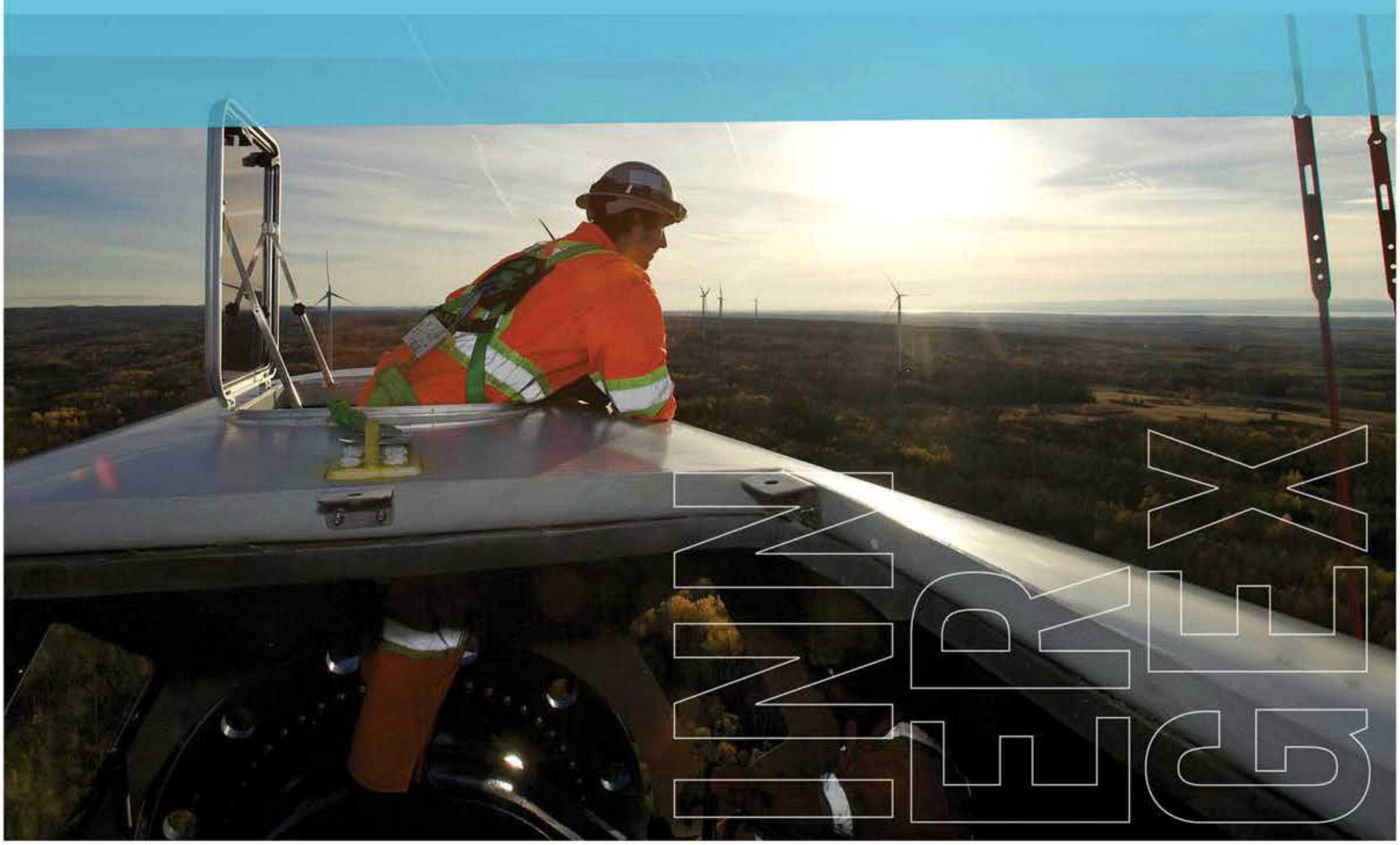
INNERGEX

Renewable Energy.
Sustainable Development.

QUARTERLY REPORT 2014

FOR THE PERIOD ENDED MARCH 31, 2014

These condensed consolidated financial statements have been neither audited nor reviewed by the Corporation's independent auditors.



MANAGEMENT'S DISCUSSION AND ANALYSIS

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

Innergex Renewable Energy Inc. is a leading Canadian independent renewable power producer. Active since 1990, the Corporation develops, owns and operates run-of-river hydroelectric facilities, wind farms and solar photovoltaic farms and carries out its operations in Quebec, Ontario and British Columbia and in Idaho, USA. The Corporation's shares are listed on the Toronto Stock Exchange under the symbols INE, INE.PR.A and INE.PR.C and its convertible debentures under the symbol INE.DB.

Innergex's mission is to increase its production of renewable energy by developing and operating high-quality facilities while respecting the environment and serving the best interests of the host communities, its partners and its investors.

INTRODUCTION

This Management's Discussion and Analysis ("MD&A") is a discussion of the operating results, cash flows and financial position of Innergex Renewable Energy Inc. ("Innergex" or the "Corporation") for the three-month period ended March 31, 2014, and reflects all material events up to May 13, 2014, the date on which this MD&A was approved by the Corporation's Board of Directors.

The MD&A should be read in conjunction with the unaudited condensed consolidated financial statements and the accompanying notes for the three-month period ended March 31, 2014, and with the Corporation's *Financial Review* at December 31, 2013. Additional information relating to Innergex, including its *Annual Information Form*, can be found on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com or on the Corporation's website at www.innergex.com.

The unaudited condensed consolidated financial statements attached to this MD&A and the accompanying notes for the three-month period ended March 31, 2014, along with the 2013 comparative figures, have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Some amounts included in this MD&A have been rounded to make reading easier, which may affect some calculations.

Q1 2014 HIGHLIGHTS

- Production was 84% of long-term average ("LTA") due mainly to below-average water flows, especially in British Columbia
- Revenues rose 5% to $37.6 million compared with the same period last year
- Adjusted EBITDA remained unchanged at $193.5 million compared with the same period last year
- A 20-year power purchase agreement was signed for the 150 MW Mesgi'g Ugju's'n wind project in Quebec
- A normal course issuer bid for up to 1 million common shares was implemented and remains in effect until March 2015
- Agreements were reached with BC Hydro for modifications to the Upper Lillooet Hydro Project, comprised of the Upper Lillooet River, Boulder Creek and North Creek hydroelectric projects in British Columbia

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ESTABLISHMENT AND MAINTENANCE OF DISCLOSURE CONTROLS AND PROCEDURES AND INTERNAL CONTROL OVER FINANCIAL REPORTING

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

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

In accordance with *Regulation 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings*, the President and Chief Executive Officer and the Chief Financial Officer and Senior Vice President of the Corporation have certified that there were no material weaknesses relating to the DC&P and ICFR for the three-month period ended March 31, 2014. During the three-month period ended March 31, 2014, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

FORWARD-LOOKING INFORMATION

To inform readers of the Corporation's future prospects, this MD&A contains forward-looking information within the meaning of applicable securities laws ("Forward-Looking Information"). Forward-Looking Information can generally be identified by the use of words such as "approximately", "may", "will", "could", "believes", "expects", "intends", "should", "plans", "potential", "project", "anticipates", "estimates", "scheduled" or "forecasts", or other comparable terminology that state that certain events will or will not occur. It represents the projections and expectations of the Corporation relating to future events or results, as of the date of this MD&A.

Future-oriented financial information: Forward-Looking Information includes future-oriented financial information or financial outlook within the meaning of securities laws, such as expected production, projected revenues, projected Adjusted EBITDA and estimated project costs, to inform readers of the potential financial impact of expected results, of the expected commissioning of Development Projects, of its ability to sustain current dividends and dividend increases and of its ability to fund its growth. Such information may not be appropriate for other purposes.

Assumptions: Forward-Looking Information is based on certain key assumptions made by the Corporation, including those concerning hydrology, wind regimes and solar irradiation, performance of operating facilities, financial market conditions and the Corporation's success in developing new facilities.

Risks and uncertainties: Forward-Looking Information involves risks and uncertainties that may cause actual results or performance to be materially different from those expressed, implied or presented by the Forward-Looking Information. These are referred to in the Corporation's *Annual Information Form* in the "Risk Factors" section and include, without limitation: the ability of the Corporation to execute its strategy; its ability to access sufficient capital resources and the state of capital markets; liquidity risks related to derivative financial instruments; variability in hydrology, wind regimes and solar irradiation; delays and cost overruns in the design and construction of projects; health, safety and environmental risks; uncertainty surrounding the development of new facilities; obtainment of permits; variability of installation performance and related penalties; equipment failure or unexpected operations and maintenance activity; interest rate fluctuations and refinancing risk; financial leverage and restrictive covenants governing current and future indebtedness; declaration of dividends at the discretion of the board; the ability to secure new power purchase agreements or to renew existing ones; changes in government support to increase electricity to be generated from renewable sources by independent power producers; the ability to attract new talent or to retain officers or key employees; litigation; performance of major counterparties; social acceptance of renewable energy projects; relationships with stakeholders; equipment supply; changes in general economic conditions; regulatory and political risks; the ability to secure appropriate land; reliance on power purchase agreements; availability and reliability of transmission systems; increases in water rental costs or changes to regulations applicable to water use; assessment of water, wind and sun resources and associated electricity production; dam failure; natural disasters and force majeure; foreign exchange fluctuations; sufficiency of insurance coverage; a credit rating that may not reflect actual performance of the Corporation or that may be lowered; potential undisclosed liabilities associated with acquisitions; integration of the facilities and projects acquired; failure to realize the anticipated benefits of acquisitions; failure to close the acquisition of the other Hydroméga hydroelectric facilities and Development Projects; reliance on shared transmission and interconnection infrastructure; the introduction of solar photovoltaic power facility operation; and fluctuations in the revenues from the Miller Creek facility based on the Mid-C spot price for electricity.

Although the Corporation believes that the expectations and assumptions on which Forward-Looking Information is based are reasonable under the current circumstances, readers are cautioned not to rely unduly on this Forward-Looking Information since no assurance can be given that it will prove to be correct. Forward-Looking Information contained herein is made as at the date of this MD&A and the Corporation does not undertake any obligation to update or revise any Forward-Looking Information, whether as a result of events or circumstances occurring after the date hereof, unless so required by legislation.

Forward-Looking Information in this MD&A

The following table outlines the Forward-Looking Information contained in this MD&A, which the Corporation considers important to better inform readers about its potential financial performance, together with the principal assumptions used to derive this information and the principal risks and uncertainties that could cause actual results to differ materially from this information.

Principal Assumptions	Principal Risks and Uncertainties
Expected production For each facility, the Corporation determines a long-term average annual level of electricity production ("LTA") over the expected life of the facility, based on engineers' studies that take into consideration a number of important factors: for hydroelectricity, the historically observed flows of the river, the operating head, the technology employed and the reserved aesthetic and ecological flows; for wind energy, the historical wind and meteorological conditions and turbine technology; and for solar energy, the historical solar irradiation conditions, panel technology and expected solar panel degradation. Other factors taken into account include, without limitation, site topography, installed capacity, energy losses, operational features and maintenance. Although production will fluctuate from year to year, over an extended period it should approach the estimated long-term average. On a consolidated basis, the Corporation estimates the LTA by adding the expected LTA of all the facilities in operation that it consolidates (excludes Umbata Falls and Viger-Denonville accounted for using the equity method).	Improper assessment of water, wind and sun resources and associated electricity production Variability in hydrology, wind regimes and solar irradiation Equipment failure or unexpected operations and maintenance activity
Projected revenues For each facility, expected annual revenues are estimated by multiplying the LTA by a price for electricity stipulated in the power purchase agreement secured with a public utility or other creditworthy counterparty. These agreements stipulate a base price and, in some cases, a price adjustment depending on the month, day and hour of delivery, except for the Miller Creek hydroelectric facility, which receives a price based on a formula using the Platts Mid-C pricing indices, and the Horseshoe Bend hydroelectric facility, for which 85% of the price is fixed and 15% is adjusted annually as determined by the Idaho Public Utility Commission. In most cases, power purchase agreements also contain an annual inflation adjustment based on a portion of the Consumer Price Index. On a consolidated basis, the Corporation estimates annual revenues by adding together the projected revenues of all the facilities in operation that it consolidates (excludes Umbata Falls and Viger-Denonville accounted for using the equity method).	Production levels below the LTA caused mainly by the risks and uncertainties mentioned above Unexpected seasonal variability in the production and delivery of electricity Lower inflation rate than expected
Projected Adjusted EBITDA For each facility, the Corporation estimates annual operating earnings by subtracting from the estimated revenues the budgeted annual operating costs, which consist primarily of operators' salaries, insurance premiums, operations and maintenance expenditures, property taxes and royalties; these are predictable and relatively fixed, varying mainly with inflation except for maintenance expenditures. On a consolidated basis, the Corporation estimates annual Adjusted EBITDA by adding together the projected operating earnings of all the facilities in operation that it consolidates*, from which it subtracts budgeted general and administrative expenses, comprised essentially of salaries and office expenses, and budgeted prospective project expenses, which are determined based on the number of Prospective Projects the Corporation chooses to develop and the resources required to do so. *Excludes Umbata Falls and Viger-Denonville accounted for using the equity method.	Variability of facility performance and related penalties Changes to water and land rental expenses Unexpected maintenance expenditures
Estimated project costs, expected obtainment of permits, start of construction, work conducted and start of commercial operation for Development Projects or Prospective Projects For each development project, the Corporation provides an estimate of project costs based on its extensive experience as a developer, directly related incremental internal costs, site acquisition costs and financing costs, which are eventually adjusted for the projected costs provided by the engineering, procurement and construction ("EPC") contractor retained for the project. The Corporation provides indications regarding scheduling and construction progress for its Development Projects and indications regarding its Prospective Projects, based on its extensive experience as a developer.	Performance of counterparties, such as the EPC contractors Delays and cost overruns in the design and construction of projects Obtainment of permits Equipment supply Interest rate fluctuations and availability of financing Relationships with stakeholders Regulatory and political risks Higher-than-expected inflation

Principal Assumptions	
Expected project financing or refinancing of Operating Facilities The Corporation provides indications of its intention to secure non-recourse project-level debt financing for its Development Projects and to refinance Operating Facilities upon the end of the term of existing project-level debt, based on the expected costs and revenues of each project, the expected remaining PPA term, an initial leverage ratio of approximately 75%-85%, as well as the Corporation's extensive experience in project financing and knowledge of capital markets.	Interest rate fluctuations and availability of financing Financial leverage and restrictive covenants governing current and future indebtedness
Intention to submit projects under requests for proposals The Corporation provides indications of its intention to submit projects under requests for proposals ("RFP") based on the state of readiness of some of its Prospective Projects and their compatibility with the announced terms of these RFPs.	Regulatory and political risks Ability of the Corporation to execute its strategy Ability to secure new power purchase agreements

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.

