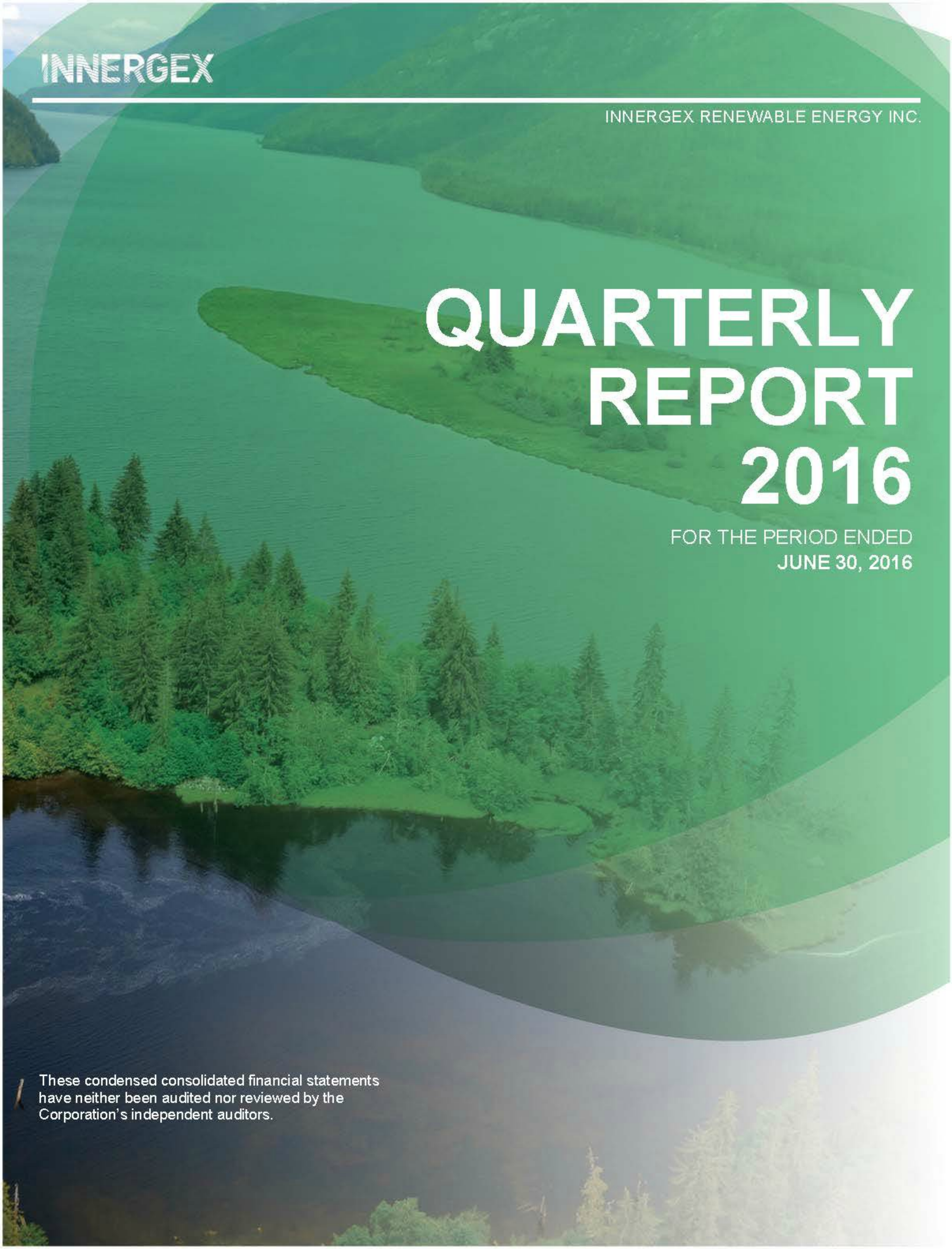

INNERGEX

INNERGEX RENEWABLE ENERGY INC.

QUARTERLY REPORT 2016

FOR THE PERIOD ENDED
JUNE 30, 2016

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

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, British Columbia, Idaho, USA, and in France. The Corporation's shares are listed on the Toronto Stock Exchange ("TSX") under the symbols INE, INE.PR.A and INE.PR.C and its convertible debentures under the symbol INE.DB.A.

Innergex's mission is to increase its production of renewable energy by developing and operating high-quality facilities while respecting the environment and balancing 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 six-month period ended June 30, 2016, and reflects all material events up to August 4, 2016, 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 consolidated financial statements and the accompanying notes for the three- and six-month periods ended June 30, 2016, and with the Corporation's *Financial Review* at December 31, 2015.

The unaudited condensed consolidated financial statements attached to this MD&A and the accompanying notes for the three- and six-month periods ended June 30, 2016, along with the 2015 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.

Q2 & HALF YEAR 2016 HIGHLIGHTS

- Innergex had a very good start of the year
  - Production was 115% of the long-term average ("LTA") for the first half of 2016 and 113% of the LTA for Q2
  - Q2 Revenues increased 25% to $87.8 million and Q2 Adjusted EBITDA rose 25% to $66.9 million compared with 2015
- Construction of the Development Projects advanced very well
  - The Upper Lillooet and Boulder Creek hydroelectric projects are making up time lost to the 2015 forest fire
  - The commercial operation date ("COD") for the Big Silver Creek project is imminent, notice that all COD requirements have been satisfied was sent to British Columbia Hydro Power and Authority
- The Corporation acquired a 87 MW wind farm portfolio in France and entered into an agreement to purchase another 44MW in France in Q1 2017 (the "French Acquisition")
- Innergex finalized the investment by the Desjardins Group Pension Plan ("Desjardins") in the French Acquisition portfolio
- The gross estimated LTA of the Mesgi'g Ugju's'n wind farm increased by 9%, resulting in an increase of $3.2 million in 2017 Projected Free Cash Flow allocated to Innergex.
- The Corporation secured land rights for more than 100 MW of prospective wind farms projects in France

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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 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 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 of the Corporation have certified that : (a) there were no material weaknesses relating to the DC&P and ICFR for the three-month period ended June 30, 2016; (b) they have limited the scope of the Corporation's design of DC&P and ICFR to exclude the controls policies and procedures of Energie Antoigné S.A.S., Energie du Porcien S.A.S, Eoles Beaumont S.A.S., Energie des Cholletz S.A.S., Eoliennes de Longueval S.A.S., Energie Des Valottes S.A.S. et Société d'Exploitation du Parc Éolien du Bois d'Anchat (the "Seven French Entities") and (c) there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR during the three-month period ended June 30, 2016. The design and evaluation of the operating effectiveness of the DC&P and ICFR for the Seven French Entities will be completed in the 12 months following the date of acquisition. Summary unaudited financial information about the Seven French Entities is presented in the Innergex Europe L.P. and its Subsidiaries section of this MD&A.

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 , projected Free Cash Flow, estimated project costs and expected project financing, to inform readers of the potential financial impact of expected results, of the expected commissioning of Development Projects, of the potential financial impact of the French Acquisition, of the Corporation's 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 for building shareholder value; its ability to raise additional capital 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; uncertainties 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; the possibility that the Corporation may not declare or pay a dividend; the ability to secure new power purchase agreements or to renew any power purchase agreement; changes in governmental 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 cost 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; foreign market growth and development risks; cybersecurity; sufficiency of insurance coverage limits and exclusions; a credit rating that may not reflect actual performance of the Corporation or a lowering (downgrade) of the credit rating; potential undisclosed liabilities associated with acquisitions; integration of the facilities and projects acquired and to be acquired; failure to realize the anticipated benefits of acquisitions, including those of the French Acquisition; reliance on shared transmission and interconnection infrastructure; and the fact that revenues from the Miller Creek facility will vary based on the spot price of 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 as 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 law.

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 together the expected LTA of all the facilities in operation that it consolidates (excludes Umbata Falls and Viger-Denonville, which are 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 Natural disaster
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, which are 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-than-expected inflation rate
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 Company estimates annual Adjusted EBITDA by adding together the projected operating earnings of all the facilities in operation that it consolidates (excludes Umbata Falls and Viger-Denonville, which are accounted for using the equity method), 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.	Variability of facility performance and related penalties Changes to water and land rental expenses Unexpected maintenance expenditures Changes in the purchase price of electricity upon renewal of a PPA

Principal Assumptions	Principal Risks and Uncertainties
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 financing risk Relationships with stakeholders Regulatory and political risks Higher-than-expected inflation Natural disaster
Projected Free Cash Flow The Corporation estimates Free Cash Flow as projected cash flow from operations before changes in non-cash operating working capital items, less estimated 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 power purchase agreement. It also adjusts for other elements, which represent cash inflows or outflows that are not representative of the Corporation's long-term cash generating capacity, such as 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 derivative financial instruments used to fix the interest rate on project-level debt or the exchange rate on equipment purchases.	Adjusted EBITDA below expectations caused mainly by the risks and uncertainties mentioned above and by higher prospective project expenses Projects costs above expectations caused mainly by the performance of counterparties and delays and cost overruns in the design and construction of projects Regulatory and political risk Interest rate fluctuations and financing risk Financial leverage and restrictive covenants governing current and future indebtedness Unexpected maintenance capital expenditures
Intention to submit projects under requests for proposals The Corporation provides indications of its intention to submit projects under requests for proposals based on the state of readiness of some of its Prospective Projects and their compatibility with the announced terms of these requests for proposals.	Regulatory and political risks Ability of the Corporation to execute its strategy for building shareholder value Ability to secure new PPAs
Expected closing of the Acquisition of the Eighth French Wind Farm under construction The Corporation reasonably expects to complete the acquisition of the Eighth French Wind Farm under construction and it has no indication as of today that the closing conditions will not be satisfied by all parties.	Regulatory and political risks Availability of the Capital Performance of the counterparties

NON IFRS MEASURES

This MD&A has been prepared in accordance with IFRS. However, some measures referred to in this MD&A are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Innergex believes that these indicators are important, as they provide management and the reader with additional information about the Corporation's production and cash generation 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. Adjusted EBITDA, Adjusted Net Earnings (Loss), Free Cash Flow and Payout Ratio are not measures recognized by IFRS and have no standardized meaning prescribed by IFRS.

References in this document to “Adjusted EBITDA” are to revenues less operating expenses, general and administrative expenses and prospective project expenses.

References to "Adjusted Net Earnings (Loss)" are to net earnings (loss) of the Corporation, to which the following elements are added (subtracted): unrealized net gain (loss) on financial instruments; realized (gain) loss on derivative financial instruments; impairment of project development costs; income tax expense (recovery) related to the above items; and the share of unrealized net loss (gain) on derivative financial instruments of joint ventures, net of related tax. Innergex uses derivative financial instruments to hedge its exposure to different risks, such as interest rate and foreign exchange risks. Accounting for derivatives under International Accounting Standards requires that all derivatives are marked-to-market with changes in the mark-to-market being taken to the profit and loss account. The application of this accounting standard results in a significant amount of profit and loss volatility arising from the use of derivatives. The Adjusted Net Earnings (Loss) of the Corporation aims at eliminating the impact of the mark-to-market rules on derivatives and the effect of impairment of projects development costs on the profit and loss of the Corporation.

References to "Free Cash Flow" are to cash flows from operating activities 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 declared and the portion of Free Cash Flow attributed to non-controlling interests, plus cash receipts by the Harrison Hydro Limited Partnership for the wheeling services to be provided to other facilities owned by the Corporation over the course of their PPA, plus or minus other elements 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 or the exchange rate on equipment purchases.

References to "Payout Ratio" are to dividends declared on common shares divided by Free Cash Flow.

Readers are cautioned that Adjusted EBITDA and Adjusted Net Earnings (Loss) 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.

ADDITIONAL INFORMATION AND UPDATES

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. 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

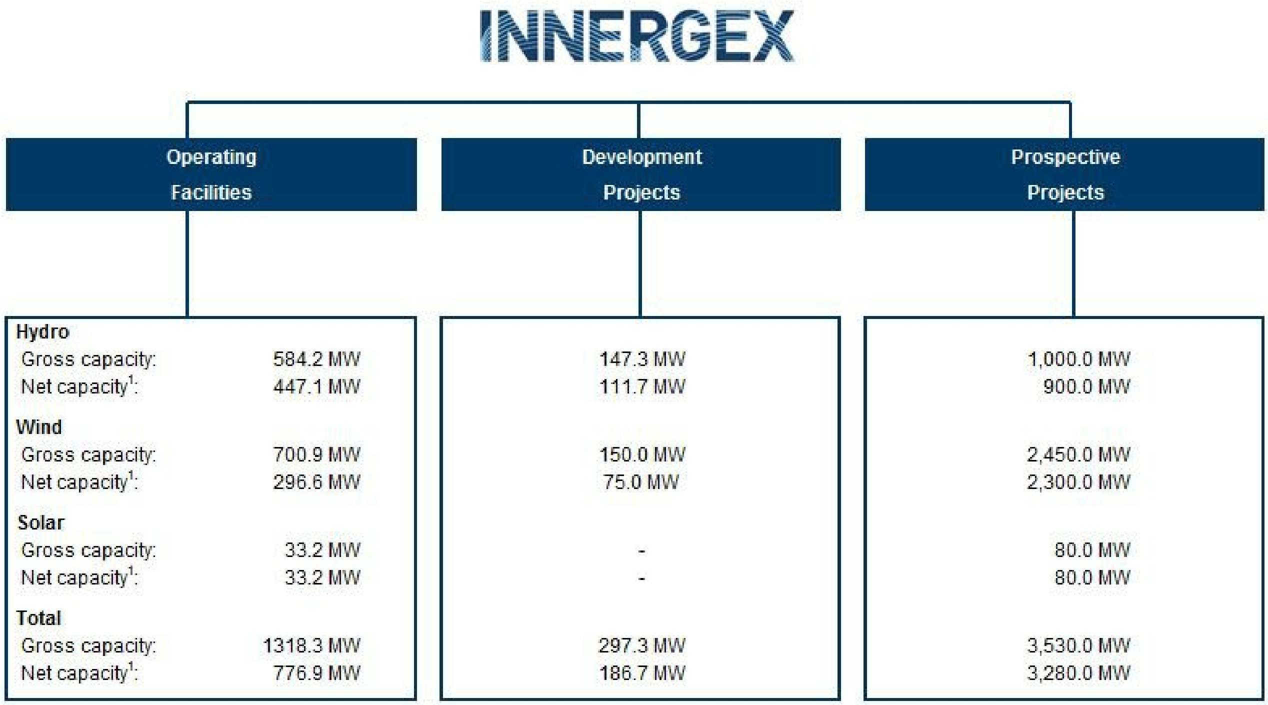
The Corporation is a developer, owner and operator of renewable power-generating facilities with a focus on hydroelectric, wind power and solar photovoltaic ("PV") projects that benefit from low operating and management costs and simple, proven technologies.

Portfolio of Assets

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

- 42 facilities in commercial operation (the "Operating Facilities"). Commissioned between 1992 and October 2015, the facilities have a weighted average age of approximately 8.0 years. They sell the generated power under long-term Power Purchase Agreements ("PPA") that have a weighted average remaining life of 17.5 years (based on gross long-term average production);
- Two projects scheduled to begin commercial operation by the end of 2016 and two projects scheduled to begin commercial operations in the first and second quarter of 2017 (all together the "Development Projects"). Construction is ongoing at all four of these projects;
- Numerous projects that have secured 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 or a Standing Offer Program (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 an attractive risk-adjusted return on invested capital and to distribute a stable dividend.

Dividend Policy

The Corporation currently distributes an annual dividend of $0.64 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.

Use Key Performance Indicators

The Corporation measures its performance using key performance indicators that include or could include comparing power generated in megawatt-hours (“MWh”) and gigawatt-hours (“GWh”) with a long-term average, Adjusted EBITDA and Adjusted EBITDA Margin, Adjusted Net Earnings (Loss), Free Cash Flow and Payout Ratio. These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. The Corporation believes that these indicators are important, as 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. Please refer to the "Non-IFRS Measures" section for more information.

