INNERGEX

INNERGEX RENEWABLE ENERGY INC.

QUARTERLY REPORT 2018

FOR THE
PERIOD ENDED
MARCH 31, 2018

These condensed consolidated interim 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, acquires, owns and operates run-of-river hydroelectric facilities, wind farms, solar photovoltaic farms and geothermal power facilities and carries out its operations in Canada, in the United States, in France and in Iceland. The Corporation's shares are listed on the Toronto Stock Exchange under the symbols INE, INE.PR.A and INE.PR.C and its convertible debentures are listed 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.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") is a discussion of the operating results, cash flows and financial position of Innergex Renewable Energy Inc. ("Innergex" or the "Corporation") for the three-month period ended March 31, 2018, and reflects all material events up to May 15, 2018, 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 condensed interim financial statements and the accompanying notes for the three-month period ended March 31, 2018.

The unaudited condensed consolidated interim financial statements attached to this MD&A and the accompanying notes for the three-month period ended March 31, 2018, along with the 2017 comparative figures, have been prepared in accordance with International Financial Reporting Standards ("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. Please refer to the "Non-IFRS Measures" section for more information.

All dollar amounts are in thousands of Canadian dollars, except amounts per share or unless otherwise indicated. Some amounts included in this MD&A have been rounded to make reading easier, which may affect some calculations.

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"). Please refer to the "Forward-Looking Information" section for more information.

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 sedar.com or on the Corporation's website at 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.

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HIGHLIGHTS

- Production was 96% of the long-term average ("LTA") for the three-month period ended March 31, 2018.
- Revenues increased 58% to $117.9 million for the three-month period ended March 31, 2018.
- Adjusted EBITDA rose 56% to $79.3 million for the three-month period ended March 31, 2018.
- Innergex completed the acquisition of all the issued and outstanding shares of Alterra Power Corp. on February 6, 2018.
- The 200 MW Flat Top wind farm in Texas, U.S. reached commercial operation on March 23, 2018.

Financial Highlights

	Three months ended March 31	
	2018	2017
OPERATING RESULTS		Restated [4]
Production (MWh)	1,136,345	722,273
Revenues	117,881	74,527
Adjusted EBITDA[1]	79,343	50,942
Innergex's share of Adjusted EBITDA of joint ventures and associates[1 2]	5,332	2,250
Adjusted EBITDA Proportionate[1]	84,675	53,192
Adjusted EBITDA Margin[1]	67.3%	68.4%
Net Loss	(14,588)	(2,496)
Adjusted Net Loss[1]	(7,221)	(6,473)
COMMON SHARES		
Dividends declared	22,495	17,882
Weigthed Average Number of Common Shares (in 000s)	122,593	108,341

	As at	
	March 31, 2018	December 31, 2017
FINANCIAL POSITION		Restated [4]
Total Assets	5,533,528	4,190,456
Non-Current Liabilities	4,168,640	3,487,487
Non-Controlling Interests	315,222	14,920
Equity Attributable to Owners	754,740	441,205

	Trailing twelve months ended March 31	
	2018	2017
CASH FLOWS		
Cash Flow From Operating Activities	226,831	71,600
Free Cash Flow[1 3]	96,233	73,659
Payout Ratio[1 3]	79%	95%

1. Adjusted EBITDA, Innergex's share of Adjusted EBITDA of joint ventures and associates, Adjusted EBITDA Proportionate, Adjusted EBITDA Margin,Adjusted Net Earnings (Loss), Free Cash Flow and Payout Ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. For more information on the calculation of Innergex's share of Adjusted EBITDA of joint ventures and associates, please refer to the "Investments in Joint Ventures and Associates" section.
3. 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.
4. For more information on the restatement, please refer to the "Accounting Changes" section.

OVERVIEW

The Corporation is a developer, acquirer, owner and operator of renewable power-generating facilities with a focus on hydroelectric, wind power, geothermal power and solar photovoltaic projects that benefit from 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:

- 64 facilities in commercial operation (the "Operating Facilities"). Commissioned between 1978 and March 2018, the facilities have a weighted average age of approximately 8.6 years. They mostly sell the generated power under long-term Power Purchase Agreements, power hedge contracts or short and long-term industrial and retail contracts ("PPA") that have a weighted average remaining life of 17.0 years (based on gross long-term average production);

- Two projects scheduled to begin commercial operations in 2019 and 2020 (the "Development Projects");

- Numerous projects that have secured land rights, for which an investigative permit application has been filed or for which a proposal has 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.

  Some Prospective Projects are targeted toward specific future Requests for Proposals and other Prospective Projects are maintained or continue to advance and will be available for future requests for proposals yet to be announced or are targeted toward negotiated PPAs with public utilities or other retail, financial or commercial entities or other various arrangements in Canada or in other countries such as France, the United States and Iceland. These numerous Prospective Projects have a combined potential net installed capacity of 8,180 MW (gross 8,850 MW).

  There is no certainty that any Prospective Project will be realized.

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

(in MW)	64 Operating Facilities	2 Development Projects	Numerous Prospective Projects
HYDRO			
Net	722.4	5.4	1,980.0
Gross	1,028.5	10.0	2,265.0
WIND			
Net	772.7	350.0	5,875.0
Gross	1,629.4	350.0	6,185.0
GEOTHERMAL			
Net	93.8	—	85.0
Gross	174.0	—	160.0
SOLAR			
Net	53.0	—	240.0
Gross	53.7	—	240.0
TOTAL			
Net	**1,641.9**	**355.4**	**8,180.0**
Gross	**2,885.6**	**360.0**	**8,850.0**

(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 sustainable dividend.

Maintain Diversification of Energy Sources

The Corporation strives to maintain a diversified portfolio of assets in terms of geography and sources of energy to alleviate any seasonal and production variations. The amount of electricity generated by the Operating Facilities is generally dependent on the availability of water flows, wind regimes, geothermal resources and solar irradiation. Lower-than-expected water flows, wind regimes, geothermal resources 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 34 hydroelectric facilities, which draw on 29 watersheds, 25 wind farms, 2 geothermal plants and 3 solar farms, providing significant diversification in terms of operating revenue sources. Furthermore, the nature of hydroelectric, wind, geothermal 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	370	12%	1,065	35%	1,002	33%	581	19%	3,018
WIND	595	30%	436	22%	388	20%	560	28%	1,979
GEOTHERMAL	320	25%	320	25%	320	25%	320	25%	1,280
SOLAR	7	19%	12	33%	13	33%	6	15%	38
Total	1,292	20%	1,833	29%	1,723	27%	1,467	23%	6,315

1. The consolidated long-term average production is the annualized LTA for the facilities in operation at May 15, 2018. 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 and Associates" section.

KEY PERFORMANCE INDICATORS

The Corporation measures its performance using key performance indicators.

- Power generation comparison with a long-term average in megawatt-hours (“MWh”) and gigawatt-hours (“GWh”);
- Adjusted EBITDA, Adjusted EBITDA Margin and Adjusted EBITDA Proportionate;
- Adjusted Net Earnings (Loss);
- Free Cash Flow; and
- Payout Ratio.

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. The indicators also facilitate the comparison of results over different periods.

These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

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

FIRST QUARTER UPDATE

Acquisition of Alterra Power Corp.

On February 6, 2018, Innergex completed the acquisition of all the issued and outstanding common shares of Alterra Power Corp. ("Alterra") (the "Transaction"). Pursuant to the Transaction, Alterra shareholders had the right to elect to receive either $8.25 in cash or 0.5563 Innergex common shares for each Alterra common share, subject in each case to pro-ration, such that the aggregate consideration paid to all Alterra shareholders consisted of approximately 25% in cash and 75% in Innergex common shares.

The Innergex common shares that were issuable to Alterra shareholders with the Transaction correspond to an ownership of approximately 18% of the combined corporation. One member of the Alterra board of directors joined the Innergex board of directors on the closing of the Transaction.

OPERATIONAL HIGHLIGHTS

Alterra complements Innergex's current operating, under construction and prospective projects, resulting in increased geographic and technological diversification through meaningful presence in the United States and Icelandic power markets and the addition of geothermal power generation to Innergex's production mix. The transaction significantly accelerates Innergex's growth profile. Alterra's and Innergex's experienced management teams, with a track record of successfully developing and operating renewable energy projects in various jurisdictions, will play an important role in developing the large growth pipeline of the combined company.

SUPPORT OF KEY SHAREHOLDERS

Innergex entered into a support agreement with Ross Beaty, Executive Chairman of Alterra, and certain related entities that had control over approximately 31% of Alterra's issued and outstanding common shares. Under the support agreement, Mr. Beaty and the related entities have elected to receive Innergex Common Shares for the entirety of the Alterra Common Shares held by them and agreed to a 12-month holding period with respect to the Innergex Common Shares received by them as a result of the Transaction.

FINANCING

Innergex has structured the financing of the cash portion of the Transaction to maintain a strong and flexible balance sheet that provides ample liquidity to fully fund Innergex's post-Transaction development portfolio. To that end, the Caisse de dépôt et placement du Québec provided Innergex with a five-year $150 million subordinated unsecured term loan at a 5.128% interest rate.

Innergex has also increased its revolving credit facilities by $225 million to $700 million. The maturity of the revolving credit facilities remains December 2022.

SUMMARY OF ALTERRA PROJECTS

Operating	Energy	Country	Ownership	Net Installed Capacity (MW)	Projected 2018 Revenues ($M)[3 4]	Projected 2018 Gross Adjusted EBITDA[2] ($M)[3 4]	Projected 2018 Net Adjusted EBITDA[5] ($M)[4]
Shannon[1]	Wind	U.S.	50%	102	23.4	12.7	6.4
East Toba	Hydro	Canada	40%	59	75.6 [6]	58.2 [6]	23.3 [6]
Montrose Creek	Hydro	Canada	40%	35			
Reykjanes 1-2	Geothermal	Iceland	54%	54	72.1 [7]	34.9 [7]	18.8 [7]
Svartsengi[8]	Geothermal	Iceland	54%	40			
Dokie	Wind	Canada	26%	37	36.6	26.5	6.8
Jimmie Creek	Hydro	Canada	51%	32	19.7	15.6	8.0
Kokomo[1]	Solar	U.S.	90%	6	1.0	0.8	0.7
Spartan[1]	Solar	U.S.	100%	14	2.0	1.6	1.6
Flat Top[1]	Wind	U.S.	51%	102	26.7	11.9	6.1
Operating				**481**			**71.7**

Under Construction	Energy	Country	Ownership	Net Installed Capacity (MW)	Projected Full Year One Revenues ($M)[3 4]	Expected Full Year One Gross Adjusted EBITDA[2] ($M)[3 4]	Expected Full Year One Net Adjusted EBITDA[5] ($M)[4]
Brúarvirkjun	Hydro	Iceland	54%	5	4.2	3.2	1.7
Under Construction				**5**			**1.7**

Prospective projects[9]	Energy	Country	Ownership	Net Capacity (MW)
Advanced-Stage				
Foard City (PTC Qualified)[10]	Wind	U.S.	100%	350
Reykjanes 4	Geothermal	Iceland	54%	16
Boswell Springs (PTC Qualified)[10]	Wind	U.S.	100%	320
Advanced-Stage				**686**
Other Prospective Projects				**>3,500**

1 The percentage of ownership reflects Innergex's portion of sponsor equity partnership.
2 Gross Adjusted EBITDA is not a recognized measure by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
3 Corresponding to 100% of the facility
4 U.S. dollar and Icelandic króna figures converted to Canadian dollars at USD-CAD rate of 1.289 and CAD-ISK rate of 78.35.
5 Net Adjusted EBITDA is not a recognized measure by IFRS and therefore may not be comparable to those presented by other issuers. It corresponds to Gross Adjusted EBITDA multiplied by ownership percentage. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
6 Reflects the combined metrics for Toba Montrose (East Toba and Montrose Creek).
7 Reflects the combined metrics for HS Orka (Reykjanes 1-2 and Svartsengi).
8 The Svartsengi geothermal facility also sells water with a gross thermal energy capacity of 190 MW.
9 There is no certainty that these projects will materialize on time or on budget and the number of MWs per project could vary.
10 PTC stands for the U.S. renewable electricity production tax credit.

The acquisition of Alterra included a 54% interest in a subsidiary that owns a 30% stake of the Blue Lagoon Geothermal Spa and Resort located in Iceland. Innergex intends to review the future ownership of this non-core asset.

The Alterra acquisition includes interest in the following entities: HS Orka hf ("HS Orka") (53.9% interest), which holds a 30% interest in Blue Lagoon hf., Dokie General Partnership ("Dokie") (25.5% interest), Flat Top Group Holdings LLC ("Flat Top") (51% sponsor equity), Jimmie Creek Limited Partnership ("Jimmie Creek") (50.99% interest), Muko Partnership Holdings, LLC ("Kokomo") (90% sponsor equity), Shannon Group Holdings, LLC ("Shannon") (50% sponsor equity), Spartan Holdings, LLC ("Spartan") (100% sponsor equity) and Toba Montrose General Partnership ("Toba Montrose") (40% interest) (collectively "Alterra Power Group Entities").

(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 first full year	
					Estimated[1] ($M)	As at March 31 ($M)	Revenues[1] ($M)	Adjusted EBITDA[1 3] ($M)
WIND (United States)								
Flat Top	51.0	200.0	872.9	13	404.8 [2]	394.9 [2]	26.7 [2]	11.9 [2]

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. Corresponding to 100% of this facility.
3. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

Flat Top
In the first quarter, the Corporation began commercial operation of the 200 MW Flat Top wind farm located in Texas, U.S. Construction began prior to its acquisition by Innergex and was substantially completed in March 2018. The Commercial Operation Date ("COD") was reached on March 23, 2018. The Flat Top wind farm will sell 100% of its output to the ERCOT power grid and set the power price on the majority of its revenue under a 13-year commodity hedge agreement with an affiliate of a large US-based financial institution, commencing on August 1, 2018. Concurrent with commercial operation, Flat Top completed a US$211.3 million tax equity financing of the project, some of whose proceeds were used primarily to retire the project's construction loan.

Construction Activities

The total project costs for the Development Project are as follows:

	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project costs	Expected first full year	
						Estimated[1] ($M)	Revenues[1] ($M)	Adjusted EBITDA[1 3] ($M)
HYDRO (Iceland)								
Brúarvirkjun	53.9	10.0	2020	80.0	- [4]	53.8 [2]	4.2 [2]	3.2 [2]

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. Corresponding to 100% of this facility.
3. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
4. Power generated to be sold on the retail market.

Brúarvirkjun
The Brúarvirkjun hydro project was acquired in the first quarter of 2018 as part of the Alterra acquisition. Site preparation work was already under way at the time of the acquisition.

As at the date of this MD&A, construction work officially started and a public open ceremony took place at the end of February, following the approval by the local government of the construction permit. The two appeals that were filed in November 2017, were dismissed. Together with the Construction Permit, the project has received its Environmental Impact Assessment ("EIA") and obtained all necessary water rights, land contracts, exploration permits, development licence and municipal approvals through a specific local land-use plan. The project now faces a new appeal (from one of the two earlier claimants) at the Appellate Committee for Environment and Resources to claim for a voiding of the construction permit. A formal response was filed against the issues and grounds raised. Commissioning is still expected to occur in the first half of 2020.

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

Development Activities

Foard City
The 350 MW Foard City wind project development is progressing very well, with site control complete, as well as other development milestones such as environmental impact assessments and the signing of local property tax abatement agreements. In May 2018, a 12-year PPA was signed for 300 MW for which sales will start upon the facility reaching commercial operation. The project located in Texas, USA has also executed an interconnection agreement with Electric Transmission Texas, LLC. On-site activities intended to qualify the Foard City wind project for US renewable tax incentives (PTCs) were performed since 2016. Full notice to proceed with construction is expected to be issued in the fourth quarter of 2018 to achieve commercial operation in the third quarter of 2019.

OPERATING RESULTS

Electricity production in the quarter was 96% of the LTA production due mainly to lower production at most of the hydro facilities in British Columbia, challenging post-commissioning activities currently being addressed at the Mesgi'g Ugju's'n and Upper Lillooet River facilities and lower wind regimes in Quebec, which were partly offset by above-average wind regimes in France.

Production increased 57%, revenues increased 58% and Adjusted EBITDA increased 56%. These increases are attributable mainly to the contribution of the facilities acquired in 2017 and 2018, to compensation received from a manufacturer for low-availability of equipment at a wind farm, to higher production at all the wind facilities in France and to the contribution of the facilities commissioned in 2017, which was partly offset by lower production at most of the British Columbia hydro facilities.

The Corporation's operating results for the three-month period ended March 31, 2018, are compared with the operating results for the same period in 2017.

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, geothermal facilities 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 March 31					
	2018			2017		
	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA
HYDRO						
Quebec	126,301	124,170	102%	133,487	124,170	108%
Ontario	24,530	24,294	101%	23,524	24,294	97%
British Columbia	179,432	213,291	84%	168,730	201,464	84%
United States	10,206	7,927	129%	6,728	7,927	85%
Subtotal	340,469	369,682	92%	332,469	357,855	93%
WIND						
Quebec	352,315	382,945	92%	304,048	367,014	83%
France	241,375	227,706	106%	77,953	88,584	88%
Subtotal	593,690	610,651	97%	382,001	455,598	84%
GEOTHERMAL						
Iceland[2]	195,637	195,128	100%	—	—	—
SOLAR						
Ontario	6,549	7,130	92%	7,803	7,181	109%
Total	1,136,345	1,182,591	96%	722,273	820,634	88%

1. The Dokie, Flat Top, Jimmie Creek, Kokomo, Shannon, Spartan, Toba Montrose, Umbata Falls, Viger-Denonville facilities and the Blue Lagoon spa are treated as joint ventures and associates and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for consistency's sake, their electricity production figures have been excluded from the production table. For more information on the Corporation's joint ventures and associates, please refer to the "Investments in Joint Ventures and Associates" section.
2. Production and LTA for the period from February 6, 2018, to March 31, 2018.