OVERVIEW

The Corporation is a developer, owner and operator of renewable power-generating facilities with a focus on hydroelectric, wind power and solar photovoltaic ("PV") projects that benefit from low operating and management costs and simple, proven technologies.

Portfolio of Assets

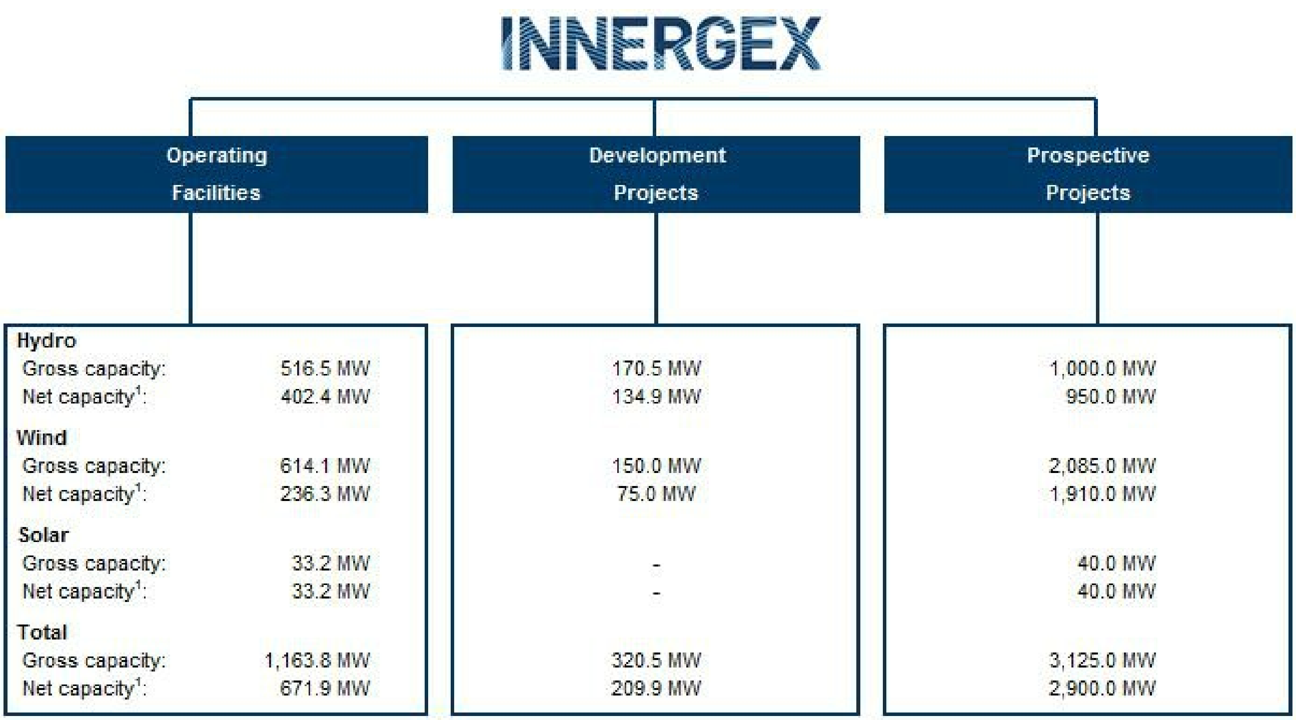
As at the date of this MD&A, the Corporation owns interests in three groups of power-generating projects:

- 32 facilities in commercial operation (the "Operating Facilities"). Commissioned between November 1994 and January 2014, the facilities have a weighted average age of approximately 6.1 years. They sell the generated power under long-term Power Purchase Agreements ("PPA") that have a weighted average remaining life of 20.1 years (based on gross long-term average production);

- Five projects scheduled to begin commercial operation between 2015 and 2016 (the "Development Projects"). Construction is ongoing at three of the projects; and

- Numerous projects that have secured certain land rights, for which an investigative permit application has been filed or for which a proposal has either been or could be submitted under a Request for Proposal ("RFP") or a Standing Offer Program ("SOP") (collectively the "Prospective Projects"). These projects are at various stages of development.

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



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 partners' ownership share.

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

BUSINESS STRATEGY

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

Annual Dividend Policy

The Corporation intends to distribute an annual dividend of $0.60 per common share, payable quarterly.

The Corporation's dividend policy is determined by its Board of Directors and is based on the Corporation's operating results, cash flows, financial condition, debt covenants, long-term growth prospects, solvency tests imposed under corporate law for the declaration of dividends and other relevant factors.

Key Performance Indicators

The Corporation measures its performance using key performance indicators that include or could include power generated in megawatt-hours ("MWh") and gigawatt-hours ("GWh"), revenues less operating expenses, general and administrative expenses and prospective project expenses ("Adjusted EBITDA") and Adjusted EBITDA divided by revenues ("Adjusted EBITDA Margin") and dividends declared on common shares divided by Free Cash Flow ("Payout Ratio"), where Free Cash Flow is defined as cash flows from operations before changes in non-cash operating working capital items, less maintenance capital expenditures net of proceeds from disposals, scheduled debt principal payments, preferred share dividends and the portion of Free Cash Flow attributed to non-controlling interests, plus cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to other facilities owned by the Corporation over the course of their PPA. Free Cash Flow is also adjusted for cash inflows or outflows that are not representative of the Corporation's long-term cash generating capacity, such as transaction costs related to realized acquisitions (which are financed at the time of the acquisition) and realized losses or gains on derivative financial instruments used to hedge the interest rate on project-level debt prior to securing such debt.

These indicators are not recognized measures under IFRS and therefore may not be comparable with those presented by other issuers. Readers are cautioned that Adjusted EBITDA should not be construed as an alternative to net earnings and Free Cash Flow should not be construed as an alternative to cash flows from operating activities as determined in accordance with IFRS. The Corporation believes that these indicators are important since they provide management and the reader with additional information about the Corporation's production and cash generating capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. These indicators also facilitate the comparison of results over different periods.

Diversification of Sources of Energy

The amount of electricity generated by the Operating Facilities is generally dependent on the availability of water flows, wind regimes and solar irradiation. Lower-than-expected water flows, wind regimes or solar irradiation in any given year could have an impact on the Corporation's revenues and hence on its profitability. Innergex owns interests in 25 hydroelectric facilities, which draw on 22 watersheds, six wind farms and one solar farm, providing significant diversification in terms of operating revenue sources. Furthermore, given the nature of hydroelectric, wind and solar power generation, seasonal variations are partially offset, as illustrated in the following table and charts:

Consolidated long-term average production[1]									
In GWh and %	Q1		Q2		Q3		Q4		Total
HYDRO	278.0	13%	774.1	36%	680.7	31%	435.6	20%	2,168.4
WIND	213.6	32%	142.8	21%	112.8	17%	207.3	31%	676.5
SOLAR[2]	7.3	19%	12.6	33%	12.7	33%	5.8	15%	38.4
Total	498.9	17%	929.4	32%	806.2	28%	648.7	22%	2,883.3

1. Annualized long-term average production ("LTA") for the facilities in operation at May 13, 2014. The LTA production is presented in accordance with revenue recognition accounting rules under IFRS and excludes production from facilities that are accounted for using the equity method, which is presented in the "Investments in Joint Ventures" section.
2. Solar farm LTA diminishes over time due to expected solar panel degradation.

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

FIRST QUARTER UPDATE

	Three months ended March 31	
	2014	2013
Power generated (MWh)	417,209	386,171
LTA production (MWh)	498,964	461,529
Revenues	37,599	35,688
Adjusted EBITDA	25,329	25,403
Adjusted EBITDA Margin	67.4%	71.2%
Net loss	(38,105)	(178)
Dividend declared per Class A Preferred Share	0.3125	0.3125
Dividend declared per Class C Preferred Share[1]	0.359375	0.492300
Dividend declared per common share	0.150	0.145

	Trailing 12-months ended March 31	
	2014	2013
Free Cash Flow[2]	49,790	52,258
Payout Ratio[2]	112%	101%

1. The initial dividend payment in the first quarter of 2013 was higher to reflect dividends accrued since the closing date of the Series C Preferred Share offering of December 11, 2012. The regular quarterly dividend amount is $0.359375.
2. For more information on the calculation and explanation of the Corporation's Free Cash Flow and Payout Ratio, please refer to the "Free Cash Flow and Payout Ratio" section.

For the three-month period ended March 31, 2014, production was 84% of the LTA, due mainly to below-average water flows in all regions except Ontario, and especially in British Columbia, partly offset by the solid performance of the wind and solar facilities. For the quarter, production increased 8%, revenues increased 5% and Adjusted EBITDA remained unchanged, compared with the same period last year. The increase in production and revenues is attributable mainly to the addition of the Magpie hydroelectric facility acquired in July 2013 and to the better performance of the wind facilities compared with the same period last year, while the contribution from the Northwest Stave River and Kwoiek Creek hydroelectric facilities, commissioned at the end of 2013, was limited given particularly low water flows in British Columbia. The smaller increase in revenues is attributable to the lower average selling price for electricity, resulting mainly from the addition of the Magpie facility, for which the selling price is considerably lower than for most other facilities of the Corporation. The flatness in Adjusted EBITDA is attributable to higher operating, general and administrative expenses, due mainly to the greater number of facilities in operation.

The Corporation recorded a net loss of $38.1 million for the three-month period ended March 31, 2014, compared with a net loss of $0.2 million for the same period in 2013, due mainly to an unrealized net loss on derivative financial instruments of $36.0 million resulting from a decrease in benchmark interest rates during the three-month period, compared with an unrealized net gain of $3.8 million resulting from an increase in benchmark interest rates during the same period last year.

Impact on net loss of the unrealized net loss or gain on derivative financial instruments	Three months ended March 31	
	2014	2013
Net loss	(38,105)	(178)
Add (Subtract): Unrealized net loss (gain) on derivative financial instruments	36,030	(3,838)
(Subtract) Add: Income tax (recovery) provision related to above item	(9,548)	998
Add (Subtract): Share of unrealized net loss (gain) on derivative financial instruments of joint ventures, net of related income tax recovery (provision)	1,101	(34)
	(10,522)	(3,052)

Excluding the unrealized net loss or gain on derivative financial instruments and the related income taxes, the net loss for the three-month period ended March 31, 2014 would have been $10.5 million, compared with a net loss of $3.1 million in 2013, due mainly to the reasons mentioned above and to higher interest expenses, attributable to the expensing of interest on the Kwoiek Creek and Northwest Stave River loans now that the facilities are in operation and to the addition of project-level debt related to the Magpie acquisition in July 2013.

Commercial Operation Officially Begins for the Northwest Stave River and Kwoiek Creek Hydroelectric Facilities

On February 18, 2014, Innergex announced the start of commercial operations of the 49.9 MW Kwoiek Creek hydroelectric facility located in British Columbia, after the Corporation and BC Hydro amended their agreement to clarify stipulated production levels, subject to approval by the British Columbia Utilities Commission. Once the approval is received, BC Hydro will accept the COD Certificate with an effective commissioning date of January 1, 2014, for the Kwoiek Creek facility.

On February 24, 2014, the Corporation announced the commissioning of the 17.5 MW Northwest Stave River hydroelectric facility located in British Columbia, after the COD certificate was approved by BC Hydro with an effective commissioning date of December 18, 2013.

The Corporation Implements a Normal Course Issuer Bid

On March 20, 2014, the Corporation announced it was proceeding with a normal course issuer bid ("NCIB"), which will enable it to purchase for cancellation up to 1 million (or approximately 1.1%) of its issued and outstanding common shares between March 24, 2014 and March 23, 2015. As as the date of this MD&A, the Corporation has not purchased any shares for cancellation under this NCIB.

Innergex and Its Partner sign a 20-year Power Purchase Agreement for the Mesgi'g Ugju's'n Wind Project

On March 24, 2014, Innergex and the Mi'gmaq communities of Quebec signed a 20-year power purchase agreement with Hydro-Québec Distribution for the 150 MW Mesgi'g Ugju's'n wind project in Quebec. For more information on the Mesgi'g Ugju's'n project, please refer to the "Development Projects" section.

The Corporation Reaches Agreements with BC Hydro on Changes to Hydroelectric Projects in British Columbia

On March 27, 2014, the Corporation announced it had reached agreements with BC Hydro regarding the Upper Lillooet Hydro Project, pursuant to which the higher installed capacities of the Upper Lillooet River and Boulder Creek projects were confirmed and the North Creek project was cancelled; these changes had been requested by the Corporation in early 2013. Also pursuant to these agreements, the commercial operation date for the Boulder Creek project will occur no earlier than July 1, 2016. For more information on the Upper Lillooet Hydro Project, please refer to the "Development Projects" section.