Maintain Diversification of Energy Sources

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 28 hydroelectric facilities, which draw on 25 watersheds, 13 wind farms and 1 solar farm, providing significant diversification in terms of operating revenue sources. Furthermore, the nature of hydroelectric, wind and solar power generation partially offsets any seasonal variations, as illustrated in the following table:

Consolidated long-term average production[1]									
In GWh and %	Q1		Q2		Q3		Q4		Total
HYDRO	337.4	14%	862.5	35%	754.8	31%	496.0	20%	2,450.9
WIND	269.2	32%	177.0	21%	141.6	17%	258.0	31%	845.9
SOLAR[2]	7.2	19%	12.4	33%	12.5	33%	5.7	15%	37.9
Total	613.9	18%	1,052.0	32%	909.0	27%	759.7	23%	3,334.6

1. The consolidated long-term average production is the annualized LTA for the facilities in operation at August 4, 2016. The LTA 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)

SECOND QUARTER UPDATE

Summary of operating and financial performance

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
PRODUCTION				
Power generated (MWh)	1,176,451	904,172	1,840,838	1,562,600
LTA (MWh)	1,045,265	971,195	1,602,286	1,513,964
Production as percentage of LTA	113%	93%	115%	103%
STATEMENT OF EARNINGS				
Revenues	87,784	70,171	150,265	127,898
Adjusted EBITDA	66,863	53,415	114,542	96,370
Adjusted EBITDA Margin	76.2%	76.1%	76.2%	75.3%
Net earnings (loss)	15,677	22,506	22,873	(15,304)
DIVIDENDS				
Dividend declared per Class A Preferred Share	0.2255	0.3125	0.451	0.625
Dividend declared per Class C Preferred Share	0.359375	0.359375	0.71875	0.71875
Dividend declared per common share	0.160	0.155	0.320	0.310

For the three-month period ended June 30, 2016, production was 113% of the LTA, due mainly to above-average results in all regimes except in the hydrologic regime in Ontario and the wind regime in France. Production increased 30%, revenues increased 25% and Adjusted EBITDA increased 25% compared with the same period last year. These increases are attributable mainly to better performance at most of the British Columbia ("BC") hydroelectric facilities and to the contribution of facilities recently commissioned or acquired (namely, the BC Tretheway Creek hydroelectric facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016 and the Seven French Entities Acquired in April 2016), which were partly offset by lower production in the wind regime in Quebec and the hydrologic regime in Ontario.

For the six-month period ended June 30, 2016, production was 115% of the LTA, due mainly to above-average results in all regimes except the hydrologic regime in Ontario and the wind regime in France. Production increased 18%, revenues increased 17% and Adjusted EBITDA increased 19% compared with the same period last year. These increases are attributable mainly to a better performance of most of the BC hydroelectric facilities and to the contribution of the above-named facilities recently commissioned or acquired by the Corporation, which were partly offset by lower production in the wind regime in Quebec and the hydrologic regime in Ontario.

The Corporation realized $15.7 million in net earnings for the three-month period ended June 30, 2016, compared with $22.5 million net earnings for the same period last year. The $6.8 million decrease in net earnings is explained mainly by the fact that, although there was a $13.4 million increase in revenues and Adjusted EBITDA and the recognition of a $2.1 million unrealized net gain on financial instruments in 2016, these were more than offset by the recognition of a $18.6 million net gain on derivative financial instruments in 2015. More precisely, in the same period last year, the Corporation recognized a $24.5 million realized loss on derivatives, which was partly offset by a $43.1 million unrealized net gain on derivative financial instruments. The impact from derivative financial instruments for the three-month period ended June 30, 2015, resulted mainly from the settlement of the Big Silver Creek bond forward contract upon the closing of the Big Silver financing.

The Corporation realized $22.9 million in net earnings for the six-month period ended June 30, 2016, compared with a $15.3 million net loss for the same period last year. The $38.2 million increase in net earnings can be explained mainly by the $18.2 million increase in adjusted EBITDA and to the smaller impact of financial instruments (and related income taxes) on the Corporation's results. More precisely, the Corporation recognized a net loss of $37.5M on derivatives for 2015 compared with a net gain of $3.4 million.

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

Adjusted Net Earnings (Loss)

When evaluating its operating results and to provide a more accurate picture of its renewable energy operating results, a key performance analysis for the Corporation is the "Adjusted Net Earnings (Loss)", which is a non-IFRS measure of the Corporation.

Impact on net earnings (loss) of Derivatives	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Net earnings (loss)	15,677	22,506	22,873	(15,304)
Add (Subtract):				
Unrealized net gain on financial instruments	(2,145)	(43,096)	(3,432)	(55,081)
Realized loss on derivative financial instruments	—	24,527	—	92,574
Income tax expense (recovery) related to above items	864	4,084	1,199	(9,499)
Share of unrealized net loss (gain) on financial instruments of joint ventures, net of related income tax	164	(603)	704	896
Adjusted Net earnings	14,560	7,418	21,344	13,586

Excluding the gains and losses on Derivatives and the related income taxes, the net earnings for the three-month period ended June 30, 2016, would have been $14.6 million, compared with net earnings of $7.4 million for the same period last year. The increase in net earnings during the three-month period is due mainly to the increase in revenues from the BC hydroelectric facilities and, to a lesser extent, from the contribution of facilities recently commissioned or acquired by the Corporation.

Excluding the gains and losses on Derivatives and the related income taxes, the net earnings for the six-month period ended June 30, 2016, would have been $21.3 million, compared with net earnings of $13.6 million in 2015, again due mainly to the increase in revenues from the BC hydroelectric facilities and, to a lesser extent, from the contribution of facilities recently commissioned or acquired by the Corporation.

Payout Ratio

	Trailing 12 months ended June 30	
	2016	2015
Free Cash Flow[1]	78,939	85,733
Payout Ratio[1]	84%	72%

1. 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 trailing twelve-month period ended June 30, 2016, the dividends on common shares declared by the Corporation corresponded to 84% of Free Cash Flow, compared with 72% for the corresponding prior twelve-month period. This negative difference is due mainly to the decrease in Free Cash Flow, resulting from slightly higher cash flows from operations in 2016 offset by greater scheduled debt principal payments and the lack of cash receipts for the wheeling services provided by the Harrison Hydro L.P. to other facilities owned by the Corporation.

Acquisition of Seven French Entities and a Private Placement of $50.0 million – Investment by Desjardins in the French Acquisition Portfolio

On April 15, 2016, Innergex completed the acquisition of seven operating wind power facilities with an installed capacity of 86.8 MW and committed to acquire another project currently under construction with an installed capacity of 44.0 MW from a German company, wpd europe GmbH, for a total of 130.8 MW. Simultaneously, the Corporation completed a private placement of $50.0 million with three Desjardins Group-affiliated entities.

The purchase price for the eight wind power projects is approximately €98.0 million (equivalent to C$144.4 million), subject to certain adjustments and including €8.1 million (or C$11.9 million) of cash and cash equivalents and €1.1 million (or C$1.4 million) in transaction costs. Of this amount, €63.9 million (or C$94.5 million) was paid for the Seven French Entities Acquired while €10.0 M (or C$14.7 million) served as a deposit for the project currently under construction. After this last project's commercial commissioning, the Corporation will pay to the seller an additional €23.0 million (or C$33.8 million), subject to certain adjustments.

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

The non-recourse debt related to the eight projects will remain at the acquired project level. The Corporation has reduced its exposure to exchange rate fluctuations with long-term currency hedging instruments.

On June 10, 2016, Innergex announced the closing of the investment by Desjardins in the French Acquisition portfolio. Innergex and Desjardins should complete the acquisition of the eighth French wind farm under construction during the first quarter of 2017, subject to regulatory authorizations and other customary closing conditions. More details on Desjardins' investment are provided below.

Overview of the acquired asset

The seven wind farms are located in northern and central France. The aggregated installed capacity of all seven farms is 86.8 MW and the annual long-term average level of electricity production is expected to reach 169,400 MWh. All the electricity produced is sold under PPAs at fixed prices, for an initial term of 15 years, with Électricité de France (six wind farms) and S.I.C.A.E Oise (one wind farm).

Project name	Gross capacity (MW)	Commencement of delivery	PPA expiry
Porcien	10.0	2009	2024
Longueval	10.0	2009	2024
Antoigné	8.0	2010	2025
Vallotes	12.0	2010	2025
Bois d'Anchat	10.0	2014	2029
Beaumont	25.0	2015	2029
Cholletz	11.8	2015	2030
Total	**86.8**		

Private Placement of Innergex's common shares for $50.0 million

To finance part of the acquisition, three Desjardins Group affiliated entities have collectively subscribed to a private placement of 3,906,250 common shares of Innergex, for gross proceeds of $50.0 million on the closing date. Moreover, the common shares issued under the private placement are subject to a statutory four-month sale restriction period after their issuance.

Partnership with Desjardins

On June 10, 2016, the Corporation announced the closing of a $38.4 million investment by Desjardins in the French Acquisition portfolio. Following this investment, the Corporation and Desjardins respectively hold 69.55% and 30.45% of the limited partnership that holds these projects.

Benefits of the acquisition

- Increases annualized Free Cash Flow
- Opens up a new market, the European market, to Innergex
- Adds high-quality, long-term wind assets

DEVELOPMENT PROJECTS

As at the date of this MD&A, the COD for the Big Silver Creek project is imminent. Pursuant to its Electricity Purchase Agreement ("EPA"), notices and documents attesting that all COD requirements have been satisfied were sent to British Columbia Hydro Power and Authority. The COD is expected in the days following the publication of this MD&A.

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

Commissioning activities

	Ownership %	Gross installed capacity (MW)	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project costs		Expected year-one	
					Estimated[1] ($M)	As at June 30 ($M)	Revenues[1] ($M)	Adjusted EBITDA[1] ($M)
HYDRO (British Columbia)								
Big Silver Creek	100.0	40.6	139.8	40	206.0	201,700.00	18.0	15.0 15

1. This information is intended to inform readers of the projects' potential impact on the Corporation's results. Actual results may vary.

Big Silver Creek

Construction of this hydroelectric facility began in June 2014. On June 22, 2015, the Corporation announced the closing of a $197.2 million non-recourse construction and term project financing for this project.

In the second quarter of 2016, efforts focused mainly on transmission line construction, turbine and generator installation, the powerhouse's electrical installation and dry commissioning. The civil works were entirely completed at the end 2015. Transmission line construction was completed at the end of June 2016, and electrical installation in July 2016. The turbine generator supply and installation contractor also completed installation and commissioning of the units in July 2016. The substation installation had commenced and its commissioning was completed during the quarter.

As at the date of this MD&A, Big Silver Creek had successfully completed the required 72-hour performance test and sent the necessary notices to that effect, as provided under the EPA.

Construction activities

During the quarter, the Corporation increased significantly the gross estimated LTA for Mesgi'g Ugju's'n, which resulted in a $4.6 million increase in expected revenues and a $4.5 million increase in Adjusted EBITDA, as explained in greater detail below.

At the end of 2015, the Corporation reviewed the total project costs anticipated to achieve the completion of the Development Projects.

As at June 30, 2016, the Corporation anticipated no further changes in the total project costs. Accordingly, the total project costs for the Development Projects were as follows:

PROJECTS UNDER CONSTRUCTION	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA[1, 2] (GWh)	PPA term (years)	Total project costs		Expected year-one	
						Estimated[1] ($M)	As at June 30 ($M)	Revenues[1] ($M)	Adjusted EBITDA[1] ($M)
HYDRO (British Columbia)									
Upper Lillooet River	66.7	81.4	2017 [4]	334.0	40	327.1 [3]	268.3 [3]	33.0 [3]	27.5 [3]
Boulder Creek	66.7	25.3	2017 [4]	92.5	40	124.1 [3]	92.7 [3]	9.0 [3]	7.5 [3]
WIND (Quebec)									
Mesgi'g Ugju's'n	50.0	150.0	2016	562.5	20	305.0 [3]	189.9 [3]	59.6 [3]	52.5 [3]
		256.7		989.0		756.2	550.9	101.6	87.5

1. This information is intended to inform readers of the projects' potential impact on the Corporation's results. Actual results may vary. These estimates are up-to-date as at the date of the MD&A.
2. Upon commissioning, LTA figures may be updated to reflect design optimization or constraints or selection of different turbines. Please refer to the “Forward-Looking Information” section for more information.
3. Corresponding to 100% of this facility.
4. The COD should be reached in the first quarter of 2017 for the Upper Lillooet hydroelectric project and in the second quarter of 2017 for the Boulder Creek hydroelectric facility. Commercial operation has been delayed due to the forest fire that forced the interruption of construction activities in the summer 2015. BC Hydro has agreed that the fire constitutes a force majeure event and consequently confirmed that the COD could be delayed up to 98 force majeure days. If financial consequences nonetheless result from the fire, the Upper Lillooet River and Boulder Creek projects expect to be indemnified for such delays by virtue of their insurance coverage.

Upper Lillooet River and Boulder Creek

The construction of the Upper Lillooet River and Boulder Creek hydroelectric facilities began in October 2013. On March 17, 2015, the Corporation announced the closing of a $491.6 million non-recourse construction and term project financing for both these projects, which has received the Clean Energy BC's Finance Award for 2015 and the 2016 Hydro Power Deal of the Year from the World Finance Magazine.

As at the date of this MD&A, due to the favorable weather this past quarter and an accelerated civil works program, significant progress had been made on the project schedule. Tunnelling at Upper Lillooet is now complete. The Upper Lillooet intake is nearing completion with mainly mechanical items remaining. Work on the Boulder Creek intake made great progress and is on track for completion later this summer. The mechanical and electrical work was completed during the quarter at the Boulder Creek powerhouse and the balance of plant installation is nearly complete. The civil works at both substations are nearly complete and the joint transmission line is progressing well. The insurance claims process for the fire is ongoing and will take time to complete. To date, interim claims have been processed and paid in an effort to maintain progress. In any case, the Corporation expects to be indemnified and to suffer no significant adverse financial consequences from the forest fire.

As a result of the accelerated construction work and the significant advancement of the schedule, the Upper Lillooet River and Boulder Creek hydroelectric facilities made up most of the time lost to last summer's forest fire.

Mesgi'g Ugju's'n

Construction of this wind farm began in May 2015. On September 28, 2015, the Corporation and its partner, the Mi'gmaq communities of Quebec, announced the closing of a $311.7 million non-recourse construction and term project financing for this project.

As at the date of this MD&A, all access roads, crane pads, and wind turbines generator ("WTG") foundations have been completed. The turbine supplier, Senvion, has delivered to the site 20 of the 47 WTGs, of which nine are fully erected and 11 are at intermediate phases of erection. The last WTG is expected to be delivered at the end of September. The twin main power transformers have been delivered and placed on their foundations. The transformer station is expected to be energized at the end of September, as originally planned. The project is forecast to finish on budget and the end of construction and the commissioning of the Mesgi'g Ugju's'n wind farm are expected for the end of 2016.

The Corporation has revised the annual forecast for the Gross estimated LTA energy yield upward from 515 GWh to 562.5 GWh, which corresponds approximately to a 9% increase. The increase is due to installation of higher capacity, higher yielding WTGs than those used for the original LTA analysis as well as lower than originally estimated losses in the electrical collector system now that the design has been finalized but also from the de-icing system for the WTG blades, which is designed to work both preventively and curatively. The previous forecast energy yield, taken from the independent engineer's analysis, did not consider the final design of the collector system or the benefit of the blade de-icing system. Senvion reports that results of the implementation of curative de-icing systems using similar technology over the last two years have met expectations.

The revised Gross estimated LTA of the Mesgi'g Ugju's'n wind farm has resulted in a $3.2 million increase in Projected Free Cash Flow allocated to Innergex. Innergex is entitled to approximately 70% of the total free cash flows that will be generated by the project for the year 2017.

PROSPECTIVE PROJECTS

With a combined potential net installed capacity of 3,280 MW (gross 3,530 MW), all the Prospective Projects are in the preliminary development stage. Some Prospective Projects are targeted toward specific future requests for proposals, such as the current request for expression of interest from Aboriginal businesses for a total of up to 40 MW of renewable generation from multiple projects in the province of New Brunswick. In Ontario, the government has launched a second phase (LRP II) of the competitive Large Renewable Procurement process. As such, a new Request for Qualifications ("RFQ") process will be issued in August 2016, for 980 MW of renewable energy from solar photovoltaic, wind, hydroelectric and bioenergy sources, following engagement with stakeholders, municipalities and indigenous communities. The government of Saskatchewan plans to issue an RFQ for wind energy in Fall 2016 and to launch an initial RFP for 100-200 MW of new wind energy in early 2017. Other Prospective Projects will be available for future requests for proposals yet to be announced or are targeted toward negotiated power purchase agreements with public utilities or other creditworthy counterparties. There is no certainty that any Prospective Project will be realized.

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

OPERATING RESULTS

Production of electricity for the last quarter was 113% of the LTA production due mainly to the above-average results in all markets except in the hydrologic regime in Ontario and in the wind regime in France.

Production increased 30%, revenues increased 25% and Adjusted EBITDA increased 25% in 2016. These increases are attributable mainly to a better performance of most of the hydroelectric facilities in British Columbia and to a certain extent to the contribution of facilities recently commissioned or acquired (meaning the BC Tretheway Creek hydroelectric facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016 and to the French acquisition in April 2016), which were partly offset by lower production in the hydrologic and wind regime in Quebec and the hydrologic regime in Ontario. The lower rate of increase for revenues than for production is explained by the fact that production exceeding certain levels is sold at a lower price.

