangible assets, excluding $3.6 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 that have a PPA as well as the costs 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, 2010, the Corporation had $9.7 million in project development costs (nil as at December 31, 2009). Prior to the Combination, the Fund had no development activities and so did not have any project development costs.

Goodwill
The Corporation had $7.9 million in goodwill as at December 31, 2010 ($8.3 million as at December 31, 2009). The decrease in the carrying amount comes from the recognition in year 2010 of a deferred tax asset related to a previous acquisition having resulted in a goodwill for the excess of the purchase price over the net assets acquired. The final evaluation of the purchase price allocation of the Pre-Combination Innergex determined that no amount had to be allocated to goodwill.

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

Long-Term Debt

As at December 31, 2010, long-term debt was $358.7 million ($224.6 million as at December 31, 2009). The increase in long-term debt results mainly from the Combination, the construction of the Montagne-Sèche and Gros-Morne wind farms and the payment of holdbacks for the Ashlu Creek project.

Long-Term Debt	December 31, 2010	December 31, 2009
	$	$
Operating Credit Facility (i)		
LIBOR advances, US$13,900 renewable until March 2013	13,825	-
BDS Credit Facility (ii)		
Bankers' acceptances renewable until March 2013	27,400	-
Facility 1		
Prime-rate advances renewable until May 2013	-	93
Bankers' acceptances renewable until May 2013	-	51,200
LIBOR advances, US$5,000 renewable until May 2013	-	5,255
Facility 2		
LIBOR advances, US$8,873 renewable until May 2013	-	9,325
Facility 3		
Bankers' acceptances renewable until May 2013	-	52,600
Term loans		
Glen Miller, floating-rate term loan maturing in 2013 (iii)	14,500	-
CAR, floating-rate term loan maturing in 2013 (iv)	49,083	-
Umbata Falls, floating-rate term loan maturing in 2014 (v)	24,348	-
Fitzsimmons Creek, floating-rate construction loan (vi)	22,551	-
Hydro-Windsor, fixed rate term loan maturing in 2016 (vii)	5,841	6,590
Rutherford Creek, fixed rate term loan maturing in 2024 (viii)	50,000	50,000
Ashlu Creek, floating-rate term loan maturing in 2025 (ix)	104,406	-
AAV, floating-rate term loan maturing in 2026 (x)	47,891	50,067
Kwoiek Creek, fixed rate subordinated term loan (xi)	150	-
Deferred financing costs	(1,305)	(569)
	358,690	224,561
Current portion of long-term debt	(9,259)	(2,758)
	349,431	221,803

Concurrently with the Combination, the bank credit facility and facilities 1, 2 and 3 were repaid, cancelled and replaced with the Operating Credit Facility and the BDS Credit Facility. Both facilities mature in March 2013. Financing costs of $1.6 million were incurred, charged against long-term debt and amortized using the effective interest rate method over the expected term of the related debts.

On September 30, 2010, the Corporation amended the BDS Credit Facility, thereby converting this $52.6 million credit facility from a term loan into a revolving credit facility.

The Corporation had the following long-term debts outstanding as at December 31, 2010:

i) a $117.4 million revolving credit 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 2013 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 consolidated senior debt to adjusted EBITDA. As at December 31, 2010, $13.8 million was due under this facility and an amount of $20.8 million was used for the issuance of letters of credit; thus the unused and available portion of the Operating Credit Facility totalled $82.7 million. As at December 31, 2010, the all-in interest rate was 3.04% on $13.8 million of LIBOR advances;

ii) a $52.6 million revolving credit facility guaranteed by the Corporation's 38% interest in the Baie-des-Sables wind farm and a security interest granted by Innergex. The facility will mature in 2013 and is not amortized. Advances are made in the form of BA, prime-rate advances, U.S. base-rate advances or LIBOR advances. In all cases, interest is calculated at the prevailing benchmark rate plus an additional margin based on Innergex's ratio of consolidated senior debt to adjusted EBITDA. As at December 31, 2010, $27.4 million was due under this facility; thus the unused and available portion of the BDS Credit Facility totalled $25.2 million. As at December 31, 2010, the all-in interest rate was 6.92% after accounting for the interest rate swap;

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, 2010, the all-in interest rate was 5.68% after accounting for the interest rate swaps;

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, 2010, the all-in interest rate was 4.82% after accounting for the interest rate swap;

v) as part of the Combination, the Corporation assumed a $24.8 million non-recourse term loan (corresponding to the Corporation's 49% ownership interest in this facility) maturing in 2014. It is secured by the Umbata Falls hydroelectric 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, 2010, the all-in interest rate was 5.31% 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. The loan is secured by the Fitzsimmons Creek hydroelectric facility and matures five years after conversion of the construction loan into a term loan. The loan's monthly principal payments will begin upon conversion and be based on a 30-year amortization period. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2010, the all-in interest rate was 7.84% after accounting for the interest rate swaps;

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. The loan 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 and bears interest at an effective fixed interest rate of 8.25%;

viii) 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 loan 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%;

ix) 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. It 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, 2010, the all-in interest rate was 6.23% after accounting for the interest rate swaps;

x) as part of the acquisition of a 38% interest in the AAV 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, 2010, the all-in interest rate was 5.93% after accounting for the interest rate swap;

xi) 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 up to an amount of $20.0 million and its partner up to an amount of $3.0 million. The loan bears interests at a rate of 20% during the development phase and 14% during the construction and operating phases. The Corporation's subordinated non-recourse term loan made to KCRLP, which is eliminated in the financial statement consolidation process, amounted to $10.1 million as at December 31, 2010.