During the three-month period ended March 31, 2018, the Corporation's facilities produced 1,136,345 MWh of electricity or 96% of the LTA of 1,182,591 MWh. Overall, the hydroelectric facilities produced 92% of their LTA due mainly to below-average water flows in British Columbia, outages at several British Columbia facilities caused by maintenance activities and winter hazards and to lower production from challenging post-commissioning activities currently being addressed at the Upper Lillooet River facility, partly offset by slightly above-average water flows in Quebec, Ontario and Idaho. Overall, the wind farms produced 97% of their LTA due mainly to below-average wind regimes in Quebec and challenging post-commissioning activities currently being addressed at the Mesgi'g Ugju's'n facility, partly offset by above-average wind regimes in France. The geothermal facilities produced 100% of their LTA. The Stardale solar farm produced 92% of its LTA due to a below-average solar regime. For more information on operating segment results, please refer to the "Segment Information" section.

The 57% production increase compared with the same period last year is due mainly to the contribution of the acquisition of Alterra and wind facilities in France in 2017, to the contribution of the Upper Lillooet River and Boulder Creek hydro facilities commissioned in 2017 and better overall performance.

The overall performance of the Corporation's facilities for the period ended March 31, 2018, demonstrates the benefits of geographic diversification and the complementarity of hydroelectric, wind, geothermal and solar power generation.

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

Financial Results

	Three months ended March 31			
	2018	2017	Change	
		Restated [3]		
Revenues	117,881	74,527	43,354	58 %
Operating expenses	25,972	16,089	9,883	61 %
General and administrative expenses	7,658	4,578	3,080	67 %
Prospective project expenses	4,908	2,918	1,990	68 %
Adjusted EBITDA[1]	79,343	50,942	28,401	56 %
Adjusted EBITDA margin[1]	67.3%	68.4%		
Finance costs	45,671	29,518	16,153	55 %
Other net expenses (revenues)	2,188	(360)	2,548	(708)%
Depreciation and amortization	39,172	29,582	9,590	32 %
Share of earnings of joint ventures and associates [2]	(3,096)	(715)	(2,381)	333 %
Unrealized net loss (gain) on financial instruments	12,143	(5,075)	17,218	(339)%
(Recovery of) income taxes expenses	(2,147)	488	(2,635)	(540)%
Net loss	(14,588)	(2,496)	(12,092)	484 %
Net loss attributable to:				
Owners of the parent	(6,617)	2,294	(8,911)	(388)%
Non-controlling interests	(7,971)	(4,790)	(3,181)	66 %
	(14,588)	(2,496)	(12,092)	484 %
Basic net (loss) earnings per share ($)	(0.07)	0.01		

1. Adjusted EBITDA and Adjusted EBITDA Margin are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. The Dokie, Flat Top, Jimmie Creek, Kokomo, Shannon, Spartan, Toba Montrose, Umbata Falls, Viger-Denonville facilities and the Blue Lagoon spa are treated as joint ventures and associates 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 and associates, please refer to the "Investments in Joint Ventures and Associates" section.
3. For more information on the restatement, please refer to the "Accounting Changes" section.

Revenues

Up 58% to $117.9 million for the three-month period ended March 31, 2018

This increase is attributable mainly to the contribution of the acquisitions of Alterra and wind facilities in France in 2017 as well as to revenue compensation received from a manufacturer for low-availability of equipment at a wind farm, higher production at the Mesgi'g Ugju's'n facility and higher production at all the French wind facilities, partly offset by lower production at the British Columbia hydro facilities.

Expenses

Up 63% to $38.5 million for the three-month period ended March 31, 2018

Operating expenses consist primarily of the operators' salaries, insurance premiums, expenditures related to operation and maintenance, property taxes, royalties and cost of power (if applicable). For the three-month period ended March 31, 2018, the Corporation recorded operating expenses of $26.0 million ($16.1 million for the corresponding period in 2017). The 61% increase for the three-month period is attributable mainly to the acquisition of Alterra in February 2018, the commissioning of the Upper Lillooet River hydro facility in March 2017 as well as to the acquisition of wind facilities in France in 2017. The operating expenses for the geothermal facilities, operated by HS Orka in Iceland, are higher as maintenance and daily operations require more work. To supplement its power production, HS Orka purchases power when needed, contributing to higher operating expenses. In 2017, operating expenses were impacted by a $3.3 million aggregate payment related to water rights for 2011 and 2012 for Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River, which were reassessed following the decision by the British Columbia Ministry of Forests, Lands and Natural Resource Operations to apply higher rental rates based on the facilities' combined production rather than apply lower rates for each facility based on its individual production, as had previously been the ministry's practice. The Corporation has filed an appeal of this decision with the Environmental Appeal Board. Since 2013, these facilities' water rights fees have been paid at the higher rates. A 49.99% portion of the water rights payment was allocated to the non-controlling interests.

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

General and administrative expenses consist primarily of salaries, professional fees and office expenses. For the three-month period ended March 31, 2018, general and administrative expenses totalled $7.7 million ($4.6 million for the corresponding period in 2017). The 67% increase for the three-month period stems mainly from the acquisition of Alterra, which includes the HS Orka geothermal operations, and from the greater number of facilities in operation.

Prospective project expenses include the costs incurred for the development of Prospective Projects. They are related to the number of Prospective Projects that the Corporation chooses to advance and the resources required to do so. For the three-month period ended March 31, 2018, prospective project expenses totalled $4.9 million ($2.9 million for the corresponding period in 2017). The 68% increase for the period is mainly attributable to activities undertaken in the quarter to submit projects in request for proposals processes, pursuing opportunities in new international markets, to future requests for proposals and expressions of interest in Canadian provinces and to the advancement of a number of prospective projects.

Adjusted EBITDA

Up 56% to $79.3 million for the three-month period ended March 31, 2018

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. Adjusted EBITDA is not recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

This increase is due mainly to higher production and revenues from the facilities commissioned and acquired in 2017 and 2018, partly offset by higher operating expenses, general and administrative expenses and prospective project expenses. The Adjusted EBITDA Margin decreased from 68.4% to 67.3% for the three-month period due mainly to a larger increase in expenses as opposed to the increase in revenues resulting from the integration of the HS Orka geothermal operations, which generate a lower margin related to its higher maintenance, daily operations and power purchasing costs, and to challenging post-commissioning activities at the Upper Lillooet River facility.

Adjusted EBITDA Proportionate

Up 59% to $84.7 million for the three-month period ended March 31, 2018

Adjusted EBITDA Proportionate, which is defined as Adjusted EBITDA plus Innergex's share of Adjusted EBITDA of the joint ventures and associates, is a key performance indicator when evaluating the Corporation's financial results. Adjusted EBITDA Proportionate is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

	Three months ended March 31	
	2018	2017
Adjusted EBITDA[1]	79,343	50,942
Innergex's share of Adjusted EBITDA of joint ventures and associates[1 2]	5,332	2,250
Adjusted EBITDA proportionate[1]	84,675	53,192

1. Adjusted EBITDA, Innergex's share of Adjusted EBITDA of joint ventures and associates and Adjusted EBITDA proportionate are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. Please refer to the "Investments in Joint Ventures and Associates" section of this MD&A for more information.

This increase is due mainly to higher Adjusted EBITDA and a higher share of Adjusted EBITDA of joint ventures and associates stemming from the addition of the facilities acquired in 2018.

Finance Costs

Up 55% to $45.7 million for the three-month period ended March 31, 2018

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. The increase is due mainly to expenses related to the facilities commissioned or acquired in 2017 and 2018.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 4.55% as at March 31, 2018 (4.43% as at December 31, 2017).

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

Other Net Expenses (Revenues)

Up to $2.2 million for the three-month period ended March 31, 2018

Other Net Expenses (Revenues) include transaction costs, realized gain on foreign exchange, gain or loss on contingent considerations, other net revenues, loss on disposal of property, plant and equipment, recovery of loan impairment and amortization of below market contracts. The increase is due mainly to the $4.3 million increase in transaction costs stemming from the acquisition of Alterra in February 2018, partly offset by realized gains on derivative financial instruments.

Depreciation and Amortization

Up 32% to $39.2 million for the three-month period ended March 31, 2018

This increase is attributable mainly to the acquisition of Alterra in 2018, the acquisition of French wind farms in 2017, the commissioning of the Upper Lillooet River hydro facility in March 2017 and the Boulder Creek hydro facility in May 2017, partly offset by an increase of the depreciation period for the Quebec wind facilities.

Share of Earnings of Joint Ventures and Associates

Share of net earnings of $3.1 million for the three-month period ended March 31, 2018, compared with $0.7 million for the corresponding period in 2017

Following the acquisition of Alterra, the Corporation owns eight more investments in joints ventures and associates. Please refer to the "Investments in Joint Ventures and associates" section for more information.

Unrealized Net Loss (Gain) on Financial Instruments

Unrealized net loss of $12.1 million for the three-month period ended March 31, 2018, compared with an unrealized net gain of $5.1 million for the corresponding period in 2017

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

The unrealized net loss on financial instruments for the three-month period ended March 31, 2018, is due to an unfavourable variation of the CAD-EUR foreign exchange rate swap and to a $9.9 million loss due to lower future aluminum prices affecting the value of the embedded derivatives related to two PPAs at HS Orka, partly offset by an unrealized gain on the conversion of intragroup loans and the amortization of the accumulated losses from the pre-hedge accounting period.

For the corresponding period last year, the Corporation recognized a $5.1 million unrealized net gain on financial instruments resulting mainly from an unrealized net gain on the foreign exchange rate swap due to a favourable change in the CAD-EUR foreign exchange rate and from the conversion of an intragroup loan. On consolidation, although the intragroup loan has been eliminated from the consolidated statement of financial position, the related exchange (gain) loss recognized in the consolidated statement of earnings survives the consolidation process.

In connection with the Alterra transaction, the Corporation entered into bond forward contracts for a total of $50.0 million to mitigate the risk of interest rate increases before the closing of the transaction. These bond forward contracts settled upon closing of the Alterra transaction in February 2018.

(Recovery of) Income Tax Expense

Recovery of tax expense at $2.1 million for the three-month period ended March 31, 2018

For the three-month period ended March 31, 2018, the Corporation recorded a current income tax expense of $2.5 million ($0.9 million for the corresponding period in 2017) and a deferred income tax recovery of $4.7 million (deferred income tax recovery of $0.4 million for the corresponding period in 2017). The $1.7 million increase in the current income tax expense is due mainly to higher income from wind facilities in France. The increase in the deferred income tax recovery is due mainly to the increase in unrealized loss on financial instruments.

Net Loss

Up to $14.6 million for the three-month period ended March 31, 2018

For the three-month period ended March 31, 2018, the Corporation recorded net loss of $14.6 million (basic and diluted net loss of $0.07 per share) compared with net loss of $2.5 million (basic and diluted net earnings of $0.01 per share) for the corresponding period in 2017. The $12.1 million increase in net loss can be explained by the $17.2 million increase in unrealized net loss on financial instruments, the $16.2 million increase in finance costs, the $9.6 million increase in depreciation and amortization and the $2.5 million increase in other net expenses (revenues), partly offset by the $28.4 million increase in Adjusted EBITDA, the $2.4 million increase in the share of earnings of joint ventures and associates and the $2.6 million recovery in income taxes.

Adjusted Net Loss

Up 12% to $7.2 million for the three-month period ended March 31, 2018

When evaluating its operating results and to provide a more accurate picture of its operating results, a key performance indicator for the Corporation is Adjusted Net Loss. Adjusted Net Loss is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

Impact on net loss of financial instruments	Three months ended March 31	
	2018	2017
		Restated [2]
Net loss	(14,588)	(2,496)
Add (Subtract):		
Unrealized net loss (gain) on financial instruments	12,143	(5,075)
Realized gain on financial instruments	(828)	—
Income tax expense related to above items	675	1,132
Share of unrealized net gain on financial instruments of joint ventures and associates, net of related income tax	(4,623)	(34)
Adjusted Net Loss[1]	(7,221)	(6,473)

1. Adjusted Net Loss is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. For more information on the restatement, please refer to the "Accounting Changes" section.

Excluding loss (gains) on financial instruments and the related income taxes, net loss for the three-month period ended March 31, 2018, would have been $7.2 million, compared with a net loss of $6.5 million in 2017. The increase in the adjusted net loss is due mainly to higher finance cost, transaction cost and depreciation and amortization, partly offset by higher Adjusted EBITDA and a higher share of earnings of joint ventures and associates.

Non-controlling Interests

Loss of $8.0 million for the three-month period ended March 31, 2018, compared with a loss of $4.8 million for the corresponding period in 2017

Non-controlling interests are related to the HS Orka hf ("HS Orka"), Harrison Hydro Limited Partnership ("HHLP"), the Creek Power Inc. subsidiaries ("Creek Power"), the Mesgi'g Ugju's'n (MU) Wind Farm, L.P. ("MU"), the Innergex Europe (2015) Limited Partnership ("Innergex Europe"), the Kwoiek Creek Resources Limited Partnership ("Kwoiek"), the Magpie Limited Partnership, the Innergex Sainte-Marguerite S.E.C. entity and the Cayoose Creek Power Limited Partnership and their respective general partners.

The larger amount of losses allocated to non-controlling interests is mainly related to losses at Creek Power due to the Upper Lillooet River and Boulder Creek hydro facilities normal winter losses from low water flows and challenging post-commissioning activities currently being addressed at Upper Lillooet River and to losses at HS Orka primarily due to the unrealized loss on the change in the fair value of embedded derivatives, partly offset by revenues at MU and by a smaller loss at HHLP, compared with the same quarter last year related to a payment in 2017 of water rights for 2011 and 2012.

LIQUIDITY AND CAPITAL RESOURCES

For the three-month period ended March 31, 2018, the Corporation generated cash flows from operating activities of $50.3 million compared with cash flows of $15.8 million for the same period last year. During this three-month period, the Corporation generated funds from financing activities of $104.6 million and used $144.2 million in funds for investing activities, mainly to pay for the acquisition of Alterra. As at March 31, 2018, the Corporation had cash and cash equivalents amounting to $73.7 million, compared with $61.9 million as at December 31, 2017.

Cash Flows from Operating Activities

Up $34.5 million to $50.3 million for the three-month period ended March 31, 2018

The increase is attributable to a $28.4 million increase in Adjusted EBITDA and a $21.1 million increase in non-cash operating working capital items, partly offset by a $10.7 million increase in the interest paid on long-term debt, a $4.3 million increase in transaction costs and a negative effect of exchange rate fluctuations of $1.9 million.

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

Cash Flows from Financing Activities

Up $50.6 million to $104.6 million for the three-month period ended March 31, 2018

The increase is attributable to a $133.4 million net increase in long-term debt in 2018, compared with a $69.3 million increase in long-term debt in 2017, which was partly offset by a $9.5 million payment for buyback of common shares, a $2.1 million increase in the payment of dividends on common shares and a $1.9 million decrease in investments from non-controlling interests.

The $133.4 million increase in long-term debt is attributable mainly to a $150 million subordinated unsecured five-year term loan contracted in February to finance the cash portion of the acquisition of Alterra, partly offset by scheduled debt repayments and the reimbursement of a loan dedicated to the consumer taxes recoverable from the government for the Theil-Rabier, Plan Fleury and Les Renardières wind facilities.

Use of Financing Proceeds	Three months ended March 31		
	2018	2017	Change
Proceeds from issuance of long-term debt (including revolving credit facility)	302,086	88,856	
Repayment of long-term debt (including revolving credit facility)	(166,104)	(19,119)	
Payment of deferred financing costs	(2,614)	(476)	
Subtotal: net increase in long-term debt	133,368	69,261	64,107
Payment of buy-back of common shares	(9,487)	—	
Investments from non-controlling interests	218	2,090	
Generation of financing proceeds	124,099	71,351	52,748
Business acquisitions	(120,258)	(35,061)	
(Increase) decrease of restricted cash and short-term investments	(10,498)	5,379	
Net funds (invested into) withdrawn from the reserve accounts	(1,388)	498	
Additions to property, plant and equipment	(17,638)	(38,421)	
Additions to other long-term assets	(1,488)	(40)	
Net use of financing proceeds	(151,270)	(67,645)	(83,625)
(Reduction) increase in working capital	(27,171)	3,706	(30,877)

During the three-month period ended March 31, 2018, the Corporation borrowed a net amount of $133.4 million, partly offset by a $9.5 million payment for the buy-back of common shares. The net amount borrowed was used for the acquisition of Alterra. The Corporation increased its restricted cash and short-term investments by $10.5 million mainly due to cash cumulated to pay the remaining construction costs for Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities and used cash to pay the remaining construction costs of the Upper Lillooet River and Boulder Creek facilities.

Cash Flows from Investing Activities

Outflow up $81.5 million to $144.2 million for the three-month period ended March 31, 2018

During the period, the main investing activities impacting cash flows were as follows: business acquisitions accounted for a $120.3 million outflow ($35.1 million outflow in 2017) for the Alterra acquisition; additions to property, plant and equipment accounted for a $17.6 million outflow ($38.4 million outflow in 2017); and fluctuations in restricted cash and short-term investments accounted for a $10.5 million outflow ($5.4 million inflow in 2017).