The Corporation's operating results for the three- and six-month periods ended June 30, 2016, are compared with the operating results for the same period in 2015.

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 LTA are determined to allow long-term forecasting of the expected power generation for each of the Corporation's facilities.

Three months ended June 30	2016				2015			
	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	216,835	214,050	101%	72.71	221,063	214,050	103%	71.96
Ontario	14,907	20,805	72%	63.03	20,459	20,805	98%	65.72
British Columbia	735,420	610,738	120%	65.77	460,174	564,115	82%	70.14
United States	20,766	16,956	122%	80.55	17,284	16,956	102%	77.91
Subtotal	987,928	862,549	115%	67.56	718,980	815,926	88%	70.76
WIND								
Quebec	151,822	142,806	106%	80.18	171,835	142,805	120%	79.65
France	22,283	27,535	81%	126.19	—	—	—%	—
Subtotal	174,105	170,341	102%	86.06	171,835	142,805	120%	79.65
SOLAR								
Ontario	14,418	12,375	117%	420.00	13,357	12,464	107%	420.00
Total	1,176,451	1,045,265	113%	74.62	904,172	971,195	93%	77.61

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 June 30, 2016, the Corporation's facilities produced 1,176 GWh of electricity or 113% of the LTA of 1,045 GWh. Overall, the hydroelectric facilities produced 115% of their LTA due mainly to above-average water flows in all markets but Ontario. Overall, the wind farms produced 102% of their LTA due to above-average wind regime in Quebec, partly offset by below-average wind regime in France. The Stardale solar farm produced 117% of its LTA due to an above-average solar regime. For more information on operating segment results, please refer to the "Segment Information" section.

The 30% production increase over the same period last year is due mainly to production that was above the LTA for most of the BC hydroelectric facilities during the quarter and, to a lesser extent, to the contribution of facilities recently commissioned or acquired, namely the BC Tretheway Creek hydro facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016 and the Seven French Entities Acquired in April 2016, which were partly offset by lower production in the wind regime in Quebec and the hydrologic regime in Ontario.

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

Six months ended June 30	2016				2015			
	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	351,087	338,220	104%	83.67	340,203	338,220	101%	78.00
Ontario	37,063	45,099	82%	65.51	39,417	45,099	87%	67.80
British Columbia	1,018,849	790,533	129%	73.67	751,758	729,604	103%	76.38
United States	28,898	24,883	116%	80.43	25,894	24,883	104%	77.72
Subtotal	1,435,897	1,198,735	120%	76.04	1,157,272	1,137,806	102%	76.59
WIND								
Quebec	360,416	356,410	101%	80.26	385,138	356,410	108%	79.92
France	22,283	27,535	81%	126.19	—	—	—%	—
Subtotal	382,699	383,945	100%	82.94	385,138	356,410	108%	79.92
SOLAR								
Ontario	22,242	19,606	113%	420.00	20,190	19,748	102%	420.00
Total	1,840,838	1,602,286	115%	81.63	1,562,600	1,513,964	103%	81.85

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 six-month period ended June 30, 2016, the Corporation's facilities produced 1,841 GWh of electricity or 115% of the LTA of 1,602 GWh. Overall, the hydroelectric facilities produced 120% of their LTA, due mainly to above-average water flows in all markets but Ontario. Overall, the wind farms produced 100% of their LTA, due to above-average wind regimes in Quebec and below-average wind regimes in France. The Stardale solar farm produced 113% of its LTA, due to an above-average solar regime. For more information on operating segment results, please refer to the "Segment Information" section.

The 18% production increase over the same period last year is due mainly to higher water flows in all markets but Ontario and, to a lesser extent, to the contribution of facilities recently commissioned or acquired, as detailed above, which was partly offset by lower production in the wind regime in Quebec and the hydrologic regime in Ontario.

The overall performance of the Corporation's facilities for the period ended June 30, 2016, 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 June 30				Six months ended June 30			
	2016		2015		2016		2015	
Revenues	87,784	100.0%	70,171	100.0%	150,265	100.0%	127,898	100.0%
Operating expenses	14,218	16.2%	11,100	15.8%	23,616	15.7%	20,347	15.9%
General and administrative expenses	3,945	4.5%	3,726	5.3%	7,632	5.1%	7,898	6.2%
Prospective project expenses	2,758	3.1%	1,930	2.8%	4,475	3.0%	3,283	2.6%
Adjusted EBITDA	66,863	76.2%	53,415	76.1%	114,542	76.2%	96,370	75.3%
Finance costs	24,608		24,540		44,102		40,957	
Other net (revenues) expenses	(233)		24,065		(407)		92,479	
Depreciation and amortization	22,135		18,781		41,572		37,578	
Share of earnings of joint ventures (note 1)	(475)		(2,200)		(24)		(1,056)	
Unrealized net gain on financial instruments	(2,145)		(43,096)		(3,432)		(55,081)	
Income tax expense (recovery of)	7,296		8,819		9,858		(3,203)	
Net earnings (loss)	15,677		22,506		22,873		(15,304)	
Net earnings (loss) attributable to:								
Owners of the parent	14,381		22,808		22,713		(6,336)	
Non-controlling interests	1,296		(302)		160		(8,968)	
	15,677		22,506		22,873		(15,304)	
Basic net earnings (loss) per share ($)	0.19		0.21		0.19		(0.10)	

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 June 30, 2016, the Corporation recorded revenues of $87.8 million, compared with $70.2 million for the three-month period ended June 30, 2015. This 25% increase is attributable mainly to better results from most of the hydroelectric facilities operating in British Columbia, compared with the same period last year, and to the contribution, to a lesser extent, of the facilities recently commissioned or acquired (the BC Tretheway Creek hydro facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016 and the French acquisition made this quarter), which were partly offset by lower revenues in the wind regime in Quebec and the hydrologic regime in Ontario. The lower rate of increase for revenues than for production is explained by the fact that the production exceeding certain levels is sold at a lower price.

For the six-month period ended June 30, 2016, the Corporation recorded revenues of $150.3 million, compared with $127.9 million for the six-month period ended June 30, 2015. This 17% increase is attributable mainly to better results in all hydroelectricity markets except Ontario and to the contribution, to a lesser extent, of the facilities recently commissioned or acquired, which were partly offset by lower revenues in the wind regime in Quebec and in the hydrologic regime in Ontario.

Expenses

Operating expenses consist primarily of the operators' salaries, insurance premiums, expenditures related to operation and maintenance, property taxes and royalties. For the three- and six-month periods ended June 30, 2016, the Corporation recorded operating expenses of $14.2 million and $23.6 million respectively ($11.1 million and $20.3 million respectively in 2015). This increase of 28% for the quarter and 16% for the six-month period is due mainly to variable costs associated with the production levels and repairs and maintenance in British Columbia as well as the addition of the Tretheway Creek hydro facility, the BC Walden North hydroelectric facility and the French acquisition.

General and administrative expenses consist primarily of salaries, professional fees and office expenses. For the three- and six-month periods ended June 30, 2016, general and administrative expenses totalled $3.9 million and $7.6 million respectively

($3.7 million and $7.9 million respectively in 2015). The 6% increase for the quarter is due mainly to the larger size of operations, while the 3% decrease for the six-month period stems mainly from resources being devoted to further pursuing the development of international markets and acquisitions, which are accounted for in the prospective project expenses and transaction costs.

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- and six-month periods ended June 30, 2016, prospective project expenses totalled $2.8 million and $4.5 million respectively ($1.9 million and $3.3 million respectively in 2015). This increase of 43% for the quarter and 36% for the six-month period is related mainly to the advancement of a number of prospective projects, to pursuing opportunities in new international markets and to current and future requests for proposals and expressions of interest in Ontario and other Canadian provinces.

Adjusted EBITDA

Adjusted EBITDA, which is defined as revenues less operating expenses, general and administrative expenses and prospective project expenses, is a key performance indicator when evaluating the Corporation's financial results.

For the three- and six-month periods ended June 30, 2016, the Corporation recorded Adjusted EBITDA of $66.9 million and $114.5 million, compared with $53.4 million and $96.4 million for the same period last year. This increase of 25% for the quarter and 19% for the six-month period is due mainly to the increase in production and revenues, partly offset by operating expenses, general and administrative expenses and prospective project expenses. As a result, the Adjusted EBITDA Margin rose from 76.1% to 76.2% for the quarter and from 75.3% to 76.2% for the six-month period.

Finance Costs

Finance costs include interest on long-term debt and convertible debentures, inflation compensation interest, amortization of financing fees, accretion of long-term debt and convertible debentures, accretion expenses on other liabilities and other finance costs. For the three-month period ended June 30, 2016, finance costs totalled $24.6 million ($24.5 million in 2015). The increase is due mainly to the rise in interest expenses on long-term debt following the French acquisition made in this quarter, partly offset by lower inflation compensation interest on the real-return bonds attributable to lower inflation during the period.

For the six-month period ended June 30, 2016, finance costs totalled $44.1 million ($41.0 million in 2015). The increase is due mainly to expenses related to the facilities recently commissioned or acquired in this quarter (the BC Tretheway Creek hydroelectric project commissioned in November 2015 and the French acquisition) and to higher inflation compensation interest on the real-return bonds attributable to higher inflation during the period.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 4.88% as at June 30, 2016 (5.23% as at June 30, 2015).

Other Net (Revenues) Expenses

Other net (revenues) expenses include transaction costs, realized loss on derivative financial instruments, realized (gain) loss on foreign exchange, other net revenues and recovery of loan impairment. The Corporation recorded, for the three- and six-month periods ended June 30, 2016, other net revenues of $0.2 million and $0.4 million (net expenses of $24.1 million and $92.6 million respectively in 2015). The significant decrease for the quarter and for the six-month period stems mainly from the fact that the Corporation encountered no realized losses during the quarter and the six-month period on its derivative financial instruments, compared to a realized loss of $24.5 million and $92.6 million respectively for the same periods last year upon settlement of the Big Silver Creek, Boulder Creek and Upper Lillooet bond forward contracts at the closing of financings.

Depreciation and Amortization

For the three- and six-month periods ended June 30, 2016, depreciation and amortization expenses totalled $22.1 million and $41.6 million respectively ($18.8 million and $37.6 million respectively in 2015). This increase is attributable mainly to the Tretheway Creek hydroelectric facility commissioned in November 2015, the BC Walden North hydroelectric facility acquired in February 2016 and the French Acquisition made in this quarter.

Share of Earnings of Joint Ventures

For the three- and six-month periods ended June 30, 2016, the Corporation recorded a share of net earnings of joint ventures of $0.5 million and $0.02 million respectively (share of net earnings of $2.2 million and of $1.1 million respectively in 2015). Please refer to the "Investments in Joint Ventures" section for more information.

Unrealized Net Gain on Financial Instruments

Derivative financial instruments are used by the Corporation to manage its exposure to the risk of rising interest rates on its existing and upcoming debt financing (“Derivatives”) and to reduce the Corporation's foreign exchange risk, thereby protecting the economic value of its projects.

Since October 2014, the Corporation has, whenever possible, used hedge accounting for new Derivatives and, since April 1, 2015, it has used hedge accounting for its existing Derivatives used to fix the interest rate on the project-level debts (with the exception of Umbata Falls) and on most of its revolving term credit facility in order to reduce the fluctuations in net earnings or losses resulting from unrealized gains or losses on these Derivatives during a given period. Under hedge accounting, most of the unrealized gains or losses on Derivatives that arise from a decrease or increase in the benchmark interest rate are recorded in other comprehensive income, while only the portion of the unrealized gain or loss related to the "ineffectiveness" and the settlement of the Derivatives will be recorded in net earnings (loss).

For the three- and six-month periods ended June 30, 2016, the Corporation recognized an unrealized net gain on derivative financial instruments of $2.1 million and $3.4 million respectively, due mainly to the increase in benchmark interest rates since December 31, 2015. For the corresponding periods last year, the Corporation recognized an unrealized net gain on Derivatives of $43.1 million and $55.1 million respectively, due mainly to the reversal of the unrealized loss accrued to December 31, 2014, upon settlement of the bond forward contracts concurrently with the closing of the Boulder Creek, Upper Lillooet and Big Silver Creek financings, which more than offset the unrealized losses on derivative financial instruments resulting from the decrease in benchmark interest rates during the corresponding periods in 2015.

For the period ended June 30, 2016, the Corporation had no Derivatives to be settled upon the closing of a project financing, as all the Development Project financings were put in place in 2015.

Income Tax Expense (Recovery)

For the three-month period ended June 30, 2016, the Corporation recorded a current income tax expense of $0.8 million ($0.9 million in 2015) and a deferred income tax expense of $6.5 million (deferred income tax expense of $7.9 million in 2015). The deferred income tax expense in this quarter is due mainly to the increase in production and the correlative revenues realized by the Corporation from its regular business activities. The deferred income tax expense of $7.9 million in 2015 was due mainly to the $43.1 million unrealized gain on Derivatives resulting from the reversal of the unrealized loss accrued upon settlement of Derivatives and from the increase in benchmark interest rates during the quarter, partly offset by the $24.5 million realized loss on Derivatives resulting from the settlement of these Derivatives. The recognition of a deferred, rather than current, income tax expense is due mainly to the existence of accumulated tax losses.

For the six-month period ended June 30, 2016, the Corporation recorded a current income tax expense of $1.5 million ($1.6 million in 2015) and a deferred income tax expense of $8.4 million (income tax recovery of $4.8 million in 2015). The deferred income tax expense is due primarily to the recognition of accounting earnings before income taxes resulting from the Corporation's regular business activities. The deferred income tax recovery for the same period last year was due mainly to a $92.6 million realized loss on derivative financial instruments resulting from the settlement of the Boulder Creek, Upper Lillooet River and Big Silver bond forward contracts upon closing of the financing for these projects, partly offset by a $55.1 million unrealized gain on Derivatives resulting from the reversal of the unrealized loss accrued upon settlement of Derivatives.

Net Earnings (Loss)

Net earnings of $15.7 million (basic and diluted net earnings of $0.19 per share), compared with net earnings of $22.5 million (basic and diluted net earnings of $0.21 per share), were recorded by the Corporation in the quarter. The decrease of $6.8 million in net earnings is explained mainly by the fact that, although there was an increase in revenues and Adjusted EBITDA of $13.4 million along with the recognition of an unrealized net gain of $2.1 million on financial instruments in 2016, these were more than offset by the recognition of a net gain of $18.6 million on derivative financial instruments in 2015. More precisely, in the same period last year, the Corporation recognized a $24.5 million realized loss on Derivatives, partly offset by an unrealized net gain of $43.1 million on derivative financial instruments. The impact from derivative financial instruments for the three-month period ended June 30, 2015, resulted mainly from the settlement of the Big Silver Creek bond forward contract upon the closing of the Big Silver financing.

For the six-month period ended June 30, 2016, the Corporation recorded net earnings of $22.9 million (basic and diluted net earnings of $0.19 per share), compared with a net loss of $15.3 million (basic and fully diluted net loss of $0.10 per share) in 2015. The difference in net earnings for the period is due mainly to the increase in revenues realized by the Corporation from the BC hydroelectric facilities and, to a lesser extent, from the contribution of facilities recently commissioned or acquired by the Corporation and the smaller impact of financial instruments on the results and the related income taxes. More precisely, as of June 30, 2016, no gain or loss on financial instruments was realized and a $3.4 million unrealized net gain on the

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

Corporation's financial instruments was recorded. In comparison, in the corresponding period last year, a $92.6 million realized loss on derivative financial instruments resulted from the settlement of the Boulder Creek, Upper Lillooet River and Big Silver Creek bond forward contracts, which was partly offset by the $55.1 million reversal of the unrealized loss accrued upon settlement of these Derivatives.

Main items explaining the change in net earnings for the three-month period ended June 30, 2016, compared with the net earnings for the corresponding period in 2015		
Main items – Positive impact	Change	Explanation
Adjusted EBITDA	13,448	Due mainly to the increase in production and revenues, partly offset by operating expenses, general and administrative expenses and prospective project expenses. As a result, the Adjusted EBITDA Margin rose from 76.1% to 76.2% for the quarter.
Other net (revenues) expenses	24,298	Due mainly to there being no realized loss during the quarter on the Corporation's Derivatives, compared with a realized loss of $24.5 million for the same period last year.
Main items – Negative impact	Change	Explanation
Unrealized net gain on financial instruments	40,951	Due mainly to hedge accounting on almost all the Corporation's financial instruments, the impact of the unrealized net gain on financial instruments is smaller this quarter, amounting to only $2.1 million. For the corresponding period last year, the Corporation recognized a $43.1 million unrealized net gain on financial instruments.