If they are not met, certain financial and non-financial covenants included in the credit agreements 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 2010 fiscal year, the Corporation and its subsidiaries have met all the financial and non-financial conditions related to their credit agreements 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. The net proceeds were used mainly to pay down long-term debt under the Operating Credit Facility. They were also used to pay for the settlement of the Ashlu Creek bond forwards. As at December 31, 2010, the debt portion of the Convertible Debentures stood at $79.3 million and the equity portion at $1.8 million (both nil as at December 31, 2009).

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 in whole or in part from time to time. Such redemption would be done at a redemption price equal to the principal amount thereof plus accrued and unpaid interest, provided that the volume weighted average trading price of the common shares on the TSX for the 20 consecutive trading days ending five trading days preceding the date on which notice of redemption is given is not less than 125% of the Conversion Price. On or after April 30, 2015, and prior to April 30, 2017, the Convertible Debentures may be redeemed in whole or in part at the option of the Corporation at a price equal to their principal amount plus accrued and unpaid interest. Subject to required regulatory approval, 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.

Preferred Shares
On September 14, 2010, the Corporation issued a total of 3,400,000 Series A Preferred Shares at $25 per share for aggregate gross proceeds of $85.0 million. 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 cumulative floating rate non-voting preferred shares, Series B (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 Bill 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 will not be redeemable by the Corporation prior to January 15, 2016.

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

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

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. Since these Derivatives are entered into with major financial institutions rated A or better by S&P, the Corporation considers the risk of illiquidity to be low.

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.

Taken together, the swap contracts shown in the following table allow the Corporation to eliminate the risk of interest rate increases on a total of $411.9 million in actual and planned long-term debt. This figure combined with the $60.0 million in existing fixed-rate debts and the $80.5 million in Convertible Debentures means that all of the Corporation's actual debt and part of its planned indebtedness are protected from interest rates increases.

Swap Contract Notional Amounts	Early termination option	December 31, 2010	December 31, 2009
		$	$
Interest rate swaps, rates ranging from 3.96% to 4.09%, expiring in June 2015	None	15,000	15,000
Interest rate swap, 4.27%, expiring in November 2016	None	3,000	3,000
Interest rate swap, 4.41%, expiring in June 2018	March 2013	30,000	30,000
Interest rate swap, 4.27%, expiring in June 2018	March 2013	52,600	52,600
Interest rate swap, 4.93%, amortized until March 2026	None	47,890	50,067
Interest rate swap, 3.45%, amortized until March 2027	December 2013	48,315	-
Forward interest rate swaps, 4.31%, amortized until June 2030	March 2011	31,690	-
Forward interest rate swaps, 4.33%, amortized until June 2031	June 2014	49,940	-
Interest rate swap, 4.11%, amortized until June 2034	None	24,348	-
Interest rate swaps, 4.70%, amortized until June 2035	June 2025	109,067	-
		411,850	150,667

Derivatives had a net negative value of $30.8 million at the end year 2010 (negative $10.2 million at the end of 2009). This difference is due to:

- a decrease in benchmark interest rates for long-term maturities since the end of 2009;
- two new interest rate swaps related to the Ashlu Creek facility that were entered into during the second quarter of 2010; and
- forward interest rate swaps related to the Montagne-Sèche and Gros-Morne wind farms that were progressively put in place starting from the second quarter of 2010 until the end of the fourth quarter of 2010.

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. The Corporation does not use hedge accounting for its Derivatives.

As at December 31, 2010, the fair market value of the derivative financial instruments related to some PPAs with Hydro-Québec was positive at $10.9 million ($10.1 million as at December 31, 2009). These instruments represent the value attributed to minimum inflation clauses of 3% per year included in these PPA contracts.

Future Income Taxes

The tax impact of temporary differences may result in future tax assets or liabilities. As at December 31, 2010, the Corporation's net future income tax liability was $63.1 million, compared with a net future income tax liability of $68.3 million as at December 31, 2009. This difference resulted mainly from the Combination and the net loss incurred during 2010.