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

DEVELOPMENT PROJECTS

The Corporation currently has five projects that are expected to reach commercial operation between 2015 and 2016.

PROJECTS UNDER CONSTRUCTION	Ownership %	Gross installed capacity (MW)	Expected COD[1]	Gross estimated LTA[2, 3] (GWh)	PPA term (years)	Total project costs		Expected year-one	
						Estimated[2] ($M)	As at Mar. 31 ($M)	Revenues[2] ($M)	Adjusted EBITDA[2] ($M)
HYDRO (British Columbia)									
Tretheway Creek	100.0	23.2	2015	81.9	40	111.5	30.2	9.0	7.5
Upper Lillooet River	66.7	81.4	2016	334.0	40	315.0 [4]	41.1 [4]	33.0 [4]	27.5 [4]
Boulder Creek	66.7	25.3	2016	92.5	40	119.2 [4]	10.2 [4]	9.0 [4]	7.5 [4]
		129.9		508.4		545.7	81.5	51.0	42.5

1. Commercial operation date.
2. This information is intended to inform readers of the projects' potential impact on the Corporation's results.
3. Upon commissioning, LTA production figures may be updated to reflect design optimization or constraints or selection of different turbines. Actual results may vary. Please refer to the "Forward-Looking Information" section for more information.
4. Corresponding to 100% of this facility.

Tretheway Creek

The construction of this hydroelectric facility began in October 2013. As at the date of this MD&A, clearing and bulk excavation for the intake, powerhouse and penstock were nearing completion. Intake concrete placement at the intake area and penstock delivery and installation at the site have begun. Excavation and rock support at the powerhouse continue as planned. In January 2014, the Corporation for all intents and purposes completed a hedging program to fix the interest rate for this project's financing through the use of derivative financial instruments until it closes the project-level financing; this effectively eliminates the project's exposure to interest rate fluctuations.

Upper Lillooet River and Boulder Creek (the "Upper Lillooet Hydro Project")

The construction of the Upper Lillooet River and Boulder Creek hydroelectric facilities began in October 2013. As planned, construction activities had been halted for the winter period and resumed in March 2014. As at the date of this MD&A, clearing for the joint transmission line and access road was ongoing and site preparation was underway. Clearing and excavation for the intake, powerhouse and tunnel are expected to start in May. In January 2014, the Corporation for all intents and purposes completed a hedging program to fix the interest rate for these projects' financing through the use of derivative financial instruments until it closes the project-level financing; this effectively eliminates the projects' exposure to interest rate fluctuations. In March 2014, the Corporation announced it had reached agreements with BC Hydro regarding the Upper Lillooet Hydro Project, pursuant to which the higher installed capacities of the Upper Lillooet River and Boulder Creek projects were confirmed and the North Creek project was cancelled; these changes had been requested by the Corporation in early 2013. Also pursuant to these agreements, the commercial operation date for the Boulder Creek project will be no earlier than July 1, 2016.

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

PROJECTS UNDER PERMIT PHASE	Ownership %	Gross installed capacity (MW)	Expected COD[1]	Gross estimated LTA[2,3] (GWh)	PPA term (years)	Total project costs		Expected year-one	
						Estimated[2] ($M)	As at Mar. 31 ($M)	Revenues[2] ($M)	Adjusted EBITDA[2] ($M)
HYDRO (British Columbia)									
Big Silver Creek	100.0	40.6	2016	139.8	40	216.0	30.0	18.0	15.0
WIND (Quebec)									
Mesgi'g Ugju's'n ("MU")	50.0	150.0	2016	515.0	20	365.0 [4]	1.2 [4]	55.0 [4]	45.0 [4]
		190.6		654.8		581.0	31.2	73.0	60.0

1. Commercial operation date.
2. This information is intended to inform readers of the projects' potential impact on the Corporation's results.
3. Upon commissioning, LTA production figures may be updated to reflect design optimization or constraints or selection of different turbines. Estimates for the Mesgi'g Ugju's'n project in particular are preliminary until the turbine supplier and EPC contractor have been selected. Actual results may vary. Please refer to the "Forward-Looking Information" section for more information.
4. Corresponding to 100% of this facility.

Big Silver Creek

The remaining permits to begin construction are in the process of being obtained and present no technical obstacles. The construction of the temporary camp commenced in early May 2014, with construction of the civil works planned to commence in June 2014. As of the date of this MD&A, the turbine and generator supplier is continuing with design, and the civil contractor is commencing the detailed design of the project components. In January 2014, the Corporation for all intents and purposes completed a hedging program to fix the interest rate for this project's financing through the use of derivative financial instruments until it closes the project-level financing; this effectively eliminates the project's exposure to interest rate fluctuations.

Mesgi'g Ugju's'n ("MU")

In March 2014, the Corporation and its Mi'gmaq partner signed a 20-year fixed-price PPA with Hydro-Québec Distribution. Rather than a selling price of $0.089 per kWh in 2014 dollars with an annual adjustment based on 100% of the Consumer Price Index until the end of the PPA, the Corporation opted for the equivalent in the form of a selling price of $0.1012 per kWh in 2014 dollars with an annual adjustment based on 100% of the Consumer Price Index through the end of 2016 and on 20% thereafter until the end of the PPA; it therefore respects the maximum of $0.09 per kWh established by the Government of Quebec under its ongoing request for proposals for 450 MW of new wind energy capacity. Furthermore, since there has been no request for a public hearing pursuant to the province's environmental review process, there will be no hearing for this project. As at the date of this MD&A, negotiations with potential turbine suppliers were ongoing. Pre-construction activities are expected to start in late 2014, construction is expected to start in 2015 and commercial operation is expected to begin at the end of 2016. In April 2014, the partners for all intents and purposes completed a hedging program to fix the interest rate for this project's financing through the use of derivative financial instruments until they close the project-level financing; this effectively eliminates the project's exposure to interest rate fluctuations.

PROSPECTIVE PROJECTS

All the Prospective Projects, with a combined potential net installed capacity of 2,900 MW (gross 3,125 MW), are in the preliminary development stage. Some Prospective Projects are targeted toward specific future RFPs, such as the current RFP for 450 MW of new wind energy procurement in Quebec or SOPs, while others will be available for future RFPs yet to be announced. There is no certainty that any Prospective Project will be realized. Additional information about the Corporation's facilities and projects can be found in the Corporation's *Annual Information Form*, which is filed on SEDAR at www.sedar.com.

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

OPERATING RESULTS

Production of electricity for the first quarter was 84% of the long-term average due mainly to below-average water flows, especially in British Columbia, partly offset by the solid performance of the wind and solar facilities.

For the first quarter, production increased 8%, revenues increased 5% and Adjusted EBITDA remained unchanged, compared with the same period last year. The increase in production and revenues is attributable mainly to the addition of the Magpie hydroelectric facility acquired in July 2013 and to the better performance of the wind facilities compared with the same period last year, while the contribution from the Northwest Stave River and Kwoiek Creek hydroelectric facilities, commissioned at the end of 2013, was limited given particularly low water flows in British Columbia. The smaller increase in revenues is attributable to the lower average selling price for electricity, resulting mainly from the addition of the Magpie facility, for which the selling price is considerably lower than for most other facilities of the Corporation. The flatness in Adjusted EBITDA is attributable to higher operating, general and administrative expenses, due mainly to the greater number of facilities in operation.

The Corporation's operating results for year ended March 31, 2014, are compared with the operating results for the same period in 2013.

Electricity Production

When evaluating its operating results, a key performance indicator for the Corporation is to compare actual electricity generation with a long-term average for each hydroelectric facility, wind farm and solar farm. These long-term averages are determined to allow long-term forecasting of the expected power generation for each of the Corporation's facilities.

Three months ended March 31	2014				2013			
	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Average price ($/MWh)[2]	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Average price ($/MWh)[2]
HYDRO								
Quebec	74,163	80,313	92%	97.74	70,686	63,317	112%	109.30
Ontario	25,065	24,294	103%	70.37	25,542	24,294	105%	70.14
British Columbia	81,036	165,489	49%	90.24	76,203	144,997	53%	89.43
United States	6,305	7,927	80%	62.43	4,129	7,927	52%	58.75
Subtotal	186,569	278,023	67%	89.61	176,560	240,535	73%	93.88
WIND								
Quebec	223,226	213,605	105%	79.59	202,676	213,605	95%	79.93
SOLAR								
Ontario	7,414	7,336	101%	420.00	6,935	7,389	94%	420.00
Total	417,209	498,964	84%	90.12	386,171	461,529	84%	92.41

1. The Umbata Falls hydroelectric facility and the Viger-Denonville wind farm are treated as joint ventures and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for the sake of consistency, their electricity production figures have been excluded from the production table. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.
2. Including all payment adjustments related to the month, day and hour of delivery, to environmental attributes and to the ecoENERGY Initiative, as applicable.

During the three-month period ended March 31, 2014, the Corporation's facilities produced 417 GWh of electricity or 84% of the LTA of 499 GWh. Overall, the hydroelectric facilities produced 67% of their LTA, as water flows were below-average in all regions except Ontario, and especially in British Columbia. Overall, the wind farms produced 105% of their LTA, due to above-average wind regimes. The Stardale solar farm produced 101% of its LTA. The 8% increase in production compared with the same period last year is attributable mainly to the addition of the Magpie hydroelectric facility acquired in July 2013 and to the better performance of the wind facilities compared with the same period last year, while the contribution from the Northwest Stave River and Kwoiek Creek hydroelectric facilities, commissioned at the end of 2013, was limited given particularly low water flows in British Columbia. The overall performance of the Corporation's facilities for the three-month period ended March 31, 2014, demonstrates the benefits of geographic diversification and the complementarity of hydroelectric, wind and solar power generation.

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

Financial Results

	Three months ended March 31			
	2014		2013	
Revenues	37,599	100.0%	35,688	100.0%
Operating expenses	7,645	20.3%	6,458	18.1%
General and administrative expenses	3,554	9.5%	3,002	8.4%
Prospective project expenses	1,071	2.8%	825	2.3%
Adjusted EBITDA	25,329	67.4%	25,403	71.2%
Finance costs	19,664		12,952	
Other net revenues	(173)		(2,373)	
Depreciation and amortization	18,847		17,461	
Share of loss of joint ventures[1]	996		126	
Unrealized net loss (gain) on derivative financial instruments	36,030		(3,838)	
(Recovery) provision for income taxes	(11,930)		1,253	
Net loss	(38,105)		(178)	
Net (loss) earnings attributable to:				
Owners of the parent	(27,419)		2,797	
Non-controlling interests	(10,686)		(2,975)	
	(38,105)		(178)	
Basic net (loss) earnings per share	(0.30)		0.01	

1. The Umbata Falls hydroelectric facility and Viger Denonville wind farm are treated as joint ventures and the Corporation's interests in these facilities are required to be accounted for using the equity method. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

Revenues

For the three-month period ended March 31, 2014, the Corporation recorded revenues of $37.6 million, compared with $35.7 million in 2013, corresponding to a 5% increase. The increase is attributable mainly to the contribution of the Magpie hydroelectric facility acquired in July 2013 and to the better performance of the wind facilities compared with the same period last year. Furthermore, the smaller increase in revenues than in production during the quarter is attributable to the lower average selling price for electricity, resulting mainly from the addition of the Magpie facility, for which the selling price is considerably lower than for most other facilities of the Corporation.

Expenses

Operating expenses: consist primarily of the operators' salaries, insurance premiums, expenditures related to operation and maintenance, property taxes, and royalties. For the three-month period ended March 31, 2014, the Corporation recorded operating expenses of $7.6 million ($6.5 million in 2013). This 18% increase is due mainly to the Corporation operating a greater number of facilities in 2014 than in 2013 following the addition of the Magpie, Kwoiek Creek and Northwest Stave River hydroelectric facilities. In addition, the aggregate payment in respect of water rights for the Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River facilities increased by $0.4 million compared with the same period last year. This change resulted from the unilateral decision by British Columbia's Ministry of Forests, Lands and Natural Resource Operations in 2013 to apply higher rental rates based on the combined production of these facilities rather than applying lower rates for each facility based on its individual production, as had previously been its practice. The Corporation has filed an appeal of this decision with the Environmental Appeal Board.

General and administrative expenses: consist primarily of salaries, professional fees and office expenses. For the three-month period ended March 31, 2014, general and administrative expenses totalled $3.6 million ($3.0 million in 2013). This 18% increase reflects the Corporation's greater number of facilities in operation, greater number of employees and normal salary increases.

Prospective project expenses: include the costs incurred for the development of Prospective Projects. They result from the number of Prospective Projects that the Corporation chooses to advance and the resources required to do so. For the three-month period ended March 31, 2014, prospective project expenses totalled $1.1 million ($0.8 million in 2013).

Adjusted EBITDA

When evaluating its financial results, a key performance indicator for the Corporation is to measure Adjusted EBITDA, which is defined as revenues less operating expenses, general and administrative expenses and prospective project expenses.

For the three-month period ended March 31, 2014, the Corporation recorded Adjusted EBITDA of $25.3 million, compared with $25.4 million for the same period last year. The fact that Adjusted EBITDA remained unchanged while revenues increased 5% during the quarter is attributable to the higher operating, general and administrative expenses, which are not directly correlated to production levels. Consequently, the Adjusted EBITDA Margin decreased from 71.2% in 2013 to 67.4% in 2014.