Main items explaining the change in net earnings for the six-month period ended June 30, 2016, compared with the net loss for the corresponding period in 2015		
Main items – Positive impact	Change	Explanation
Adjusted EBITDA	18,172	Due mainly to the increase in production and revenues, partly offset by operating expenses, general and administrative expenses and prospective project expenses. As a result, the Adjusted EBITDA Margin rose from 75.3% to 76.2% for the six-month period.
Other net (revenues) expenses	92,886	. Due mainly to no impact of Derivatives in this period compared to a $92.5 million loss resulting from the settlement of bond forward contracts upon closing of the Upper Lillooet, Boulder Creek and Big Silver project financings.
Main items – Negative impact	Change	Explanation
Unrealized net gain on financial instruments	51,649	Due mainly to hedge accounting on almost all the Corporation's financial instruments, the impact of the unrealized net gain on financial instruments is smaller this quarter and amounts to $3.4 million. For the corresponding period last year, the Corporation recognized a $55.1 million unrealized net gain on financial instruments, due mainly to the reversal of the unrealized losses upon settlement of the Boulder Creek and Upper Lillooet bond forward contracts.
Deferred income tax expense	13,219	Due mainly to the lack of significant impacts from derivative financial instruments on the Corporation's computation of net earnings (loss) in the first six-month of 2016 compared with corresponding period of 2015, as explained above. The amount of deferred income tax expense in this period was determined mainly by the amount of net earnings realized by the Corporation.

Non-controlling Interests

Non-controlling interests are related to the six hydroelectric facilities of the Harrison Hydro Limited Partnership, the Creek Power Inc. subsidiaries, the Kwoiek Creek Resources Limited Partnership, the Mesgi'g Ugju's'n (MU) Wind Farm, L.P., the Magpie Limited Partnership, the Innergex Sainte-Marguerite S.E.C. entity, the Innergex Europe (2015) Limited Partnership and their respective general partners. For the three- and six-month periods ended June 30, 2016, the Corporation allocated earnings of $1.3 million and $0.2 million respectively to non-controlling interests (losses of $0.3 million and $9.0 million respectively in 2015). Please refer to the "Non-Wholly Owned Subsidiaries" section for more information.

Number of Common Shares Outstanding

Weighted average number of common shares outstanding (000s)	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Weighted average number of common shares	107,318	101,235	105,657	101,071
Effect of dilutive elements on common shares[1]	996	331	812	403
Diluted weighted average number of common shares	108,314	101,566	106,469	101,474

1. During the three-month and the six-month periods ended June 30, 2016, all of the 3,425,684 stock options (all of the 3,425,684 stock options for the three-month and the six-month periods ended June 30, 2015) were dilutive. During the three-month and six-month periods ended June 30, 2016, none of the 6,666,667 shares that can be issued on conversion of convertible debentures were dilutive (none of the 7,472,113 shares were dilutive for the same periods in 2015).

The Corporation's Equity Securities

As at	August 4, 2016	June 30, 2016	June 30, 2015
Number of common shares	108,022,175	107,972,113	101,268,879
Number of 4.25% convertible debentures	100,000	100,000	—
Number of 5.75% convertible debentures	—	—	79,578
Number of Series A Preferred Shares	3,400,000	3,400,000	3,400,000
Number of Series C Preferred Shares	2,000,000	2,000,000	2,000,000
Number of stock options outstanding	3,425,684	3,425,684	3,425,684

As at the date of this MD&A and since June 30, 2016, the increase in the number of common shares of the Corporation is attributable to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at June 30, 2016, the increase in the number of common shares since June 30, 2015 is attributable mainly to the conversion, at the holders' request, of a portion of the 5.75% convertible debentures into 3,566,851 common shares, to the issuance of 3,906,250 shares to three Desjardins Group-affiliated entities under a private placement of common shares of Innergex as well as to the DRIP, partly offset by the purchase and cancellation of 1,190,173 shares under the Corporation's normal course issuer bid. The variation in the number of convertible debentures is due to the issuance of 100,000 convertible debentures bearing interest at a rate of 4.25% and the redemption or conversion of convertible debentures bearing interest at a rate of 5.75%.

LIQUIDITY AND CAPITAL RESOURCES

For the six-month period ended June 30, 2016, the Corporation generated cash flows from operating activities of $59.3 million, compared with the use of $31.6 million for the same period last year. During this six-month period, the Corporation generated funds from financing activities of $126.9 million and used funds for investing activities of $164.3 million, mainly to pay for the construction of its Development Projects and the Acquisition of Seven French Entities in France. As at June 30, 2016, the Corporation had cash and cash equivalents amounting to $62.1 million, compared with $40.7 million as at December 31, 2015.

Cash Flows from Operating Activities

For the six-month period ended June 30, 2016, cash flows generated by operating activities totalled $58.9 million ($31.6 million used in 2015). The change of $90.6 million was attributable mainly to the $92.6M realized loss on derivative financial instruments realized in 2015.

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

Cash Flows from Financing Activities

For the six-month period ended June 30, 2016, cash flows generated by financing activities totalled $126.9 million (compared with $255.5 million generated in 2015). The cash flows from the financing activities are attributable mainly to a $105.0 million net increase in long-term debt and $50.0 million from a private placement of common shares of Innergex with three Desjardins Group-affiliated entities, partly offset by the payment of $34.5 million in dividends.

The $105.0 million net increase in long-term debt is attributable mainly to the $488.2 million in additional funds from the Development Projects-level debts, partly reduced by the repayment of $381.2 million of long-term debt (including revolving term credit facility).

Use of Financing Proceeds	Six months ended June 30	
	2016	2015
Proceeds from issuance of long-term debt (including revolving term credit facility)	488,206	686,911
Repayment of long-term debt (including revolving term credit facility)	(381,249)	(389,246)
Payment of deferred financing costs	(1,998)	(8,134)
Sub-total: net increase in long-term debt	104,959	289,531
Proceeds from issuance of common shares	50,000	—
Proceeds from exercise of share options	—	394
Investments from non-controlling interests	6,392	—
Generation of financing proceeds	161,351	289,925
Business acquisitions	(102,795)	—
Realized loss on derivative financial instruments	—	(92,574)
Decrease (increase) of restricted cash and short-term investments	145,207	(93,334)
Net funds withdrawn from (invested into) the reserve accounts	171	(2,923)
Additions to property, plant and equipment	(204,135)	(108,005)
Additions to project development costs	—	(29,104)
Additions to other long-term assets	(14,626)	(399)
Net use of financing proceeds	(176,178)	(326,339)
Reduction in working capital	(14,827)	(36,414)

During the six-month period ended June 30, 2016, the Corporation borrowed $488.2 million, mainly to pay for the construction of the Development Projects, to realize the Walden facility and the Seven French Entities Acquired and to make a deposit for the French entity to be acquired at commissioning. It also used $145.2 million in restricted cash to continue construction of the Development Projects. During the corresponding period in 2015, the Corporation borrowed $686.9 million, mainly to pay for construction of the Upper Lillooet River, Boulder Creek and Big Silver Creek projects, the pre-construction development of the Mesgi'g Ugju's'n project and the $92.6 million realized loss on derivative financial instruments resulting from the settlement of the Boulder Creek, Upper Lillooet River and Big Silver bond forward contracts. It also increased restricted cash by $93.3 million, as the use of cash to pay for construction costs related to the Tretheway Creek, Boulder Creek, Upper Lillooet River and Big Silver Creek projects was more than offset by the proceeds received from the Boulder Creek, Upper Lillooet River and Big Silver Creek project debts.

Cash Flows from Investing Activities

For the six-month period ended June 30, 2016, cash flows used by investing activities amounted to $164.3 million ($233.7 million in 2015). During this period, the main investing activities that impacted cash flows were as follows: additions to property, plant and equipment accounted for a $204.1 million outflow ($108.0 million outflow in 2015); fluctuations in restricted cash and short-term investments accounted for a $145.2 million inflow ($93.3 million outflow in 2015); additions to other long-term assets accounted for a $14.6 million outflow ($0.4 million outflow in 2015) from a deposit made for the acquisition of a wind farm in France; and business acquisitions accounted for an $102.8 million outflow (none in 2015) for the acquisition of the Walden Facility and the Seven French Entities Acquired. In 2015, the Corporation used $29.1 million for additions to project development costs.

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

Cash and Cash Equivalents

As at June 30, 2016, the Corporation had cash and cash equivalents amounting to $62.1 million ($40.7 million as at December 31, 2015). For the six-month period ended June 30, 2016, cash and cash equivalents increased by $21.5 million (decreased by $9.6 million in 2015) as a net result of its operating, financing and investing activities.

DIVIDENDS

The following dividends were declared by the Corporation:

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Dividends declared on common shares[1]	17,276	15,697	33,917	31,361
Dividends declared on common shares ($/share)[1]	0.1600	0.1550	0.3200	0.3100
Dividends declared on Series A Preferred Shares	767	1,063	1,533	2,125
Dividends declared on Series A Preferred Shares ($/share)	0.2255	0.3125	0.4510	0.6250
Dividends declared on Series C Preferred Shares	719	719	1,438	1,437
Dividends declared on Series C Preferred Shares ($/share)	0.359375	0.359375	0.718750	0.718750

1. The increase in dividends declared on common shares is mainly attributable to the conversion, at the holders' request, of a portion of the 5.75% convertible debentures into 3,566,851 common shares, to the issuance of 3,906,250 shares to three Desjardins Group-affiliated entities under a private placement of common shares of Innergex as well as to the DRIP, partly offset by the purchase and cancellation of 1,190,173 shares under the Corporation's normal course issuer bid.

The following dividends will be paid by the Corporation on October 17, 2016:

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
08/04/2016	9/30/2016	10/17/2016	0.1600	0.2255	0.359375

On February 24, 2016, the Board of Directors increased the annual dividend from $0.62 to $0.64 per common share, payable quarterly.

FINANCIAL POSITION

As at June 30, 2016, the Corporation had $3,441 million in total assets, $2,940 million in total liabilities, including $2,449 million in long-term debt, and $500.9 million in shareholders' equity. The Corporation also had a working capital ratio of 1.56:1.00 (2.15:1.00 as at December 31, 2015). In addition to cash and cash equivalents amounting to $62.1 million, the Corporation had restricted cash and short-term investments of $167.5 million and reserve accounts of $49.0 million. The explanations below highlight the most significant changes in statement of financial position items during the six-month period ended June 30, 2016.

Assets

Highlights of significant changes in total assets during the six-month period ended June 30, 2016

- A $123.7 million net decrease in cash and cash equivalents and restricted cash and short-term investments, due mainly to the amounts used to pay for construction costs on the Development Projects, partly offset by cash and cash equivalents from the French Acquisition;
- A $325.3 million increase in property, plant and equipment, due mainly to the construction of the Development Projects, the acquisition of the Walden Facility on February 25, 2016, and the purchase on April 15, 2016, of the Seven French Entities, partly offset by the depreciation for the period;
- A $68.9 million increase in intangible assets, due mainly to the acquisition of the Walden Facility and the purchase of the Seven French Entities, partly offset by the amortization for the period; and
- A $13.3 million increase in other long term assets, due mainly to a deposit in view of the acquisition, upon commissioning, of an eighth wind project in France.

Working Capital Items

Working capital was positive at $105.1 million, as at June 30, 2016, with a working capital ratio of 1.56:1.00. As at December 31, 2015, working capital was positive at $212.2 million, with a working capital ratio of 2.15:1.00. The decrease in the working capital ratio is due mainly to a $145.2 million decrease in restricted cash and short-term investments.

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 June 30, 2016, the Corporation had drawn $165.9 million and US$13.9 million as cash advances, while $64.0 million had been used for issuing letters of credit.

Cash and cash equivalents amounted to $62.1 million as at June 30, 2016, compared with $40.7 million as at December 31, 2015. The increase stems mainly from higher revenues during the second quarter and from the purchase of the Seven French Entities.

Restricted cash and short-term investments amounted to $167.5 million as at June 30, 2016, compared with $312.7 million as at December 31, 2015. The decrease stems mainly from the amounts used to pay for construction of the Development Projects.

Accounts receivable increased from $37.1 million to $54.0 million between December 31, 2015 and June 30, 2016, due mainly to higher business revenues generated from better results from most of the hydro facilities operating in British Columbia and to commodity taxes to be received from the construction of the Development Projects, as at June 30, 2016, and, compared to December 31, 2015.

Accounts payable and other payables from December 31, 2015, to June 30, 2016, decreased from the amount of $95.5 million to $90.6 million, due mainly to payments of accounts payable by Tretheway Creek and Big Silver, partly offset by additional construction activity at the Boulder Creek and Upper Lillooet River projects.

Current portion of long-term debt amounted to $61.1 million as at June 30, 2016, compared, as at December 31, 2015, with $55.0 million. The increase stems mainly from Stardale's long-term debt increase on its borrowing and from the purchase of the Seven French Entities.

Reserve Accounts

Reserve accounts consist of a hydrology/wind reserve, established at the start of commercial operation at a facility to compensate for the variability of cash flows related to fluctuations in hydrology or wind regime and to other unpredictable events, and a major maintenance reserve, established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity. The Corporation had $48.1 million in long-term reserve accounts as at June 30, 2016, compared with $41.5 million as at December 31, 2015. The increase is due to mandatory investments in reserves for the Seven French Entities Acquired. The availability of funds in the hydrology/wind and major maintenance reserve accounts are in large part restricted by credit agreements.

Property, Plant and Equipment

*Property, plant and equipmen*t are comprised mainly of hydroelectric facilities, wind farms and a solar farm that are either in operation or under construction. The Corporation had $2,500 million in property, plant and equipment as at June 30, 2016, compared with $2,174 million as at December 31, 2015. The increase stems mainly from the construction of the Development Projects, the purchase of the Walden Facility on February 25, 2016, and the acquisition on April 15, 2016, of seven wind power projects in France, partly offset by depreciation.

Intangible assets

Intangible assets consist of various power purchase agreements, permits and licenses. They also include the extended warranty for the Montagne Sèche and Gros-Morne wind farm turbines. The Corporation had $541.1 million in intangible assets as at June 30, 2016, compared with $472.3 million as at December 31, 2015. The increase is due mainly to the acquisition of the Walden Facility and the acquisition of seven wind power projects in France on April 15, 2016, partly offset by amortization.

Investments in Joint Ventures

Investments in joint ventures represent the Corporation's ownership portion of joint ventures, which are accounted for using the equity method. As at June 30, 2016, the Corporation had $8.5 million in investments in joint ventures, compared with $9.3 million as at December 31, 2015. This $0.8 million decrease reflects a portion of $0.1 million in distributions from Viger-Denonville, L.P. made by the joint venture to the Corporation during the period and the recognition of a $0.7 million distribution related to the Umbata Falls Facility. The other portion of $0.9 million in distributions received from Viger-Denonville, L.P. has been recorded in other long-term liabilities, while the partnership's net loss has not been recorded. Please refer to the "Investments in Joint Ventures" section for more information.

Liabilities and Shareholders' Equity

Derivative Financial Instruments and Risk Management

The Corporation uses derivative financial instruments ("Derivatives") to manage its exposure to the risk of increasing interest rates on its debt financing and its exposure to exchange rate fluctuations on the future repatriation of cash flows from its French operations. The Corporation does not own or issue any Derivatives for speculation purposes.

Interest rate swap contracts allow the Corporation to eliminate the risk of interest rate increases on actual floating-rate debts. These totalled $525.7 million as at June 30, 2016.

As part of the acquisition of the wind farms in France, the Corporation entered into hedge agreements to reduce the Corporation's foreign exchange risk on a portion of the distributions expected to be repatriated from France over the next 25 years following the acquisition of the Seven French Entities on April 15, 2016. The foreign exchange forwards, amortized until 2041, are translated to Canadian dollars from euro at a rate of 1.7575. The forwards contracts mature in 2018. As at the date of this MD&A, the Corporation had €95.8 million (C$168.4 million) in foreign exchange forward contracts outstanding (it had no euro foreign exchange forward contracts as at December 31, 2015).

Again, as part of the acquisition of the Seven French Entities, one of the wind farm entities holds a hedge agreement to mitigate the risk of fluctuations in the interest rates on its long-term debt. The interest rate swap is amortized over time. The interest rate swap matures in 2030. As at the date of this MD&A, the interest rate swap had an outstanding value of C$14.9 million (it had no interest rate swap for a foreign project as at December 31, 2015).