Off-Balance-Sheet Arrangements

As at December 31, 2010, the Corporation had issued letters of credit totalling $24.4 million to meet its obligations under its various PPAs and other agreements. Of this amount, $20.8 million was issued under its Operating Credit Facility and the remainder under the projects' non-recourse credit facilities. As at that date, Innergex had also issued corporate guarantees to support the construction of the Montagne-Sèche and Gros-Morne wind farms for a total of $21.1 million.

Shareholders' Equity

As at December 31, 2010, the shareholders' equity of the Corporation totalled $347.3 million, compared with $189.5 million as at December 31, 2009. The difference is attributable mainly to the Combination and to the Series A Preferred Shares issuance.

On August 29, 2010, the 200,000 warrants then outstanding expired. They were exercisable at a strike price of $12.50 per warrant. Earlier in 2010, in connection with the Combination, their book value was adjusted to their fair value, which was estimated to be nil.

As at March 23, 2011, the Corporation has a total of 59,532,606 common shares, 80,500 Convertible Debentures, 3,400,000 Series A Preferred Shares, 17,750,000 subscription receipts and 1,842,024 stock options outstanding. As at December 31, 2009, it had 42,930,243 common shares outstanding.

Contractual Obligations

Expected Contractual Obligations as at December 31, 2010

Contractual obligations	Total	Under 1 year	1 to 3 years	4 to 5 years	Over 5 years
	$	$	$	$	$
Long-term debt including convertible debentures	441,426	9,175	116,550	41,841	273,860
Interest on long-term debt and convertible debentures	206,914	27,046	54,991	38,940	85,937
Operating leases	8,892	386	793	823	6,890
Purchase (Contractual) obligations[1]	136,146	76,472	30,001	3,281	26,392
Other[2]	3,523	578	951	870	1,124
Total contractual obligations	796,901	113,657	203,286	85,755	394,203

1. Purchase obligations are mainly derived from turbine supply agreements and engineering, procurement and construction contracts.
2. Other long-term obligations are mainly comprised of office leases.

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

ADJUSTED CASH FLOWS FROM OPERATING ACTIVITIES AND DIVIDENDS

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 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:

Adjusted Cash Flows from Operating Activities	For the year ended December 31, 2010	For the year ended December 31, 2009
	$	$
Cash flow from operating activities	23,356	34,946
Change in non-cash working capital items	25,712	(1,542)
Net withdrawals from (investments in) the reserve accounts (not funded from long-term debt)	42	(515)
Adjusted cash flows from operating activities	49,110	32,889
Dividends declared on Series A Preferred Shares	1,520	-
Dividends declared on common shares	33,323	29,404
Weighted average number of common shares outstanding – basic	55,530	42,930
Dividends declared on common shares ($ per share)	0.607	0.685

For the year ended December 31, 2010, Innergex generated $49.1 million in adjusted cash flows from operating activities ($32.9 million in 2009). This improvement is due mainly to a $21.3 million increase in EBITDA combined with a $2.6 million positive variation in current income taxes, partially offset by a $10.0 million increase in interests. During 2010, the Corporation also declared dividends of $1.5 million on Series A Preferred Shares (nil in 2009) and $33.3 million on common shares or $0.607 per common share ($29.4 million or $0.685 per common share in 2009).

SEGMENT INFORMATION

Geographic Segments

The Corporation has 13 hydroelectric facilities and three wind farms in Canada and one hydroelectric facility in the United States. For the year ended December 31, 2010, operating revenues generated by the Horseshoe Bend hydroelectric facility located in the United States totalled $2.7 million ($3.4 million in 2009), representing contributions of 3.0% (5.7% in 2009) to the Corporation's consolidated operating revenues for these periods.

Reportable Segments

The Corporation has three reportable segments: (a) hydroelectric generation; (b) wind power generation; and (c) 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 2010 audited consolidated financial statements. 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.

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.

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

Reportable Segments	Hydroelectric Generation	Wind Power Generation	Site Development	Total
	$	$	$	$
Year ended December 31, 2010				
Power generated (MW-hr)	922,167	305,268	-	1,227,435
Gross operating revenues from external clients	64,870	24,230	-	89,100
Expenses:				
Operating expenses	9,430	2,927	-	12,357
Stock-based compensation	127	76	128	331
General and administrative expenses	2,751	1,447	1,745	5,943
Prospective projects expenses	-	-	2,371	2,371
Earnings before interest, income taxes, depreciation and amortization and other items	52,562	19,780	(4,244)	68,098
As at December 31, 2010				
Goodwill	7,901	-	-	7,901
Total assets	599,996	254,947	75,887	930,830
Acquisition of property, plant and equipment during the year	1,304	318	37,224	38,846
Year ended December 31, 2009				
Power generated (MW-hr)	610,235	213,754	-	823,989
Gross operating revenues from external clients	41,833	16,792	-	58,625
Expenses:				
Operating expenses	6,177	2,064	-	8,241
General and administrative expenses	2,624	982	-	3,606
Earnings before interest, income taxes, depreciation and amortization and other items	33,032	13,746	-	46,778
As at December 31, 2009				
Goodwill	8,269	-	-	8,269
Total assets	330,157	177,984	-	508,141
Acquisition of property, plant and equipment during the year	938	360	-	1,298