Finance Costs

Finance costs include interest on long-term debt and convertible debentures, inflation compensation interest, amortization of financing fees, amortization of the revaluation of long-term debt and convertible debentures, accretion expenses on other liabilities and other finance costs. For the three-month period ended March 31, 2014, finance costs totalled $19.7 million ($13.0 million in 2013). This increase is due mainly to the expensing of interest on the Kwoiek Creek and Northwest Stave River loans now that the facilities are in operation, to the addition of project-level debt related to the Magpie acquisition in July 2013, to higher interest expense on the higher project-level debt for the Carleton wind farm refinanced in June 2013 and to inflation compensation interest on the real return bonds owing to higher inflation during the period, compared with the negative inflation compensation interest for the same period last year.

As at March 31, 2014, 95% of the Corporation's outstanding debt, including convertible debentures, was fixed or hedged against interest rate movements (95% as at March 31, 2013). The effective all-in interest rate on the Corporation's debt and convertible debentures was 5.41% as at March 31, 2014 (5.58% as at March 31, 2013). The decrease stems mainly from a lower interest rate on the revolving term credit facility, the addition of the Northwest Stave River loan that bears a low fixed-interest rate of 5.30% and the addition of the Magpie project debt, which bears an all-in interest rate of 4.48%, partly offset by the refinancing in June 2013 of the Carleton loan at a higher all-in interest rate of 5.41% (4.84% previously), which has been hedged by an interest-rate swap contract since November 2008.

Other Net Revenues

Other net revenues include transaction costs, realized losses on foreign exchange, settlement of claims received in connection with an acquisition and other net revenues. For the three-month period ended March 31, 2014, the Corporation recorded other net revenues of $0.2 million (other net revenues of $2.4 million in 2013). This variation stems mainly from the $2.0 million claims settlement received in 2013.

Depreciation and Amortization

For the three-month period ended March 31, 2014, depreciation and amortization expenses totalled $18.8 million ($17.5 million in 2013). This increase is attributable mainly to the larger asset base resulting from the addition of the Magpie hydroelectric facility and the beginning of operations of the Kwoiek Creek and Northwest Stave River hydroelectric facilities. Taken alone, amortization expenses decreased for the quarter as a result of a change in accounting estimates to amortize intangible assets of the Quebec hydroelectric facilities, which reflects the renewal rights of their PPAs for periods of 20 to 25 years.

Share of Loss of Joint Ventures

For the three-month period ended March 31, 2014, the share of loss of joint ventures totalled $1.0 million ($0.1 million in 2013). For the Umbata Falls hydroelectric facility, above-average production and positive Adjusted EBITDA were relatively unchanged from the same period last year but were offset by an unrealized net loss on derivative financial instruments recorded as a result of a decrease in benchmark interest rates during the quarter, compared with an unrealized net gain following an increase in benchmark interest rates for the same period last year. For the Viger-Denonville wind farm, the positive contribution of Adjusted EBITDA following the start of commercial operations in November 2013 was also offset by an unrealized net loss on derivative financial instruments. Please refer to the "Investments in Joint Ventures" section for more information.

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

Derivative Financial Instruments

The Corporation uses derivative financial instruments to manage its exposure to the risk of rising interest rates on its debt financing ("Derivatives"), thereby protecting the economic value of its projects. Innergex also has derivative financial instruments embedded in some of its PPAs (the minimum 3% inflation clause applied to the selling price). The Corporation does not use hedge accounting for its derivative financial instruments nor does it own or issue financial instruments for speculative purposes. Since several interest rate swaps are entered into for a term equal in length to the underlying debt amortization schedule, which can reach 30 years, a Derivative's fair market value can be very sensitive to quarter-to-quarter variations in long-term interest rates.

For the three-month period ended March 31, 2014, the Corporation recognized an unrealized net loss on derivative financial instruments of $36.0 million, due mainly to the decrease in benchmark interest rates since the end of 2013. For the corresponding period of 2013, Innergex recognized an unrealized net gain on derivative financial instruments of $3.8 million, due mainly to the increase in benchmark interest rates since December 31, 2012.

In January 2014, the Corporation completed a hedging program to fix the interest rate on future project-level debt for the Upper Lillooet River, Boulder Creek, Tretheway Creek and Big Silver Creek Development Projects. In April 2014, the Corporation and its partner completed a hedging program to fix the interest rate on future project-level debt for the Mesgi'g Ugju's'n Development Project. As at the date of this MD&A, the Corporation had entered into derivative financial instruments totaling $595.0 million. Upon the closing of each fixed-rate or interest-swapped long-term financing, the Corporation will settle the corresponding derivative financial instruments, which will result in a realized gain or loss on derivative financial instruments. These gains or losses will serve to offset a higher or lower interest rate on the project-level debt. As at March 31, 2014, the derivatives to be settled upon closing of financing had a negative market value of $19.3 million.

Provision for Income Taxes

For the three-month period ended March 31, 2014, the Corporation recorded a current income tax provision of $0.8 million ($0.8 million in 2013) and deferred income tax recoveries of $12.7 million (provision of $0.4 million in 2013). The difference in the deferred income tax provision for the year is due primarily to an unrealized net loss on derivative financial instruments, compared with an unrealized net gain on derivative financial instruments for the same period last year.

Non-controlling Interests

For the three-month period ended March 31, 2014, the Corporation allocated losses of $10.7 million to non-controlling interests (losses of $3.0 million in 2013). These non-controlling interests are related mostly to the six hydroelectric facilities of Harrison Hydro L.P. (the "Harrison Hydro L.P."), the Creek Power Inc. subsidiaries, the Kwoiek Creek facility, the Mesgi'g Ugju's'n (MU) Wind Farm L.P. and their respective general partners. The greater net loss is due mainly to the recognition of an unrealized net loss on derivative financial instruments, compared with an unrealized net gain for the same period last year, and to a greater net loss of the Harrison Hydro L.P. Please refer to the "Non-Wholly Owned Subsidiaries" section for more information.

Net Loss

For the three-month period ended March 31, 2014, the Corporation recorded a net loss of $38.1 million (basic and diluted net loss of $0.30 per share), compared with a net loss of $0.2 million (basic and diluted net earnings of $0.01 per share) in 2013.

Main items contributing to the greater net loss for the three months ended March 31, 2014, compared with the corresponding period in 2013

Main items – Positive impact	Variation	Explanation
Revenues	21,604	Due mainly to the increase in production from the greater number of facilities in operation.
Deferred recovery of income taxes	13,130	Due mainly to an unrealized net loss on derivative financial instruments.
Main items – Negative impact	**Variation**	**Explanation**
Unrealized net loss on derivative financial instruments	39,868	Due mainly to a decrease in benchmark interest rates during the first quarter, compared with an increase in benchmark interest rates during the same period last year.
Finance costs	6,712	Due mainly to the expensing of interest on the Kwoiek Creek and Northwest Stave River loans, the addition of project-level debt related to Magpie and higher inflation compensation interest of $2.4 million on the real return bonds.
Other net revenues	2,200	Due mainly to a settlement of claims received in the first quarter of 2013.

Number of Shares Outstanding

Weighted average number of common shares outstanding (000s)	Three months ended March 31	
	2014	2013
Weighted average number of common shares	95,827	93,913
Effect of dilutive elements on common shares[1]	163	114
Diluted weighted average number of common shares	95,990	94,027

1. During the three-month period ended March 31, 2014, 1,243,000 of 3,073,684 stock options (1,263,000 of 2,736,684 during the three-month period ended March 31, 2013) and 7,558,684 shares that can be issued on conversion of convertible debentures (7,558,684 during the three-month period ended March 31, 2013) were excluded from the calculation of the diluted weighted average number of shares outstanding as the exercise price was above the common shares' average market price. During the three-month period ended March 31, 2014, 1,830,684 of 3,073,684 stock options (nil as at March 31, 2013) were excluded from the calculation of diluted net loss per shares as it was anti-dilutive due to a net loss available to commons shareholders.

As at March 31, 2014, the Corporation had a total of 95,860,979 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares, 2,000,000 Series C Preferred Shares and 3,073,684 stock options outstanding. As at March 31, 2013, it had 93,964,093 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares, 2,000,000 Series C Preferred Shares and 2,736,684 stock options outstanding.

As at the date of this MD&A, the Corporation had a total of 96,058,824 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares, 2,000,000 Series C Preferred Shares and 3,073,684 stock options outstanding. The increase in the number of common shares since March 31, 2014, is attributable to the Dividend Reinvestment Plan ("DRIP").

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

LIQUIDITY AND CAPITAL RESOURCES

For the three-month period ended March 31, 2014, the Corporation used cash flows from operating activities of $5.3 million, compared with generating $12.2 million for the same period last year. During this period, the Corporation generated funds from financing activities of $9.6 million and used funds for investing activities of $15.5 million, mainly to pay for the construction of its five Development Projects. As at March 31, 2014, the Corporation had cash and cash equivalents amounting to $23.2 million, compared with $34.3 million as at December 31, 2013.

Cash Flows from Operating Activities

For the three-month period ended March 31, 2014, cash flows used by operating activities totalled $5.3 million ($12.2 million generated in 2013). This variation is attributable mainly to higher finance costs, a negative net variation of $8.6 million in non-cash operating working capital items and a negative variation in other net revenues.

Cash Flows from Financing Activities

For the three-month period ended March 31, 2014, cash flows generated by financing activities totalled $9.6 million ($17.4 million used in 2013). This variation is attributable mainly to a net increase in long-term debt of $28.7 million, reflecting drawings on the revolving term credit facility to pay for construction activity of the five Development Projects.

Use of Financing Proceeds	Three months ended March 31	
	2014	2013
Proceeds from issuance of long-term debt	34,316	11,999
Net proceeds from issuance of preferred shares	—	(351)
Generation of financing proceeds	34,316	11,648
Repayment of long-term debt	(11,004)	(17,431)
Payment of deferred financing costs	(52)	(42)
Payment of other liabilities	(112)	—
Decrease in restricted cash and short-term investments	21,275	19,612
Net funds withdrawn from the reserve accounts	738	1,227
Additions to property, plant and equipment	(25,449)	(37,069)
Additions to intangible assets	—	(27)
Additions to project development costs	(11,420)	(2,023)
Investments in joint ventures	—	(725)
(Additions to) Reduction of other long-term assets	(625)	9
Net use of financing proceeds	(26,649)	(36,469)
Increase in (Reduction of) working capital	7,667	(24,821)

During the three-month period ended March 31, 2014, the Corporation borrowed $34.3 million to pay for the construction of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects and the pre-construction development of the Big Silver Creek and Mesgi'g Ugju's'n projects and used $21.3 million in restricted cash mainly to pay accounts payable related to the Kwoiek Creek and Northwest Stave River facilities. During the corresponding period of 2013, the Corporation borrowed $12.0 million and used $24.8 million of its working capital to pay for the construction of the Gros-Morne, Kwoiek Creek and Northwest Stave River projects, to repay long-term debts and to reduce drawings under the revolving term credit facility.

Cash Flows from Investing Activities

For the three-month period ended March 31, 2014, cash flows used by investing activities amounted to $15.5 million ($19.0 million in 2013). During this period, additions to property, plant and equipment accounted for a $25.4 million outflow ($37.1 million outflow in 2013) and additions to project development costs accounted for a $11.4 million outflow ($2.0 million outflow in 2013). These items were partly offset by a decrease in restricted cash and short-term investments, which accounted for a $21.3 million inflow ($19.6 million outflow in 2013).

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

Cash and Cash Equivalents

For the three-month period ended March 31, 2014, cash and cash equivalents decreased by $11.1 million (decreased by $24.3 million in 2013) as a net result of its operating, financing and investing activities. As at March 31, 2014, the Corporation had cash and cash equivalents amounting to $23.2 million ($34.3 million as at December 31, 2013).

DIVIDENDS

The following dividends were declared by the Corporation:

	Three months ended March 31	
	2014	2013
Dividends declared on common shares[1]	14,379	13,625
Dividends declared on common shares ($ per share)[1]	0.1500	0.1450
Dividends declared on Series A Preferred Shares	1,063	1,063
Dividends declared on Series A Preferred Shares ($ per share)	0.3125	0.3125
Dividends declared on Series C Preferred Shares[2]	719	984
Dividends declared on Series C Preferred Shares ($ per share)[2]	0.359375	0.492300

1. On February 25, 2014, the Board of Directors increased the annual dividend that the Corporation intends to distribute from $0.58 to $0.60 per common share, payable quarterly.
2. The initial dividend payment in the first quarter of 2013 was higher to reflect dividends accrued since the closing date of the Series C Preferred Share offering of December 11, 2012. The regular quarterly dividend amount is $0.359375.

The following dividends will be paid by the Corporation on July 15, 2014:

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
5/13/2014	6/30/2014	7/15/2014	0.1500	0.3125	0.359375

FINANCIAL POSITION

As at March 31, 2014, the Corporation had $2,344 million in total assets, $1,737 million in total liabilities, including $1,365 million in long-term debt and $607.1 million in shareholders' equity.

Also at March 31, 2014, the Corporation had a working capital ratio of 0.84:1.00 (1.18:1.00 as at December 31, 2013). In addition to cash and cash equivalents amounting to $23.2 million, the Corporation had restricted cash and short-term investments of $28.5 million and reserve accounts of $46.9 million at the end of the quarter.

The explanations below highlight the most significant changes in balance sheet items during the three-month period ended March 31, 2014.

Assets

Highlights of significant variations in total assets during the first quarter

- A net decrease in cash and cash equivalents and restricted cash and short-term investments from $84.0 million as at December 31, 2013, to $51.6 million as at March 31, 2014, due mainly to amounts being drawn to pay for the construction of the Kwoiek Creek and Northwest Stave projects;
- An increase in accounts receivable from $19.8 million to $24.1 million, as explained in the "Working Capital Items" section below;
- A decrease in loans to related parties of $6.8 million due mainly to the completion of a $6.8 million distribution by the Harrison Hydro L.P. initiated in the fourth quarter of 2013.