Cash and Cash Equivalents

Up $11.8 million to $73.7 million for the three-month period ended March 31, 2018

For the three-month period ended March 31, 2018, cash and cash equivalents increased by $11.8 million (increased by $6.1 million for the corresponding period in 2017) as a net result of its operating, financing and investing activities.

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

SHARE CAPITAL STRUCTURE

Information on Capital Stock

Number of Common Shares Outstanding

Weighted average number of common shares outstanding (000s)	Three months ended March 31	
	2018	2017
Weighted average number of common shares	122,593	108,341
Effect of dilutive elements on common shares[1]	719	954
Diluted weighted average number of common shares	123,312	109,295

1. As at March 31, 2018, 2,579,684 of the 2,782,599 stock options (3,331,684 of the 3,457,432 for the three-month period ended March 31, 2017) were dilutive. During the three-month period ended March 31, 2018, none of the 6,666,667 shares that can be issued on conversion of convertible debentures were dilutive (none of the 6,666,667 shares were dilutive for the same period in 2017).

The Corporation's Equity Securities

	As at		
	May 15, 2018	March 31, 2018	March 31, 2017
Number of common shares	132,566,525	132,321,661	108,375,159
Number of 4.25% convertible debentures	100,000	100,000	100,000
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	2,782,599	2,782,599	3,457,432

As at the opening of the market on May 15, 2018, and since March 31, 2018, the increase in the number of common shares of the Corporation is attributable mainly to the issuance of 244,864 shares related to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at March 31, 2018, the increase in the number of common shares since March 31, 2017, is attributable mainly to the issuance of 24,327,225 shares on February 6, 2018, in connection with the Alterra acquisition, of 251,193 shares related to the DRIP and of 121,378 following the exercise of stock options, net of 753,294 shares purchased for cancellation under the normal course issuer bid ("NCIB").

Dividends

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 test imposed under corporate law for the declaration of dividends and other relevant factors.

The following dividends were declared by the Corporation:

	Three months ended March 31	
	2018	2017
Dividends declared on common shares[1]	22,495	17,882
Dividends declared on common shares ($/share)	0.170	0.165
Dividends declared on Series A Preferred Shares	767	767
Dividends declared on Series A Preferred Shares ($/share)	0.2255	0.2255
Dividends declared on Series C Preferred Shares	719	719
Dividends declared on Series C Preferred Shares ($/share)	0.3594	0.3594

1. The increase in dividends declared on common shares is attributable to the issuance of 24,327,225 shares on February 6, 2018, related to the Alterra acquisition, the increase in the quarterly dividend and the issuance of shares under the DRIP, partly offset by shares repurchased under NCIB.

The following dividends will be paid by the Corporation on July 16, 2018:

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
05/15/2018	6/29/2018	7/16/2018	0.170	0.2255	0.359375

On February 21, 2018, the Board of Directors increased the quarterly dividend from $0.165 to $0.170 per common share, corresponding to an annual dividend of $0.68 per common share. This is the fifth consecutive $0.02 annual dividend increase.

Normal Course Issuer Bid

Under the normal course issuer bid on the Corporation's common shares ("Common Shares") and the normal course issuer bid on its Cumulative Rate Reset Preferred Shares, Series A ("Series A Shares") and Cumulative Redeemable Fixed Rate Preferred Shares, Series C ("Series C Shares") (collectively, the "Bids") covering the period between March 24, 2016, and March 23, 2017, the Corporation did not repurchase any Common Shares, Series A Shares or Series C Shares for cancellation.

In August 2017, the Corporation proceeded with a normal course issuer bid on its Common Shares (the "New Bid") covering the period between August 17, 2017, and August 16, 2018. The Corporation may purchase for cancellation up to 2,000,000 of its Common Shares, representing approximately 1.84% of the 108,640,790 issued and outstanding Common Shares as at August 14, 2017.

Under the New Bid, the Corporation has entered into an automatic purchase plan agreement with a designated broker to allow for purchases of Common Shares at times when it would ordinarily not be permitted to do so due to self-imposed blackout periods or regulatory restrictions.

Under the New Bid, during the three-month period ended March 31, 2018, the Corporation purchased 697,212 Common Shares at an average price of $13.60 per share, for an aggregate consideration of $9.5 million.

FINANCIAL POSITION

As at March 31, 2018, the Corporation had $5,534 million in total assets, $4,464 million in total liabilities, including $3,630 million in long-term debt, and $1,070 million in shareholders' equity. The Corporation also had a working capital ratio of 0.81:1.00 (0.90:1.00 as at December 31, 2017). In addition to cash and cash equivalents amounting to $73.7 million, the Corporation had restricted cash and short-term investments of $74.5 million and reserve accounts of $51.8 million. The explanations below highlight the most significant changes in the statement of financial position items during the three-month period ended March 31, 2018.

Assets

Highlights of significant changes in total assets during the period ended March 31, 2018

- A $535.3 million increase in property, plant and equipment, due mainly to the 2018 Alterra acquisition and the foreign exchange rate effect on the property, plant and equipment in France, partly offset by the depreciation for the period;
- A $439.2 million increase in investments in joint ventures and associates, due mainly to to the 2018 Alterra acquisition, which included eight joint ventures and associates' projects;
- A $204.5 million increase in intangible assets, due mainly to the 2018 Alterra acquisition and the foreign exchange rate effect on the net intangibles in France, partly offset by the amortization.

Working Capital Items

Working capital was negative at $54.9 million, as at March 31, 2018, with a working capital ratio of 0.81:1.00 (as at December 31, 2017, working capital was negative at $25.2 million, with a working capital ratio of 0.90:1.00). The decrease in the working capital ratio is due to lower accounts receivable, higher derivative financial instruments in liabilities and higher accounts payable, partly offset by higher cash and cash equivalents and higher restricted cash and short-term investments.

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

The Corporation considers its current level of working capital to be sufficient to meet its needs. As at March 31, 2018, the Corporation had $700.0 million in revolving term credit facilities and had drawn $379.0 million and US$13.9 million as cash advances, while $33.6 million had been used for issuing letters of credit, leaving $269.4 million available.

Cash and cash equivalents amounted to $73.7 million as at March 31, 2018, compared with $61.9 million as at December 31, 2017. The increase stems mainly from the revenue compensation received from a manufacturer for low-availability of equipment at a wind farm and from the Alterra acquisition.

Restricted cash and short-term investments amounted to $74.5 million as at March 31, 2018, compared with $58.7 million as at December 31, 2017. The increase stems mainly from the restricted cash cumulated to pay for the remaining construction costs for Rougemont 1-2, Vaite, Plan Fleury and Les Renardières facilities and from restricted cash related to a grant that HS Orka is participating in and administering, which was received and is to be distributed to the grant partners, partly offset by amounts used to pay for construction of the Upper Lillooet River and Boulder Creek facilities.

Accounts receivable decreased from $87.5 million to $79.1 million between December 31, 2017, and March 31, 2018, due mainly to the reimbursement of commodity taxes for the Plan Fleury facility and compensation received from a manufacturer for low-availability of equipment at a wind farm, partly offset by the accounts receivable acquired with Alterra.

Accounts payable and other payables from December 31, 2017, to March 31, 2018, increased from $91.0 million to $111.3 million, due mainly to accounts payable acquired with Alterra, partly offset by payment of construction costs related to the Upper Lillooet River and Boulder Creek facilities.

Derivative financial instruments from December 31, 2017, to March 31, 2018, increased from $22.7 million to $44.4 million, due mainly to an unfavourable variation in the CAD-EUR foreign exchange swaps and to the Alterra acquisition, partly offset by a positive variation on interest rate swaps attributable to amortization or to a favourable variation in the interest rates.

Current portion of long-term debt amounted to $108.4 million as at March 31, 2018, compared with $109.9 million as at December 31, 2017. The minor decrease stems mainly from the reimbursement of a loan dedicated to the consumer taxes recoverable from the government for the Theil-Rabier, Plan Fleury and Les Renardières wind facilities, partly offset by the addition of Alterra.

Reserve Accounts

Reserve accounts consist of a hydrology/wind reserve, which was 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 regimes and to other unpredictable events, and a major maintenance reserve, which was established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity. The Corporation had $51.8 million in long-term reserve accounts as at March 31, 2018, compared with $50.0 million as at December 31, 2017. The minor increase is mainly due to mandatory investments made during the period.

The availability of funds in the hydrology/wind and major maintenance reserve accounts is restricted by credit agreements.

The Corporation also has reserve accounts for dismantling the French wind farms at the end of their service life. The Corporation had $0.3 million in long-term dismantling reserve accounts as at March 31, 2018.

Property, Plant and Equipment

*Property, plant and equipmen*t are comprised mainly of hydroelectric facilities, wind farms, geothermal power plants and a solar farm that are either in operation or under construction. As at March 31, 2018, the Corporation had $3,723 million in property, plant and equipment compared with $3,188 million as at December 31, 2017. The increase stems mainly from the acquisition of Alterra in 2018 and to the foreign exchange rate effect on the property, plant and equipment in France, partly offset by the depreciation for the period.

Intangible Assets

Intangible assets consist of various power purchase agreements, permits and licenses. The Corporation had $858.6 million in intangible assets as at March 31, 2018, compared with $654.1 million as at December 31, 2017. The increase is due mainly to the acquisition of Alterra in 2018 and to the foreign exchange rate effect on the net intangibles in France, partly offset by the amortization.

Project Development Costs

Project Development Costs refers to the costs incurred to acquire prospective projects and develop hydroelectric, wind, geothermal and solar facilities. The Corporation had $41.0 million in project development costs as at March 31, 2018, compared with nil as at December 31, 2017. The increase is due to the acquisition of Alterra in 2018.

Investments in Joint Ventures and Associates

Investments in Joint Ventures and Associates is initially recognized at cost and adjusted thereafter to recognize the Corporation's share of the profit and loss and other comprehensive income of the joint ventures and associates. The Corporation had $450.2 million in investments in joint ventures and associates as at March 31, 2018, compared with $11.0 million as at December 31, 2017. The increase is due mainly to the acquisition of Alterra in 2018, which included eight joint ventures and associates' projects.

Goodwill

Goodwill is the excess of the purchase price over the aggregate fair value of net assets acquired. The Corporation had $100.1 million in goodwill as at March 31, 2018, compared with $38.6 million as at December 31, 2017. The increase is due to the acquisition of Alterra.

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. Derivatives also include embedded derivatives such as the ones included in two PPAs at HS Orka related to aluminum prices.

Interest rate swap contracts allow the Corporation to eliminate the risk of interest rate increases on actual floating-rate debts. These totalled $1,018.8 million as at March 31, 2018.

Foreign exchange forward contracts allow the Corporation to hedge its exposure to foreign exchange rate on its investments in France. These totalled $577.7 million as at March 31, 2018.

Overall, Derivatives had a net negative value of $120.6 million as at March 31, 2018 (net negative value of $62.3 million as at December 31, 2017). The change in Derivatives is primarily due to the Derivatives acquired through the acquisition of Alterra. Further increases in the Derivative liability are a result of an unfavourable variation in the CAD-EUR foreign exchange swaps and a decrease in future aluminum prices which results in an unfavourable variation in the embedded derivatives related to two PPAa at HS Orka. The unfavourable variations are partially offset by a positive variation on the interest rate swaps.

Long-Term Debt

As at March 31, 2018, long-term debt totalled $3,630 million ($3,157 million as at December 31, 2017). The $473.0 million increase results mainly from the $150 million subordinated unsecured 5-year term loan contracted in February to finance the cash portion of the acquisition of Alterra, from the addition of long-term debt from Alterra and from the foreign exchange rate effect on the long-term debt in France, partly offset by scheduled repayments of project-level debts.

On February 6, 2018, Innergex increased its revolving credit facilities by $225 million to $700 million and added a new lender to the syndicate of lenders. This increase enables the Corporation to pursue the development and construction of its portfolio. The maturity of the revolving credit facilities remains December 2022.

As at March 31, 2018, 91% of the Corporation's outstanding debt, including convertible debentures, was fixed or hedged against interest rate movements (94% as at December 31, 2017).

Since the beginning of the 2018 fiscal year, the Corporation and its subsidiaries have met all material financial and non-financial conditions related to their credit agreements, trust indentures, PPAs and power hedges. Were they not met, certain financial and non-financial covenants included in the credit agreements, trust indentures, PPAs or power hedges 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, including amounts shown in current liabilities, consist of contingent considerations, asset retirement obligations, pension fund obligation, below market contracts, various liabilities related to future ownership rights owned by First Nations and interest payable on the Innergex Sainte-Marguerite, S.E.C. debenture. As at March 31, 2018, other liabilities totalled $134.2 million ($80.0 million in 2017). The increase is mostly attributable to the addition of Alterra which included a $29.4 million pension fund obligation related to HS Orka and $20.8 million related to below market contracts.

Following the acquisition of HS Orka, existing long-term power sales contracts in place at HS Orka at the time of acquisition were recognized at fair value by comparing the contracted prices with the prevailing market prices. The contracted prices were lower than the prevailing market prices. As a result, these pre-existing contracts were considered to be below market and a liability was recognized at fair value as part of the purchase price allocation for HS Orka. The Corporation amortizes the fair value of below market sales contracts over the remaining contract term and records the amount in other net expense.

Shareholders' Equity

As at March 31, 2018, the Corporation's shareholders' equity totalled $1,070.0 million, including $315.2 million of non-controlling interests, compared with $456.1 million as at December 31, 2017, which included $14.9 million of non-controlling interests. This $613.8 million increase in total shareholders' equity is attributable mainly to $330.6 million of shares issued for the acquisition of Alterra and to the $300.3 million increase in non-controlling interest of which $296.5 million was related to the acquisition of Alterra and to the recognition of other items of comprehensive income totaling $36.2 million, partly offset by $24.0 million in dividends declared on common and preferred shares, a $9.5 million payment for the buyback of Common Shares and the recognition of a $14.6 million net loss.

Contingencies

In February 2016, HS Orka issued a legal letter to HS Veitur hf demanding full payment of a long-term receivable related to the shared pension liability. A $9.9 million claim was filed and is included under accounts receivable on the balance sheet. This was following receipt of a termination notice by HS Veitur of an agreement regarding payments of the pension liability, sent on December 31, 2015. The two companies had reached an agreement on HS Veitur's share in 2011 and, based on this agreement, HS Orka considers its claim to be fully valid. Negotiations have not settled the matter. The court proceedings took place in March 2018. On April 17, 2018, the First Court of Iceland ruled in favor of HS Orka. HS Veitur has 30 days to file an appeal to the Supreme Court.

Off-Balance-Sheet Arrangements

As at March 31, 2018, the Corporation had issued letters of credit totaling $56.5 million to meet its obligations under its various PPAs and other agreements. Of this amount, $33.6 million was issued under its revolving term credit facilities, either on a temporary basis during the construction of the Upper Lillooet River and Boulder Creek facilities, which ended recently, or for projects in operation, with the remainder being issued under the projects' non-recourse credit facilities. As at that date, Innergex had also issued a total of $37.0 million in corporate guarantees used mainly to guarantee the long-term currency hedging instruments of its operations in France and to support the performance of the Brown Lake and Miller Creek hydroelectric facilities and the construction of the Mesgi'g Ugju's'n facility.

Tax equity investors in U.S. projects generally require sponsor guaranties as a condition to their investment. To support the tax equity investments at Shannon, Kokomo, Spartan and Flat Top, Alterra, a subsidiary of Innergex, has executed guarantees effective on funding of the tax equity investments indemnifying the tax equity investors against certain breaches of project level representations, warranties and covenants and other events.The Corporation believes these indemnifications cover matters that are substantially under its control and are very unlikely to occur.

FREE CASH FLOW AND PAYOUT RATIO

Free Cash Flow and Payout Ratio calculation[1]	Trailing twelve months ended March 31 2018	2017
Cash flows from operating activities	226,831	71,600
Add (Subtract) the following items:		
Changes in non-cash operating working capital items	(44,857)	60,969
Maintenance capital expenditures net of proceeds from disposals	(5,210)	(2,587)
Scheduled debt principal payments	(70,798)	(46,093)
Free Cash Flow attributed to non-controlling interests[2]	(13,744)	(6,256)
Dividends declared on Preferred shares	(5,942)	(5,942)
Adjust for the following elements:		
Transaction costs related to realized acquisitions	10,781	1,968
Realized gain on derivative financial instruments	(828)	—
Free Cash Flow	96,233	73,659
Dividends declared on common shares	76,234	69,765
Payout Ratio	79%	95%
Dividends declared on common shares and paid in cash[3]	70,368	64,394
Payout Ratio - after the impact of the DRIP	73%	87%

1. Free Cash Flow and Payout ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of the MD&A for more information.
2. The portion of Free Cash Flow attributed to non-controlling interests is subtracted, regardless of whether 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.
3. These are 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.

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. 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.

For the trailing twelve-month period ended March 31, 2018, the Corporation generated Free Cash Flow of $96.2 million, compared with $73.7 million for the corresponding period last year. The increase in Free Cash Flow is due mainly to higher cash flows from operating activities before changes in non-cash operating working capital items, partly offset by higher maintenance capital expenditures net of proceeds from disposals and higher Free Cash Flow attributed to non-controlling interests and greater scheduled debt principal payments.

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.