Hydroelectric Generation Segment

For the year ended December 31, 2010, the hydroelectric generation segment produced 3% less power than the long-term average due to lower-than-anticipated hydrologic conditions at some of the segment's facilities, resulting in gross operating revenues of $64.9 million. In 2009, production was similar to the long-term average resulting in gross operating revenues of $41.8 million. As a result of the Combination, the contribution of the Glen Miller, Umbata Falls, Ashlu Creek and Fitzsimmons Creek facilities has been included in the results since March 30, 2010. Consequently, gross operating revenues and EBITDA increased $23.0 million and $19.5 million respectively compared with 2009.

The increase in total assets since December 31, 2009, is attributable to the Combination, partially offset by depreciation and amortization of property, plant and equipment as well as intangible assets.

Wind Power Generation Segment
The wind power generation segment produced 4% less power than expected in 2010, resulting in gross operating revenues of $24.2 million. This performance is due mainly to lower-than-anticipated wind conditions at the BDS wind farm and to a five-day shutdown of the AAV wind farm in January 2010, which was caused by transmission line work carried out by Hydro-Québec. In 2009, production was 6% below expectations. This was the result of weather conditions below long-term averages and to a seven-day shutdown of the AAV wind farm in December 2009, which was caused by transmission line work carried out by Hydro-Québec.

As a result of the Combination, the contribution of the Carleton wind farm has been included in the results since March 30, 2010. Consequently, gross operating revenues and EBITDA increased $7.4 million and $6.0 million respectively compared with 2009.

Total assets have increased since December 31, 2009, as a result of the Combination, partially offset by depreciation and amortization of property, plant and equipment as well as intangible assets.

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, 2009, results from the Combination.

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 upon the closing of the Combination. As a result, amounts were only paid during the first quarter of 2010. During this quarter, the Fund paid $0.6 million for services provided under these three agreements. For the 12-month period ended December 31, 2009, the Fund paid $2.0 million 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 amounts to $174.9 million and was accounted for under Section 1581 of the Canadian Institute of Chartered Accountants ("CICA") Handbook. 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 4a) to the Corporation's 2010 audited consolidated financial statements.

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 generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from those 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, future income taxes, as well as the fair value of financial assets and liabilities including derivatives. These estimates and assumptions are based on current 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 income in the period in which they are made. Other significant accounting policies are listed in Note 2 to the Corporation's 2010 audited consolidated financial statements.

ACCOUNTING CHANGES

Changes made in 2010:
No changes to accounting policies were made in 2010.

International Financial Reporting Standards
The Canadian Accounting Standards Board has announced the adoption of International Financial Reporting Standards ("IFRS") for publicly accountable enterprises in Canada. Effective January 1, 2011, companies must convert from Canadian GAAP to IFRS. Accordingly, the Corporation will adopt IFRS effective in the quarter ending March 31, 2011.

The Corporation has begun assessing major items requiring adjustments in connection with the adoption of IFRS. A schedule has been prepared of the steps to be followed by the Corporation in order to meet the changeover date. At this time, the impact on the Corporation's future financial position and results of operations is not fully determined or estimated.

Accounting policies
The Corporation has started its detailed assessment and evaluation of the impact the IFRS will have on accounting and financial presentation as well as the various accounting policies that the Corporation could adopt. To this end, the Corporation has been assessing the various choices provided in IFRS 1, "First-time Adoption of International Financial Reporting Standards," to prepare the opening balance sheet as at January 1, 2010, and has been discussing with its auditors for that purpose. The Corporation will not elect to revaluate its property, plant and equipment at their fair market value.

An analysis of the impact on the financial statements' items has been almost completed. The items identified as having a potentially significant impact on the opening balance sheet or on the statements of earnings are property, plant and equipment, investments in associates and joint ventures, classification of unitholders' equity, business combination and deferred tax.

The potential impact from property, plant and equipment comes from its disclosure in its various components, and their various useful lives. The property, plant and equipment and their useful lives components have been determined by management and will range from 15 to 75 years for hydroelectric facilities and from 15 to 25 years for wind farm facilities. The detailed computation of the adjustments required to depreciation is almost completed. The expected effect is an increase of depreciation of approximately $0.6 million per year when considering assets acquired through the Combination. Under IFRS, the opening balance sheet as of January 1, 2010, will see a decrease of approximately $2.0 million in the net book value of the property, plant and equipment.

IAS 31 – *Investments in Joint* Ventures is currently under revision by the IASB and the new standard is not yet finalized. The effective date for the application of the revised standard is yet to be determined. It is expected that IAS 31 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 statement of financial position and the statement of operations. 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 statement of financial position and the statement of operations are expected to change significantly.