Overall, Derivatives had a net negative value of $81.3 million at June 30, 2016 (negative $67.7 million at December 31, 2015). The increase is due mainly to the drop in benchmark interest rates since the end of 2015. These figures exclude the impact of Derivatives used to hedge loans of the Corporation's joint ventures. For information on the impact of derivative financial instruments used in the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

Long-Term Debt

As at June 30, 2016, long-term debt totalled $2,449 million ($2,215 million as at December 31, 2015). The $233.4 million increase results mainly from the addition of the Seven French Entities project-level debts, the issuance of a $32.0 million debenture carrying an interest rate of 8.0% to Desjardins for its investment in the French Acquisition, additional drawings on Innergex's credit facility, from Stardale's long-term debt increase on its borrowing and from additional drawings on Upper Lillooet and Mesgi'g Ugju's'n's financings, partly offset by the scheduled repayment of project-level debts.

On January 18, 2016, the Corporation executed an amending agreement to extend its revolving term credit facility from 2019 to 2020. On February 22, 2016, Stardale renegotiated its long-term debt to increase its borrowing by $12.1 million for a total of $109.0 million. The loan bears interest at the BA rate plus an applicable credit margin that was reduced upon refinancing for a total floating-rate of 2.48% at refinancing. The principal repayments are variable and are set at $6.1million for the 12-month period following the refinancing. The all-in effective interest rate is 5.36% (5.99% previously) after accounting for the interest rate swap.

On June 10, 2016, the Corporation announced Desjardins' investment in the wind project portfolio acquired in France and a project under construction to be acquired at a later date. Following this investment, Desjardins owns 30.45% of Innergex Europe (2015) Limited Partnership, the limited partnership that holds these projects. Desjardins' initial investment is $38.4 million, of which $32.0 million was lent to the partnership through a debenture facility, carrying an interest rate of 8.0%.

As at June 30, 2016, 99% of the Corporation's outstanding debt, including convertible debentures, was fixed or hedged against interest rate movements (99% as at December 31, 2015).

Since the beginning of the 2016 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.

Other liabilities

Other liabilities usually consist of contingent considerations, asset retirement obligations and interests payable on the SM-1 LP debenture relating to the Corporation's facilities. Since the first quarter of 2016, it has also included a portion of the distributions made by Viger-Denonville, L.P. to Innergex, as explained in greater detail in the "Investments in Joint Ventures" section.

As at June 30, 2016, other liabilities totalled $20.8 million ($13.4 million as at December 31, 2015). The $7.4 million increase results mainly from the addition of $4.5 million in asset retirement obligations from the Seven French Entities Acquired, $1.9 million in interests payable on the SM-1 LP debenture and a $0.9 million portion of the distributions made by Viger-Denonville, L.P. to Innergex.

Shareholders' Equity

As at June 30, 2016, the Corporation's shareholders' equity totalled $500.9 million, including $22.0 million of non-controlling interests, compared with $471.6 million, including $21.9 million of non-controlling interests, as at December 31, 2015. This $29.3 million increase in total shareholders' equity is attributable mainly to the realization of $22.9 million in net earnings, to the issuance of 3,906,250 shares to three Desjardins Group-affiliated entities under a private placement of common shares of Innergex, partly offset by $36.9 million in dividends declared on common and preferred shares, and to the recognition of other items of comprehensive loss totalling $13.4 million.

For the six-month period ended June 30, 2016, the Corporation recognized under the other items of comprehensive loss a $18.1 million unrealized net loss on derivative financial instruments due mainly to the decrease in benchmark interest rates since December 31, 2015.

Off-Balance-Sheet Arrangements

As at June 30, 2016, the Corporation had issued letters of credit totaling $115.8 million to meet its obligations under its various PPAs and other agreements. Of this amount, $64.0 million was issued under its revolving term credit facility, for the most part on a temporary basis during the construction of the Development Projects, with the remainder being issued under the projects' non-recourse credit facilities. As at that date, Innergex had also issued a total of $30.6 million in corporate guarantees used mainly to support the performance of the Brown Lake hydroelectric facility and the construction of the Mesgi'g Ugju's'n project.

(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 operating activities 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 derivative financial instruments used to hedge the interest rate on project-level debt prior to securing such debt or the exchange rate on equipment purchases.

Free Cash Flow and Payout Ratio calculation	Trailing 12 months ended June 30	
	2016	2015
Cash flows from operating activities	95,137	36,363
Add (Subtract) the following items:		
Changes in non-cash operating working capital items	8,727	(8,317)
Maintenance capital expenditures net of proceeds from disposals	(3,752)	(2,926)
Scheduled debt principal payments	(38,929)	(31,342)
Free Cash Flow attributed to non-controlling interests[1]	(4,645)	(7,541)
Dividends declared on Preferred shares	(6,533)	(7,125)
Cash receipt for wheeling services to be provided by the Harrison Hydro L.P. to other facilities[2]	—	5,419
Adjust for the following elements:		
Transaction costs related to realized acquisitions	1,950	263
Realized losses on derivative financial instruments	26,984	100,939
Free Cash Flow	78,939	85,733
Dividends declared on common shares	66,201	61,518
Payout Ratio - before the impact of the DRIP	84%	72%
Dividends declared on common shares and paid in cash[3]	63,168	51,140
Payout Ratio - after the impact of the DRIP	80%	60%

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. These amounts represent cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to the Big Silver and Tretheway Creek facilities respectively, 49.99% of which was included in the Free Cash Flow 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 were paid in common shares.

For the trailing 12 months ended June 30, 2016, the Corporation generated Free Cash Flow of $78.9 million, compared with $85.7 million for the same period last year. This decrease is due mainly to slightly higher cash flows from operating in 2016, offset by greater scheduled debt principal payments and the lack of cash receipts for the wheeling services provided by the Harrison Hydro L.P. to other facilities owned by the Corporation.

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 on ended June 30, 2016, the dividends on common shares declared by the Corporation corresponded to 84% of Free Cash Flow, compared with 72% for the corresponding prior 12-month period. This negative change is due mainly to the decrease in Free Cash Flow explained above and to the higher number of common shares outstanding by virtue of the conversion, at the holders' request, of a portion of the 5.75% convertible debentures into 3,566,851 common shares, to the issuance of 3,906,250 shares to three Desjardins Group-affiliated entities under a private placement of common shares of Innergex as well as to the DRIP, partly offset by the purchase and cancellation of 1,190,173 shares under the Corporation's normal course issuer bid.

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. For the trailing 12-month period ending on June 30, 2016, the Corporation incurred prospective project expenses of $9.2 million, compared with $6.4 million for the corresponding prior period. This 43% increase is attributable mainly to the advancement of a number of prospective projects and to pursuing opportunities in new international markets. Excluding these discretionary expenses, the Corporation's Payout Ratio would have been approximately 9% points lower for the twelve-month period ending on June 30, 2016, and approximately 5% points lower for the corresponding prior period.

Furthermore, the Corporation does not expect to require additional equity in order to complete its current four Development Projects, given the anticipated increase in cash flows from operations once these projects have been commissioned, the project-level financing that the Corporation has secured for these projects and the additional equity provided by the DRIP.

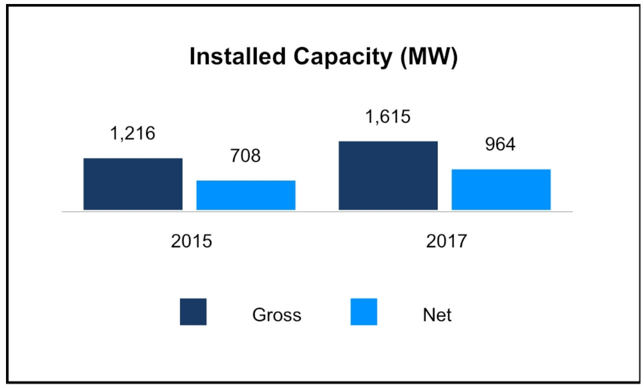
OUTLOOK FOR 2017

The Corporation makes certain projections to provide readers with an indication of its business activities and operating performance once the four existing Development Projects have been commissioned. These projections also include the data for the Walden Facility and the Seven French Entities Acquired, which were acquired by the Corporation in the first and second quarters of 2016, respectively. These projections do not take into account possible acquisitions, divestments or additional Development Projects following the award of any new power purchase agreements.

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

Projected Installed Capacity

The Corporation believes that installed capacity provides a good indication of the size and magnitude of its operations. Once the four Development Projects have been commissioned and following the acquisition of Walden and the Seven French Entities, the Corporation expects its net installed capacity to increase from 708 MW (gross 1,216 MW) at the end of the year 2015 to 964 MW (gross 1,615 MW) in 2017, corresponding to a 36% increase (gross 33%). Net installed capacity reflects the fact that some of the Corporation's Operating Facilities are not wholly owned. Installed capacity includes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method.



Projected Long-Term Average Production (LTA)

A key performance indicator for the Corporation is to compare actual electricity generation with the expected LTA production for each facility. Once the four Development Projects have been commissioned and following the acquisition of Walden and the Seven French Entities, the Corporation expects its annualized consolidated LTA production to increase from 3,130 GWh at the end of the year 2015 to 4,418 GWh in 2017, corresponding to a 41% increase. Consolidated LTA production is presented in accordance with revenue recognition accounting rules under IFRS and excludes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method

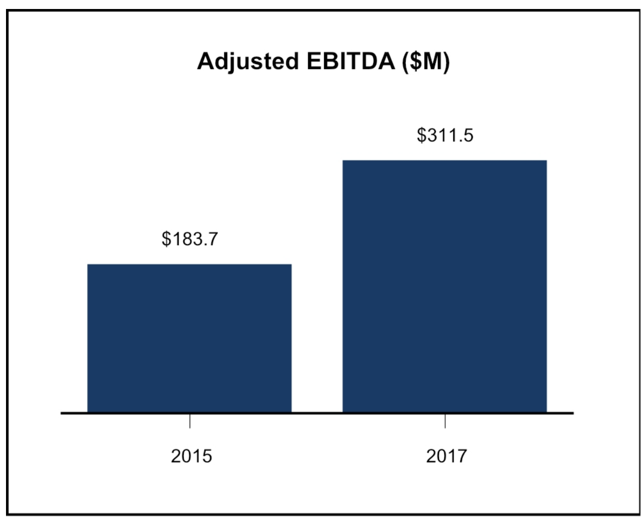
Annualized Consolidated LTA Production (GWh)

	2015	Starting in 2017
Hydro	2,415.9	3,019.4
Wind	676.5	1,360.9
Solar[1]	37.9	37.6
Total	3,130.3	4,417.9

1. Solar farm LTA diminishes over time due to expected solar panel degradation

Projected Adjusted EBITDA

A key performance indicator for the Corporation is Adjusted EBITDA generation. Once the four Development Projects have been commissioned and following the acquisition of Walden and the Seven French Entities, the Corporation expects to generate annualized Adjusted EBITDA starting in 2017 of approximately $311.5 million (adjusted for an inflation component thereafter), compared with $183.7 million in 2015. This represents an annual compound growth rate of approximately 30% for the 2015-2017 period. Adjusted EBITDA is presented in accordance with revenue recognition accounting rules under IFRS and excludes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method. The annual Adjusted EBITDA for these facilities combined attributable to the Corporation is approximately $8.0 million.

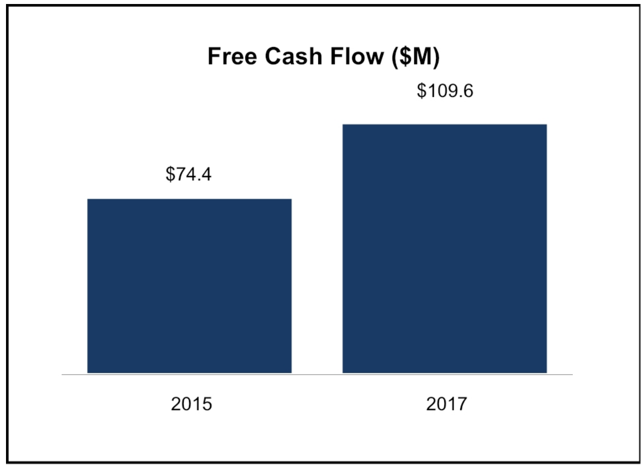


It should be noted that Adjusted EBITDA does not take into account the impact of interest and principal payments on the Corporation's existing debt and on the project-level debt financing.

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

Projected Free Cash Flow

Another key performance indicator for the Corporation is the Free Cash Flow generated from its operations and available for distribution to common shareholders and for reinvestment to fund its growth. Once the four Development Projects have been commissioned and following the acquisition of Walden and the Seven French Entities, the Corporation expects to generate Free Cash Flow in 2017 of approximately $109.6 million, compared with $74.4 million in 2015. This represents an annual compound growth rate of approximately 21% for the 2015-2017 period and will reflect the cash flows generated by the Corporation's 46 Operating Facilities at that time, after taking into account maintenance capital expenditures, scheduled debt principal payments, preferred share dividends and the portion of Free Cash Flow attributed to non-controlling interests. For 2017, the increase in Free Cash Flow of $4.6 million (to $109.6 million), compared with the information published as at December 31, 2015, is due mainly to the acquisition of the seven French wind farm facilities and the increase in production at the Mesgi'g Ugju's'n wind farm.



For more information on the principal assumptions used in determining projected financial information and the principal risks and uncertainties related thereto, please refer to the "Forward-Looking Information" section.

SEGMENT INFORMATION

Geographic Segments

As at June 30, 2016, the Corporation owns interests in 27 hydroelectric facilities, six wind farms and one solar farm in Canada, seven wind farms in France and one hydroelectric facility in the United States. The Corporation operates in three principal geographical areas, which are detailed below:

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Revenues				
Canada	83,300	68,824	145,129	125,885
France	2,812	—	2,812	—
United States	1,673	1,347	2,324	2,013
	87,785	70,171	150,265	127,898

As at	June 30, 2016	December 31,2015
Non-current assets, excluding financial instruments and deferred income tax assets		
Canada	2,874,327	2,704,788
France	247,730	—
United States	7,359	8,043
	3,129,416	2,712,831

Canada

For the three and six-month period ended June 30, 2016, the Corporation recorded revenues in Canada of $83.3 million and $145.1 million respectively, compared with $68.8 million and $125.9 million for the same periods last year. The increase in Canadian revenues is attributable mainly to better results from most of the British Columbia hydroelectric facilities compared with the same period last year, and to the contribution, to a lesser extent, of the recently commissioned facilities, namely the BC Tretheway Creek hydroelectric facility commissioned in November 2015 and the BC Walden North hydroelectric facility acquired in February 2016, which were partly offset by lower revenues in the wind regime in Quebec and in the hydrologic regime in Ontario.

For the period ended June 30, 2016, the increase in non-current assets, excluding financial instruments and deferred income tax assets in Canada, stems mainly from the construction of the Development Projects and the purchase of the Walden facility on February 25, 2016.

France

For the period ended and as at June 30, 2016, the increase in revenues and in non-current assets, excluding financial instruments and deferred income tax assets in France, stems mainly from the Seven French Entities Acquired on April 15, 2016.

United States

For the three and six-month period ended June 30, 2016, the Corporation recorded revenues in the United States of $1.7 million and $2.3 million respectively, compared with $1.3 million and $2.0 million for the same periods last year. The increase in revenues from the United States is attributable mainly to better operating results from the Horseshoe Bend hydroelectric facility compared with the same period last year. The Horseshoe Bend facility produced 122% of its LTA for the period ended on June 30, 2016. For the period ended June 30, 2016, the decrease in non-current assets stems mainly from depreciation and foreign exchange fluctuations.