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

For the trailing twelve-month ended March 31, 2018, the dividends on common shares declared by the Corporation amounted to 79% of Free Cash Flow, compared with 95% for the corresponding period last year. This positive change results mainly from the recent commissioning of the Mesgi'g Ugju's'n, Upper Lillooet River and Boulder Creek facilities and the acquisition of wind facilities in 2017 which generated higher Free Cash Flow, partly offset by higher dividend payments as a result of the issuance of 24,327,225 shares on February 6, 2018, related to the Alterra acquisition, to the increase in the quarterly dividend and to additional shares following the exercise of stock options and issued under the DRIP.

The Payout Ratio reflects the Corporation's decision to invest yearly 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 twelve-month period ended March 31, 2018, the Corporation incurred prospective project expenses of $14.0 million, compared with $11.5 million for the corresponding period last year. This 22% increase for the period is mainly attributable to activities undertaken in the quarter to submit projects in request for proposals processes, pursuing opportunities in new international markets, to future requests for proposals and expressions of interest in Canadian provinces and to the advancement of a number of prospective projects. Excluding these discretionary expenses, the Corporation's Payout Ratio would have been approximately 10% points lower for the trailing twelve-month period ended March 31, 2018, and approximately 13% points lower for the prior period.

Furthermore, given the anticipated cash flows from operations, the project-level financing secured for the project and the additional equity provided by the DRIP, the Corporation does not expect to require additional equity in order to complete its Brúarvirkjun project currently under construction.

SEGMENT INFORMATION

Geographic Segments

As at March 31, 2018, and excluding its investments in joint ventures and associates, the Corporation had interests in 29 hydroelectric facilities, six wind farms and one solar farm in Canada, 15 wind farms in Europe, one hydroelectric facility in the United States and two geothermal facilities in Iceland. The Corporation operates in four principal geographical areas, which are detailed below.

	Three months ended March 31	
	2018	2017
Revenues		
Canada	68,431	64,489
France	32,219	9,480
Iceland	16,417	—
United States	814	558
	117,881	74,527

	As at	
	March 31, 2018	December 31, 2017
Non-current assets, excluding derivatives financial instruments and deferred tax assets		
Canada	3,159,307	2,977,859
France	1,003,446	973,740
Iceland	899,096	—
United States	186,271	7,052
	5,248,120	3,958,651

Canada

Revenues up 6% to $68.4 million for the three-month period ended March 31, 2018

The increase in Canadian revenues is attributable mainly to revenue compensation received from a manufacturer for low-availability of equipment at a wind farm and the commissioning of Upper Lillooet River and Boulder Creek hydro facilities in 2017, partly offset by lower production at the British Columbia hydro facilities.

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

For the period ended March 31, 2018, the increase in non-current assets, excluding derivative financial instruments and deferred income tax assets in Canada, stems mainly from the acquisition of Alterra, partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

France

Revenues up 240% to $32.2 million for the three-month period ended March 31, 2018

The increase in revenues in France is attributable mainly to the contribution of the acquisition of wind facilities in 2017 and to higher production at all wind facilities.

For the period ended March 31, 2018, the change in non-current assets, excluding derivative financial instruments and deferred income tax assets in France, stems from foreign exchange rate effect, partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

Iceland

Revenues at $16.4 million for the three-month period ended March 31, 2018

The increase in revenues and in non-current assets, excluding financial instruments and deferred income tax assets, stems from the two geothermal facilities acquired in February 2018 as part of the acquisition of Alterra.

United States

Revenues up 46% to $0.8 million for the three-month period ended March 31, 2018

The increase in revenues can mainly be explained by higher production at the Horseshoe Bend facility.

For the period ended March 31, 2018, the increase in non-current assets is attributable mainly to the acquisition of Alterra, which owns interest in several US-based joint ventures and associates that are not consolidated.

Operating Segments

As at March 31, 2018, the Corporation had five operating segments: hydroelectric generation, wind power generation, geothermal power generation, solar power generation and site development.

Through its hydroelectric, wind power, geothermal power and solar power generation segments, the Corporation sells electricity produced by its hydroelectric, wind, geothermal and solar facilities mainly to publicly owned utilities or other creditworthy counterparties. Through its site development segment, Innergex analyzes potential sites and develops hydroelectric, wind, geothermal 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, 2017. 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, geothermal and 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.

	SUMMARY OPERATING RESULTS					
	Hydroelectric	Wind	Geothermal	Solar	Site Development	Total
Three months ended March 31, 2018						
Power generated (MWh)	340,469	593,690	195,637	6,549	—	1,136,345
Revenues	34,663	64,051	16,417	2,750	—	117,881
Expenses:						
Operating expenses	9,855	7,429	8,519	169	—	25,972
General and administrative expenses	2,657	2,622	2,345	34	—	7,658
Prospective project expenses	—	—	—	—	4,908	4,908
Adjusted EBITDA[1]	22,151	54,000	5,553	2,547	(4,908)	79,343
Three months ended March 31, 2017						
Power generated (MWh)	332,469	382,001	—	7,803	—	722,273
Revenues	34,358	36,892	—	3,277	—	74,527
Expenses:						
Operating expenses	10,739	5,175	—	175	—	16,089
General and administrative expenses	2,765	1,422	—	55	336	4,578
Prospective project expenses	—	—	—	—	2,918	2,918
Adjusted EBITDA[1]	20,854	30,295	—	3,047	(3,254)	50,942

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

	FINANCIAL POSITION					
	Hydroelectric	Wind	Geothermal	Solar	Site Development	Total
As at March 31, 2018						
Goodwill	15,180	41,894	42,762	303	5	100,144
Total assets	2,525,449	1,899,336	932,785	106,408	69,550	5,533,528
Total liabilities	2,186,081	1,618,357	460,430	112,966	85,732	4,463,566
Acquisition of property, plant and equipment during the period	401	153	7,803	98	223	8,678
As at December 31, 2017 (Restated [1])						
Goodwill	8,269	30,311	—	—	—	38,580
Total assets	2,425,646	1,651,537	—	101,449	11,824	4,190,456
Total liabilities	2,093,158	1,515,468	—	99,902	25,803	3,734,331
Acquisition of property, plant and equipment during the year	18,804	352,968	—	12	185,884	557,668

1. For more information on the restatement, please refer to the "Accounting Changes" section.

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

Hydroelectric Generation Segment

Revenues up 1% to $34.7 million for the three-month period ended March 31, 2018

For the three-month period ended March 31, 2018, this segment produced 92% of the LTA, compared with production at 93% of the LTA last year. The decrease in the percentage of the LTA is attributable mainly to lower production from the Quebec facilities compared to last year.

The slight increase in revenues compared with last year is due mainly to the contribution of the Upper Lillooet River hydroelectric facility commissioned in March 2017 and to higher production at the Ashlu Creek and Idaho facilities, partly offset by lower production at the Quebec facilities. Expenses for the period were lower due mainly to a $3.3 million aggregate payment in 2017 related to water rights for 2011 and 2012 for Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River, which were reassessed following the decision by the British Columbia Ministry of Forests, Lands and Natural Resource Operations to apply higher rental rates based on the facilities' combined production rather than applying lower rates for each facility based on its individual production, as had previously been the ministry's practice. Since 2013, the facilities' water rights fees have been paid at the higher rates. A 49.99% portion of the water rights payment is allocated to the non-controlling interests. The decrease in expenses was partly offset by a greater number of facilities in operation.

The increase in total assets since December 31, 2017, stems mainly from the acquisition of Alterra, which was partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2017, is attributable mainly to the acquisition of Alterra, partly offset by scheduled repayment of long-term debt.

Wind Power Generation Segment

Revenues up 74% to $64.1 million for the three-month period ended March 31, 2018

For the three-month period ended March 31, 2018, this segment produced 97% of the LTA compared with production at 84% of the LTA last year. The increase in the percentage of LTA is due mainly to above-average wind regimes in France, partly offset by below-average wind regimes in Quebec.

Revenues increased due mainly to the contribution of the wind facilities acquired in France in 2017, to compensation from a manufacturer for low-availability of equipment at a wind farm and to higher production from all wind facilities in France, partly offset by lower production at the Quebec facilities.

The increase in total assets since December 31, 2017, is mainly attributable to the acquisition of Alterra which owns interest in several joint ventures and associates and to foreign exchange rate effect, partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2017, is attributable mainly to the acquisition of Alterra which owns interest in several joint ventures and associates and to foreign exchange rate effect, which was partly offset by the scheduled repayment of long-term debt.

Geothermal Power Generation Segment

Revenues at $16.4 million for the three-month period ended March 31, 2018

For the three-month period ended March 31, 2018, this segment produced 100% of the LTA.

The increase in revenues stem from the two geothermal facilities acquired in February 2018 as part of the Alterra acquisition.

The increase in total assets since December 31, 2017, results mainly from the addition of the two geothermal facilities acquired in February 2018, partly offset by depreciation of property, plant and equipment and from amortization of intangible assets.

The increase in total liabilities since December 31, 2017, results mainly from the addition of the two geothermal facilities acquired in February 2018, partly offset by the scheduled repayment of long-term debt.

Solar Power Generation Segment

Revenues down 16% to $2.8 million for the three-month period ended March 31, 2018

For the three-month period ended March 31, 2018, this segment which includes one solar farm in Ontario produced 92% of the LTA compared with production at 109% of the LTA last year. The decrease in the percentage of LTA is due to below-average solar irradiation this quarter.

The decrease in revenues can be explained by lower production than last year.

The increase in total assets since December 31, 2017, results mainly from the acquisition of Alterra which owns interest in several joint ventures and associates, which was partly offset by depreciation of property, plant and equipment and the amortization of intangible assets.

The increase in total liabilities since December 31, 2017, is mainly due to the acquisition of Alterra which owns interest in several joint ventures and associates, partly offset by the scheduled repayment of long-term debt.

Site Development Segment

Expenses up 51% to $5 million for the three-month period ended March 31, 2018

This increase in expenses is mainly due to investments made to pursue growth opportunities and to the addition of projects with the Alterra acquisition.

The increase in total assets since December 31, 2017, stems mainly from the development projects acquired with Alterra.

Since December 31, 2017, the increase in total liabilities is mainly due to the debt raised to acquire development projects with the Alterra acquisition.

QUARTERLY FINANCIAL INFORMATION

Restated [2]	Three months ended			
(in millions of dollars, unless otherwise stated)	Mar. 31, 2018	Dec. 31, 2017	Sept. 30, 2017	June 30, 2017
Power generated (MWh)	1,136,345	1,106,060	1,243,099	1,322,781
Revenues	117.9	108.0	108.2	109.5
Adjusted EBITDA[1]	79.3	80.1	81.8	85.9
Realized and unrealized net (loss) gain on financial instruments	(12.1)	(1.4)	(1.0)	(0.5)
Net (loss) earnings	(14.6)	3.4	4.2	13.9
Net (loss) earnings attributable to owners of the parent	(6.6)	7.0	5.7	14.4
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(0.07)	0.05	0.04	0.12
Dividends declared on preferred shares	1.5	1.5	1.5	1.5
Dividends declared on common shares	22.5	17.9	17.9	17.9
Dividends declared on common shares, $ per share	0.170	0.165	0.165	0.165

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. For more information on the restatement, please refer to the "Accounting Changes" section.

Restated [2]	Three months ended			
(in millions of dollars, unless otherwise stated)	Mar. 31, 2017	Dec 31, 2016	Sept. 30, 2016	June 30, 2016
Power generated (MWh)	722,273	848,967	831,840	1,176,451
Revenues	74.5	73.3	69.3	87.8
Adjusted EBITDA[1]	50.9	50.3	51.2	66.9
Realized and unrealized net gain (loss) on financial instruments	5.1	2.2	(1.3)	2.2
Net (loss) earnings	(2.5)	8.8	0.4	15.7
Net earnings attributable to owners of the parent	2.3	9.8	3.4	14.4
Net earnings attributable to owners of the parent ($ per share – basic and diluted)	0.01	0.08	0.02	0.12
Dividends declared on preferred shares	1.5	1.5	1.5	1.5
Dividends declared on common shares	17.9	17.3	17.3	17.3
Dividends declared on common shares, $ per share	0.165	0.165	0.160	0.165

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. For more information on the restatement, please refer to the "Accounting Changes" section. Only data from 2017 was restated.

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 48% 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. Geothermal production is fairly stable throughout the year.

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 can also influence these figures, some of which have a relatively stable quarter-to-quarter impact while others are more variable. For the Corporation, the factors responsible for the largest fluctuations in net earnings (loss) are the unrealized and realized gains (losses) on financial instruments arising from the increase (decrease) in benchmark interest rates, foreign exchange fluctuations and fluctuations in future expected aluminum prices. Historical analysis of net earnings (losses) should take these factors into account. It should be noted that the unrealized changes in the market value of derivative financial instruments result from interest rate fluctuations, foreign exchange fluctuations and changes in the value of embedded derivatives linked to aluminum 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 AND ASSOCIATES

Electricity Production

	Three months ended March 31					
	2018			2017		
	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA
Toba Montrose [2]	3,766	10,295	37%	—	—	—
Shannon [2]	121,744	117,437	104%	—	—	—
Flat Top [3]	19,637	22,626	87%	—	—	—
Dokie [2]	39,694	43,764	91%	—	—	—
Jimmie Creek [2]	613	775	79%	—	—	—
Umbata Falls	19,677	16,927	116%	25,928	16,927	153%
Viger-Denonville	22,383	20,300	110%	20,429	20,300	101%
Spartan [2]	1,673	1,935	86%	—	—	—
Kokomo [2]	1,070	1,405	76%	—	—	—

1. Corresponds to 100% of the facility's electricity production and LTA.
2. For the period from February 6, 2018, to March 31, 2018.
3. For the period from March 23, 2018, to March 31, 2018.

Innergex's share of Adjusted EBITDA of joint ventures and associates

	Three months ended March 31	
	2018	2017
Innergex's share of Adjusted EBITDA of joint ventures and associates[1]:		
Toba Montrose (40%)	(91)	—
Shannon (50%) [2]	2,331	—
Flat Top (51%)[2 4]	(21)	—
Dokie (25.5%)	1,024	—
Jimmie Creek (50.99%)	(282)	—
Umbata Falls (49%)	704	976
Viger-Denonville (50%)	1,419	1,274
Spartan (100%) [3]	168	—
Kokomo (90%) [2]	80	—
	5,332	2,250

1. Innergex's share of Adjusted EBITDA of joint ventures and associates is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information
2. Ownership interest is in the sponsor equity of Shannon, Flat Top and Kokomo.
3. Ownership interest is 100% of sponsor equity of Spartan, however, joint control exists through the Corporation's tax equity arrangement.
4. Flat Top began commercial operation on March 23, 2018.

The summarized financial information below are the amounts shown in the joint ventures' and associates' financial statements prepared in accordance with IFRS.

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

Toba Montrose

The Corporation holds a 51% voting interest and 40% participating economic interest in East Toba and Montrose Creek hydro facilities ("Toba Montrose"). In 2046, the Corporation's economic interest will increase to 51% for no additional consideration.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenues	569
Operating, general and administrative expenses	796
Adjusted EBITDA[1]	(227)
Finance costs	3,780
Other net expenses	913
Depreciation and amortization	2,617
Net loss	(7,537)
Other comprehensive loss	(3,239)
Total comprehensive loss	(10,776)

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the period from February 6, 2018, to March 31, 2018, production was 37% of the LTA due mainly to below-average water flows.

For the period from February 6, 2018, to March 31, 2018, the negative Adjusted EBITDA can be explained by the first quarter being the period with the lowest power generation for the East Toba and Montrose Creek facilities.

For the period from February 6, 2018, to March 31, 2018, the other comprehensive loss is attributable mainly to changes in forward interest rates related to the interest rate swap.

Summary Statements of Financial Position

	As at March 31, 2018
Current assets	13,137
Non-current assets	679,927
	693,064
Current liabilities	14,257
Non-current liabilities	479,096
Partner's equity	199,711
	693,064

Toba Montrose 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 $92.7 million used to hedge the interest rate of the Toba Montrose loan had a net negative value of $32.3 million at March 31, 2018.

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

Shannon

The Corporation holds a 50% sponsor equity interest in the Shannon wind facility, with the remaining 50% sponsor equity interest and tax equity interest held by third parties.

Summary Statements of Earnings and Comprehensive Income (Loss)

	Period of 54 days ended March 31, 2018
Revenues	6,187
Operating, general and administrative expenses	1,526
Adjusted EBITDA[1]	4,661
Other net expenses	38
Depreciation and amortization	1,639
Net earnings	2,984
Other comprehensive loss	(10,258)
Total comprehensive loss	(7,274)
Net earnings attributable to:	
Sponsors:	
Innergex	3,333
Other sponsor	3,333
Tax equity investors	(3,682)
	2,984
Total comprehensive loss attributable to:	
Sponsors:	
Innergex	(1,649)
Other sponsor	(1,649)
Tax equity investors	(3,976)
	(7,274)
Distributions received from the joint venture by the Corporation	693

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the period from February 6, 2018, to March 31, 2018, production was 104% of the LTA due mainly to above-average wind regimes.

On June 29, 2015, Shannon entered into a long-term power hedge covering the period from June 1, 2016, to May 31, 2029. The power hedge provides for Shannon to receive a fixed dollar amount per MWh for a fixed quantity of power. Shannon and the hedge provider settle net on a monthly basis. The other comprehensive loss consists solely of the effective portion of changes in the fair value of the power hedge. Shannon hedges approximately 75% of its output and the power hedge had a net positive value of $26.3 million at March 31, 2018.