Several investments in associates and joint ventures are consolidated in Innergex under Canadian GAAP. These investments are either, fully consolidated, proportionally consolidated or consolidated as variable interest entities. Under the IAS 31 revised standard, some of these investments might have to be accounted for as investments on the balance sheet with their results recognized as share of net earnings of an entity subject to significant influence. The analysis of these differences is underway to identify which entities might be affected. As of today, the main difference identified by the Corporation is that the accounting of the Umbata Falls facility could be modified. Under Canadian GAAP, Umbata Falls L.P. is the sole proportionally consolidated entity and is done so according to the Corporation's 49% interest in the Umbata Falls facility. Under the revised standard, Umbata Falls L.P. should be accounted for as an investment on the balance sheet with 49% of its net results recognized as share of net earnings of an entity subject to significant influence. This will decrease both total assets and liabilities on the balance sheet. Accounting for other joint ventures should remain similar to Canadian GAAP.

Prior to the Combination, the Fund's equity was comprised of trust units issued to unitholders. The Fund was contractually required to make distributions to its unitholders for an amount at least equivalent to its taxable income. Under IFRS, the trust units will be considered as financial instruments and reclassified as liabilities with variation in fair value and distributions recognized in the Consolidated statements of Earnings.

For former business Combinations, no significant immediate impact on the financial statements is anticipated on adoption of IFRS as the Corporation expects to take advantage of the IFRS 1 exemption, which avoids the requirement to retrospectively restate all business combinations prior to the date of transition to IFRS. However, a number of differences between IFRS and Canadian GAAP will affect the business acquisition realized with the Combination. Under IFRS, all assets and liabilities of an acquired business are recorded at fair value. Estimated obligations for contingent considerations and contingencies are also recorded at fair value at the acquisition date. In addition, acquisition-related costs are expensed as incurred. Under Canadian GAAP, acquisition-related costs form part of the consideration paid for the acquisition and contingent considerations are recorded as part of the cost of the acquisition when the contingency is resolved and the consideration is issued or becomes issuable.

In transitioning to IFRS, the Corporation deferred tax will be impacted by the tax effects resulting from the IFRS changes discussed above.

An internal draft of the 2011 first quarter financial statements has been prepared, including all related notes needed to be disclosed as per IFRS.

Information Technology
The Corporation is reviewing the needs for systems upgrades and modifications. However, the IFRS conversion will not result in major system conversion.

Internal control
The process for establishing and maintaining internal controls over financial reporting will be adjusted to reflect the changes in accounting procedures.

Disclosure controls and procedures
A monitoring system of the adjustments has been established during 2010 in order to restate financial statements and ensure their compliance with the IFRS. In the first quarter of 2011, Innergex prepared an internal draft IFRS financial statements for the year 2010.

Financial reporting expertise
During 2009 and 2010, the Corporation's accounting staff has taken intensive IFRS training. The Corporation is also working closely with its auditor to identify any adjustment required for the transition to IFRS' compliant financial statements.

Discussions and presentations to the members of the Audit Committee are also being made in order to prepare them with the new information and modification that will be made to the financial statements.

Business issues
The Corporation has begun discussions with its lending financial institutions to ensure that adjustments related to IFRS will not have an impact on the methods of calculating financial ratios. Based on the expected changes identified at this time, there are no foreseen issues with the existing wording of debt covenants and related agreements as a result of the conversion to IFRS.

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, 2010.

Execution of Strategy

The Corporation's strategy for building shareholder value 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. 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 issuance of additional equity or quasi-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 will be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund future development or expansion. There is 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 of additional common shares, or debt securities convertible into 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.

Operations

The major operations risks are hydroelectric facility or wind farm performance and equipment failure risk. The revenues generated by the Corporation's hydroelectric facilities and wind farms are largely dependent on the amount of electrical energy generated by these hydroelectric facilities and wind farms. Such risks are minimized by the high quality of the hydroelectric facilities and wind farms, by well-designed maintenance programs that ensure that the facilities and wind farms operate at peak efficiency, and by insurance covering equipment failure and loss of revenue, among other factors. The Corporation also makes annual deposits in Major maintenance reserve accounts, to be used to fund major repairs when needed, in order to maintain the generating capacity of its hydroelectric facilities and wind farms.

Hydrology and Wind 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.

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.

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.

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 developing 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 that unforeseen costs or taxes are incurred, the Corporation could be adversely affected.

Project Performance
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, 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 defects 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 flow from operations may be dedicated to the payment of the principal and of interest on their indebtedness, thereby reducing funds available for future operations; (iii) certain of the Corporation's and its subsidiaries' borrowings may 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 ability of the Corporation and its subsidiaries to obtain additional financing, to withstand downturns in business and to 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 ability of the Corporation and its subsidiaries to grow the business, acquire needed assets and take other actions that the Corporation or its subsidiaries might otherwise consider appropriate or desirable.