Operating Segments

As at June 30, 2016, 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, 2015. 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)

SUMMARY OPERATING RESULTS Three months ended June 30, 2016	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	987,928	174,105	14,418	—	1,176,451
Revenues	66,744	14,984	6,056	—	87,784
Expenses:					
Operating expenses	10,674	3,343	201	—	14,218
General and administrative expenses	2,032	1,204	40	669	3,945
Prospective project expenses	—	—	—	2,758	2,758
Adjusted EBITDA	54,038	10,437	5,815	(3,427)	66,863
Three months ended June 30, 2015					
Power generated (MWh)	718,980	171,835	13,357	—	904,172
Revenues	50,874	13,687	5,610	—	70,171
Expenses:					
Operating expenses	8,458	2,473	169	—	11,100
General and administrative expenses	1,977	955	42	752	3,726
Prospective project expenses	—	—	—	1,930	1,930
Adjusted EBITDA	40,439	10,259	5,399	(2,682)	53,415

SUMMARY OPERATING RESULTS Six months ended June 30, 2016	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	1,435,897	382,699	22,242	—	1,840,838
Revenues	109,184	31,739	9,342	—	150,265
Expenses:					
Operating expenses	17,784	5,473	359	—	23,616
General and administrative expenses	3,984	2,151	80	1,417	7,632
Prospective project expenses	—	—	—	4,475	4,475
Adjusted EBITDA	87,416	24,115	8,903	(5,892)	114,542
Six months ended June 30, 2015					
Power generated (MWh)	1,157,272	385,138	20,190	—	1,562,600
Revenues	88,638	30,780	8,480	—	127,898
Expenses:					
Operating expenses	15,257	4,708	382	—	20,347
General and administrative expenses	4,375	1,889	85	1,549	7,898
Prospective project expenses	—	—	—	3,283	3,283
Adjusted EBITDA	69,006	24,183	8,013	(4,832)	96,370

FINANCIAL POSITION As at June 30, 2016	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Goodwill	8,269	—	—	—	8,269
Total assets	1,800,877	577,540	112,976	949,955	3,441,348
Total liabilities	1,331,761	389,045	118,808	1,100,857	2,940,471
Acquisition of property, plant and equipment during the period	3,304	157,687	—	198,082	359,073
As at December 31, 2015					
Goodwill	8,269	—	—	—	8,269
Total assets	1,806,873	332,698	114,543	874,189	3,128,303
Total liabilities	1,344,518	213,415	107,641	991,172	2,656,746
Acquisition of property, plant and equipment during the year	4,051	871	81	299,549	304,552

Hydroelectric Generation Segment

For the three-month period ended June 30, 2016, this segment produced 115% of the LTA and generated revenues of $66.7 million, compared with a production at 88% of the LTA and revenues of $50.9 million for the same period last year. The revenue and production increases in this segment is due mainly to production above the long-term average of the hydroelectric facilities in British Columbia during the quarter, to the contribution of the Tretheway Creek hydroelectric facility, which began commercial operation in November 2015, and to the contribution of the Walden North hydroelectric facility acquired in February 2016.

For the six-month period ended June 30, 2016, this segment produced 120% of the LTA and generated revenues of $109.2 million, compared with a production at 102% of the LTA and revenues of $88.6 million for the same period last year. The revenue and production increases in this segment is due mainly to production above the long-term average of the Quebec and British Columbia hydroelectric facilities during the period, to the contribution of the Tretheway Creek hydroelectric facility, which began commercial operation in November 2015, and to the contribution of the Walden North hydroelectric facility acquired in February 2016.

The decrease in total assets since December 31, 2015, is attributable mainly to the depreciation of property, plant and equipment and amortization of intangible assets, partly offset by the addition of the Walden Facility.

The decrease in total liabilities since December 31, 2015, is attributable mainly to the scheduled repayment of long-term debt.

Wind Power Generation Segment

For the three-month period ended June 30, 2016, this segment produced 102% of the LTA and generated revenues of $15.0 million, compared with production at 120% of the LTA and revenues of $13.7 million for the same period last year. The decrease of the LTA compared to last year is due mainly to lower wind regimes at the Quebec facilities and the below LTA wind regime at the French facilities. The revenue increase is due solely to the French Acquisition.

For the six-month period ended June 30, 2016, this segment produced 100% of the LTA and generated revenues of $31.7 million, compared with production at 108% of the LTA and revenues of $30.8 million for the same period last year. The production decrease is due mainly to lower wind regimes at the Quebec facilities and the below LTA wind regime at the French facilities. The revenue increase is due solely to the French Acquisition.

The increase in total assets since December 31, 2015, is attributable mainly to the French Acquisition, partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2015, is attributable mainly to the French Acquisition, partly offset by the scheduled repayment of long-term debt.

Solar Power Generation Segment

For the three-month period ended June 30, 2016, this segment produced 117% of the LTA and generated revenues of $6.1 million, compared with production at 107% of the LTA and revenues of $5.6 million for the same period last year.

For the six-month period ended June 30, 2016, this segment produced 113% of the LTA and generated revenues of $9.3 million, compared with production at 102% of the LTA and revenues of $8.5 million for the same period last year.

The increase in production and revenues for both the second quarter and the six-month period stems mainly from solar irradiation higher than for the same period last year.

The decrease in total assets since December 31, 2015, results mainly from depreciation of property, plant and equipment and from amortization of intangible assets.

The increase in total liabilities since December 31, 2015, is attributable to Stardale's increase in its long-term debt borrowing, partly offset by a scheduled repayment.

Site Development Segment

For the three-month and six-month periods ended June 30, 2016, site development expenses were $3.4 million and $5.9 million respectively, compared with $2.7 million and $4.8 million respectively in 2015. The increase is due mainly to prospective project expenses incurred for the advancement of a number of Prospective Projects and to pursuing opportunities in new international markets.

The increase in total assets since December 31, 2015, is attributable mainly to payments made for costs incurred for the construction of the Development Projects, partly offset by a decrease in restricted cash, which was used to pay for the construction of the Development Projects. Since December 31, 2015, the increase in total liabilities has been due mainly to drawings on the Boulder Creek, Upper Lillooet River and Mesgi'g Ugju's'n project financings.

QUARTERLY FINANCIAL INFORMATION

	Three months ended			
(in millions of dollars, unless otherwise stated)	June 30, 2016	Mar. 31, 2016	Dec. 31, 2015	Sept. 30, 2015
Power generated (MWh)	1,176,451	664,387	647,062	777,975
Revenues	87.8	62.5	56.3	62.7
Adjusted EBITDA	66.9	47.7	38.8	48.6
Realized and unrealized net gain (loss) on financial instruments	2.2	1.3	2.0	(2.7)
Impairment of project development costs	—	—	(51.7)	—
Net earnings (loss)	15.7	7.2	(34.4)	1.3
Net earnings (loss) attributable to owners of the parent	14.4	8.3	(30.6)	5.8
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.19	0.07	(0.31)	0.04
Dividends declared on preferred shares	1.5	1.5	1.8	1.8
Dividends declared on common shares	17.3	16.6	16.1	16.2
Dividends declared on common shares, $ per share	0.160	0.160	0.155	0.155

	Three-months ended			
(in millions of dollars, unless otherwise stated)	Jun 30, 2015	Mar. 31, 2015	Dec. 31, 2014	Sept. 30, 2014
Power generated (MWh)	904,172	658,427	819,903	826,617
Revenues	70.2	57.7	68.2	66.4
Adjusted EBITDA	53.4	43.0	48.7	51.7
Realized and unrealized net gain (loss) on financial instruments	18.6	(56.0)	(49.6)	(15.3)
Impairment of project development costs	—	—	—	—
Net earnings (loss)	22.5	(37.8)	(27.6)	(4.5)
Net earnings (loss) attributable to owners of the parent	22.8	(29.1)	(18.9)	(0.7)
Net loss attributable to owners of the parent ($ per share – basic and diluted)	0.21	(0.31)	(0.21)	(0.02)
Dividends declared on preferred shares	1.8	1.8	1.8	1.8
Dividends declared on common shares	15.7	15.7	15.1	15.1
Dividends declared on common shares, $ per share	0.155	0.155	0.150	0.150

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 is 73% 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.

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

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 unrealized and realized gains (losses) on derivative financial instruments arising from the increase (decrease) in benchmark interest rates. Historical analysis of net earnings (losses) should take this factor into account. It should be borne in mind that the unrealized changes in 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 or Payout Ratio.

INVESTMENTS IN JOINT VENTURES

The Corporation's material joint ventures at the end of the reporting period were Umbata Falls Limited Partnership ("Umbata Falls, L.P.") (49% interest) and Parc éolien communautaire Viger-Denonville, s.e.c. (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 June 30	2016				2015			
	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	41,284	37,823	109%	84.93	47,244	37,823	125%	84.86
Viger-Denonville	14,864	15,450	96%	149.47	18,634	15,450	121%	149.13

Six months ended June 30	2016				2015			
	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	69,393	54,750	127%	84.93	69,346	54,750	127%	84.83
Viger-Denonville	36,632	35,750	102%	149.47	44,085	35,750	123%	149.13

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.

Summary Statements of Earnings and Comprehensive Income – Umbata Falls, L.P.

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Revenues	3,506	4,009	5,894	5,883
Operating and general and administrative expenses	231	219	466	394
Adjusted EBITDA	3,275	3,790	5,428	5,489
Finance costs	633	678	1,263	1,271
Other net revenues	(8)	(13)	(16)	(21)
Depreciation and amortization	1,004	1,004	2,008	2,011
Unrealized net loss (gain) on financial instruments	676	(1,589)	2,124	409
Net earnings and comprehensive income	970	3,710	49	1,819

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

For the three- and six-month periods ended June 30, 2016, production was 109% and 127% respectively of the LTA, due mainly to above-average water flows.

The decrease in Adjusted EBITDA for the three-month period ended June 30, 2016, is due mainly to lower production levels than for the same period last year. For the six-month period ended June 30, 2016, the Adjusted EBITDA was relatively stable between the two periods.

Net earnings and comprehensive income were $1.0 million and $0.05 million respectively for the three- and six-month periods ended June 30, 2016, compared with $3.7 million and $1.8 million for the same periods last year, reflecting a decrease in the results. If the net earnings and comprehensive income mirror the previously discussed production changes, they were also impacted by the recognition of unrealized net losses on derivative financial instruments. For the three-month period ended June 30, 2016, Umbata Falls L.P. recognized an unrealized loss of $0.7 million, compared with an unrealized net gain of $1.6 million for the same period last year. For the six-month period ended June 30, 2016, Umbata Falls L.P. recognized a $2.1 million unrealized loss, compared with an unrealized net loss of $0.4 million for the same period last year. These losses, resulting from the decrease in benchmark interest rates during the second quarter, decreased the net earnings and comprehensive income for both periods.

Summary Statements of Financial Position – Umbata Falls, L.P.

As at	June 30, 2016	December 31, 2015
Current assets	3,564	2,223
Non-current assets	66,478	68,467
	70,042	70,690
Current liabilities	3,135	3,062
Non-current liabilities	49,529	48,852
Partners' equity	17,378	18,776
	70,042	70,690

As at June 30, 2016, the reduction in partners' equity stems from the net loss of $0.05 million generated for the six-month period and a distribution of $1.4 million to the partners. To manage its exposure to the risk of increasing interest rates on its debt financing, Umbata Falls, L.P. uses a derivative financial instrument but does not own or issue any derivative financial instruments for speculation purposes. An amortizing interest-rate swap totaling $43.7 million used to hedge the interest rate on the Umbata Falls loan had a net negative value of $10.2 million at June 30, 2016 (negative value of $8.1 million at December 31, 2015).

Viger-Denonville, L.P.

Summary Statements of Earnings and Comprehensive Income – Viger-Denonville, L.P.

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Revenues	2,222	2,779	5,475	6,575
Operating and general and administrative expenses	434	470	940	959
Adjusted EBITDA	1,788	2,309	4,535	5,616
Finance costs	907	908	1,836	1,828
Other net revenues	(8)	(13)	(11)	(31)
Depreciation and amortization	731	728	1,462	1,458
Unrealized net (gain) loss on financial instruments	(166)	(79)	(289)	2,028
Net earnings	324	765	1,537	333
Other comprehensive (loss) income	(768)	1,390	(2,220)	1,390
Total other comprehensive (loss) income	(444)	2,155	(683)	1,723

For the three- and six-month periods ended June 30, 2016, production was 96% and 102% respectively of the LTA, due mainly to below-average wind regime during the three-month period, as opposed to an above-average wind regime for the six-month period. The decrease in Adjusted EBITDA is due mainly to lower production levels than for the same periods last year.

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

On April 1, 2015, the Corporation began using hedge accounting in the treatment of existing derivative financial instruments used to fix the interest rate on the Viger-Denonville project-level debt in order to reduce the fluctuations in net earnings or losses resulting from unrealized gains or losses on these derivative financial instruments during a given period. Under hedge accounting, most of the unrealized gains or losses on derivative financial instruments that arise from a decrease or increase in the benchmark interest rate will be recorded as other comprehensive income or loss.

For the three-month period ended on June 30, 2016, the decrease in net earnings, compared with the net earnings for the same period last year, is due mainly to lower production levels. For the six-month period ended on June 30, 2016, the increase in net earnings, compared with the net earnings for the same period last year, is due mainly to the recognition of an unrealized net gain on financial instruments compared with a loss in the comparative period, partly offset by lower production levels.

Summary Statements of Financial Position – Viger-Denonville, L.P.

As at	June 30, 2016	December 31, 2015
Current assets	1,523	2,426
Non-current assets	58,062	59,518
	59,585	61,944
Current liabilities	4,276	4,500
Non-current liabilities	57,738	57,191
(Deficit) Partners' equity	(2,429)	253
	59,585	61,944

As at June 30, 2016, the reduction in partners' equity stems mainly from a distribution of $2.0 million and by the recognition of an other comprehensive loss for the six-month period. In addition, 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 derivative financial instruments for speculation purposes. An amortizing interest-rate swap totaling $52.8 million used to hedge the interest rate of the Viger-Denonville loan had a net negative value of $8.7 million at June 30, 2016 (negative $6.2 million at December 31, 2015).

During the first quarter of 2016, a distribution made by Viger-Denonville, L.P. to its partners turned the partnership's equity to a deficit. As such, and as per Innergex's accounting policies, the Corporation discontinued recognizing its share of losses in Viger-Denonville, L.P. Furthermore, as the partners' equity is in a deficit position, the portion of the distributions made by the partnership to Innergex are recorded in other long-term liabilities in Innergex's Statements of Financial Position.

NON-WHOLLY OWNED SUBSIDIARIES

On June 10, 2016, Innergex announced the closing of the investment by Desjardins in the French Acquisition. Following this investment, the Corporation and Desjardins respectively hold 69.55% and 30.45% of the limited partnership that holds these projects. Summarized financial information regarding Innergex Europe L.P. and its subsidiaries, in which Desjardins has a material non-controlling interest, is set out below. Amounts are shown before intragroup eliminations.

Innergex Europe L.P. and Its Subsidiaries

On April 15, 2016, Innergex completed the acquisition of seven operating wind power projects in France. The Corporation realized the acquisition through wholly owned foreign subsidiaries of Innergex Europe L.P. Up to the investment made by Desjardins, 100% of the units of Innergex Europe L.P. were owned by the Corporation. On June 10, 2016, Desjardins invested $38.4 million in exchange for 30.45% of the common units and a $31,965 debenture issued by Innergex Europe L.P. The participation in the common units is reflected in the non-controlling interest account.

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

Summary Statements of Earnings and Comprehensive Income – Innergex Europe L.P. and Its Subsidiaries

	Period of 77 days ended June 30, 2016
Revenues	2,812
Adjusted EBITDA	1,683
Net loss	(3,743)
Other comprehensive loss	(135)
Total comprehensive loss	(3,878)
Net loss attributable to:	
Owners of the parent	(3,313)
Non-controlling interests	(430)
	(3,743)
Total comprehensive loss attributable to :	
Owners of the parent	(3,422)
Non-controlling interests	(456)
	(3,878)

Since the April 15, 2016, acquisition and up to June 30, 2016, production was 81% of the LTA, due mainly to the below-average wind regime in France. The net loss for the period is due mainly to lower revenues, which result from below-average production, and to acquisition and financing costs. The financing costs include $0.1 million of interest payable to Desjardins on the $32.0 million debenture, $1.3 million of preferred return payable to Innergex on the $73.1 million preferred units and $0.6 million of interest payable to Innergex on a temporary bridge loan. Excluding these three elements, the net loss would have been $1.7 million.

Although the Corporation acquired the Seven French Entities in the present quarter, it is worth mentioning that for the six-month period ended June 30, 2016, production was 104% of the LTA for the seven wind farms in France. This is due primarily to production that was 118% of the LTA in the first quarter of 2016, although production was below-average in the quarter ended June 30, 2016.

Summary Statements of Financial Position – Innergex Europe

As at	June 30, 3016
Current assets	13,673
Non-current assets	250,869
	264,542
Current liabilities	9,280
Non-current liabilities	252,741
Equity attributable to owners	1,780
Non-controlling interests	741
	264,542

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

Seven French Entities

The following figures are excluded from the controls policies and procedures of the Corporation as stated in the Establishment and Maintenance of DC&P and ICFR section of this MD&A.

Summary financial information about the Seven French Entities is set out below:

Summary Statements of Earnings and Comprehensive Income – Seven French Entities

	Period of 77 days ended June 30, 2016
Revenues	2,812
Adjusted EBITDA	1,784
Net loss	(2,017)
Other comprehensive loss	(29)
Total comprehensive loss	(2,046)

Summary Statements of Financial Position – Seven French Entities

As at	June 30, 3016
Current assets	12,622
Non-current assets	230,067
	242,689
Current liabilities	11,409
Non-current liabilities	185,996
Equity attributable to owners	45,284
	242,689

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

ACCOUNTING CHANGES

New and revised IFRS issued

IAS 1 - Presentation of Financial Statements

The IASB issued Disclosure Initiative (Amendments to IAS 1), which addressed concerns expressed about some of the existing presentation and disclosure requirements in IAS 1 and ensured that entities are able to use judgment when applying those requirements. In addition, the amendments clarified the requirements in other comprehensive income. Those amendments must be applied for annual periods beginning on or after January 1, 2016. The application of this standard has not had any material impact on the amounts reported for the current year.