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

Summary Statements of Financial Position

	As at March 31, 2018
Current assets	6,554
Non-current assets	355,517
	362,071
Current liabilities	5,839
Non-current liabilities	15,752
Sponsors equity interest	113,681
Tax equity interest	226,799
	362,071

One of the primary incentives for renewable energy in the United States has been the production tax credit program ("PTC"), whereby corporations that generate electricity from renewable energy sources, including wind, are eligible for tax credits which provide a tax benefit for each unit of generation for the first 10 years of the facility's operation (until 2025). The Shannon tax equity investors are allocated a portion of Shannon's taxable income (losses) and PTCs and a portion of the cash generated until they achieve an agreed after–tax investment return (the "Flip Point"). After the Flip Point, the Shannon tax equity investors will be allocated 5% of cash distributions and taxable income (losses) and the sponsors will be allocated 95% of all cash distributions and taxable income (losses).

For the period from February 6, 2018, to March 31, 2018, the wind facility generated approximately $3.5 million of PTCs.

The Tax Equity Investors and Sponsors' taxable income (losses) and PTCs and cash distributions allocations are detailed in the table below. These allocations will change when the Tax Equity Investors reach their expected return.

	Tax Equity Investors	Sponsors
Taxable income (losses) and PTCs	99.0%	1.0%
Cash distributions	64.1%	35.9%

Due to exceptionally low winds at the facility in certain portions of 2016 and 2017, there is currently a higher allocation of cash to the Tax Equity Investors, which commenced in the first quarter of 2017. The cash allocations are based on a quarterly test measuring cumulative generation for the project since tax equity funding (December 14, 2015) with allocations to the Sponsors and Tax Equity Investors based on cumulative allocations.

Tax equity investors in U.S. projects generally require sponsor guaranties as a condition to their investment. To support the tax equity investments at Shannon, Alterra, a subsidiary of Innergex, executed a guarantee indemnifying the tax equity investors against certain breaches of project level representations, warranties and covenants and other events. The Corporation believes these indemnifications cover matters which are substantially under its control, and are very unlikely to occur.

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

Flat Top

The Corporation holds a 51% sponsor equity interest in the Flat Top wind facility, with the remaining 49% sponsor equity interest and tax equity interest held by third parties. The wind farm began commercial operation on March 23, 2018.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenues	359
Operating, general and administrative expenses	401
Adjusted EBITDA[1]	(42)
Other net revenues	(3)
Depreciation and amortization	207
Unrealized net loss on derivative financial instruments	4,112
Net loss	(4,358)
Other comprehensive loss	(3,519)
Total comprehensive loss	(7,877)
Net loss attributable to:	
Sponsors:	
Innergex	1,047
Other sponsor	1,006
Tax equity investors	(6,411)
	(4,358)
Total comprehensive loss attributable to:	
Sponsors:	
Innergex	(773)
Other sponsor	(743)
Tax equity investors	(6,361)
	(7,877)

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the period from March 23, 2018, to March 31, 2018, production was 87% of the LTA due mainly to post-commissioning activities.

For the period from March 23, 2018, to March 31, 2018, Adjusted EBITDA was impacted by below-LTA production levels.

On May 24, 2017, Flat Top entered into a long-term power hedge covering the period from August 1, 2018, to July 31, 2031. The power hedge provides for the Corporation to receive a fixed dollar amount per MWh for a fixed quantity of power. Flat Top and the hedge provider settle net on a monthly basis. The other comprehensive income consists solely of the effective portion of changes in the fair value of the power hedge. Flat Top hedges approximately 81% of its output and the power hedge had a net positive value of $1.0 million at March 31, 2018.

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

Summary Statements of Financial Position

	As at March 31, 2018
Current assets	30,090
Non-current assets	447,319
	477,409
Current liabilities	28,885
Non-current liabilities	12,239
Sponsors equity interest	168,432
Tax equity interest	267,853
	477,409

One of the primary incentives for renewable energy in the United States has been the production tax credit program ("PTC"), whereby corporations that generate electricity from renewable energy sources, including wind, are eligible for tax credits which provide a tax benefit for each unit of generation for the first 10 years of the facility's operation (until 2028). The Flat Top Tax Equity Investors are allocated a portion of Flat Top's taxable income (losses) and PTCs and a portion of the cash generated until they achieve an agreed after-tax investment return. After the Flip Point, the Flat Top Tax Equity Investors will be allocated 5% of cash distributions and taxable income (losses) and the sponsors will be allocated 95% of all cash distributions and taxable income (losses).

For the period from March 23, 2018, to March 31, 2018, the wind facility generated approximately $0.6 million of PTCs.

The Tax Equity Investors and Sponsors' taxable income (losses) and PTCs and cash distributions allocations are detailed in the table below. These allocations will change when the Tax Equity Investors reach their expected return.

	Tax Equity Investors	Sponsors
Taxable income (losses) and PTCs	99.00%	1.00%
Cash distributions	21.97%	78.03%

Tax equity investors in U.S. projects generally require sponsor guaranties as a condition to their investment. To support the tax equity investments at Flat Top, Alterra, a subsidiary of Innergex, executed a guarantee indemnifying the Tax Equity Investors against certain breaches of project level representations, warranties and covenants and other events. The Corporation believes these indemnifications cover matters that are substantially under its control and very unlikely to occur.

Dokie

The Corporation holds a 25.5% interest in the Dokie wind facility.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenues	5,089
Operating, general and administrative expenses	1,073
Adjusted EBITDA[1]	4,016
Finance costs	1,699
Other net expenses	332
Depreciation and amortization	1,997
Net loss	(12)

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the period from February 6, 2018, to March 31, 2018, production was 91% of the LTA due mainly to below-average wind regimes.

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

Summary Statements of Financial Position

	As at March 31, 2018
Current assets	13,211
Non-current assets	233,532
	246,743
Current liabilities	2,077
Non-current liabilities	149,128
Partner's equity	95,538
	246,743

Jimmie Creek

The Corporation holds a 50.99% interest in the Jimmie Creek hydro facility.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenues	107
Operating, general and administrative expenses	659
Adjusted EBITDA[1]	(552)
Finance costs	1,579
Other net revenues	(235)
Depreciation and amortization	809
Net loss and comprehensive loss	(2,705)

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the period from February 6, 2018, to March 31, 2018, production was 79% of the LTA due mainly to below-average water flows.

For the period from February 6, 2018, to March 31, 2018, the negative Adjusted EBITDA can be explained by the first quarter being the period with the lowest power generation for the Jimmie Creek facility.

Summary Statements of Financial Position

	As at March 31, 2018
Current assets	6,123
Non-current assets	234,794
	240,917
Current liabilities	2,904
Non-current liabilities	166,842
Partner's equity	71,171
	240,917

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

Umbata Falls

The Corporation holds a 49% interest in the Umbata Falls hydro facility.

Summary Statements of Earnings and Comprehensive Income

	Three months ended March 31	
	2018	2017
Revenues	1,681	2,208
Operating and general and administrative expenses	244	217
Adjusted EBITDA[1]	1,437	1,991
Finance costs	569	601
Other net revenues	(17)	(8)
Depreciation and amortization	1,003	1,004
Unrealized net (gain) loss on financial instruments	(411)	33
Net earnings and comprehensive income	293	361

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the three-month period ended March 31, 2018, production was 116% of the LTA due to above-average water flows.

The decrease in Adjusted EBITDA for the three-month period ended March 31, 2018, is due mainly to lower production and revenues this quarter compared with the same period last year.

For the three-month period ended March 31, 2018, Umbata Falls L.P. recorded net earnings and comprehensive income of $0.3 million, compared with $0.4 million for the same period last year. The decrease reflects the lower revenues, partly offset by a higher unrealized net gain on financial instruments.

Summary Statements of Financial Position

	As at	
	March 31, 2018	December 31, 2017
Current assets	3,241	3,550
Non-current assets	59,666	60,658
	62,907	64,208
Current liabilities	2,681	3,512
Non-current liabilities	40,160	40,924
Partners' equity	20,066	19,772
	62,907	64,208

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

Viger-Denonville

The Corporation holds a 50% interest in the Viger-Denonville wind facility.

Summary Statements of Earnings and Comprehensive Income

	Three months ended March 31	
	2018	2017
Revenues	3,366	3,062
Operating and general and administrative expenses	528	514
Adjusted EBITDA[1]	2,838	2,548
Finance costs	818	874
Other net revenues	(16)	(8)
Depreciation and amortization	627	730
Unrealized net gain on financial instruments	(170)	(124)
Net earnings	1,579	1,076
Other comprehensive income (loss)	235	(129)
Total other comprehensive income	1,814	947
Distributions received from the joint venture by the Corporation	663	290

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the three-month period ended March 31, 2018, production was 110% of the LTA due mainly to an above-average wind regime.

For the three-month period ended March 31, 2018, the Adjusted EBITDA increased due mainly to higher revenues compared with last year.

For the three-month period ended on March 31, 2018, the increase in net earnings compared with last year is due mainly to higher Adjusted EBITDA, lower finance costs and lower depreciation and amortization.

For the three-month period ended on March 31, 2018, the increase in other comprehensive income is attributable mainly to unrealized net gains on financial instruments.

Summary Statements of Financial Position

	As at	
	March 31, 2018	December 31, 2017
Current assets	2,483	3,005
Non-current assets	53,196	53,812
	55,679	56,817
Current liabilities	4,127	4,355
Non-current liabilities	48,521	49,920
Partners' equity	3,031	2,542
	55,679	56,817

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

Spartan

The Corporation owns 100% of the sponsor equity interest in the Spartan solar facility and none of the tax equity interest which is owned by a third party.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenues	209
Operating, general and administrative expenses	41
Adjusted EBITDA[1]	168
Finance costs	110
Other net expenses	29
Depreciation and amortization	228
Unrealized net gain on derivative financial instruments	(1)
Net loss	(198)
Other comprehensive income	260
Total comprehensive income	62
Net loss attributable to:	
Sponsor	(30)
Tax equity investor	(168)
	(198)
Total comprehensive income attributable to:	
Sponsor	(27)
Tax equity investor	89
	62

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

Summary Statements of Financial Position

	As at March 31, 2018
Current assets	1,967
Non-current assets	27,615
	29,582
Current liabilities	1,824
Non-current liabilities	12,458
Sponsor equity interest	3,129
Tax equity interest	12,171
	29,582

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

Kokomo

The Corporation holds a 90% sponsor equity interest in the Kokomo solar facility, with the remaining 10% sponsor equity interest and tax equity interest held by third parties.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenues	115
Operating, general and administrative expenses	26
Adjusted EBITDA[1]	89
Finance costs	62
Other net expenses	14
Depreciation and amortization	111
Net loss	(98)
Other comprehensive income	135
Total comprehensive income	37
Net loss attributable to:	
Sponsors	(15)
Tax equity investor	(83)
	(98)
Total comprehensive income attributable to:	
Sponsors	(15)
Tax equity investor	52
	37

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

Summary Statements of Financial Position

	As at March 31, 2018
Current assets	138
Non-current assets	13,021
	13,159
Current liabilities	556
Non-current liabilities	5,687
Sponsors equity interest	2,186
Tax equity interest	4,730
	13,159

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

Blue Lagoon

HS Orka holds a 30% interest in Blue Lagoon hf., which operates the Blue Lagoon geothermal spa in Iceland.

Reconciliation of the carrying amount of the interest in the associate recognized in the consolidated financial statements:

	As at March 31, 2018
Opening Balance, January 1, 2018	—
Preliminary fair value pursuant to acquisition of Alterra	141,135
Share of comprehensive income	2,052
Foreign exchange	7,198
Ending Balance, March 31, 2018	150,385

Commitments of joint ventures and associates

As at March 31, 2018, the Corporation's share of the expected schedule of commitment payments for the joint ventures and associates are as follows:

Years of	Wind Power Generation
2018	4,596
2019	7,067
2020	7,067
2021	7,067
2022	7,067
Thereafter	95,081
Total	127,945

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

NON-WHOLLY OWNED SUBSIDIARIES

HS Orka hf ("HS Orka")

The Corporation holds a 53.9% interest in HS Orka which produces and sells electricity from two operating geothermal plants located in Iceland, namely Reykjanes and Svartgensi.

Summary Statements of Earnings and Comprehensive Income – HS Orka

	Period of 54 days ended March 31, 2018
Revenues	16,417
Adjusted EBITDA[1]	1,754
Net loss [2]	(2,837)
Other comprehensive income	36,805
Total comprehensive income	33,968
Net loss attributable to:	
Owners of the parent	(1,529)
Non-controlling interests	(1,308)
	(2,837)
Total comprehensive income attributable to:	
Owners of the parent	18,309
Non-controlling interests	15,659
	33,968

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. Expenses also include non-cash expenses such as depreciation and amortization totalling $3.3 million and unrealized net loss on financial instruments related to embedded derivatives totalling $9.9 million.

Summary Statements of Financial Position – HS Orka

	As at March 31, 2018
Current assets	23,133
Non-current assets	893,756
	916,889
Current liabilities	38,571
Non-current liabilities	211,548
Equity attributable to owners of the parent	359,389
Non-controlling interests	307,381
	916,889

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

ENTITIES EXCLUDED FROM THE CORPORATION'S CONTROL POLICIES AND PROCEDURES

As stated in the "Establishment and Maintenance of DC&P and ICFR" section of this MD&A, the figures for Energies du Plateau Central (Rougemont-1), Energies du Plateau Central 2 (Rougemont-2), Energie du Rechet (Vaite), Éole de Plan Fleury, Les Renardières and Alterra Power Group Entitites are excluded from the Corporation's control policies and procedures.

Summary financial information about the Rougemont 1-2, Vaite, Plan Fleury, Les Renardières and Alterra Power Group Entities is set out below:

Summary Statement of Earnings and Comprehensive Income – Rougemont 1-2 and Vaite

	Three months ended March 31, 2018
Revenues	11,497
Adjusted EBITDA[1]	8,994
Net earnings	2,503
Other comprehensive income	764
Total comprehensive income	3,267

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

Summary Statement of Financial Position – Rougemont 1-2 and Vaite

	As at March 31, 2018
Current assets	35,036
Non-current assets	481,255
	516,291
Current liabilities	36,656
Non-current liabilities	437,238
Equity	42,397
	516,291

Summary Statement of Earnings and Comprehensive Income – Plan Fleury and Les Renardières

	Three months ended March 31, 2018
Revenues	5,025
Adjusted EBITDA[1]	4,601
Net earnings	1,842
Other comprehensive loss	116
Total comprehensive income	1,958

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

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

Summary Statement of Financial Position – Plan Fleury and Les Renardières

	As at March 31, 2018
Current assets	27,765
Non-current assets	168,567
	196,332
Current liabilities	26,654
Non-current liabilities	124,738
Equity	44,940
	196,332

Summary Statement of Earnings and Comprehensive Income – Alterra Power Group Entities

	Period of 54 days ended March 31, 2018
Revenues	16,417
Adjusted EBITDA[1]	4,655
Net loss	(4,474)
Other comprehensive income	17,171
Total comprehensive income	12,697

1. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

Summary Statement of Financial Position – Alterra Power Group Entities

	As at March 31, 2018
Current assets	27,524
Non-current assets	1,305,839
	1,333,363
Current liabilities	43,668
Non-current liabilities	518,751
Equity	463,563
Non-controlling interests	307,381
	1,333,363

RELATED PARTY TRANSACTIONS

Related party transactions conducted in the normal course of operations are measured at fair value which is the amount established and agreed to by the related parties, unless specific requirements within IFRS require different treatment.

As part of the Alterra Acquisition, the following debts were assumed: (i) in 2011, Ross J. Beaty, chairman of the board of directors and a large shareholder of Alterra, entered into a revolving credit facility with Alterra (the “Credit Facility”). The Credit Facility had a borrowing capacity of $20 million and made funds available to Alterra on a revolving basis at an interest rate of 8% per annum, compounded and payable monthly. In addition, a standby fee in the amount of 0.75% of the Credit Facility and a drawdown fee in the amount of 1.5% of amounts advanced, were payable in cash. The Credit Facility matured on March 31, 2018. Alterra had borrowed $17.3 million under the Credit Facility; and (ii) in October 2016, Ross J. Beaty loaned, through a five-year term bond, US$35.7 million to Alterra’s subsidiary Magma Energy Sweden A.B (the “Bond”). The Bond paid interest at 8.5% per annum with an upfront fee of 2% of the principal which was paid at closing of the financing. The Bond was collateralized by 15% of the outstanding shares in HS Orka. To optimize its treasury management, the Corporation repaid both the Credit Facility and the Bond in the first quarter.

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

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 EBITDA Margin, Adjusted EBITDA Proportionate, Innergex's share of Adjusted EBITDA of joint ventures and associates, 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. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Readers are cautioned that Adjusted EBITDA should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Operating Results" section of this MD&A for the reconciliation of Adjusted EBITDA.

References in this document to "Adjusted EBITDA Margin" are to Adjusted EBITDA divided by revenues. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance.

References in this document to "Innergex's share of Adjusted EBITDA of the joint ventures and associates" are to Innergex's ownership interest in the equity or in the sponsors' equity when applicable of the Adjusted EBITDA of the joint ventures and associates. Please refer to the "Investments in Joint Ventures and Associates" section of this MD&A for the reconciliation of Adjusted EBITDA Proportionate.