Declaration of dividends on common and preferred shares is at the discretion of the Board of Directors
Holders of common 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.

Holders of Series A Preferred Shares have a right to dividends on such shares since such dividends are cumulative but they need to be declared by the Board of Directors to be paid. 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

For the three-month periods ended (unaudited):

Quarterly Financial Information (unaudited) for the Three-Month Periods Ended:				
(in millions of dollars, unless otherwise stated)	Dec 31, 2010	Sept. 30, 2010	June 30, 2010	Mar. 31, 2010
Power generated (MW-hr)	343,754	356,262	369,753	157,666
Gross operating revenues	26.0	24.7	24.8	13.6
EBITDA	18.9	19.8	18.8	10.7
Net earnings (loss)	14.3[a]	(10.9)[b]	(6.5)[c]	(0.5)
Net earnings (loss) ($ per share – basic and diluted)	0.21[a]	(0.19)[b]	(0.11)[c]	(0.01)
Cash flows from operating activities	10.9	15.4	(5.7)	2.8
Change in non-cash working capital items	2.4	(1.5)	19.9	4.9
Net (investments in) withdrawals from the reserve accounts (not funded from long-term debt)	(0.1)	(0.3)	(0.5)	0.9
Adjusted cash flows from operating activities	13.2	13.6	13.8	8.6
Dividends declared on Series A Preferred Shares	1.5	-	-	-
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

[a] Excluding the unrealized gain on derivative financial instruments of $15.5 million and the related future income tax provision of $4.1 million, the net earnings for Q4-2010 would have been $2.9 million ($0.05 per basic and diluted common share).

[b] Excluding the unrealized loss on derivative financial instruments of $20.1 million and the related future income tax recovery of $5.4 million, the net earnings for Q3-2010 would have been $3.8 million ($0.06 per basic and diluted common share).

[c] Excluding the unrealized loss on derivative financial instruments of $14.1 million and the related future income tax recovery of $3.8 million, the net earnings for Q2-2010 would have been $3.8 million ($0.06 per basic and diluted common share).

Quarterly Financial Information (unaudited) for the Three-Month Periods Ended:				
(in millions of dollars, unless otherwise stated)	Dec 31, 2009	Sept. 30, 2009	June 30, 2009	Mar. 31, 2009
Power generated (MW-hr)	189,011	223,302	247,764	163,912
Gross operating revenue	13.2	15.0	16.5	13.9
EBITDA	10.2	11.9	13.6	11.1
Net earnings (loss)	7.0	2.8	13.4[d]	3.0
Net earnings (loss) ($ per share – basic and diluted)	0.16	0.07	0.31[d]	0.07
Cash flows from operating activities	4.8	10.3	11.4	8.4
Change in non-cash working capital items	2.4	(2.1)	(1.4)	(0.4)
Net withdrawals from (investments in) the reserve accounts (not funded from long-term debt)	-	0.2	(0.8)	0.2
Adjusted cash flows from operating activities	7.2	8.4	9.2	8.1
Dividends declared on common shares	7.4	7.4	7.4	7.3
Dividends declared on common shares ($ per share)	0.171	0.171	0.171	0.171

[d] Excluding the unrealized foreign exchange gain of $0.2 million, the unrealized gain on derivative financial instruments of $11.2 million and the related future income tax provision of $2.8 million, the net earnings for Q2-2009 would have been $4.7 million ($0.11 per basic and diluted common share).

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, gross operating revenue, EBITDA and adjusted cash flows from operating activities vary from one quarter to another. As the Corporation's total average long-term production is 74% hydroelectric, this seasonality can be explained by hydrologic conditions 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 attenuates this seasonality. The production of the wind farms also partially compensates for this seasonality experienced by hydroelectric facilities, as wind conditions are generally best in the first quarter of a typical year.

By excluding non-recurring items, readers would expect that the net earnings and net earnings per share reflect this seasonality characteristic of run-of-river hydroelectric plants and wind farms. However, other factors also influence net earnings and net earnings 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 and net earnings per share is change in the market value of derivative financial instruments. Historical analysis of net earnings and net earnings per share should therefore take this factor 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 adjusted cash flows from operating activities.

FOURTH-QUARTER RESULTS

Operating Facilities

During the fourth quarter of 2010, the Corporation's Operating Facilities produced 343,754 MW-hr (189,011 MW-hr in 2009). This increase is essentially due to the Combination.

Compared with the estimated long-term average, the Corporation produced 6% more energy than expected despite the 14-day shutdown of the three Portneuf facilities in November and December 2010 due to transmission line work carried out by Hydro-Québec. More specifically, the St-Paulin and Chaudière facilities respectively generated 67% and 45% more electricity than anticipated due to better-than-expected hydrology conditions.

Revenues

Revenues from operating activities totalled $26.0 million in the fourth quarter of 2010 ($13.2 million in 2009). This performance is due to additional revenues resulting from the Combination ($9.6 million) and higher revenues from the pre-combination assets of the Fund (positive impact of $3.2 million).