Working Capital Items

As at March 31, 2014, working capital was negative at $16.6 million with a working capital ratio of 0.84:1.00. As at December 31, 2013, working capital was positive at $19.1 million with a working capital ratio of 1.18:1.00. The decrease in the working capital ratio over this period is due to decrease of $11.1 million in cash and cash equivalents, of $21.3 million in restricted cash and short-term investments and of $6.8 million in loans to related parties and to an increase of $19.3 million in the current liability portion of derivative financial instruments, which are explained separately below. These items were partly offset by the $4.3 million increase in accounts receivable and the $23.9 million decrease in accounts payable, also explained separately below.

The Corporation considers its current level of working capital to be sufficient to meet its needs. The Corporation can also use its $425.0 million revolving term credit facility if necessary. As at March 31, 2014, the Corporation had drawn US$13.9 million and $200.2 million as cash advances, while $32.4 million had been used for issuing letters of credit.

Restricted cash and short-term investments: are related to the Harrison Hydro L.P., the Kwoiek Creek loan and the Northwest Stave River loan. As at March 31, 2014, restricted cash and short-term investments amounted to $28.5 million, of which $5.8 million was related to the Harrison Hydro L.P., $18.0 million to the Kwoiek Creek loan and $4.6 million to the Northwest Stave River loan ($49.7 million as at December 31, 2013, of which $6.7 million was related to the Harrison Hydro L.P., $31.5 million to the Kwoiek Creek loan and $11.6 million to the Northwest Stave River loan). The decrease stems mainly from amounts being drawn to pay for construction of the Kwoiek Creek and Northwest Stave River projects.

Accounts receivable: increased from $19.8 million as at December 31, 2013, to $24.1 million as at March 31, 2014. The increase stems mainly from revenues generated.

Loans to related parties: decreased from $6.8 million as at December 31, 2013, to nil as at March 31, 2014, as the Harrison Hydro L.P. completed a distribution that resulted in a $6.8 million decrease in loans to related parties, as well as a corresponding decrease in non-controlling interests with no impact on net earnings or cash flows.

Accounts payable and other payables: decreased from $48.3 million as at December 31, 2013, to $24.3 million as at March 31, 2014, due mainly to payments made in relation to the construction of the Kwoiek Creek and Northwest Stave River facilities.

Derivative financial instruments included in current liabilities: increased from $12.9 million as at December 31, 2013, to $32.3 million as at March 31, 2014, due mainly to the increase in bond forward contracts entered into to hedge the interest rate on future project-level financing for the Development Projects, and to the decrease in benchmark interest rates since December 31, 2013. These short-term derivatives will be refinanced with long-term project-level debt in the coming months.

Property, Plant and Equipment

Property, plant and equipment are comprised mainly of hydroelectric facilities, wind farms and a solar farm that are either in operation or under construction. They are recorded at cost less accumulated depreciation and accumulated impairment losses. The Corporation had $1,592 million in property, plant and equipment as at March 31, 2014, compared with $1,583 million as at December 31, 2013. This increase stems mainly from the ongoing construction of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects, largely offset by depreciation.

Liabilities and Shareholders' Equity

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. The Corporation does not own or issue any Derivatives for speculation purposes. The Corporation does not use hedge accounting to account for its Derivatives. Interest rate swap contracts allow the Corporation to eliminate the risk of interest rate increases in actual floating-rate debts, which debts totalled $483.1 million as at March 31, 2014. Consequently, as at March 31, 2014, interest rate swaps related to outstanding debts combined with the $816.3 million in existing fixed-rate debts and $79.9 million in convertible debentures mean that 95% of outstanding debts, including those of joint ventures, are protected from interest rate increases.

In addition, bond forward contracts allow the Corporation to eliminate the risk of interest rate increases in planned long-term debt that it will need to secure for its Development Projects. As at the date of this MD&A, the Corporation had entered into bond forward contracts totaling $595.0 million ($475.0 million as at March 31, 2014, and $340.0 million as at December 31, 2013) for the Upper Lillooet River, Boulder Creek, Tretheway Creek, Big Silver Creek and Mesgi'g Ugju's'n projects. Upon the closing of each fixed-rate or interest-swapped long-term financing, the Corporation will settle the corresponding derivative financial instruments, which will result in a realized gain or loss on derivative financial instruments. These gains or losses will serve to offset a higher or lower interest rate on the project-level debt. As at March 31, 2014, the derivatives to be settled upon closing of financing had a negative market value of $19.3 million.

Derivatives had a net negative value of $66.7 million at March 31, 2014 (negative $31.0 million at December 31, 2013). This variation is due mainly to a decrease in benchmark interest rates since the end of 2013. These figures exclude the impact of derivatives used to hedge loans of the Corporation's joint ventures. For information on the impact of derivatives used in the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

Long-Term Debt

As at March 31, 2014, long-term debt totalled $1,365 million ($1,340 million as at December 31, 2013). The $24.7 million increase in long-term debt results mainly from drawings under the revolving term credit facility to fund construction costs of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects and pre-construction development costs of the Big Silver Creek and Mesgi'g Ugju's'n projects until the project-level financing for each of these projects is secured and the revolving term credit facility can be paid down. This increase was partly offset by the scheduled repayment of project-level debt.

Since the beginning of the 2014 fiscal year, the Corporation and its subsidiaries have met all the financial and non-financial conditions related to their credit agreements, trust indentures and PPAs. Were they not met, certain financial and non-financial covenants included in the credit agreements or trust indentures 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.

Shareholders' Equity

As at March 31, 2014, the shareholders' equity of the Corporation totalled $607.1 million, including $63.9 million of non-controlling interests, compared with $665.9 million, including $81.4 million of non-controlling interests as at December 31, 2013. This $58.9 million decrease in total shareholders' equity is attributable mainly to the recognition of a $38.1 million net loss and to dividends declared on preferred and common shares of $16.2 million.

Off-Balance-Sheet Arrangements

As at March 31, 2014, the Corporation had issued letters of credit totaling $44.5 million to meet its obligations under its various PPAs and other agreements. Of this amount, $32.4 million was issued under its revolving term credit facility and the remainder under the projects' non-recourse credit facilities. As at that date, Innergex had also issued a total of $11.0 million in corporate guarantees to support the construction of the Gros-Morne wind farm and the performance of the Brown Lake hydroelectric facility.

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

FREE CASH FLOW AND PAYOUT RATIO

Free Cash Flow

When evaluating its operating results, a key performance indicator for the Corporation is the cash flows available for distribution to common shareholders and for reinvestment to fund the Corporation's growth. Free Cash Flow is a non-IFRS measure that the Corporation calculates as cash flows from operations before changes in non-cash operating working capital items, less maintenance capital expenditures net of proceeds from disposals, scheduled debt principal payments and preferred share dividends declared. It also subtracts the portion of Free Cash Flow attributed to non-controlling interests regardless of whether an actual distribution to non-controlling interests is made in order to reflect the fact that such distribution may not occur in the period the Free Cash Flow is generated, and adds back cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to other facilities owned by the Corporation over the course of their PPAs. The Corporation also adjusts for other elements that represent cash inflows or outflows that are not representative of the Corporation's long-term cash generating capacity. Such adjustments include adding back transaction costs related to realized acquisitions (which are financed at the time of the acquisition) and adding back realized losses or subtracting realized gains on derivate financial instruments used to hedge the interest rate on project-level debt prior to securing such debt.

Free Cash Flow and Payout Ratio calculation	Trailing 12-months ended March 31	
	2014	2013
Cash flows from operating activities	104,817	78,873
(Subtract) Add the following items:		
Changes in non-cash operating working capital items	(21,709)	(8,308)
Maintenance capital expenditures net of proceeds from disposals	(2,676)	(2,788)
Scheduled debt principal payments	(26,995)	(21,526)
Free Cash Flow attributed to non-controlling interests[1]	(5,195)	(5,160)
Dividends declared on Preferred shares	(7,126)	(5,235)
Cash receipt for wheeling services to be provided by the Harrison Hydro L.P. to other facilities[2]	4,916	—
Adjust for the following elements:		
Transaction costs related to realized acquisitions	499	2,275
Realized losses on derivative financial instruments	3,259	14,127
Free Cash Flow	49,790	52,258
Dividends declared on common shares	55,721	52,532
Payout Ratio - before the impact of the DRIP	112%	101%
Dividends declared on common shares and to be paid in cash[3]	38,526	46,576
Payout Ratio - after the impact of the DRIP	77%	89%

1. The portion of Free Cash Flow attributed to non-controlling interests is subtracted, regardless of whether or not an actual distribution to non-controlling interests is made, in order to reflect the fact that such distributions may not occur in the period they are generated.
2. The $4.9 million represents a cash receipt by the Harrison Hydro L.P. for the wheeling services to be provided to the Northwest Stave River facility, a portion of which was attributed to non-controlling interests.
3. Represents dividends declared on common shares outstanding that were not registered in the DRIP at the time of the declaration; the dividends declared on common shares registered in the DRIP will be paid in common shares.

For the trailing 12-month period ended March 31, 2014, the Corporation generated Free Cash Flow of $49.8 million, compared with $52.3 million for the same period last year. This decrease is due mainly to the greater scheduled debt principal payments, as cash flows from operating activities, before changes in non-cash operating working capital items and adjusted for realized losses on derivative financial instruments, remained relatively unchanged. This is attributable mainly to production being below the long-term average over a longer period during the trailing 12-month period ended March 31, 2014, compared with the same period last year, especially in the hydroelectric generation segment.

Payout Ratio

The Payout Ratio represents the dividends declared on common shares divided by Free Cash Flow. The Corporation believes it is a measure of its ability to sustain current dividends and dividend increases as well as its ability to fund its growth.

For the trailing 12-month period ended March 31, 2014, the dividends on common shares declared by the Corporation corresponded to 112% of Free Cash Flow, compared with 101% for the corresponding prior 12-month period. The negative variation is due mainly to the decrease in Free Cash Flow explained above as well as to the increase in dividends declared on common shares resulting from the higher number of shares outstanding by virtue of the DRIP.

The Payout Ratio reflects the Corporation's decision to invest each year in advancing the development of its Prospective Projects, which investments must be expensed as incurred. The Corporation considers such investments essential to its long-term growth and success, as it believes that the greenfield development of renewable energy projects offers the greatest potential internal rates of return and represents the most efficient use of management's expertise and value-added skills.

Furthermore, the Corporation does not expect to require additional equity in order to complete its current five Development Projects, given the anticipated increase in cash flows from operations, the project-level financing that the Corporation intends to secure for these projects and the additional equity provided by the DRIP.

SEGMENT INFORMATION

Geographic Segments

As at March 31, 2014, the Corporation had interests in 24 hydroelectric facilities, six wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the three-month period ended March 31, 2014, the revenues generated by the Horseshoe Bend hydroelectric facility in the United States totalled $0.4 million ($0.2 million in 2013), corresponding to a 1.0% contribution (0.7% in 2013) to the Corporation's consolidated revenues for these periods. The increase is due mainly to improved water flows compared with 2013, although they remained below the long-term average.

Operating Segments

As at March 31, 2014, the Corporation had four operating segments: hydroelectric generation, wind power generation, solar power generation and site development.

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

The accounting policies for these segments are the same as those described in the "Significant Accounting Policies" section of the Corporation's audited consolidated financial statements for the year ended December 31, 2013. The Corporation evaluates performance based on Adjusted EBITDA and accounts for inter-segment and management sales at cost. Any transfers of assets from the site development segment to the hydroelectric, wind or solar power generation segments are accounted for at cost.

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

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

Three-months ended March 31, 2014	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	186,569	223,226	7,414	—	417,209
Revenues	16,718	17,767	3,114	—	37,599
Expenses:					
Operating expenses	5,060	2,270	315	—	7,645
General and administrative expenses	2,155	881	83	435	3,554
Prospective project expenses	—	—	—	1,071	1,071
Adjusted EBITDA	9,503	14,616	2,716	(1,506)	25,329
Three-months ended March 31, 2013					
Power generated (MWh)	176,560	202,676	6,935	—	386,171
Revenues	16,575	16,200	2,913	—	35,688
Expenses:					
Operating expenses	4,077	2,070	311	—	6,458
General and administrative expenses	1,848	595	118	441	3,002
Prospective project expenses	—	—	—	825	825
Adjusted EBITDA	10,650	13,535	2,484	(1,266)	25,403

As at March 31, 2014	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Goodwill	8,269	—	—	—	8,269
Total assets	1,596,254	384,219	125,264	238,345	2,344,082
Total liabilities	1,138,308	247,582	115,841	235,275	1,737,006
Acquisition of property, plant and equipment during the period	576	67	—	21,835	22,478
As at December 31, 2013					
Goodwill	8,269	—	—	—	8,269
Total assets	1,449,527	387,062	128,146	412,339	2,377,074
Total liabilities	949,570	248,594	116,085	396,890	1,711,139
Acquisition of property, plant and equipment during the year	66,581	1,213	100	89,501	157,395

Hydroelectric Generation Segment

For the three-month period ended March 31, 2014, this segment produced 67% of the LTA and generated revenues of $16.7 million, compared with production at 73% of the LTA and revenues of $16.6 million for the same period last year. In Ontario, water flows have remained at or above average levels. In Quebec, water flows were more irregular: above-average at some facilities and below-average at others. In British Columbia, water flows remained below-average at all facilities except Brown Lake. In the United States, water flows were below average. The 1% increase in revenues stems mainly from the contribution of the Magpie facility acquired in July 2013.