IFRS 11- Joint arrangement

IFRS 11 was amended in May 2014 to add new guidance on how to account for the acquisition of an interest in a joint operation that constitutes a business. The amendments are effective for annual periods beginning on or after January 1, 2016. The application of this standard has not had any material impact on the amounts reported for the current year.

SUBSEQUENT EVENTS

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 ($)
08/04/2016	09/30/2016	10/17/2016	0.1600	0.2255	0.359375

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS

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

	Notes	Three months ended June 30 2016	Three months ended June 30 2015	Six months ended June 30 2016	Six months ended June 30 2015
Revenues		87,784	70,171	150,265	127,898
Expenses					
Operating	4	14,218	11,100	23,616	20,347
General and administrative		3,945	3,726	7,632	7,898
Prospective projects		2,758	1,930	4,475	3,283
Earnings before finance costs, income taxes, depreciation, amortization, other net (revenues) expenses, share of earnings of joint ventures and unrealized net gain on financial instruments		66,863	53,415	114,542	96,370
Finance costs	5	24,608	24,540	44,102	40,957
Other net (revenues) expenses	6	(233)	24,065	(407)	92,479
Earnings (loss) before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments		42,488	4,810	70,847	(37,066)
Depreciation	4,9	15,070	13,241	28,853	26,498
Amortization	4	7,065	5,540	12,719	11,080
Share of earnings of joint ventures		(475)	(2,200)	(24)	(1,056)
Unrealized net gain on financial instruments		(2,145)	(43,096)	(3,432)	(55,081)
Earnings (loss) before income taxes		22,973	31,325	32,731	(18,507)
Income tax expense (recovery of)					
Current		845	879	1,472	1,630
Deferred		6,451	7,940	8,386	(4,833)
		7,296	8,819	9,858	(3,203)
Net earnings (loss)		15,677	22,506	22,873	(15,304)
Net earnings (loss) attributable to:					
Owners of the parent		14,381	22,808	22,713	(6,336)
Non-controlling interests		1,296	(302)	160	(8,968)
		15,677	22,506	22,873	(15,304)
Weighted average number of common shares outstanding (in 000s)	7	107,318	101,235	105,657	101,071
Basic net earnings (loss) per share ($)	7	0.19	0.21	0.19	(0.10)
Diluted weighted average number of common shares outstanding (in 000s)	7	108,314	101,566	106,469	101,474
Basic net earnings (loss) per share ($)	7	0.19	0.21	0.19	(0.10)

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

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

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

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Net earnings (loss)	15,677	22,506	22,873	(15,304)
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:				
Foreign exchange (loss) gain on translation of self-sustaining foreign subsidiaries	(510)	(114)	(1,091)	624
Related deferred tax	65	15	153	(82)
Foreign exchange gain (loss) on the designated hedges on the investments in self-sustaining foreign subsidiaries	343	133	1,009	(620)
Related deferred tax	(76)	(17)	(164)	82
Change in fair value of hedging instruments	(5,972)	10,060	(18,087)	8,265
Related deferred tax	1,582	(2,652)	4,787	(2,179)
Share of change in fair value of hedging instruments of joint venture	—	695	—	695
Related deferred tax	—	(183)	—	(183)
Share of non-controlling interests in foreign exchange loss on translation of self-sustaining foreign subsidiaries	(27)	—	(27)	—
Share of non-controlling interests in change in fair value of hedging instruments	(421)	264	(1,359)	264
Related deferred tax	46	(68)	130	(68)
Other comprehensive (loss) income	(4,970)	8,133	(14,649)	6,798
Total comprehensive income (loss)	10,707	30,639	8,224	(8,506)
Other comprehensive (loss) income attributable to:				
Owners of the parent	(4,568)	7,937	(13,393)	6,602
Non-controlling interests	(402)	196	(1,256)	196
	(4,970)	8,133	(14,649)	6,798
Total comprehensive income attributable to:				
Owners of the parent	9,813	30,745	9,320	266
Non-controlling interests	894	(106)	(1,096)	(8,772)
	10,707	30,639	8,224	(8,506)

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at	Notes	June 30, 2016	December 31, 2015
Assets			
Current assets			
Cash and cash equivalents		62,133	40,663
Restricted cash and short-term investments		167,513	312,720
Accounts receivable		54,031	37,073
Reserve accounts		856	1,315
Income tax receivable		7	4
Derivative financial instruments		1,572	1,209
Prepaid and others		6,183	4,363
		292,295	397,347
Non-current assets			
Reserve accounts		48,131	41,521
Property, plant and equipment	9	2,499,536	2,174,222
Intangible assets		541,122	472,271
Investments in joint ventures		8,515	9,327
Derivative financial instruments		7,895	2,768
Deferred tax assets		15,051	15,356
Goodwill		8,269	8,269
Other long-term assets		20,534	7,222
		3,441,348	3,128,303

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at	Notes	June 30, 2016	December 31, 2015
Liabilities			
Current liabilities			
Dividends payable to shareholders		18,761	17,892
Accounts payable and other payables		90,623	95,466
Income tax payable		1,178	1,234
Derivative financial instruments		15,145	15,337
Current portion of long-term debt		61,131	54,995
Current portion of other liabilities		370	246
		187,208	185,170
Non-current liabilities			
Derivative financial instruments		75,630	56,348
Long-term debt	10	2,387,654	2,160,438
Other liabilities		20,800	13,429
Liability portion of convertible debentures		94,131	93,430
Deferred tax liabilities		175,048	147,931
		2,940,471	2,656,746
Shareholders' equity			
Common share capital		160,071	108,541
Contributed surplus from reduction of capital on common shares		775,413	775,413
Preferred shares		131,069	131,069
Share-based payment		2,215	2,174
Equity portion of convertible debentures		1,877	1,877
Deficit		(576,828)	(567,848)
Accumulated other comprehensive loss		(14,969)	(1,576)
Equity attributable to owners		478,848	449,650
Non-controlling interests		22,029	21,907
Total shareholders' equity		500,877	471,557
		3,441,348	3,128,303

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

	Equity attributable to owners										
Six months ended June 30, 2016	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 loss	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2016	103,938	108,541	775,413	131,069	2,174	1,877	(567,848)	(1,576)	449,650	21,907	471,557
Net earnings							22,713		22,713	160	22,873
Other items of comprehensive loss								(13,393)	(13,393)	(1,256)	(14,649)
Total comprehensive income (loss)	—	—	—	—	—	—	22,713	(13,393)	9,320	(1,096)	8,224
Common shares issued on April 15, 2016 : private placement (Note 3b))	3,906	50,000							50,000		50,000
Common shares issued through dividend reinvestment plan	128	1,530							1,530		1,530
Share-based payment					41				41		41
Investments from non-controlling interests							5,195		5,195	1,218	6,413
Dividends declared on common shares							(33,917)		(33,917)		(33,917)
Dividends declared on preferred shares							(2,971)		(2,971)		(2,971)
Balance June 30, 2016	107,972	160,071	775,413	131,069	2,215	1,877	(576,828)	(14,969)	478,848	22,029	500,877

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

	Equity attributable to owners										
Six months ended June 30, 2015	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 (loss) income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2015	100,672	62,224	784,482	131,069	2,050	1,340	(466,336)	(15)	514,814	47,411	562,225
Net loss							(6,336)		(6,336)	(8,968)	(15,304)
Other items of comprehensive income								6,602	6,602	196	6,798
Total comprehensive (loss) income	—	—	—	—	—	—	(6,336)	6,602	266	(8,772)	(8,506)
Common shares issued through dividend reinvestment plan	466	5,154							5,154		5,154
Share-based payment					107				107		107
Share options exercised	45	462			(68)				394		394
Convertible debenture converted in common shares	86	922				(21)			901		901
Distributions to non-controlling interests									—	(5,249)	(5,249)
Dividends declared on common shares							(31,361)		(31,361)		(31,361)
Dividends declared on preferred shares							(3,563)		(3,563)		(3,563)
Balance June 30, 2015	101,269	68,762	784,482	131,069	2,089	1,319	(507,596)	6,587	486,712	33,390	520,102

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

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

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

	Notes	Six months ended June 30 2016	2015
Operating activities			
Net earnings (loss)		22,873	(15,304)
Items not affecting cash:			
Depreciation	9	28,853	26,498
Amortization		12,719	11,080
Share of earnings of joint ventures		(24)	(1,056)
Unrealized net gain on financial instruments		(3,432)	(55,081)
Inflation compensation interest	5	2,446	685
Amortization of financing fees	5	509	388
Accretion of long-term debt and convertible debentures	5	770	277
Accretion expenses on other liabilities	5	232	310
Share-based payment		41	107
Deferred income taxes		8,386	(4,833)
Others		173	(30)
Interest on long-term debt and convertible debentures	5	39,713	38,871
Interest paid		(37,164)	(37,009)
Distributions received from joint ventures		1,708	4,556
Current income tax expense		1,472	1,630
Net income taxes paid		(1,502)	(1,878)
Effect of exchange rate fluctuations		(657)	324
		77,116	(30,465)
Changes in non-cash operating working capital items	11	(18,181)	(1,180)
		58,935	(31,645)
Financing activities			
Dividends paid on common shares		(31,221)	(25,611)
Dividends paid on preferred shares		(3,266)	(3,562)
Distributions to non-controlling interests		—	(5,249)
Investments from non-controlling interests		6,392	—
Increase of long-term debt		488,206	686,911
Repayment of long-term debt		(381,249)	(389,246)
Payment of deferred financing costs		(1,998)	(8,134)
Proceeds from issuance of common shares		50,000	—
Proceeds from exercise of share options		—	394
		126,864	255,503

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

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

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

		Six months ended June 30	
		2016	2015
	Notes		
Investing activities			
Cash acquired on business acquisitions		11,887	—
Business acquisitions	3	(102,795)	—
Decrease (increase) of restricted cash and short-term investments		145,207	(93,334)
Net funds withdrawn from (invested into) the reserve accounts		171	(2,923)
Additions to property, plant and equipment		(204,135)	(108,005)
Additions to project development costs		—	(29,104)
Additions to other long-term assets		(14,626)	(399)
Proceeds from disposal of property, plant and equipment		—	29
		(164,291)	(233,736)
Effects of exchange rate changes on cash and cash equivalents		(38)	233
Net increase (decrease) in cash and cash equivalents		21,470	(9,645)
Cash and cash equivalents, beginning of period		40,663	54,609
Cash and cash equivalents, end of period		62,133	44,964
Cash and cash equivalents is comprised of:			
Cash		58,008	27,904
Short-term investments		4,125	17,060
		62,133	44,964

Additional information is presented in Note 11.

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

DESCRIPTION OF BUSINESS

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

These unaudited condensed consolidated financial statements were approved by the Board of Directors on August 4, 2016.

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 AND REVISED IFRS

New and revised IFRS issued

IAS 1 - Presentation of Financial Statements

The IASB issued Disclosure Initiative (Amendments to IAS 1), which addressed concerns expressed about some of the existing presentation and disclosure requirements in IAS 1 and ensured that entities are able to use judgment when applying those requirements. In addition, the amendments clarified the requirements in other comprehensive income. Those amendments must be applied for annual periods beginning on or after January 1, 2016. The application of this standard has not had any material impact on the amounts reported for the current year.

IFRS 11- Joint arrangement

IFRS 11 was amended in May 2014 to add new guidance on how to account for the acquisition of an interest in a joint operation that constitutes a business. The amendments are effective for annual periods beginning on or after January 1, 2016. The application of this standard has not had any material impact on the amounts reported for the current year.

3. BUSINESS ACQUISITIONS

a. Acquisition of assets of Walden

On February 25, 2016, the Corporation and Cayoose Creek Development Corporation ("Cayoose") finalized the acquisition of the Walden ("Walden") run-of-river hydroelectric facility located in British Columbia, Canada. The purchase price of $9,200 for the Walden facility was paid in cash, of which $870 was paid as a deposit in the fourth quarter of 2015 and was classified under other long-term assets as at December 31, 2015.

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

The Corporation and Cayoose respectively own 51% and 49% of the participating units of Cayoose Creek Limited Partnership ("Cayoose L.P."), formed for the acquisition of the Walden facility.

All power generated from the facility is sold to British Columbia Hydro and Power Authority.

Additional cash flows generated from the assets acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. The acquisition of the Walden facility added an additional installed gross capacity of approximately 16 MW to the Corporation's portfolio of operational hydroelectric facilities.

The following table reflects the preliminary purchase price allocation:

	Preliminary purchase price allocation
Property, plant and equipment	1,786
Intangible assets	8,078
Deferred tax liabilities	(664)
Net assets acquired	9,200

The transaction costs relating to this acquisition have been expensed as transaction costs of the business combination in accordance with IFRS 3 (see note 6).

If the acquisition had taken place on January 1, 2016, the consolidated revenues and net earnings for the six-month period ended June 30, 2016 would have been $150,378 and $22,823 respectively.

The amounts of revenues and net earnings of Cayoose LP since February 25, 2016 included in the consolidated statement of earnings are $1,376 and $769 respectively for the 127 days ended June 30, 2016.

b. Acquisition of 7 operating wind facilities in France

On April 15, 2016, the Corporation finalized the acquisition of a portfolio of 7 operating wind facilities located in France ("the Seven French Entities Acquired"). The purchase price for the wind power projects is a net cash consideration of €63,971 (equivalent to C$94,465), subject to certain adjustments.

In the first quarter of 2016 an amount of €10,100 (or C$14,700) was also paid as a deposit for a project currently under construction.

All power generated from the operating facilities is sold to Electricité de France and S.I.C.A.E Oise.

Additional cash flows generated from the assets acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. The Seven French Entities Acquired added an additional gross installed capacity of 86.8 MW to the Corporation's portfolio of operational wind farms.

To finance part of the acquisition, three Desjardins Group affiliated entities have collectively subscribed to a private placement of 3,906,250 common shares of the Corporation for proceeds of $50,000.

The following table reflects the preliminary purchase price allocation:

	Preliminary purchase price allocation	
	(in thousands of €)	(in thousands of $)
Cash and cash equivalents	8,050	11,887
Accounts receivable	2,315	3,419
Prepaid and others	1,018	1,503
Reserve accounts	4,449	6,570
Property, plant and equipment	106,543	157,330
Intangible assets	51,258	75,692
Accounts payable and other payables	(1,952)	(2,882)
Current portion of derivative financial instruments	(42)	(62)
Long-term debt	(88,150)	(130,170)
Derivative financial instruments	(213)	(315)
Asset retirement obligations	(3,129)	(4,620)
Deferred tax liabilities	(16,176)	(23,887)
Net assets acquired	63,971	94,465

The transaction costs relating to this acquisition have been expensed as transaction costs of the business combination in accordance with IFRS 3 (see note 6).

If the acquisition had taken place on January 1, 2016, the consolidated revenues and net earnings for the six-month period ended June 30, 2016 would have been $159,391 and $23,931 respectively.

The amounts of revenues and net loss of the facilities since April 15, 2016 included in the consolidated statement of earnings are $2,812 and $1,947 respectively for the 77 days ended June 30, 2016.

4. OPERATING EXPENSES

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Salaries	983	1,075	2,096	2,048
Insurance	704	626	1,366	1,279
Operation and maintenance	5,828	4,860	9,400	8,645
Property taxes and royalties	6,703	4,539	10,754	8,375
	14,218	11,100	23,616	20,347

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) (unaudited)

5. FINANCE COSTS

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Interest on long-term debt and on convertible debentures	20,315	19,469	39,713	38,871
Inflation compensation interest	3,339	4,327	2,446	685
Amortization of financing fees	259	197	509	388
Accretion of long-term debt and convertible debentures	308	146	770	277
Accretion expenses on other liabilities	136	151	232	310
Others	251	250	432	426
	24,608	24,540	44,102	40,957

6. OTHER NET (REVENUES) EXPENSES

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Transaction costs	355	—	1,266	—
Realized loss on derivative financial instruments	—	24,527	—	92,574
Realized (gain) loss on foreign exchange	(33)	(100)	(543)	561
Other net revenues	(538)	(333)	(828)	(627)
Loss (gain) on disposal of property, plant and equipment	173	(29)	173	(29)
Recovery of loan impairment	(190)	—	(475)	—
	(233)	24,065	(407)	92,479

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

7. EARNINGS PER SHARE

The net earnings (loss) per share is computed as follows:

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Net earnings (loss) attributable to owners of the parent	14,381	22,808	22,713	(6,336)
Dividends declared on preferred shares	(1,485)	(1,782)	(2,971)	(3,563)
Net earnings (loss) available to common shareholders	12,896	21,026	19,742	(9,899)
Weighted average number of common shares (in 000s)	107,318	101,235	105,657	101,071
Basic net earnings (loss) per share ($)	0.19	0.21	0.19	(0.10)
Weighted average number of common shares (in 000s)	107,318	101,235	105,657	101,071
Effect of dilutive elements on common shares (in 000s) (a)	996	331	812	403
Diluted weighted average number of common shares (in 000s)	108,314	101,566	106,469	101,474
Diluted net earnings (loss) per share ($) (b)	0.19	0.21	0.19	(0.10)

a. Stock options for which the exercise price was above the average market price of common shares are excluded from the calculation of diluted weighted average number of shares outstanding. During the three-month and the six-month periods ended June 30, 2016, all of the 3,425,684 stock options (all of the 3,425,684 for the three-month and the six-month periods ended June 30, 2015) were dilutive.