References in this document to "Adjusted EBITDA Proportionate" are to Adjusted EBITDA plus Innergex's share of Adjusted EBITDA of the joint ventures and associates. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Readers are cautioned that Adjusted EBITDA Proportionate should not be construed as an alternative to net earnings, as determined in accordance with IFRS.

References to "Adjusted Net Earnings (Loss)" are to net earnings or losses of the Corporation, to which the following elements are added (subtracted): unrealized net (gain) loss on financial instruments; realized (gain) loss on financial instruments; income tax expense (recovery) related to the above items; and the share of unrealized net (gain) loss on derivative financial instruments of joint ventures and associates, net of related tax. Innergex uses derivative financial instruments to hedge its exposure to various 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 of the derivatives for which hedge accounting is not applied 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 that are not designated for hedge accounting. The Adjusted Net Earnings (Loss) of the Corporation aims to eliminate the impact of the mark-to-market rules on derivatives on the profit and loss of the Corporation. Innergex believes that the analysis and presentation of net earnings or loss on this basis enhances understanding of the Corporation's operating performance. Readers are cautioned that Adjusted Net Earnings (Loss) should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Operating Results" section of this MD&A for the reconciliation of Adjusted Net Earnings (Loss).

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 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), 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. Innergex believes that presentation of this measure enhances the understanding of the Corporation's cash generation capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. Readers are cautioned that Free Cash Flow should not be construed as an alternative to cash flows from operating activities, as determined in accordance with IFRS. Please refer to the "Free Cash Flow and Payout Ratio" section of this MD&A for the reconciliation of Free Cash Flow.

References to “Payout Ratio” are to dividends declared on common shares divided by Free Cash Flow. Innergex believes that this is a measure of its ability to sustain current dividends and dividend increases as well as its ability to fund its growth.

This MD&A contains references to the Alterra Power Corp. acquisition and its Gross Adjusted EBITDA, Net Adjusted EBITDA and Projected Revenues which are not recognized under IFRS, have no standardized meaning prescribed by them 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 cash generation capabilities and facilitates the comparison of results over different periods.

References in this document to "Gross Adjusted EBITDA" are to Projected Revenues less operating expenses (including cost of power, if applicable) and general and administrative expenses. Readers are cautioned that Gross Adjusted EBITDA should not be construed as an alternative to net earnings as determined in accordance with IFRS.

References in this document to "Net Adjusted EBITDA" corresponds to Gross Adjusted EBITDA multiplied by Innergex's ownership interest in the equity or in the sponsors' equity when applicable.

References to "Projected Revenues" are to expected gross production of a project multiplied by the price of the associated power purchase agreement, the projected merchant price of electricity or secured financial power hedge contract. In these contracts, any pricing mechanisms that stipulate price adjustments depending on merchant prices reflect management's current views and expectations, subject to change, of the merchant prices. (HS Orka Projected Revenues are calculated from total generation produced by HS Orka multiplied by a mix of long- and short-term industrial and retail contracts as well as revenue from hot and cold water sales and other revenues.)

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”), including the Corporation's power production, prospective projects, successful development, construction and financing of the projects under construction and the advanced-stage prospective projects, estimates of recoverable geothermal energy resources, business strategy, future development and growth prospects, business integration, governance, business outlook, objectives, plans and strategic priorities, and other statements that are not historical facts. Forward-Looking Information can generally be identified by the use of words such as “approximately”, “may”, “will”, "could", “believes", “expects", “intends”, "should", “plans”, “potential”, "project", “anticipates”, “estimates”, “scheduled” or “forecasts”, or other comparable terminology that state that certain events will or will not occur. It represents the projections and expectations of the Corporation relating to future events or results as of the date of this MD&A.

Future-oriented financial information: Forward-Looking Information includes future-oriented financial information or financial outlook within the meaning of securities laws, such as expected production, projected revenues, projected Adjusted EBITDA, and estimated project costs, to inform readers of the potential financial impact of expected results, of the expected commissioning of Development Projects, of the potential financial impact of the acquisitions, of the Corporation's ability to sustain current dividends 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, geothermal resources and solar irradiation, performance of operating facilities, project performance, economic, financial and financial market conditions, the Corporation’s success in developing new facilities, expectations and assumptions concerning availability of capital resources.

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 “Risk Factors” section of the Annual Information Form 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 the capital markets; liquidity risks related to derivative financial instruments; variability in hydrology, geothermal resources, wind regimes and solar irradiation; delays and cost overruns in the design and construction of projects; the ability to secure new power purchase agreements or renew any power purchase agreement; fluctuation affecting prospective power prices; health, safety and environmental risks; uncertainties surrounding the development of new facilities; obtainment of permits; 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; potential undisclosed liabilities associated with the Alterra Acquisition; failure to realize the anticipated benefits of the Alterra Acquisition; integration of the Alterra Acquisition; changes in governmental support to increase electricity to be generated from renewable sources by independent power producers; variability of installation performance and related penalties; 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; exposure to many different forms of taxation in various jurisdictions; changes in general economic conditions; regulatory and political risks; ability to secure appropriate land; reliance on PPAs; availability and reliability of transmission systems (including due to reliance on third parties); foreign market growth and development risks; foreign exchange fluctuations; increases in water rental cost or changes to regulations applicable to water use; assessment of water, wind, geothermal and sun resources and associated electricity production; natural disasters and *force majeure*; 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; integration of the facilities and projects acquired and to be acquired; failure to realize the anticipated benefits of acquisitions; 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; risks related to U.S. production and investment tax credits, changes in U.S. corporate tax rates and availability of tax equity financing; host country economic, social and political conditions; risk inherent to geothermal resources; aluminum price risks; geological occurrences, rockslides, avalanches or other occurrences outside the Corporation's control; adverse claims to property title; unknown liabilities; reliance on intellectual property and confidential agreements to protect our rights and confidential information.

There are also risks inherent to the Alterra Transaction, including incorrect assessments of the value of the other entity. There can be no assurance that the strategic, operational or financial benefits expected to result from the Alterra Transaction will be realized.

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; for solar energy, the historical solar irradiation conditions, panel technology and expected solar panel degradation; and for geothermal power, the historical geothermal resources, natural depletion of geothermal resources over time, the technology used and the potential of energy loss to occur before delivery. 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 Dokie, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls and Viger-Denonville, which are accounted for using the equity method).	Improper assessment of water, wind, sun and geothermal resources and associated electricity production Variability in hydrology, wind regimes, solar irradiation and geothermal resources Natural depletion of geothermal resources 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 mainly. 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, 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. Revenues at the HS Orka facilities also fluctuates with the price of aluminum, as certain of those PPAs are linked to such price. 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 Dokie, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls, Viger-Denonville and Blue Lagoon spa, 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 Changes in the purchase price of electricity upon renewal of a PPA
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, royalties and cost of power (if applicable); these are predictable and relatively fixed, varying mainly with inflation (except for maintenance expenditures and cost of power). 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 Dokie, East Toba, Flat Top, Jimmie Creek, Kokomo, Montrose Creek, Shannon, Spartan, Umbata Falls, Viger-Denonville and Blue Lagoon spa, 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.	Lower revenues caused mainly by the risks and uncertainties mentioned above Variability of facility performance and related penalties Unexpected maintenance expenditures

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 Outcome of insurance claims
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
Qualification for PTCs For certain Development Projects in the United States, the Corporation has conducted on and off-site activities expected to qualify its Development Projects for PTCs or ITC at the full rate and to obtain tax equity financing on such basis. To assess the potential qualification of a project, the Corporation takes into account the construction work performed and the timing of such work.	Risks related to U.S. Production Tax Credit, Investment Tax Credit, changes in U.S. Corporate Tax Risks related to the project qualification to be eligible to PTCs and ITC Rates and availability of Tax Equity Financing Regulatory and political risks Delays and cost overruns in the design and construction of projects Obtainment of permits
Alterra's Projected Revenues For each facility, expected annual revenues are estimated by multiplying the expected production by the price of the associated power purchase agreement or secured financial power hedge contract. Any pricing mechanisms in these contracts that stipulate price adjustment depending on merchant prices reflect management's current views and expectations, subject to change, of the merchant prices. HS Orka's Projected Revenues are calculated from the total generation produced by the HS Orka assets multiplied by a mix of long- and short-term industrial and retail contracts as well as revenue from hot and cold water sales and other revenues. U.S. dollar and Icelandic króna figures are converted to Canadian dollars at the USD-CAD rate of 1.289 and CAD-ISK rate of 78.35.	Production levels below the expected production caused mainly by the risks and uncertainties mentioned above Unexpected seasonal variability in the production and delivery of electricity Lower than expected inflation rate Change in the purchase price of electricity upon renewal of a PPA Negative change of merchant price of electricity Negative change of the currency exchange rates
Alterra's Projected Gross Adjusted EBITDA and Net Adjusted EBITDA For each facility, annual operating earnings are estimated by subtracting from the estimated Projected Revenues the budgeted annual operating costs, which consist primarily of operators' salaries, insurance premiums, operating and maintenance expenditures, property taxes, royalties and the cost of power (if applicable) these are predictable and relatively fixed, varying mainly with inflation (except for maintenance expenditures and cost of power).	Lower revenues caused mainly by the risks and uncertainties mentioned above Variability of facility performance and related penalties Unexpected maintenance expenditures

ACCOUNTING CHANGES

Revised IFRS affecting the reported financial performance and financial position in the current period

IFRS 2 – Share-based Payments

In June 2016, the IASB issued amendments to IFRS 2 Share-based Payments, clarifying how to account for certain types of share-based payment transactions. The amendments provide requirements on the accounting for: the effects of vesting and non-vesting conditions on the measurement of cash-settled share-based payments; share-based payment transactions with a net settlement feature for withholding tax obligations; and a modification to the terms and conditions of a share-based payment that changes the classification of the transaction from cash-settled to equity-settled. The amendments are effective for annual periods beginning on or after January 1, 2018. The application of the amendments of this standard has not had any material impact on the amounts reported for the current period.

IFRS 15 – Revenue from Contracts with Customers

In May 2014, IASB issued IFRS 15 – Revenue from Contracts with Customers (“IFRS 15”). This standard replaces IAS 11 Construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfers of Assets from Customers, and SIC-31 Revenue-Barter Transactions Involving Advertising Services. IFRS 15 applies to all contracts with customers except those that are within the scope of other IFRSs. IFRS 15 is effective for annual periods commencing on or after January 1, 2018. The application of this standard has not had any material impact on the amounts reported for the current period.

Retrospective application of IFRS 9 (2014) Financial Instruments

In July 2014, the IASB issued the complete IFRS 9 (2014), Financial Instruments ("IFRS 9 (2014)"). IFRS 9 (2014) differs in some regards from IFRS 9 (2013) which the Corporation early adopted effective October 1, 2014. IFRS 9 (2014) includes updated guidance on the classification and measurement of financial assets. The final standard also amends the impairment model by introducing a new expected credit loss model for calculating impairment. The mandatory effective date of IFRS 9 (2014) is for annual periods beginning on or after January 1, 2018, and must be applied retrospectively with some exemptions. The application of this standard had an impact on the amounts reported for the current period.

A clarification to IFRS 9 was released in October 2017 related to the treatment of a modification of a financial liability that does not result in the derecognition of the financial liability. The amortised cost of the financial libailty is recalculated using the modified cash flows and the original effective interest rate. Any change in the amortised cost is recognised in the statement of earnings in revenue or expense on the date of the modification or at the date of the application of IFRS 9 (2014). This change is required to be applied retrospectively.

The following changes shows the effects of the retrospective application to the modification of the Montagne-Sèche, L.P. debt in 2014 and the Stardale L.P. debt in 2016:

	As presented on January 1,2017	Application of IFRS 9 (2014)	Restated balance as of January 1, 2017
Long-term debt	2,507,236	(8,980)	2,498,256
Deferred tax liabilities	176,965	2,403	179,368
Deficit	(601,157)	6,577	(594,580)

	As presented on December 31, 2017	Application of IFRS 9 (2014)	Restated balance as of December 31, 2017
Long-term debt	3,047,583	(8,104)	3,039,479
Deferred tax liabilities	215,593	2,168	217,761
Deficit	(651,233)	5,936	(645,297)

	Year ended December 31, 2017	Application of IFRS 9 (2014)	Restated balance for the year ended December 31, 2017
Finance costs	146,766	876	147,642
Deferred income taxes expenses	3,154	(235)	2,919

	Three months ended March 31, 2017	Application of IFRS 9 (2014)	Restated balance for the period ended March 31, 2017
Finance costs	29,297	221	29,518
Deferred income taxes expenses	(338)	(59)	(397)

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

IFRS Issued but Not Yet Effective

IFRS 16 – Leases (IFRS 16)

On January 13, 2016, the IASB issued IFRS 16 that provides a comprehensive model for the identification of lease arrangements and their treatment in the financial statements of both lessees and lessors. It supersedes IAS 17 Leases and its associated interpretive guidance. Significant changes were made to lessee accounting with the distinction between operating and finance leases removed and assets and liabilities recognized in respect of all leases (subject to limited exceptions for short-term leases and leases of low value assets). In contrast, IFRS 16 does not include significant changes to the requirements for lessors. IFRS 16 is effective January 1, 2019, with earlier application permitted. Employees of the Corporation took training courses in order to start evaluating the impact this standard is expected to have on its consolidated financial statements. Identification of the leases to which this standard might apply has begun.

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

In accordance with Regulation 52-109 respecting 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 they have designed, or caused it 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 made known to the President and Chief Executive Officer and the Chief Financial Officer by others, particularly during the period in which the interim 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 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.

There were no significant weakness relating to the design of DC&P as at March 31, 2018. Moreover, there were no material weakness relating to the design of ICFR as at March 31, 2018.

During the period beginning on January 1, 2018 and ended on March 31, 2018, there was no change in the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

The President and Chief Executive Officer and the Chief Financial Officer have also limited the scope of the Corporation's design of DC&P and ICFR to exclude the controls, policies and procedures of Energies du Plateau Central (Rougemont-1), Energies du Plateau Central 2 (Rougemont-2), Energie du Rechet (Vaite), Éole de Plan Fleury, Les Renardières and the Alterra Power Group Entities (collectively "entities excluded from the Corporation's control policies and procedures"). The evaluation of the design and the operating effectiveness of the DC&P and ICFR for these entities will be completed in the 12 months following their dates of acquisition. A summary of the financial information about the entities excluded is presented in the "Entities Excluded From the Corporation's Control Policies and Procedures" section of this MD&A.

SUBSEQUENT EVENTS

Petition filed for permission to appeal on water rights

On January 14, 2014, Harrison Hydro Project Inc., Fire Creek Project Limited Partnership, Lamont Creek Project Limited Partnership, Stokke Creek Project Limited Partnership, Tipella Creek Project Limited Partnership and Upper Stave Project Limited Partnership (the "Appellants") filed appeals with the Environmental Appeal Board challenging a determination by the Comptroller of Water Rights respecting the water rental rates to be charged under the Water Act (R.S.B.C. 1996, c. 483) in respect of the Fire Creek Facility, Lamont Creek Facility, Stokke Creek Facility, Tipella Creek Facility and Upper Stave River Facility. On December 8, 2015, the Environmental Appeal Board Decision issued its decision rejecting the appeal. On January 20, 2016, an application for judicial review was filed to the British Columbia Supreme Court ("BCSC"). On February 27, 2017, the BCSC declined to set aside the Environmental Appeal Board Decision. On March 21, 2017, the Appellants filed an appeal of the BCSC decision and on February 8, 2018, in a split decision, the British Columbia Court of Appeal refused to set aside the BCSC decision. The Appellants have filed a petition for permission to appeal to the Supreme Court of Canada on April 3, 2018. The outcome of the judicial review could affect the expenses of these entities on an annual basis going forward which would represent approximately $1.6 million aggregate annual increase for water rights. The amount for such potential increase water rights rentals was recorded in the years 2013, 2014, 2015, 2016 and 2017 results of the Corporation, which owns a 50.0024% indirect interest in those facilities.

In addition, on March 23, 2017, the Comptroller of the Water Rights issued adjusted rental statements to the Appelants for years 2011 and 2012 for an amount of $3.3 million in aggregate. The amount claimed was paid under protest and the Appelants have filed a Notice of Appeal of that decision to the Environmental Board of Appeal, which is stayed until the British Columbia Court of Appeal appeal mentioned in the preceding paragraph is resolved.

Electricity purchase agreements renewed with BC Hydro
On April 16, 2018, Innergex announced the renewal of the electricity purchase agreement for the Brown Lake hydro facility. The renewed agreement is for a 40-year term and is effective as of April 1, 2018. The agreement is subject to approval by the British Columbia Utilities Commission.

On April 16, 2018, Innergex and Sekw'el'was Cayoose Creek Band announced the renewal of the electricity purchase agreement for the Walden North hydro facility. The renewed agreement is for a 40-year term and is effective as of April 1, 2018. The agreement is subject to approval by the British Columbia Utilities Commission.

First Court rules in favor of HS Orka
In February 2016, HS Orka issued a legal letter to HS Veitur hf demanding full payment of the long-term receivable in relation to the shared pension liability. This was following receipt of a termination notice by HS Veitur of an agreement regarding payments of the pension liability, sent on December 31, 2015. The two companies had reached an agreement in 2011 on HS Veitur's share and HS Orka considers its claim on the basis of that agreement to be fully valid. Negotiations have not settled the matter. The court proceedings took place in March 2018. On April 17, 2018, the First Court of Iceland ruled in favor of HS Orka. HS Veitur has 30 days from April 17, 2018 to file an appeal to the Supreme Court. A claim for $9.9 million was filed and is included in accounts receivable on the balance sheet.