The increase in total assets since December 31, 2013, is attributable mainly to the increase in property, plant and equipment relating to the transfer of the Kwoiek Creek facility from the Site Development segment, partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2013, is attributable mainly to the transfer of the Kwoiek Creek loan from the Site Development segment, partly offset by the scheduled repayment of long-term debt.

Wind Power Generation Segment

For the three-month period ended March 31, 2014, this segment produced 105% of the LTA and generated revenues of $17.8 million, compared with production at 95% of the LTA and revenues of $16.2 million for the same period last year. Wind regimes were above-average at most wind farms. The 10% increase in revenues is due mainly to production levels that were greater than for the same period last year.

The decrease in total assets since December 31, 2013, is attributable mainly to depreciation of property, plant and equipment and amortization of intangible assets.

The decrease in total liabilities since December 31, 2013, is attributable mainly to the scheduled repayment of long-term debt.

Solar Power Generation Segment

For the three-month period ended March 31, 2014, this segment produced 101% of the LTA and generated revenues of $3.1 million, compared with production at 94% of the LTA and revenues of $2.9 million for the same period last year. Solar irradiation was average for the quarter. The 7% increase in revenues is due mainly to production in line with the LTA, compared with below-average production as a result of unusually large snowfalls and snow removal activities hampered by cold weather during the same period last year.

The decrease in total assets since December 31, 2013, results mainly from depreciation of property, plant and equipment as well as amortization of intangible assets.

The decrease in total liabilities since December 31, 2013, results mainly from scheduled repayment of long-term debt.

Site Development Segment

For the three-month period ended March 31, 2014, site development expenses were $1.5 million, compared with $1.3 million in 2013. The increase is due mainly to higher prospective project expenses.

The decrease in total assets since December 31, 2013 is attributable mainly to the transfer of the Kwoiek Creek facility to the hydroelectric generation segment, partly offset by payments made for costs incurred for the construction of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects and pre-construction activities of the Big Silver Creek and Mesgi'g Ugju's'n projects.

The decrease in total liabilities since December 31, 2013 is attributable mainly to the transfer of the Kwoiek Creek loan to the hydroelectric generation segment, partly offset by the increase in derivative financial instruments following the Corporation's completion of the hedging program to fix the interest rate on future project-level debt for its Development Projects.

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

QUARTERLY FINANCIAL INFORMATION

	Three-months ended			
(in millions of dollars, unless otherwise stated)	Mar. 31, 2014	Dec. 31, 2013	Sept. 30, 2013	June 30, 2013
Power generated (MWh)	417,209	496,613	706,495	792,541
Revenues	37.6	41.4	58.0	63.2
Adjusted EBITDA	25.3	25.6	46.7	51.3
Unrealized net loss (gain) on derivative financial instruments	36.0	(11.7)	(2.4)	(27.3)
Net (loss) earnings	(38.1)	3.4	11.1	31.0
Net (loss) earnings attributable to owners of the parent	(27.4)	6.3	10.8	28.3
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(0.30)	0.05	0.09	0.28
Dividends declared on preferred shares	1.8	1.8	1.8	1.8
Dividends declared on common shares	14.4	13.9	13.8	13.7
Dividends declared on common shares, $ per share	0.150	0.145	0.145	0.145

	Three-months ended			
(in millions of dollars, unless otherwise stated)	Mar. 31, 2013	Dec. 31, 2012	Sept. 30, 2012	June 30, 2012
Power generated (MWh)	386,171	531,564	559,379	694,661
Revenues	35.7	47.1	47.1	54.3
Adjusted EBITDA	25.4	34.2	36.7	44.6
Unrealized net (gain) loss on derivative financial instruments	(3.8)	(5.3)	(9.5)	27.1
Net loss	(0.2)	(0.6)	(0.7)	(11.9)
Net earnings (loss) attributable to owners of the parent	2.8	1.8	(0.2)	(9.1)
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.01	0.00	(0.01)	(0.12)
Dividends declared on preferred shares	2.0	1.1	1.1	1.1
Dividends declared on common shares	13.6	13.6	13.5	11.8
Dividends declared on common shares, $ per share	0.145	0.145	0.145	0.145

Comparing the results for the most recent quarters illustrates the seasonality that is characteristic of the Corporation's production and the variability of power generated, revenues and Adjusted EBITDA from quarter to quarter. As the Corporation's annualized consolidated LTA production is 75% hydroelectric, this seasonality can be explained by water flows that are normally at their highest in the second quarter due to the snow melt season and at their lowest in the first quarter due to the cold temperatures, which limit precipitation in the form of rain. However, premiums for the electricity generated during the coldest months of the year included in some PPAs of the Corporation's hydroelectric facilities attenuate this seasonality. Wind regimes are generally best in the first quarter, while solar irradiation is at its highest during the summer months and at its lowest during the winter months.

Readers may expect the net earnings or losses to reflect this seasonality characteristic of run-of-river hydroelectric facilities, wind farms and solar farms. However, other factors also influence these figures, some of which have a relatively stable quarter-to-quarter impact while others are more variable. For the Corporation, the factor responsible for the largest fluctuations in net earnings (loss) is the change in the market value of derivative financial instruments. Historical analysis of net earnings (loss) 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 fluctuations and do not have an impact on the Corporation's Adjusted EBITDA, finance costs, cash flows from operating activities, Free Cash Flow and Payout Ratio.

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

INVESTMENTS IN JOINT VENTURES

The Corporation's material joint ventures at the end of the reporting period were Umbata Falls, L.P. (49% interest) and Viger-Denonville, L.P. (50% interest).

A summary of the electricity production and financial information for the Corporation's material joint ventures is presented below. The summarized financial information corresponds to amounts shown in the joint ventures' financial statements prepared in accordance with IFRS.

Electricity Production

Three months ended March 31	2014				2013			
	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Average price ($/MWh)[2]	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Average price ($/MWh)[2]
Umbata Falls	18,773	16,927	111%	83.77	18,839	16,927	111%	84.38
Viger-Denonville	23,285	20,300	115%	148.55	—	—	—	—

1. Corresponds to 100% of the facility's electricity production and LTA.
2. Including payments received from the ecoENERGY Initiative for Umbata Falls.

Umbata Falls, L.P.

Umbata Falls' Summary Statements of Earnings and Comprehensive Income

	Three months ended March 31	
	2014	2013
Revenues	1,573	1,590
Operating and general and administrative expenses	191	181
Adjusted EBITDA	1,382	1,409
Finance costs	611	611
Other net revenues	(12)	(8)
Depreciation and amortization	1,003	1,006
Unrealized net loss (gain) on derivative financial instruments	1,500	(460)
Net (loss) earnings and comprehensive (loss) income	(1,720)	260

For the three-month period ended March 31, 2014, production was above-average thanks to above-average water flows, similar to last year. Revenues and Adjusted EBITDA were also comparable to the same period last year. The net loss generated is attributable to an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates since the end of 2013, compared with an unrealized net gain on derivative financial instruments resulting from the increase in benchmark interest during the same period last year.

Umbata Falls' Summary Statements of Financial Position

As at	March 31, 2014	December 31, 2013
Current assets	4,078	3,685
Non-current assets	74,868	75,864
Current liabilities	47,586	47,972
Non-current liabilities	3,356	1,852
Partners' equity	28,004	29,725

In view of its July 2014 term maturity, the Umbata Falls loan has been recorded in the current portion of long-term debt. Umbata Falls, L.P. expects to refinance the outstanding balance by that date. In addition, Umbata Falls, L.P. uses a derivative financial instrument to manage its exposure to the risk of increasing interest rates on its debt financing and does not own or issue any Derivatives for speculation purposes. An interest-rate swap totaling $46.4 million used to hedge the interest rate on 100% of the Umbata Falls loan had a net negative value of $4.5 million at March 31, 2014 (negative $3.0 million at December 31, 2013).

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

Viger-Denonville, L.P.

Viger-Denonville's Summary Statements of Earnings and Comprehensive Income

	Three months ended March 31	
	2014	2013
Revenues	3,459	—
Operating and general and administrative expenses	541	2
Adjusted EBITDA	2,918	(2)
Finance costs	839	—
Other net revenues	(6)	—
Depreciation and amortization	835	—
Unrealized net loss on derivative financial instruments	1,557	504
Net loss and comprehensive loss	(307)	(506)

For the three-month period ended March 31, 2014, revenues and Adjusted EBITDA reflect the operation of the Viger-Denonville wind farm, which was commissioned in November 2013. The net loss generated is attributable to an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates since the end of 2013.

Viger-Denonville's Summary Statements of Financial Position

As at	March 31, 2014	December 31, 2013
Current assets	10,923	9,221
Non-current assets	62,887	63,940
Current liabilities	9,065	8,200
Non-current liabilities	44,904	44,813
Partners' equity	19,841	20,148

Viger-Denonville, L.P. uses a derivative financial instrument to manage its exposure to the risk of increasing interest rates on its debt financing and does not own or issue any Derivatives for speculation purposes. An interest-rate swap totaling $58.5 million used to hedge the interest rate of the Viger-Denonville loan had a net negative value of $2.4 million at March 31, 2014 (negative $0.9 million at December 31, 2013).

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

NON-WHOLLY OWNED SUBSIDIARIES

Summarized financial information regarding each of the Corporation's subsidiaries that has material non-controlling interests is set out below. Amounts are shown before intragroup eliminations.

Harrison Hydro L.P. and Its Eight Subsidiaries

Harrison Hydro's Summary Statements of Earnings and Comprehensive Income

	Three months ended March 31	
	2014	2013
Revenues	4,398	4,854
Adjusted EBITDA	2,204	2,602
Net loss and comprehensive loss	(8,572)	(5,644)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(4,428)	(2,965)
Non-controlling interests	(4,144)	(2,679)
	(8,572)	(5,644)

For the three-month period ended March 31, 2014, the decrease in revenues and Adjusted EBITDA is due mainly to lower production levels compared with the same period last year, which have remained below the LTA as a result of below-average water flows in British Columbia. The greater net loss is also attributable to inflation compensation interest on the real return bonds of $0.2 million, compared with negative inflation compensation interest of $2.1 million for the same period last year.

Harrison Hydro's Summary Statements of Financial Position

As at	March 31, 2014	December 31, 2013
Current assets	9,952	30,143
Non-current assets	658,479	662,749
Current liabilities	12,428	13,925
Non-current liabilities	459,722	460,511
Equity attributable to owners	119,264	130,497
Non-controlling interests	77,017	87,959

As at March 31, 2014, the decrease in non-current assets is due mainly to depreciation of fixed assets. Furthermore, Harrison Hydro L.P. distributed $13.6 million in 2013. The distribution was made in the form of non-interest bearing loans of $6.8 million each to the Corporation and its partners, which were presented as loans to partners at December 31, 2013. On January 1, 2014, these loans were reimbursed directly from distributions from Harrison Hydro L.P., and a corresponding decrease in non-controlling interests was recorded in 2014 with no impact to cash flows.

Harrison Hydro's Summary Statements of Cash Flows

	Three months ended March 31	
	2014	2013
Net cash outflow from operating activities	(5,678)	(5,888)
Net cash outflow from financing activities	(1,448)	(1,371)
Net cash inflow from investing activities	577	482
Net decrease in cash and cash equivalents	(6,549)	(6,777)

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

Creek Power Inc. and Its Six Subsidiaries

Creek Power's Summary Statements of Earnings and Comprehensive Income

	Three months ended March 31	
	2014	2013
Revenues	3	10
Adjusted EBITDA	(489)	(379)
Net loss and comprehensive loss	(13,497)	(830)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(8,994)	(546)
Non-controlling interest	(4,504)	(284)
	(13,498)	(830)

For the three-month period ended March 31, 2014, the recognition of a net loss is due mainly to an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates since December 31, 2013, compared with a much smaller decrease in benchmark interest rates during the same period last year.

Creek Power's Summary Statements of Financial Position

As at	March 31, 2014	December 31, 2013
Current assets	995	6,593
Non-current assets	85,360	67,349
Current liabilities	25,710	13,547
Non-current liabilities	83,282	69,534
Deficit attributable to owners	(18,891)	(9,897)
Non-controlling interest	(3,746)	758

The increase in balance sheet items is due mainly to construction spending for the Upper Lillooet River and Boulder Creek projects.

Creek Power's Summary Statements of Cash Flows

	Three months ended March 31	
	2014	2013
Net cash outflow from operating activities	(449)	(277)
Net cash inflow from financing activities	9,189	628
Net cash outflow from investing activities	(8,800)	(593)
Net decrease in cash and cash equivalents	(60)	(242)

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

Kwoiek Creek Resources L.P. and Its General Partner

Kwoiek Creek Resources' Summary Statements of Earnings and Comprehensive Income

	Three months ended March 31	
	2014	2013
Revenues	376	—
Adjusted EBITDA	(153)	(3)
Net loss and comprehensive loss	(3,924)	(3)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(1,894)	(1)
Non-controlling interest	(2,030)	(2)
	(3,924)	(3)

For the three-month period ended March 31, 2014, the modest revenue generation is attributable to below-average production resulting from below-average water flows. The net loss is attributable mainly to the depreciation expense and interest costs incurred.