Expenses

In the fourth quarter of 2010, the Corporation recorded $3.9 million in operating expenses ($2.1 million in 2009) related to the operation of the power producing facilities. This increase was expected and is the result of the Combination which means that the Corporation operated a greater number of facilities in 2010 than in 2009.

Non-cash stock-based compensation of $0.1 million was recorded in the fourth quarter of 2010 (nil in 2009). Stock-based compensation relates to the amortization of the fair value of stock options granted concurrently with the Initial Public Offering of the Pre-Combination Innergex in December 2007 and stock options also granted in June 2010.

The Corporation also recorded general and administrative expenses of $1.9 million during the period ($0.9 million in 2009). This increase is due to the larger scale of the Corporation resulting from the Combination.

Prospective projects expenses totalled $1.2 million during the fourth quarter of 2010 (nil in 2009). Prior to the Combination, such expenses were not incurred by the Fund.

The Corporation incurred $6.9 million in interests during the most recent quarter of 2010 ($3.2 million in 2009). This increase is due to the issuance of Convertible Debentures and to the increase in long-term debt resulting from the Combination.

During the fourth quarter of 2010, the Corporation recorded an unrealized net gain on derivative financial instruments of $15.5 million (unrealized net gain of $4.8 million in 2009). This unrealized net gain is due mainly to the increase in benchmark interest rates since the end of the third quarter of 2010. This gain had no cash impact on the Corporation's results.

For the quarter ended December 31, 2010, other revenues were $0.1 million (not material in 2009). This increase is due to a higher average cash balance in 2010 than in 2009 which generated interest income.

The depreciation and amortization expense totalled $8.7 million in the fourth quarter of 2010 ($5.4 million in 2009). The difference is attributable mostly to the greater asset base resulting from the Combination.

For the quarter ended in December 31, 2010, recovery of current income taxes totalled $1.0 million (recovery of $0.2 million in 2009). 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 provision of $5.4 million in the fourth quarter of 2010 stemming primarily from an unrealized gain on derivative financial instruments. For the corresponding period in 2009, the Corporation recorded a future income tax recovery of $0.4 million.

Net Earnings

The Corporation posted net earnings of $14.3 million (basic and diluted net earnings of $0.21 per share) for the fourth quarter of 2010. For the corresponding period in 2009, net earnings totalled $7.0 million (basic and diluted net earnings of $0.16 per share). This $7.3 million variation is attributable mainly to an $8.7 million increase in EBITDA and to a $10.7 million positive variation in the fair market value of derivative financial instruments. These positive elements were offset by a $3.7 million increase in interests, a $3.2 million increase in depreciation and amortization and a $5.1 million variation in income tax provisions.

The basic and diluted per-share figures for the three-month period ended December 31, 2010, are based on a weighted average number of 59,532,606 and 59,608,667 common shares outstanding respectively. As per Canadian GAAP, 1,034,000 stock options were non-dilutive during the period concerned since 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. Convertible Debentures were also non-dilutive. For the corresponding period ended December 31, 2009, per-share figures were based on a weighted average number of 42,930,243 common shares outstanding. No Convertible Debentures or options were outstanding during this period of 2009.

As at March 23, 2011, and December 31, 2010, the Corporation had a total of 59,532,606 common shares, 80,500 Convertible Debentures, 3,400,000 Series A Preferred Shares, 17,750,000 subscription receipts and 1,842,024 stock options outstanding. As at December 31, 2009, it had 42,930,243 common shares outstanding.

SUBSEQUENT EVENTS

BC Hydro SOP

On January 25, 2011, BC Hydro released its revised SOP. Among other things, BC Hydro has raised the upper limit on project size (from 9.9 MW to 15.0 MW) and the electricity rates applicable to each region. Innergex is currently evaluating the impact of this announcement, as some of its Prospective Projects could be eligible under the program.

Acquisition of Cloudworks Energy Inc. and $166 Million Equity Offering

On February 14, 2011, Innergex announced that it had entered into a definitive agreement (the "Agreement") with the shareholders of Cloudworks Energy Inc. ("Cloudworks") to acquire all of the issued and outstanding shares of Cloudworks (the "Acquisition"). Cloudworks will be acquired for an aggregate consideration, subject to certain adjustments, of $185 million (the "Purchase Price"), approximately $145.7 million of which will be payable in cash (the "Cash Consideration") and approximately $39.3 million of which will be payable by the issuance, by way of private placement, of common shares of the Corporation at a price of $9.75 per common share.

Cloudworks' portfolio of assets consists of a 50.01% interest in six run-of-river hydroelectric facilities with a combined gross installed capacity of 150 MW (the "Harrison Operating Facilities"); full ownership of 76 MW of run-of-river hydroelectric projects under development with 40-year 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. Cloudworks' assets will increase the Corporation's installed capacity by 23% (from 325.5 MW to 400.5 MW). The Acquisition will increase Innergex's weighted average remaining PPA term from approximately 21 to 25 years, when including Development Projects.