Extension of foreign exchange forward contracts
On April 23, 2018, the Corporation extended all its foreign exchange forward contracts that hedge its exposure to foreign exchange rate on its investment in France. The contracts have been extended for a period of two years following their original expiry date ranging from April 2018 to August 2019.

Contracts	Maturity	Early termination option	Notional Amounts April 23, 2018
Contracts used to hedge the foreign exchange risk			
Foreign exchange forwards amortizing until 2041, allowing translation at a fixed rate of CAD 1.7332/Euro (before 1.7575/Euro)	2020 (before 2018)	none	159,344
Foreign exchange forwards amortizing until 2042, allowing translation at a fixed rate of CAD 1.7340/Euro (before 1.7588/Euro)	2020 (before 2018)	none	49,957
Foreign exchange forwards amortizing until 2041, allowing translation at a fixed rate of CAD 1.6850/Euro (before 1.7150)	2021 (before 2019)	none	111,945
Foreign exchange forwards amortizing until 2043, allowing translation at a fixed rate of CAD 1.7654/Euro (before 1.7890)	2021 (before 2019)	none	167,963
Foreign exchange forwards amortizing until 2043, allowing translation at a fixed rate of CAD 1.7804/Euro (before 1.8011)	2021 (before 2019)	none	80,941

Power purchase agreement signed for a wind project in Texas, USA
On May 7, 2018, Innergex announced that it has signed a 12-year power purchase agreement for 300 MW of wind energy from its 350 MW Foard City development project. Sales under the power purchase agreement will start upon the facility reaching commercial operation. The project located in Texas, USA, has also executed an interconnection agreement with Electric Transmission Texas, LLC. On-site activities intended to qualify the Foard City wind project for US renewable tax incentives (PTCs) were performed since 2016. Full notice to proceed with construction is expected to be issued in the fourth quarter of 2018 to achieve commercial operation in the third quarter of 2019.

Acquisition of remaining interests in three hydro facilities
On May 15, 2018, Innergex announced that it has acquired Ledcor Power Ltd,'s 33.3% interest in Creek Power Inc., a company that indirectly owns the Fitzsimmons Creek (7.5 MW), Boulder Creek (25.3 MW) and Upper Lillooet River (81.4 MW) hydro facilities located in British Columbia as well as a portfolio of prospective projects. Innergex already owned the other 67.7%

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

interest in Creek Power Inc. Innergex also owned all the preferred equity for an amount of $98.4 million bearing an annualized after-tax return of 12.9%.

Partnership and acquisition in Chile

On May 15, 2018, Innergex and Energía Llaima, a renewable energy company located in Chile, are pleased to announce that they have been selected in a bid process to acquire in partnership the Duqueco hydro project (140 MW) which includes two hydro facilities in Chile. The acquisition is subject to certain regulatory approvals in Chile and to reaching a final partnership agreement between the parties. In addition, Innergex has signed an exclusivity agreement with Energía Llaima for a joint venture partnership to acquire a 50% stake in the company. Final agreements should be reached in the coming weeks in respect to this venture.

The Duqueco hydro project includes two hydro facilities commissioned in 2001, Peuchen (85 MW) and Mampil (55 MW). Innergex is expecting an Adjusted EBITDA of approximately US$21 million ($26.8 million) annually for the Duqueco project. The purchase price, net of an estimated US$10 million ($12.8 million) of cash, is approximately US$210 million ($268 million), subject to certain adjustments and a financing of US$140 million ($178.8 million) is to be granted by a South America bank, Itaú, to cover a portion of the purchase price. Innergex's net share of the remaining purchase price will amount to about US $80 million ($102.2 million). In addition, the Corporation made a deposit to secure financing of US$10 million ($12.8 million). Both amounts will be paid through available funds under its corporate revolving credit facility.

Energía Llaima owns interest in two facilities in operations, a run-of-river hydro facility (12 MW) and a solar thermal facility (34 MW), two run-of-river hydro facilities in development (125 MW) and other early development stage projects. Upon signing a final partnership agreement, Innergex would own 50% of Energía Llaima for a total commitment of US$110 million ($140.5 million) to be invested in the next three years. In addition to the investment in the Duqueco project, Innergex will invest an additional US$10 million ($12.8 million) in Energía Llaima to contribute to its working capital. With these investments, Innergex's commitment would almost be reached.

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS

	Notes	Three months ended March 31 2018	2017 (Restated Note 2.2)
Revenues		117,881	74,527
Expenses			
Operating	4	25,972	16,089
General and administrative		7,658	4,578
Prospective projects		4,908	2,918
Earnings before finance costs, income taxes, depreciation, amortization, other net expenses (revenues), share of earnings of joint ventures and associates and unrealized net loss (gain) on financial instruments		79,343	50,942
Finance costs	5	45,671	29,518
Other net expenses (revenues)	6	2,188	(360)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and associates and unrealized net loss (gain) on derivative financial instruments		31,484	21,784
Depreciation	4,10	28,538	21,817
Amortization	4	10,634	7,765
Share of earnings of joint ventures and associates	7	(3,096)	(715)
Unrealized net loss (gain) on financial instruments	8	12,143	(5,075)
Loss before income taxes		(16,735)	(2,008)
(Recovery of) income taxes expenses			
Current		2,538	885
Deferred		(4,685)	(397)
		(2,147)	488
Net loss		(14,588)	(2,496)
Net loss attributable to:			
Owners of the parent		(6,617)	2,294
Non-controlling interests		(7,971)	(4,790)
		(14,588)	(2,496)
Weighted average number of common shares outstanding (in 000s)	9	122,593	108,341
Basic net (loss) earnings per share ($)	9	(0.07)	0.01
Diluted weighted average number of common shares outstanding (in 000s)	9	123,312	109,295
Diluted net (loss) earnings per share ($)	9	(0.07)	0.01

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

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Notes	Three months ended March 31 2018	2017 (Restated Note 2.2)
Net loss		(14,588)	(2,496)
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:			
Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries		26,554	(17)
Related deferred tax		(390)	—
Foreign exchange (loss) gain on the designated hedges on the investments in self-sustaining foreign subsidiaries		(1,997)	291
Related deferred tax		692	(76)
Change in fair value of hedging instruments		3,659	(895)
Related deferred tax		(847)	240
Share of change in fair value of hedging instruments of joint ventures and associates		(7,935)	—
Related deferred tax		1,125	—
Share of non-controlling interests in:			
Foreign exchange gain on translation of self-sustaining foreign subsidiaries		16,158	32
Foreign exchange (loss) gain on the designated hedges on the investments in self-sustaining foreign subsidiaries		(743)	79
Change in fair value of hedging instruments		8	(26)
Related deferred tax		(108)	2
Items of comprehensive income (loss) that will not be subsequently reclassified to earnings:			
Defined benefit plan actuarial losses		(11)	—
Related deferred tax		2	—
Other comprehensive income (loss)		36,167	(370)
Total comprehensive income (loss)		21,579	(2,866)
Other comprehensive income (loss) attributable to:			
Owners of the parent		20,852	(457)
Non-controlling interests		15,315	87
		36,167	(370)
Total comprehensive income (loss) attributable to:			
Owners of the parent		14,235	1,837
Non-controlling interests		7,344	(4,703)
		21,579	(2,866)

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

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	Notes	March 31, 2018	December 31, 2017 (Restated Note 2.2)
ASSETS			
Current assets			
Cash and cash equivalents		73,694	61,914
Restricted cash and short-term investments		74,453	58,676
Accounts receivable		79,092	87,500
Derivative financial instruments	8	3,521	5,416
Prepaid and others		9,313	8,104
		240,073	221,610
Non-current assets			
Reserve accounts		51,786	49,970
Property, plant and equipment	10	3,723,494	3,188,238
Intangible assets		858,567	654,081
Project development costs		40,970	—
Investments in joint ventures and associates	7	450,245	11,011
Derivative financial instruments	8	7,182	9,558
Deferred tax assets		38,154	11,873
Goodwill		100,144	38,580
Other long-term assets		22,913	5,535
		5,533,528	4,190,456

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

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	Notes	March 31, 2018	December 31, 2017 (Restated Note 2.2)
LIABILITIES			
Current liabilities			
Dividends payable to shareholders		23,980	19,406
Accounts payable and other payables		111,287	91,032
Income tax payable		5,156	3,282
Derivative financial instruments	8	44,424	22,749
Current portion of long-term debt	11	108,416	109,875
Current portion of other liabilities		1,663	500
		294,926	246,844
Non-current liabilities			
Derivative financial instruments	8	86,850	54,494
Long-term debt	11	3,522,017	3,039,479
Other liabilities		132,493	79,507
Liability portion of convertible debentures		96,592	96,246
Deferred tax liabilities		330,688	217,761
		4,463,566	3,734,331
SHAREHOLDERS' EQUITY			
Common share capital	12	335,593	2,867
Contributed surplus from reduction of capital on common shares		933,037	939,047
Preferred shares		131,069	131,069
Share-based payment		1,734	1,713
Equity portion of convertible debentures		1,877	1,877
Deficit		(679,351)	(645,297)
Accumulated other comprehensive income		30,781	9,929
Equity attributable to owners		754,740	441,205
Non-controlling interests		315,222	14,920
Total shareholders' equity		1,069,962	456,125
		5,533,528	4,190,456

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Equity attributable to owners									
For the three-month period ended March 31, 2018	Common shares capital account	Contributed surplus from reduction of capital on common shares	Preferred shares	Share-based payment	Equity portion of convertible debentures	Deficit	Accumulated other comprehensive income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2018 (Restated Note 2.2)	2,867	939,047	131,069	1,713	1,877	(645,297)	9,929	441,205	14,920	456,125
Net loss						(6,617)		(6,617)	(7,971)	(14,588)
Other items of comprehensive income							20,852	20,852	15,315	36,167
Total comprehensive (loss) income	—	—	—	—	—	(6,617)	20,852	14,235	7,344	21,579
Common shares issued on February 6, 2018 (Note 3)	330,607							330,607		330,607
Business acquisition (Note 3)								—	296,534	296,534
Common shares issued through dividend reinvestment plan	1,191							1,191		1,191
Share buyback of common shares	(20)	(6,010)				(3,457)		(9,487)		(9,487)
Share-based payment				21				21		21
Shares vested - PSP plan	948							948	—	948
Distributions to non-controlling interests								—	(3,794)	(3,794)
Investments from non-controlling interests								—	218	218
Dividends declared on common shares						(22,495)		(22,495)		(22,495)
Dividends declared on preferred shares						(1,485)		(1,485)		(1,485)
Balance March 31, 2018	335,593	933,037	131,069	1,734	1,877	(679,351)	30,781	754,740	315,222	1,069,962

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the three-month period ended March 31, 2017	Equity attributable to owners									
	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, 2017 (Restated Note 2.2)	162,862	775,413	131,069	2,199	1,877	(594,580)	(1,743)	477,097	14,712	491,809
Net earnings (loss) (Restated Note 2.2)						2,294		2,294	(4,790)	(2,496)
Other items of comprehensive (loss) income							(457)	(457)	87	(370)
Total comprehensive income (loss)	—	—	—	—	—	2,294	(457)	1,837	(4,703)	(2,866)
Common shares issued through dividend reinvestment plan	2,695							2,695		2,695
Share-based payment				24				24		24
Distributions to non-controlling interests								—	(1,000)	(1,000)
Investments from non-controlling interests								—	2,090	2,090
Dividends declared on common shares						(17,882)		(17,882)		(17,882)
Dividends declared on preferred shares						(1,485)		(1,485)		(1,485)
Balance March 31, 2017	165,557	775,413	131,069	2,223	1,877	(611,653)	(2,200)	462,286	11,099	473,385

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

	Notes	Three months ended March 31 2018	2017 (Restated Note 2.2)
OPERATING ACTIVITIES			
Net loss		(14,588)	(2,496)
Items not affecting cash:			
Depreciation		28,538	21,817
Amortization		10,634	7,765
Share of earnings of joint ventures and associates		(3,096)	(715)
Unrealized net loss (gain) on financial instruments		12,143	(5,075)
Inflation compensation interest	5	1,709	875
Amortization of financing fees	5	984	761
Accretion of long-term debt and convertible debentures	5	543	422
Accretion expenses on other liabilities	5	555	232
Amortization of below market contracts	6	(460)	—
Actuarial gain from pension fund		(44)	—
Share-based payment		21	24
Deferred income taxes		(4,685)	(397)
Others		(61)	(35)
Interest on long-term debt and convertible debentures	5	41,170	26,979
Interest paid		(35,930)	(25,218)
Gain on contingent considerations	6	—	(257)
Distributions received from joint ventures and associates		1,386	290
Current income tax expense		2,538	885
Net income taxes paid		(837)	(674)
Effect of exchange rate fluctuations		(1,019)	905
		39,501	26,088
Changes in non-cash operating working capital items	13	10,768	(10,307)
		50,269	15,781
FINANCING ACTIVITIES			
Dividends paid on common shares		(16,729)	(14,614)
Dividends paid on preferred shares		(1,485)	(1,485)
Distributions to non-controlling interests		(1,259)	(1,000)
Investments from non-controlling interests		218	2,090
Increase of long-term debt		302,086	88,856
Repayment of long-term debt		(166,104)	(19,119)
Payment of deferred financing costs		(2,614)	(476)
Payment of other liabilities		—	(246)
Payment for buyback of common shares		(9,487)	—
		104,626	54,006

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

		Three months ended March 31	
		2018	2017
	Notes		(Restated Note 2.2)
INVESTING ACTIVITIES			
Cash acquired on business acquisitions	3	7,113	4,989
Business acquisitions	3	(120,258)	(35,061)
(Increase) decrease of restricted cash and short-term investments		(10,498)	5,379
Net funds (invested into) withdrawn from the reserve accounts		(1,388)	498
Additions to property, plant and equipment		(17,638)	(38,421)
Additions intangible assets		(1,672)	—
Reductions of (additions to) other long-term assets		184	(40)
Proceeds from disposal of property, plant and equipment		—	1
		(144,157)	(62,655)
Effects of exchange rate changes on cash and cash equivalents		1,042	(986)
Net increase in cash and cash equivalents		11,780	6,146
Cash and cash equivalents, beginning of period		61,914	56,227
Cash and cash equivalents, end of period		73,694	62,373
Cash and cash equivalents is comprised of:			
Cash		70,254	60,109
Short-term investments		3,440	2,264
		73,694	62,373

Additional information is presented in Note 13.

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

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

DESCRIPTION OF BUSINESS

Innergex Renewable Energy Inc. ("Innergex" or 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, geothermal power projects and solar photovoltaic sectors. The head office of the Corporation is located at 1225 St-Charles Street West, 10th floor, Longueuil, Qc, J4K 0B9, Canada.

These unaudited condensed consolidated interim financial statements were approved by the Board of Directors on May 15, 2018.

The Corporation's revenues are variable with each season and 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. 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 unaudited condensed consolidated interim 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. Except as described below, the same accounting policies and methods of application as described in the Corporation's latest annual report have been used. However, these unaudited condensed consolidated interim 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 unaudited condensed consolidated interim 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 IFRS

2.1 Revised IFRS affecting the reported financial performance and financial position in the current period

IFRS 2- Share-based Payments

In June 2016, the IASB issued amendments to IFRS 2 Share-based Payments, clarifying how to account for certain types of share-based payment transactions. The amendments provide requirements on the accounting for: the effects of vesting and non-vesting conditions on the measurement of cash-settled share-based payments; share-based payment transactions with a net settlement feature for withholding tax obligations; and a modification to the terms and conditions of a share-based payment that changes the classification of the transaction from cash-settled to equity-settled. The amendments are effective for annual periods beginning on or after January 1, 2018. The application of the amendments of this standard has not had any material impact on the amounts reported for the current period.

IFRS 15- Revenue from Contracts with Customers

In May 2014, IASB issued IFRS 15 – Revenue from Contracts with Customers ("IFRS 15"). This standard replaces IAS 11 Construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the Construction of Real Estate, IFRIC 18 Transfers of Assets from Customers, and SIC-31 Revenue-Barter Transactions Involving Advertising Services. IFRS 15 applies to all contracts with customers except those that are within the scope of other IFRSs. IFRS 15 is effective for annual periods commencing on or after January 1, 2018. The application of this standard has not had any material impact on the amounts reported for the current period.

2.2 Retrospective application of IFRS 9 (2014) Financial Instruments

In July 2014, the IASB issued the complete IFRS 9 (2014), Financial Instruments ("IFRS 9 (2014)"). IFRS 9 (2014) differs in some regards from IFRS 9 (2013) which the Corporation early adopted effective October 1, 2014. IFRS 9 (2014) includes updated guidance on the classification and measurement of financial assets. The final standard also amends the impairment model by introducing a new expected credit loss model for calculating impairment. The mandatory effective date of IFRS 9 (2014) is for annual periods beginning on or after January 1, 2018, and must be applied retrospectively with some exemptions. The application of this standard had an impact on the amounts reported for the current period.

A clarification to IFRS 9 was released in October 2017 related to the treatment of a modification of a financial liability that does not result in the derecognition of the financial liability. The amortised cost of the financial liabilty is recalculated using the modified cash flows and the original effective interest rate. Any change in the amortised cost is recognised in the statement of earnings in revenue or expense on the date of the modification or at the date of the application of IFRS 9 (2014). This change is required to be applied retrospectively.