Kwoiek Creek Resources' Summary Statements of Financial Position

As at	March 31, 2014	December 31, 2013
Current assets	21,249	34,019
Non-current assets	178,624	177,928
Current liabilities	5,071	23,694
Non-current liabilities	213,374	202,901
Deficit attributable to owners	(9,408)	(7,514)
Non-controlling interests	(9,164)	(7,134)

Kwoiek Creek Resources' Summary Statements of Cash Flows

	Three months ended March 31	
	2014	2013
Net cash outflow from operating activities	(2,728)	(4,611)
Net cash (outflow) inflow from financing activities	(28)	2,989
Net cash inflow (outflow) from investing activities	3,339	(3,766)
Net increase (decrease) in cash and cash equivalents	583	(5,388)

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

Mesgi'g Ugju's'n (MU) Wind Farm L.P. and Its General Partner ("Mesgi'g Ugju's'n")

The Mesgi'g Ugju's'n subsidiary was created on March 21, 2014.

Mesgi'g Ugju's'n's Summary Statement of Earnings and Comprehensive Income

	Period of 10 days ended March 31, 2014
Revenues	—
Adjusted EBITDA	—
Net earnings and comprehensive earnings	121
Net earnings and comprehensive income attributable to:	
Owners of the parent	121
Non-controlling interest	—
	121

Mesgi'g Ugju's'n's Summary Statement of Financial Position

As at	March 31, 2014
Current assets	642
Non-current assets	2,215
Current liabilities	315
Non-current liabilities	121
Equity attributable to owners	2,421
Non-controlling interest	—

The non-current assets pertain mainly to project development costs incurred to date.

Mesgi'g Ugju's'n's Summary Statement of Cash Flows

	Period of 10 days ended March 31, 2014
Net cash outflow from operating activities	(73)
Net cash inflow from financing activities	1,101
Net cash outflow from investing activities	(687)
Net increase in cash and cash equivalents	341

ACCOUNTING CHANGES

Application of New IFRS Standards

IFRIC 21 Levies

In May 2013, the International Accounting Standards Board (”IASB”) issued IFRIC 21 – Levies (“IFRIC 21”), an interpretation of IAS 37 – Provisions, Contingent Liabilities and Contingent Assets (“IAS 37”), on the accounting for levies imposed by governments. IAS 37 sets out criteria for the recognition of a liability, one of which is the requirement for the entity to have a present obligation as a result of a past event (“obligating event”). IFRIC 21 clarifies that the obligating event that gives rise to a liability to pay a levy is the activity described in the relevant legislation that triggers the payment of the levy. This standard have been adopted and applied in these financial statements. The application of this standard has not had any material impact on the amounts reported for the current year.

SUBSEQUENT EVENTS

Approval of amendments to the Kwoiek Creek PPA by the British Columbia Utilities Commission

On April 24, 2014, the British Columbia Utilities Commission approved the amendments between BC Hydro and the Corporation and its partner, clarifying stipulated production levels under the PPA for the Kwoiek Creek hydroelectric facility. As a result, BC Hydro has accepted the COD certificate with an effective commissioning date of January 1, 2014.

Discount of 2.5% granted on the price of shares issued under the Dividend Reinvestment Plan (DRIP)

On May 13, 2014, the Corporation elected to grant a discount of 2.5% on the purchase price of shares issued to shareholders participating in the DRIP. Consequently, starting with the next dividend payment on July 15, 2014 to shareholders of record on June 30, 2014, the price will be the weighted-average trading price of the common shares on the Toronto Stock Exchange during the five (5) business days immediately preceding the dividend payment date, less the discount of 2.5%.

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS

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

	Notes	Three months ended March 31 2014	2013
Revenues		37,599	35,688
Expenses			
Operating	3	7,645	6,458
General and administrative		3,554	3,002
Prospective projects		1,071	825
Earnings before finance costs, income taxes, depreciation, amortization, other net revenues, share of loss of joint ventures and unrealized net loss (gain) on derivative financial instruments		25,329	25,403
Finance costs	4	19,664	12,952
Other net revenues	5	(173)	(2,373)
Earnings before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net loss (gain) on derivative financial instruments		5,838	14,824
Depreciation	3,7	13,659	12,009
Amortization	3	5,188	5,452
Share of loss of joint ventures		996	126
Unrealized net loss (gain) on derivative financial instruments		36,030	(3,838)
(Loss) earnings before income taxes		(50,035)	1,075
(Recovery) provision for income taxes			
Current		751	804
Deferred		(12,681)	449
		(11,930)	1,253
Net loss		(38,105)	(178)
Net (loss) earnings attributable to:			
Owners of the parent		(27,419)	2,797
Non-controlling interests		(10,686)	(2,975)
		(38,105)	(178)
Weighted average number of common shares outstanding (in 000s)	6	95,827	93,913
Basic net (loss) earnings per share ($)	6	(0.30)	0.01
Diluted weighted average number of common shares outstanding (in 000s)	6	95,990	94,027
Diluted net (loss) earnings per share ($)	6	(0.30)	0.01

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

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

	Three months ended March 31	
	2014	2013
Net loss	(38,105)	(178)
Items of comprehensive income (loss) that will be subsequently reclassified to profit or loss:		
Foreign exchange gain on translation of self-sustaining foreign subsidiaries	241	96
Deferred income tax provision	(32)	(12)
Foreign exchange loss on the designated portion of the US dollar denominated debt used as hedge on the investment in self-sustaining foreign subsidiaries	(244)	(99)
Deferred income tax recovery	32	13
Other comprehensive loss	(3)	(2)
Total comprehensive loss	(38,108)	(180)
Total comprehensive (loss) income attributable to:		
Owners of the parent	(27,422)	2,795
Non-controlling interests	(10,686)	(2,975)
	(38,108)	(180)

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at	Notes	March 31, 2014	December 31, 2013
Assets			
Current assets			
Cash and cash equivalents		23,166	34,267
Restricted cash and short-term investments		28,470	49,745
Accounts receivable		24,113	19,799
Reserve accounts		1,473	1,771
Income tax receivable		37	80
Derivative financial instruments		1,658	7,563
Loans to related parties	11	—	6,798
Prepaid and others		5,876	5,085
		84,793	125,108
Reserve accounts		45,382	45,791
Property, plant and equipment	7	1,592,126	1,583,417
Intangible assets		460,958	466,093
Project development costs		82,758	81,643
Investments in joint ventures		23,643	24,639
Derivative financial instruments		5,908	7,066
Deferred tax assets		5,944	1,804
Goodwill		8,269	8,269
Other long-term assets		34,301	33,244
		2,344,082	2,377,074

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at	Notes	March 31, 2014	December 31, 2013
Liabilities			
Current liabilities			
Dividends payable to shareholders		16,160	15,651
Accounts payable and other payables		24,309	48,258
Income tax liabilities		1,132	2,216
Derivative financial instruments		32,256	12,915
Current portion of long-term debt		27,260	26,649
Current portion of other liabilities		310	362
		101,427	106,051
Construction holdbacks		2,795	1,347
Derivative financial instruments		35,707	26,081
Accrual for acquisition of long-term assets		13,623	9,855
Long-term debt		1,337,819	1,313,718
Other liabilities		10,662	10,567
Liability portion of convertible debentures		79,877	79,831
Deferred tax liabilities		155,096	163,689
		1,737,006	1,711,139
Shareholders' equity			
Common shares capital		12,515	10,374
Contributed surplus from reduction of capital on common shares		784,482	784,482
Preferred shares		131,069	131,069
Share-based payment		1,872	1,806
Equity portion of convertible debentures		1,340	1,340
Deficit		(388,388)	(344,809)
Accumulated other comprehensive income		241	244
Equity attributable to owners		543,131	584,506
Non-controlling interests		63,945	81,429
Total shareholders' equity		607,076	665,935
		2,344,082	2,377,074

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

	Equity attributable to owners										
For the three-month period ended March 31, 2014	Number of common shares (In 000s)	Common shares capital account	Contributed surplus from reduction of capital on common shares	Preferred shares	Share-based payment	Equity portion of convertible debentures	Deficit	Accumulated other comprehensive income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2014	95,655	10,374	784,482	131,069	1,806	1,340	(344,809)	244	584,506	81,429	665,935
Net loss							(27,419)		(27,419)	(10,686)	(38,105)
Other items of comprehensive income								(3)	(3)		(3)
Total comprehensive loss	—	—	—	—	—	—	(27,419)	(3)	(27,422)	(10,686)	(38,108)
Common shares issued through dividend reinvestment plan	206	2,141							2,141		2,141
Share-based payment					66				66		66
Distributions to non-controlling interests (Note 11)										(6,798)	(6,798)
Dividends declared on Common shares							(14,379)		(14,379)		(14,379)
Dividends declared on Preferred shares							(1,781)		(1,781)		(1,781)
Balance March 31, 2014	95,861	12,515	784,482	131,069	1,872	1,340	(388,388)	241	543,131	63,945	607,076

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

	Equity attributable to owners										
For the three-month period ended March 31, 2013	Number of common shares (In 000s)	Common shares capital account	Contributed surplus from reduction of capital on common shares	Preferred shares	Share-based payment	Equity portion of convertible debentures	Deficit	Accumulated other comprehensive income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2013	93,660	120,500	656,281	131,069	1,511	1,340	(330,621)	241	580,321	107,611	687,932
Net earnings (loss)							2,797		2,797	(2,975)	(178)
Other items of comprehensive loss								(2)	(2)		(2)
Total comprehensive income (loss)	—	—	—	—	—	—	2,797	(2)	2,795	(2,975)	(180)
Common shares issued through dividend reinvestment plan	304	3,021							3,021		3,021
Share-based payment					86				86		86
Dividends declared on Common shares							(13,625)		(13,625)		(13,625)
Dividends declared on Preferred shares							(2,047)		(2,047)		(2,047)
Balance March 31, 2013	93,964	123,521	656,281	131,069	1,597	1,340	(343,496)	239	570,551	104,636	675,187

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

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

		Three months ended March 31	
		2014	2013
	Notes		
Operating activities			
Net loss		(38,105)	(178)
Items not affecting cash:			
Depreciation		13,659	12,009
Amortization		5,188	5,452
Share of loss of joint ventures		996	126
Unrealized net loss (gain) on derivative financial instruments		36,030	(3,838)
Inflation compensation interest	4	232	(2,124)
Amortization of financing fees	4	256	218
Amortization of revaluation of long-term debt and convertible debentures	4	394	417
Accretion expenses on other liabilities	4	155	123
Share-based payment		66	86
Deferred income taxes		(12,681)	449
Effect of exchange rate fluctuations		236	131
Others		(166)	—
Interest on long-term debt and convertible debentures	4	18,428	14,318
Interest paid		(18,637)	(14,577)
Distributions received from joint ventures		—	725
Provision for current income taxes		751	804
Net income taxes paid		(1,808)	(250)
		4,994	13,891
Changes in non-cash operating working capital items	9	(10,291)	(1,717)
		(5,297)	12,174
Financing activities			
Dividends paid on common shares		(11,729)	(10,560)
Dividends paid on preferred shares		(1,781)	(1,063)
Increase of long-term debt		34,316	11,999
Repayment of long-term debt		(11,004)	(17,431)
Payment of deferred financing costs		(52)	(42)
Payment of other liabilities		(112)	—
Net proceeds from issuance of preferred shares		—	(351)
		9,638	(17,448)

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

UNAUDITED CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

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

		Three months ended March 31	
		2014	2013
	Notes		
Investing activities			
Decrease of restricted cash and short-term investments		21,275	19,612
Net funds withdrawn from the reserve accounts		738	1,227
Additions to property, plant and equipment		(25,449)	(37,069)
Additions to intangible assets		—	(27)
Additions to project development costs		(11,420)	(2,023)
Investments in joint ventures		—	(725)
(Additions to) reduction of other long-term assets		(625)	9
Proceeds from disposal of property, plant and equipment		3	—
		(15,478)	(18,996)
Effects of exchange rate changes on cash and cash equivalents		36	8
Net decrease in cash and cash equivalents		(11,101)	(24,262)
Cash and cash equivalents, beginning of period		34,267	49,496
Cash and cash equivalents, end of period		23,166	25,234
Cash and cash equivalents is comprised of:			
Cash		14,302	12,584
Short-term investments		8,864	12,650
		23,166	25,234

Additional information is presented in Note 9.

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

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

DESCRIPTION OF BUSINESS

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

These unaudited condensed consolidated financial statements were approved by the Board of Directors on May 13, 2014.

The Corporation's revenues are variable with each season and are normally at their lowest in the first quarter due to cold temperature. As a result, earnings of interim periods should not be considered as indicative of results for an entire year.

1. BASIS OF PRESENTATION AND STATEMENT OF COMPLIANCE

These condensed consolidated financial statements have been prepared using accounting policies consistent with International Financial Reporting Standards ("IFRS"). The condensed consolidated financial statements are in compliance with IAS-34 Interim Financial Reporting. The same accounting policies and methods of application as described in the Corporation's latest annual report have been used. However, these condensed consolidated financial statements do not include all disclosures required under IFRS and, accordingly, should be read in conjunction with the audited consolidated financial statements and the notes thereto included in the Corporation's latest annual report.

The condensed consolidated financial statements have been prepared on a historical cost basis, except for certain financial instruments that are measured at fair values as described in the significant accounting policies included in the Corporation's latest annual report.

2. APPLICATION OF NEW IFRS AFFECTING THE REPORTED FINANCIAL PERFORMANCE AND FINANCIAL POSITION IN THE CURRENT YEAR

IFRIC 21 - Levies

In May 2013, the International Accounting Standards Board ("IASB") issued IFRIC 21 – Levies ("IFRIC 21"), an interpretation of IAS 37 – Provisions, Contingent Liabilities and Contingent Assets ("IAS 37"), on the accounting for levies imposed by governments. IAS 37 sets out criteria for the recognition of a liability, one of which is the requirement for the entity to have a present obligation as a result of a past event ("obligating event"). IFRIC 21 clarifies that the obligating event that gives rise to a liability to pay a levy is the activity described in the relevant legislation that triggers the payment of the levy. This standard have been adopted and applied in these financial statements. The application of this standard has not had any material impact on the amounts reported for the current year.