The Acquisition enterprise value of Cloudworks is approximately $415 million. In addition to the $185 million Purchase Price, Innergex's share of the Harrison Operating Facilities' non-recourse long-term debt will be approximately $265 million (based on a 50.01% ownership). However Innergex will benefit from its share of cash on hand and funded reserve accounts, which are subject to certain restrictions, for an aggregate total of approximately $35 million.

To finance the Cash Consideration, Innergex has sold subscription receipts of Innergex through a syndicate of underwriters on a bought-deal basis. The agreement with the syndicate includes the issuance of 17,750,000 subscription receipts at a price of $9.35 per subscription receipt to raise gross proceeds of approximately $165,962,500. The proceeds of the subscription receipt financing will be held in escrow pending the completion of the Acquisition. The subscription receipts are exchangeable on a one-for-one basis for common shares of Innergex upon the closing of the Acquisition for no additional consideration or further action.

Viger-Denonville Community Wind Project

On March 17, 2011, Hydro-Québec, the Rivière-du-Loup RCM and Innergex executed the PPA that was previously awarded on December 20, 2010, by Hydro-Québec. The PPA will now be submitted to the Régie de l'énergie for approval. The Corporation expects the 24.6 MW wind farm to start commercial operation on December 1, 2013. The Corporation owns 50% of the project with the Rivière-du-Loup RCM owning the other 50%.

Solar Applications under the FIT Program in Ontario

Since the beginning of 2011, Innergex has submitted two applications under the FIT Program for solar photovoltaic projects in Ontario for a total of 20.0 MW. These two latest applications bring Innergex's total number of applications under the FIT Program for solar photovoltaic projects to four, for a total capacity of 39.0 MW when combined with the two applications submitted in the fourth quarter of 2010.

Information for Investors

Stock Exchange Listing

Common Shares of Innergex Renewable Energy Inc. are listed on the TSX under the symbol INE.
Series A Preferred Shares of Innergex Renewable Energy Inc. are listed on the TSX under the symbol INE.PR.A.
Convertible Debentures of Innergex Renewable Energy Inc. are listed on the TSX under the symbol INE.DB.
Subscription receipts of Innergex Renewable Energy Inc. are listed on the TSX under the symbol INE.R.

Rating Agencies

Innergex Renewable Energy Inc. is rated BBB- by S&P and BBB (low) by DBRS.
Series A Preferred Shares of Innergex Renewable Energy Inc. are rated P-3 by S&P and Pfd-3 (low) by DBRS.

Transfer Agent and Registrar

Computershare Trust Company of Canada
1500 University Street, Suite 700, Montreal, Quebec, H3A 3S8
Telephone: 1 800 564-6253 or 514 982-7555
Email: service@computershare.com

Auditors

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

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.

Investor Relations

If you have inquiries, please visit our website at www.innergex.com or contact:

Jean Trudel
Vice President – Finance and Investor Relations

Édith Ducharme
Director – Financial Communications and Investor Relations

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Sustainable Development.

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CORPORATE INFORMATION

BOARD OF DIRECTORS

Pierre Brodeur [1, 4, 7]
John A. Hanna [1, 3]
Lise Lachapelle [1, 5]
Jean La Couture [1, 2, 8, 9]
Richard Laflamme [1, 6, 8, 10]
Daniel L. Lafrance [1, 4]
William A. Lambert [1, 6, 10]
Michel Letellier [11]
Susan M. Smith [1, 6, 10]

1. "Independent" within the meaning of National Instrument 52-110 of the Canadian Securities Administrators
2. Chairman of the Board and ad hoc member of all committees
3. Chair of the Audit Committee
4. Member of the Audit Committee
5. Chair of the Corporate Governance Committee
6. Member of the Corporate Governance Committee
7. Chair of the Human Resources Committee
8. Member of the Human Resources Committee
9. Chair of the Nominating Committee
10. Member of the Nominating Committee
11. President and Chief Executive Officer

MANAGEMENT

Richard Blanchet, P.Eng., M.Sc.
Vice President Western Region
– Hydroelectric Energy

Normand Bouchard, Eng.
Vice President – Wind Energy

Renaud de Batz, Geologist, M.Sc., MBA
Vice President Eastern Region
– Hydroelectric Energy

Guy Dufort
Vice President – Public Affairs

Peter Grover, Eng.
Vice President – Project Management

François Hébert
Vice President – Operation
and Maintenance

Michel Letellier, MBA
President and Chief Executive Officer
and Director

Jean Perron, CA, CMA
Vice President and Chief Financial Officer

Jean Trudel, MBA
Vice President – Finance
and Investor Relations

Une version française du présent rapport annuel est disponible sur demande.


INNERGEX