During the three-month and six-month periods ended June 30, 2016, none of the 6,666,667 shares that can be issued on conversion of convertible debentures were dilutive (none of the 7,472,113 shares were dilutive for the same periods in 2015).

b. During the six-month period ended June 30, 2015, all of the 3,425,684 stock options were excluded as they were anti-dilutive in the calculation of the diluted net loss per share.

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

8. DERIVATIVE FINANCIAL INSTRUMENTS

As part of the acquisition of the wind farms in France, the Corporation entered into hedge agreements to reduce the Corporation's foreign exchange risk.

Contracts	Maturity	Early termination option	Notional Amounts June 30, 2016	Notional Amounts December 31, 2015
Contracts for which hedge accounting is used:				
Foreign exchange forwards amortizing until 2041, translated at CAD1.7575/Euro	2018	None	168,390	—

As part of the acquisition of the wind farms in France, one of the wind farm holds hedge agreement to mitigate the risk of fluctuations in the interest rates on its long-term debt.

Contracts	Maturity	Early termination option	Notional Amounts June 30, 2016	Notional Amounts December 31, 2015
Contracts for which hedge accounting is used:				
Interest rate swap, 2.64%, amortizing, translated at CAD 1.4354/Euro	2030	None	14,928	—

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

9. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Other equipments	Total
Cost							
As at January 1, 2016	2,623	1,427,025	372,038	124,274	531,591	9,194	2,466,745
Additions	—	1,288	275	—	197,768	626	199,957
Business acquisitions (Note 3)	286	1,500	157,322	—	—	8	159,116
Dispositions	—	(207)	—	—	—	—	(207)
Other changes	—	—	—	—	—	(263)	(263)
Net foreign exchange differences	(11)	(540)	(4,398)	—	—	(2)	(4,951)
As at June 30, 2016	2,898	1,429,066	525,237	124,274	729,359	9,563	2,820,397
Accumulated depreciation							
As at January 1, 2016	—	(164,117)	(100,307)	(21,820)	—	(6,279)	(292,523)
Depreciation	—	(14,664)	(10,319)	(2,978)	—	(892)	(28,853)
Dispositions	—	34	—	—	—	—	34
Other changes	—	—	—	—	—	263	263
Net foreign exchange differences	—	193	21	—	—	4	218
As at June 30, 2016	—	(178,554)	(110,605)	(24,798)	—	(6,904)	(320,861)
Carrying amount as at June 30, 2016	2,898	1,250,512	414,632	99,476	729,359	2,659	2,499,536

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

Additions in the current period include $21,089 of capitalized financing costs ($30,341 for the year ended December 31, 2015) 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 $2,890 ($2,622 as at December 31, 2015).

10. LONG-TERM DEBT

a. Revolving term credit facility

On January 18, 2016, the Corporation executed an amending agreement to extend its revolving term credit facility from 2019 to 2020.

b. Refinancing of Stardale long-term debt

On February 22, 2016, Stardale has renegotiated its long-term debt to increase its borrowing by $12,138 for a total of $109,000. The loan bears interest at the BA rate plus an applicable credit margin that has been reduced upon refinancing for a total floating-rate of 2.48% at refinancing. The principal repayments are variable and are set at $6,054 for the 12-month following the refinancing. The all-in effective interest rate is 5.36% (5.99% before) after accounting for the interest rate swap.

c. Long-term debt for wind farms in France

As part of the acquisition in France, the Corporation assumed the long-term debt of seven wind farms. Also, following this acquisition, a debenture was issued to finance a portion of the acquisition cost.

	Interests rate 2016	Maturity	June 30, 2016	December 31, 2015
Terms loans - France (Non-recourse to the Corporation and with an Euro currency origin)				
a) Cholletz, floating-rate term loan	1.90%	2017	2,153	—
b) Valottes, fixed rate term loan	2.69%	2024	6,697	—
c) Antoigné, fixed rate term loan	2.67%	2025	9,740	—
d) Bois d'Anchat, fixed rate term loan	3.20%	2025	1,443	—
e) Longueval, fixed rate term loan	1.86%	2025	8,712	—
e) Longueval, fixed rate term loan	1.67%	2025	3,081	—
f) Porcien, fixed rate term loan	1.86%	2025	8,712	—
f) Porcien, fixed rate term loan	1.67%	2025	3,434	—
b) Valottes, fixed rate term loan	1.80%	2026	11,860	—
g) Beaumont, fixed rate term loan	2.16%	2027	5,423	—
g) Beaumont, fixed rate term loan	2.63%	2027	1,384	—
d) Bois d'Anchat, fixed rate term loan	2.25%	2030	14,388	—
a) Cholletz, fixed rate term loan	2.23%	2030	14,928	—
g) Beaumont, fixed rate term loan	2.42%	2031	29,426	—
			121,381	—
Debenture - Canada (Non-recourse to the Corporation and with a CAD currency origin)				
h) Innergex Europe, fixed rate debenture	8.00%	2046	31,965	—
			153,346	—

Amounts below are in thousands of Euro.

a) Cholletz

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €11,900.

- A €1,500 loan bearing interest at 1.9%, repayable in quarterly installments and maturing in 2017. The principal repayments are set to €1,000 for the 12-month period following the acquisition.

- A €10,400 loan bearing interest at 2.23% until 2026 and at variable rate plus an applicable margin afterwards, repayable in quarterly installments and maturing in 2030. The principal will begin to be amortized in 2017.

The debt is secured by the Assets of Energie des Cholletz S.A.S. with a carrying value of approximately €21,993.

b) Valottes

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €12,021.

- A €4,749 loan bearing interest at 2.69%, repayable in quarterly installments and maturing in 2024. The principal repayments are set to €374 for the 12-month period following the acquisition.

- A €7,273 loan bearing interest at 5.34%, repayable quarterly installments and maturing in 2026. The principal repayments are set to €727 for the 12-month period following the acquisition. The term loan was accounted for at its fair market value of $8,502 for an effective rate of 1.80%.

The debt is secured by the Assets of Energie des Valottes S.A.S. with a carrying value of approximately €23,798.

c) Antoigné

As part of the Seven French Entities Acquired, the Corporation assumed a €6,964 term loan, bearing interest at 2.67%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €714 for the 12-month following the acquisition. The loan is secured by the assets of Energie Antoigné S.A.S. with a carrying value of approximately €14,563.

d) Bois d'Anchat

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €11,205.

- A €1,005 loan bearing interest at 3.20%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €19 for the 12-month following the acquisition.

- A €10,200 loan bearing interest at 2.25%, repayable in quarterly installments and maturing in 2030. The principal repayments are set to €704 for the 12-month following the acquisition.

The debt is secured by the assets of Société d'Exploitation du Parc Éolien du Bois d'Anchat with a carrying value of approximately €22,965.

e) Longueval

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €7,881.

- A €6,069 loan bearing interest at 1.86%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €799 for the 12-month period following the acquisition.

- A €1,812 loan bearing interest at 5.73%, repayable in semi-annual installments and maturing in 2025. The principal repayments are set to €70 for the 12-month period following the acquisition. The term loan was accounted for at its fair market value of $2,186 for an effective rate of 1.67%.

The debt is secured by the Assets of Eoliennes de Longueval S.A.S. with a carrying value of approximately €16,460.

f) Porcien

As part of the Seven French Entities Acquired, the Corporation assumed two loan facilities for a total value of €8,116.

- A €6,069 loan bearing interest at 1.86%, repayable in quarterly installments and maturing in 2025. The principal repayments are set to €799 for the 12-month period following the acquisition.

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

- A €2,047 loan bearing interest at 5.73%, repayable in semi-annual installments and maturing in 2025. The principal repayments are set to €111 for the 12-month period following the acquisition. The term loan was accounted for at its fair market value of $2,454 for an effective rate of 1.67%.

The debt is secured by the Assets of Energie du Porcien S.A.S. with a carrying value of approximately €16,782.

g) Beaumont

As part of the Seven French Entities Acquired, the Corporation assumed three loan facilities for a total value of €25,131.

- A €3,649 loan bearing interest at 3.78%, repayable in quarterly installments and maturing in 2027. The principal repayments are set to €430 for the 12-month period following the acquisition. The term loan was accounted for at its fair market value of $3,999 for an effective rate of 2.16%.

- A €982 loan bearing interest at 2.63%, repayable in quarterly installments and maturing in 2027. The principal repayments are set to €36 for the 12-month period following the acquisition.

- A €20,500 loan bearing interest at 2.42%, repayable in quarterly installments and maturing in 2031. The principal repayments are set to €1,042 for the 12-month period following the acquisition.

The debt is secured by the Assets of Eoles Beaumont S.A.S. with a carrying value of approximately €52,514.

h) Innergex Europe (2015) Limited Partnership

Following the Seven French Entities Acquired, a debenture was issued to the other partner for a total proceeds of $ 31,965 . This debenture carries an interest rate of 8% compounded yearly and payable quarterly if funds are available. The debenture will be repayable in full in 2046. The Corporation invested a total of $73,011 in preferred units of Innergex Europe (2015) Limited Partnership which carries a preferred return rate of 8% compounded yearly and payable at the same time as the debenture. The preferred units are eliminated into the consolidation process.

11. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Six months ended June 30	
	2016	2015
Accounts receivable and income tax receivable	(14,187)	(10,713)
Prepaid and others	2	(700)
Accounts payable and other payables and income tax liabilities	(3,996)	10,233
	(18,181)	(1,180)

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

b. Additional information

	Six months ended June 30	
	2016	2015
Interest paid (including $20,660 capitalized interest ($9,945 in 2015))	57,824	46,954
Non-cash transactions		
in unpaid property, plant and equipment	(4,318)	13,557
in unpaid development costs	—	(4,218)
in unpaid issuance costs of common shares	(95)	—
in common shares issued through the conversion of convertible debentures	—	(922)
in common shares issued through share options exercised	—	(68)
in common shares issued through dividend reinvestment plan	(1,531)	(5,154)
loans to partners in exchange of non-controlling interests in subsidiaries	(21)	—

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

12. SUBSIDIARIES

Innergex Europe (2015) Limited Partnership and its subsidiaries

The Corporation owned 100% of the participating units of Innergex Europe (2015) Limited Partnership, formed for the acquisition of seven operating wind farms in France on April 15, 2016.

On June 10, 2016, Desjardins subscribed an amount of $38,357 in exchange of 30.45% of the common units and a debenture of $31,965 issued by Innergex Europe (2015) Limited Partnership.

The summarized financial information below represents amounts before intragroup eliminations.

As at	June 30, 2016
Summary Statement of Financial Position	
Current assets	13,673
Non-current assets	250,869
	264,542
Current liabilities	9,280
Non-current liabilities	252,741
Equity attributable to owners	1,780
Non-controlling interests	741
	264,542

	Period of 77 days ended June 30, 2016
Summary Statement of Earnings and Comprehensive loss	
Revenues	2,812
Expenses [1]	6,555
Net loss	(3,743)
Other comprehensive loss	(135)
Total comprehensive loss	(3,878)
Net loss attributable to:	
Owners of the parent	(3,313)
Non-controlling interests	(430)
	(3,743)
Total comprehensive loss attributable to:	
Owners of the parent	(3,422)
Non-controlling interests	(456)
	(3,878)

1. Expenses include $142 of interest payable to Desjardins on the $31,965 debenture, $1,282 of preferred return payable to Innergex on the $73,011 preferred units and $600 of interest payable to Innergex on a temporary bridge loan. Excluding these three elements, the Net loss would have been $1,719.

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

13. SEGMENT INFORMATION

Geographic segments

The Corporation owns interests in 27 hydroelectric facilities, six wind farms and one solar farm in Canada, seven wind farms in France and one hydroelectric facility in the United States. The Corporation operates in three principal geographical areas, which are detailed below:

	Three months ended June 30		Six months ended June 30	
	2016	2015	2016	2015
Revenues				
Canada	83,300	68,824	145,129	125,885
France	2,812	—	2,812	—
United States	1,673	1,347	2,324	2,013
	87,785	70,171	150,265	127,898

As at	June 30, 2016	December 31,2015
Non-current assets, excluding financial instruments and deferred income tax assets		
Canada	2,874,327	2,704,788
France	247,730	—
United States	7,359	8,043
	3,129,416	2,712,831

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) expenses , share of loss of joint ventures and unrealized net gain on 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) (unaudited)

Three months ended June 30, 2016 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	66,744	14,984	6,056	—	87,784
Expenses:					
Operating	10,674	3,343	201	—	14,218
General and administrative	2,032	1,204	40	669	3,945
Prospective projects	—	—	—	2,758	2,758
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and unrealized net gain on financial instruments	54,038	10,437	5,815	(3,427)	66,863
Finance costs					24,608
Other net revenues					(233)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments					42,488
Depreciation					15,070
Amortization					7,065
Share of earnings of joint ventures					(475)
Unrealized net gain on financial instruments					(2,145)
Earnings before income taxes					22,973

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

Three months ended June 30, 2015 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	50,874	13,687	5,610	—	70,171
Expenses:					
Operating	8,458	2,473	169	—	11,100
General and administrative	1,977	955	42	752	3,726
Prospective projects	—	—	—	1,930	1,930
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses, share of earnings of joint ventures and unrealized net gain on financial instruments	40,439	10,259	5,399	(2,682)	53,415
Finance costs					24,540
Other net expenses					24,065
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments					4,810
Depreciation					13,241
Amortization					5,540
Share of earnings of joint ventures					(2,200)
Unrealized net gain on financial instruments					(43,096)
Earnings before income taxes					31,325

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

Six months ended June 30, 2016 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	109,184	31,739	9,342	—	150,265
Expenses:					
Operating	17,784	5,473	359	—	23,616
General and administrative	3,984	2,151	80	1,417	7,632
Prospective projects	—	—	—	4,475	4,475
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and unrealized net gain on financial instruments	87,416	24,115	8,903	(5,892)	114,542
Finance costs					44,102
Other net revenues					(407)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments					70,847
Depreciation					28,853
Amortization					12,719
Share of earnings of joint ventures					(24)
Unrealized net gain on financial instruments					(3,432)
Earnings before income taxes					32,731

As at June 30, 2016					
Goodwill	8,269	—	—	—	8,269
Total assets	1,800,877	577,540	112,976	949,955	3,441,348
Total liabilities	1,331,761	389,045	118,808	1,100,857	2,940,471
Acquisition of property, plant and equipment during the period	3,304	157,687	—	198,082	359,073

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

Six months ended June 30, 2015 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	88,638	30,780	8,480	—	127,898
Expenses:					
Operating	15,257	4,708	382	—	20,347
General and administrative	4,375	1,889	85	1,549	7,898
Prospective projects	—	—	—	3,283	3,283
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses, share of earnings of joint ventures and unrealized net gain on financial instruments	69,006	24,183	8,013	(4,832)	96,370
Finance costs					40,957
Other net expenses					92,479
Loss before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on financial instruments					(37,066)
Depreciation					26,498
Amortization					11,080
Share of earnings of joint ventures					(1,056)
Unrealized net gain on financial instruments					(55,081)
Loss before income taxes					(18,507)

As at December 31, 2015					
Goodwill	8,269	—	—	—	8,269
Total assets	1,806,873	332,698	114,543	874,189	3,128,303
Total liabilities	1,344,518	213,415	107,641	991,172	2,656,746
Acquisition of property, plant and equipment during the year	4,051	871	81	299,549	304,552

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

14. 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 ($)
08/04/2016	09/30/2016	10/17/2016	0.1600	0.2255	0.359375

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.A.

Rating Agencies

Innergex Renewable Energy Inc. is rated BBB- by S&P.
Series A Preferred Shares of Innergex Renewable Energy Inc. are rated P-3 by S&P.
Series C Preferred Shares of Innergex Renewable Energy Inc. are rated P-3 by S&P.

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:

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