3. OPERATING EXPENSES

	Three months ended March 31	
	2014	2013
Salaries	788	649
Insurance	567	488
Operation and maintenance	3,402	3,068
Property taxes and royalties	2,888	2,253
	7,645	6,458

Depreciation and amortization recorded in the consolidated statements of earnings are mainly related to operating expenses incurred to generate revenues.

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

4. FINANCE COSTS

	Three months ended March 31	
	2014	2013
Interest on long-term debt and on convertible debentures	18,428	14,318
Inflation compensation interest	232	(2,124)
Amortization of financing fees	256	218
Amortization of revaluation of long-term debt and convertible debentures	394	417
Accretion expenses on other liabilities	155	123
Others	199	—
	19,664	12,952

5. OTHER NET REVENUES

	Three months ended March 31	
	2014	2013
Transaction costs	—	111
Realized loss on foreign exchange	256	66
Other net revenues	(429)	(550)
Settlement of claims received in relation with an acquisition	—	(2,000)
	(173)	(2,373)

6. COMPUTATION OF NET (LOSS) EARNINGS AVAILABLE TO COMMON SHAREHOLDERS

The net (loss) earnings attributable to owners of the parent are adjusted for the dividends on the preferred shares as follows:

	Three months ended March 31	
	2014	2013
Net (loss) earnings attributable to owners of the parent	(27,419)	2,797
Dividends declared on preferred shares	(1,781)	(2,047)
Net (loss) earnings available to commons shareholders	(29,200)	750
Weighted average number of common shares (in 000s)	95,827	93,913
Basic net (loss) earnings per share ($)	(0.30)	0.01
Weighted average number of common shares (in 000s)	95,827	93,913
Effect of dilutive elements on common shares (in 000s) (a)	163	114
Diluted weighted average number of common shares (in 000s)	95,990	94,027
Diluted net (loss) earnings per share ($) (b)	(0.30)	0.01

a. During the three-month period ended March 31, 2014, 1,243,000 of 3,073,684 stock options (1,263,000 of 2,736,684 for the three-month period ended March 31, 2013) and 7,558,684 shares which can be issued on conversion of convertible debentures (7,558,684 for the three-month period ended March 31, 2013) were excluded from the calculation of diluted weighted average number of shares outstanding as the exercise price was above the average market price of common shares.

b. During the three-month period ended March 31, 2014, 1,830,684 of 3,073,684 stock options (nil for the period ended March 31, 2013) were excluded from the calculation of diluted net loss per shares as it was anti-dilutive due to a net loss available to common shareholders.

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

7. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Other equipments	Total
Cost							
As at January 1, 2014	2,141	1,063,065	370,729	124,205	201,742	7,473	1,769,355
Additions	—	488	67	—	21,835	88	22,478
Transfer of assets upon commissioning	—	154,175	—	—	(154,175)	—	—
Dispositions	—	(298)	—	—	—	(46)	(344)
Other changes	—	17	—	—	—	(17)	—
Net foreign exchange differences	4	222	—	—	—	5	231
As at March 31, 2014	2,145	1,217,669	370,796	124,205	69,402	7,503	1,791,720
Accumulated depreciation							
As at January 1, 2014	—	(107,529)	(64,772)	(9,915)	—	(3,722)	(185,938)
Depreciation	—	(7,424)	(4,370)	(1,488)	—	(377)	(13,659)
Dispositions	—	30	—	—	—	45	75
Net foreign exchange differences	—	(69)	—	—	—	(3)	(72)
As at March 31, 2014	—	(114,992)	(69,142)	(11,403)	—	(4,057)	(199,594)
Carrying amount as at March 31, 2014	2,145	1,102,677	301,654	112,802	69,402	3,446	1,592,126

All of the property, plant and equipment are given as securities under the respective project financing or for the corporate financing.

Additions in the current period include $401 of capitalized financing costs ($13,359 for the year ended December 31, 2013) incurred prior to their intended use.

The financing costs related to a specific project financing are entirely capitalized to the specific property, plant and equipment. Financing costs related to the revolving term credit facility are capitalized for the portion of the financing actually used for a specific property, plant and equipment.

The cost of facilities were reduced by investment tax credits of $1,161 ($1,161 as at December 31, 2013).

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

8. DIVIDENDS

The following are the dividends paid by the Corporation during the year.

Record date	Payment date	Dividends per common share ($)	Dividends per Preferred Series A share ($)	Dividends per Preferred Series C share ($)
12/31/2013	1/15/2014	0.1450	0.3125	0.359375
3/31/2014	4/15/2014	0.1500	0.3125	0.359375
		0.2950	0.6250	0.718750

9. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	March 31, 2014	March 31, 2013
Accounts receivable and income tax receivable	(4,251)	5,186
Prepaid and others	(791)	(421)
Accounts payable, other payables and income tax liabilities	(5,249)	(6,482)
	(10,291)	(1,717)

b. Additional information

	March 31, 2014	March 31, 2013
Interest paid (including $405 capitalized interest ($2,757 in 2013))	19,042	17,334
Non-cash transactions		
in unpaid property, plant and equipment	(3,006)	(10,845)
in unpaid development costs	(10,305)	(782)
in unpaid intangible assets	—	(27)
in unpaid issuance costs of preferred shares	—	(351)
in common shares issued through dividend reinvestment plan	(2,141)	(3,021)

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

10. SUBSIDIARIES

Mesgi'g Ugju's'n (MU) Wind Farm L.P. and Its General Partner

In March 2014, the Corporation and its Mi'gmaq partner signed a 20-year fixed-price Purchase Power Agreement. This project is for the construction and operation of a wind farm located in Québec. According to the agreement signed, the voting rights held by non-controlling interest is 50% even though the Corporation owns more than 50% of the economic interest in Mesgi'g Ugju's'n (MU) Wind Farm L.P.

The summarized financial information below represents amounts before intragroup eliminations.

As at	March 31, 2014
Summary Statement of Financial Position	
Current assets	642
Non-current assets	2,215
Current liabilities	315
Non-current liabilities	121
Equity attributable to owners	2,421
Non-controlling interest	—

	Period of 10 days ended March 31, 2014
Summary Statement of Earnings and Comprehensive income	
Revenues	—
Expenses (other net revenues)	(121)
Net earnings and comprehensive income	121
Net earnings and comprehensive income attributable to:	
Owners of the parent	121
Non-controlling interest	—
	121
Summary Statement of Cash Flows	
Net cash outflow from operating activities	(73)
Net cash inflow from financing activities	1,101
Net cash outflow from investing activities	(687)
Net increase in cash and cash equivalents	341

Financial support to structured entity

Based on the contractual arrangements between the Corporation and the other partner signed during the first quarter of 2014, the Corporation concluded that it has control over Mesgi'g Ugju's'n (MU) Wind Farm L.P.

The Corporation is responsible for financing equity required by the project. Mi'gmawei Mawiomi Resources L.P., the other partner, can participate in the financing of the equity for an amount up to a maximum of $10,000.

The Corporation invested a total of $2,300 in Mesgi'g Ugju's'n (MU) Wind Farm L.P. preferred equity. This investment provides the Corporation with revenues in the form of preferred distributions.

Distributions on preferred units will subsequently be payable subject to the availability of gross revenues. The cumulated distributions on preferred units are payable before making any distributions on common units.

11. RELATED PARTY TRANSACTIONS

The Harrison Hydro L.P. distributed $13,600 in 2013. The funds were distributed in the form of non-interest bearing loans of $6,798 each to the Corporation and its partners, which were presented as loans to partners as at December 31, 2013. On January 1, 2014, the $6,798 loans were reimbursed directly from distributions from the Harrison Hydro L.P. and a corresponding decrease in non-controlling interests was recorded in 2014 with no impact to cash flows.

12. SEGMENT INFORMATION

Geographic segments

The Corporation owns interests in 24 hydroelectric facilities, six wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the period ended March 31, 2014, revenues generated by the Horseshoe Bend hydroelectric facility located in the United States totalled $394 ($243 in 2013), representing a contribution of 1.0% for the period ended March 31, 2014 (0.7% in 2013) to the Corporation’s consolidated revenues for these periods.

Operating segments

The Corporation has four operating segments: (a) hydroelectric generation (b) wind power generation (c) solar power generation and (d) site development.

Through its hydroelectric, wind power and solar power generation segments, the Corporation sells electricity produced by its hydroelectric, wind farm and solar facilities to publicly owned utilities or other creditworthy counterparties. Through its site development segment, it analyzes potential sites and develops hydroelectric, wind and solar facilities up to the commissioning stage.

The accounting policies for these segments are the same as those described in the significant accounting policies. The Corporation evaluates performance based on earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of (earnings) loss of joint ventures and unrealized net (gain) loss on derivative financial instruments. The Corporation accounts for inter-segment and management sales at cost. Any transfers of assets from the site development segment to the hydroelectric, wind power generation or solar power generation segments are accounted for at cost.

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

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

Three-month period ended March 31, 2014					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	16,718	17,767	3,114	—	37,599
Expenses:					
Operating	5,060	2,270	315	—	7,645
General and administrative	2,155	881	83	435	3,554
Prospective projects	—	—	—	1,071	1,071
Earnings before finance costs, income taxes, depreciation, amortization, other net revenues, share of loss of joint ventures and unrealized net loss on derivative financial instruments	9,503	14,616	2,716	(1,506)	25,329
Finance costs					19,664
Other net revenues					(173)
Earnings before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net loss on derivative financial instruments					5,838
Depreciation					13,659
Amortization					5,188
Share of loss of joint ventures					996
Unrealized net loss on derivative financial instruments					36,030
Loss before incomes taxes					(50,035)

As at March 31, 2014					
Goodwill	8,269	—	—	—	8,269
Total assets	1,596,254	384,219	125,264	238,345	2,344,082
Total liabilities	1,138,308	247,582	115,841	235,275	1,737,006
Acquisition of property, plant and equipment during the period	576	67	—	21,835	22,478

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

Three-month period ended March 31, 2013					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	16,575	16,200	2,913	—	35,688
Expenses:					
Operating	4,077	2,070	311	—	6,458
General and administrative	1,848	595	118	441	3,002
Prospective projects	—	—	—	825	825
Earnings before finance costs, income taxes, depreciation, amortization, other net revenues, share of loss of joint ventures and unrealized net gain on derivative financial instruments	10,650	13,535	2,484	(1,266)	25,403
Finance costs					12,952
Other net revenues					(2,373)
Earnings before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net gain on derivative financial instruments					14,824
Depreciation					12,009
Amortization					5,452
Share of loss of joint ventures					126
Unrealized net gain on derivative financial instruments					(3,838)
Earnings before income taxes					1,075

As at December 31, 2013					
Goodwill	8,269	—	—	—	8,269
Total assets	1,449,527	387,062	128,146	412,339	2,377,074
Total liabilities	949,570	248,594	116,085	396,890	1,711,139
Acquisition of property, plant and equipment during the year	66,581	1,213	100	89,501	157,395

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

13. SUBSEQUENT EVENTS

a. Dividends declared by the Board of Directors

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
05/13/2014	06/30/2014	07/15/2014	0.1500	0.3125	0.359375

On February 25, 2014, the Board of Directors increased the annual dividend that the Corporation intends to distribute from $0.58 to $0.60 per common share, payable quarterly.

b. Approval of amendments to the Kwoiek Creek PPA by the British Columbia Utilities Commission

On April 24, 2014, the British Columbia Utilities Commission approved the amendments between BC Hydro and the Corporation and its partner, clarifying stipulated production levels under the PPA for the Kwoiek Creek hydroelectric facility. As a result, BC Hydro has accepted the COD certificate with an effective commissioning date of January 1, 2014.

c. Discount of 2.5% granted on the price of shares issued under the Dividend Reinvestment Plan (DRIP)

On May 13, 2014, the Corporation elected to grant a discount of 2.5% on the purchase price of shares issued to shareholders participating in the DRIP. Consequently, starting with the next dividend payment on July 15, 2014 to shareholders of record on June 30, 2014, the price will be the weighted-average trading price of the common shares on the Toronto Stock Exchange during the five (5) business days immediately preceding the dividend payment date, less the discount of 2.5%.

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.
Series C Preferred Shares of Innergex Renewable Energy Inc. are listed on the TSX under the symbol INE.PR.C.
Convertible Debentures of Innergex Renewable Energy Inc. are listed on the TSX under the symbol INE.DB.

Rating Agencies

Innergex Renewable Energy Inc. is rated BBB- by S&P and BB (high) by DBRS (unsolicited).
Series A Preferred Shares of Innergex Renewable Energy Inc. are rated P-3 by S&P and Pfd-4 (high) by DBRS (unsolicited).
Series C Preferred Shares of Innergex Renewable Energy Inc. are rated P-3 by S&P and Pfd-4 (high) by DBRS (unsolicited).

Transfer Agent and Registrar

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Email: service@computershare.com

Dividend Reinvestment Plan

Innergex Renewable Energy Inc. implemented a Dividend Reinvestment Plan (DRIP) for its common shareholders, which enables eligible holders of common shares to acquire additional common shares of the Corporation by reinvesting all or part of their cash dividends. For more information about the Corporation's DRIP, please visit our Website or contact the DRIP administrator, Computershare Trust Company of Canada.

Independent Auditor

Deloitte LLP

Investor Relations

If you have inquiries, please visit our website or contact:

Jean Trudel, MBA
Chief Investment Officer and Senior Vice President – Communications

Marie-Josée Privyk, CFA, SIPC
Director – Investor Relations

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