The following changes shows the effects of the retrospective application to the modification of the Montagne-Sèche, L.P. debt in 2014 and the Stardale L.P. debt in 2016:

	As presented on January 1,2017	Application of IFRS 9 (2014)	Restated balance as of January 1, 2017
Long-term debt	2,507,236	(8,980)	2,498,256
Deferred tax liabilities	176,965	2,403	179,368
Deficit	(601,157)	6,577	(594,580)

	As presented on December 31, 2017	Application of IFRS 9 (2014)	Restated balance as of December 31, 2017
Long-term debt	3,047,583	(8,104)	3,039,479
Deferred tax liabilities	215,593	2,168	217,761
Deficit	(651,233)	5,936	(645,297)

	Year ended December 31, 2017	Application of IFRS 9 (2014)	Restated balance for the year ended December 31, 2017
Finance costs	146,766	876	147,642
Deferred income taxes expenses	3,154	(235)	2,919

	Three months ended March 31, 2017	Application of IFRS 9 (2014)	Restated balance for the period ended March 31, 2017
Finance costs	29,297	221	29,518
Deferred income taxes expenses	(338)	(59)	(397)

2.3 IFRS issued but not yet effective

IFRS 16 Leases (IFRS 16)

On January 13, 2016, the IASB issued IFRS 16 that provides a comprehensive model for the identification of lease arrangements and their treatment in the financial statements of both lessees and lessors. It supersedes IAS 17 Leases and its associated interpretive guidance. Significant changes were made to lessee accounting with the distinction between operating and finance leases removed and assets and liabilities recognized in respect of all leases (subject to limited exceptions for short-term leases and leases of low value assets). In contrast, IFRS 16 does not include significant changes to the requirements for lessors. IFRS 16 is effective January 1, 2019, with earlier application permitted. Employees of the Corporation took training courses in order to start evaluating the impact this standard is expected to have on its consolidated financial statements. Identification of the leases to which this standard might apply has begun.

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

3. BUSINESS ACQUISITIONS

a. Acquisition of Alterra Power Corp

On February 6, 2018, Innergex acquired all of the issued and outstanding common shares of Alterra Power Corp ("Alterra") .

The Innergex common shares issuable to Alterra shareholders with the transaction represent an ownership of approximately 18% of the combined corporation. One member of the Board of Directors of Alterra joined the Board of Directors of Innergex at the closing of the Transaction.

The total purchase price for Alterra is $450,865 comprised of a cash consideration of $120,258 and the issuance of 24,327,225 common shares of the Corporation at a price of $13.59 for a value of $330,607.

Alterra and its subsidiaries are engaged in the development, construction and operation of renewable energy projects. As at February 6, 2018, Alterra's operating facilities consisted of a 53.9% net interest in two geothermal power plants in Iceland ("Svartsengi" and "Reykjanes"), and a 30% interest in Blue Lagoon, which operates the Blue Lagoon geothermal spa in Iceland ("Blue Lagoon"). It also consisted of a 40% net interest in two run of river hydro power plants ("Toba Montrose"), a 25.5% net interest in a wind farm ("Dokie"), a 51% net interest in a run of river hydro power plant ("Jimmie Creek") in British Columbia, a 50% net interest in the sponsor equity of a wind farm ("Shannon") located in Texas, a 90% net interest in the sponsor equity of a solar project ("Kokomo") located in Indiana and a 100% net interest in the sponsor equity of a solar project ("Spartan") located in Michigan.

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. Alterra added an additional gross installed capacity of 2,896 MW to the Corporation's portfolio.

The following table reflects the preliminary acquisition accounting and the fair value of the net assets acquired:

	Preliminary acquisition accounting
Cash and cash equivalents	7,113
Restricted cash and short-term investments	4,213
Accounts receivable	17,774
Prepaid and others	3,895
Property, plant and equipment	487,607
Intangible assets	191,548
Project development costs	39,304
Investments in joint ventures and associates	430,709
Goodwill	59,923
Other long term assets	16,281
Accounts payable and other payables	(39,610)
Long-term debt	(305,045)
Derivative financial instruments	(31,194)
Other liabilities	(48,168)
Deferred tax liabilities	(86,951)
Non controlling interests	(296,534)
Net assets acquired	450,865

The acquisition accounting remains subject to the completion of the valuation of working capital adjustments, property, plant and equipment, intangible assets, project development costs, investments in joint ventures and associates, goodwill, long-term debt, deferred tax liabilities and consequential adjustments.

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

If the acquisition had taken place on January 1, 2018, the consolidated revenues and net loss for the three-month period ended March 31, 2018 would have been $129,286 and $37,179 respectively.

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

The amounts of revenues and net loss of the facilities since February 6, 2018 included in the consolidated statement of earnings are $16,417 and $4,474 respectively for the 54 days ended March 31, 2018.

4. OPERATING EXPENSES

	Three months ended March 31	
	2018	2017
Salaries	1,308	1,277
Insurance	1,180	877
Operation and maintenance	17,142	5,550
Property taxes and royalties	6,342	8,385
	25,972	16,089

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

5. FINANCE COSTS

	Three months ended March 31	
	2018	2017
		Restated (Note 2.2)
Interest on long-term debt and on convertible debentures	41,170	26,979
Inflation compensation interest	1,709	875
Amortization of financing fees	984	761
Accretion of long-term debt and convertible debentures	543	422
Accretion expenses on other liabilities	555	232
Others	710	249
	45,671	29,518

6. OTHER NET EXPENSES (REVENUES)

	Three months ended March 31	
	2018	2017
Transaction costs	5,015	683
Realized gain on derivative financial instruments	(828)	—
Realized gain on foreign exchange	(814)	(67)
Gain on contingent considerations	—	(257)
Other net revenues	(725)	(719)
Amortization of below market contract	(460)	—
	2,188	(360)

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

7. INVESTMENTS IN JOINT VENTURES AND ASSOCIATES

7.1 Details of material joint ventures and associates

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the joint arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

Associates are those entities in which the Corporation has significant influence, but not control, over the financial and operating policies. Significant influence is presumed to exist when the Corporation holds between 20% and 50% of the voting power of another entity.

Joint ventures and associates are accounted for using the equity method in these consolidated financial statements.

Details of the Corporation's material joint ventures and associates at the end of the reporting periods are as follows:

Joint ventures and associates	Principal activity	Place of creation and principal place of operation	Proportion of ownership interest and voting rights held by the Corporation	
			March 31, 2018	December 31, 2017
Toba Montrose	Own and operate two hydroelectric facilities	British Columbia	40%	—
Shannon	Own and operate a wind farm	Texas	50% [1]	—
Flat top	Own and operate a wind farm	Texas	51% [1]	—
Dokie	Own and operate a wind farm	British Columbia	25.5%	—
Jimmie Creek	Own and operate a hydroelectric facility	British Columbia	50.99%	—
Umbata Falls	Own and operate a hydroelectric facility	Ontario	49%	49%
Viger-Denonville	Own and operate a wind farm	Québec	50%	50%
Spartan	Own and operate a solar facility	Michigan	100% [2]	—
Kokomo	Own and operate a solar facility	Indiana	90% [1]	—
Blue Lagoon	Own and operate a geothermal spa	Iceland	30% [3]	—

1. Ownership interest is in the sponsor equity of Shannon, Flat Top and Kokomo
2. Ownership interest is 100% of sponsor equity of Spartan, however, joint control exists through the Corporation's tax equity arrangement
3. Ownership interest is through HS Orka hf. (which the Corporation owns 53.9%), which owns a 30% interest in the Blue Lagoon

Carrying amounts of the investments in joint ventures and associates	As at	
Joint ventures and associates	March 31, 2018	December 31, 2017
Toba Montrose	79,884	—
Shannon	56,841	—
Flat top	85,900	—
Dokie	24,362	—
Jimmie Creek	36,290	—
Umbata Falls	9,832	9,688
Viger-Denonville	1,515	1,271
Spartan	3,129	—
Kokomo	1,967	—
Blue Lagoon	150,385	—
Others	140	52
	450,245	11,011

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

The summarized financial information below represents amounts shown in the joint ventures' and associates' financial statements prepared in accordance with IFRS.

Toba Montrose

The Corporation holds a 51% voting interest and a 40% participating economic interest in East Toba and Montrose Creek hydro facilities ("Toba Montrose"). In 2046, the Corporation's economic interest will increase to 51% for no additional consideration and its partner's economic interest will decrease from 60% to 49%.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenue	569
Operating, general and administrative expenses	796
	(227)
Finance costs	3,780
Other net expenses	913
Depreciation and amortization	2,617
Net loss	(7,537)
Other comprehensive loss	(3,239)
Total comprehensive loss	(10,776)

Summary Statements of Financial Position

As at	March 31, 2018
Cash and cash equivalents	10,421
Other current assets	2,716
Current assets	13,137
Non-current assets	679,927
	693,064
Accounts payable and other payables	4,888
Other current liabilities	9,369
Current liabilities	14,257
Non-current liabilities	479,096
Partner's equity	199,711
	693,064

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	March 31, 2018
Net assets of the joint venture	199,711
Proportion of the Corporation's ownership interest in the joint venture	40%
Carrying amount of the Corporation's interest in the joint venture	79,884

Toba Montrose's Debt

At the date of the acquisition of Alterra, Toba Montrose had total loan facilities of $436,589.

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

The debt consists of two credit facilities which were entered into on November 8, 2007. The first is a $370,000, 38-year senior secured credit facility with a fixed interest rate to correspond with the three-year construction period and a repayment period over the 35-year term of the project's PPA with BC Hydro. The interest rate on this credit facility is 6.173% per annum. The second credit facility is a $100,000, 38-year senior secured credit facility with a floating interest rate, to correspond with the three-year construction period and a repayment period over the 35-year term of the project's PPA with BC Hydro. The floating interest rate on this credit facility is based on three month Bankers' Acceptance Rates plus a credit spread of 1.60% per annum. The principal repayments for both debts are set to $6,226 for the twelve month period following March 31, 2018.

Toba Montrose holds an interest rate swap contract which provides for quarterly settlements from November 1, 2010 to June 30, 2045. Pursuant to the interest rate swap agreement, Toba Montrose will receive interest on a notional amount at the three-month Bankers' Acceptance Rate from the counterparty and will pay interest on the notional amount at an interest rate of 5.341% per annum. The notional amount is $92,699 at March 31, 2018 and is reduced in amounts based on the scheduled principal repayments on the floating rate facility over the life of the interest rate swap.

Toba Montrose is subject to certain covenants regarding its loan agreements and as at March 31, 2018 was in compliance with all debt covenants.

Shannon

The Corporation holds a 50% sponsor equity interest in the Shannon wind facility, with the remaining 50% sponsor equity interest and tax equity interest held by third parties.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenue	6,187
Operating, general and administrative expenses	1,526
	4,661
Other net expenses	38
Depreciation and amortization	1,639
Net earnings	2,984
Other comprehensive loss	(10,258)
Total comprehensive loss	(7,274)
Net earnings attributable to:	
Sponsors:	
Innergex	3,333
Other sponsor	3,333
Tax equity investors	(3,682)
	2,984
Total comprehensive loss attributable to:	
Sponsors:	
Innergex	(1,649)
Other sponsor	(1,649)
Tax equity investors	(3,976)
	(7,274)
Distributions received from the joint venture by the Corporation	693

On June 29, 2015 Shannon entered into a long-term power hedge covering the period from June 1, 2016 to May 31, 2029. The power hedge provides for Shannon to receive a fixed dollar per MWh for a fixed quantity of power. Shannon and the Hedge Provider settle net on a monthly basis. The other comprehensive loss consists solely of the effective portion of changes in the fair value of the power hedge.

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

Summary Statements of Financial Position

As at	March 31, 2018
Cash and cash equivalents	4,123
Other current assets	2,431
Current assets	6,554
Non-current assets	355,517
	362,071
Accounts payable and other payables	1,319
Other current liabilities	4,520
Current liabilities	5,839
Non-current liabilities	15,752
Sponsors equity interest	113,681
Tax equity interest	226,799
	362,071

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	March 31, 2018
Net assets of the joint venture attributable to sponsors	113,681
Proportion of the Corporation's ownership interest in the joint venture	50%
Carrying amount of the Corporation's interest in the joint venture	56,841

The results of Shannon are calculated in accordance with the hypothetical liquidation at book value ("HLBV") method which allocates earnings or losses by measuring the distribution amounts that would be due to the members (investors) in a hypothetical liquidation of the entity at the net book value of the underlying assets. The HLBV method is consistent with accounting guidance which prescribes using this method for allocations where disproportionate allocations of cash and tax attributes occur and is the method that most appropriately reflects how an increase or decrease in net assets of the venture will affect cash payments to investors (both sponsors and tax equity investors) over the life of the venture and upon its liquidation.

One of the primary incentives for renewable energy in the United States has been the production tax credits program ("PTC"), whereby corporations that generate electricity from renewable energy sources, including wind, are eligible for tax credits which provide a tax benefit for each unit of generation for the first ten years of the facility's operation (until 2025). The Shannon tax equity investors are allocated a portion of Shannon's taxable income (losses) and PTCs and a portion of the cash generated until they achieve an agreed after-tax investment return (the "Flip Point"). After the Flip Point, the Shannon tax equity investors will be allocated 5% of cash distributions and taxable income (losses), and the sponsors will be allocated 95% of all cash distributions and taxable income (losses).

For the period from February 6, 2018 to March 31, 2018, the wind facility generated approximately $3.5 million of PTCs.

The Tax Equity Investors and Sponsors' taxable income (losses) and PTCs and cash distributions allocations are detailed in the table below. These allocations will change when the Tax Equity Investors reach their expected return.

	Tax Equity Investors	Sponsors
Taxable income (losses) and PTCs	99.0%	1.0%
Cash distributions	64.1%	35.9%

Tax equity investors in US wind projects generally require sponsor guaranties as a condition to their investment. To support the tax equity investment in Shannon, Alterra Power Corp, a subsidiary of Innergex, executed a guarantee indemnifying the tax equity investors against certain breaches of project level representations, warranties and covenants and other events. The Corporation believes these indemnifications cover matters which are substantially under its control, and are very unlikely to occur.

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

Flat Top

The Corporation holds a 51% sponsor equity interest in the Flat Top wind facility, with the remaining 49% sponsor equity interest and tax equity interest held by third parties. The wind farm began commercial operation on March 23, 2018.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenue	359
Operating, general and administrative expenses	401
	(42)
Other net revenues	(3)
Depreciation and amortization	207
Unrealized net loss on derivative financial instruments	4,112
Net loss	(4,358)
Other comprehensive loss	(3,519)
Total comprehensive loss	(7,877)
Net loss attributable to:	
Sponsors:	
Innergex	1,047
Other sponsor	1,006
Tax equity investors	(6,411)
	(4,358)
Total comprehensive loss attributable to:	
Sponsors:	
Innergex	(773)
Other sponsor	(743)
Tax equity investors	(6,361)
	(7,877)

On May 24, 2017 Flat Top entered into a long-term power hedge covering the period from August 1, 2018 to July 31, 2031. The power hedge provides for the Corporation to receive a fixed dollar per MWh for a fixed quantity of power. Flat Top and the Hedge Provider settle net on a monthly basis. The other comprehensive income consists solely of the effective portion of changes in the fair value of the power hedge.

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

Summary Statements of Financial Position

As at	March 31, 2018
Cash and cash equivalents	28,870
Other current assets	1,220
Current assets	30,090
Non-current assets	447,319
	477,409
Accounts payable and other payables	12,380
Other current liabilities	16,505
Current liabilities	28,885
Non-current liabilities	12,239
Sponsors equity interest	168,432
Tax equity interest	267,853
	477,409

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	March 31, 2018
Net assets of the joint venture attributable to sponsors	168,432
Proportion of the Corporation's ownership interest in the joint venture	51%
Carrying amount of the Corporation's interest in the joint venture	85,900

As of the date of the acquisition of Alterra, Flat Top had total construction loan of US$211,082.

On March 23, 2018, Flat Top achieved commercial operations and concurrently Flat Top's US$216,678 construction loan was retired by a US$211,300 tax equity investment, a US$2,902 security deposit placed by Alterra on July 19, 2017 for future capital contributions and further capital contributions from the other sponsor.

The results of Flat Top are calculated in accordance with the HLBV method.

Flat Top is part of the PTC program in the United States which provide a tax benefit for each unit of generation for the first ten years of the facility's operation (until 2028). The Flat Top tax equity investors are allocated a portion of Flat Top's taxable income (losses) and PTCs and a portion of the cash generated until they achieve an agreed after-tax investment return (the "Flip Point"). After the Flip Point, the Flat Top tax equity investors will be allocated 5% of cash distributions and taxable income (losses), and the sponsors will be allocated 95% of all cash distributions and taxable income (losses).

For the period from March 23, 2018 to March 31, 2018, the wind facility generated approximately $0.6 million of PTCs.

The Tax Equity Investors and Sponsors' taxable income (losses) and PTCs and cash distributions allocations are detailed in the table below. These allocations will change when the Tax Equity Investors reach their expected return.

	Tax Equity Investors	Sponsors
Taxable income (losses) and PTCs	99.00%	1.00%
Cash distributions	21.97%	78.03%

Tax equity investors in US wind projects generally require sponsor guaranties as a condition to their investment. To support the tax equity investment in Flat Top, Alterra Power Corp, a subsidiary of Innergex, executed a guarantee indemnifying the tax equity investors against certain breaches of project level representations, warranties and covenants and other events. The Corporation believes these indemnifications cover matters which are substantially under its control, and are very unlikely to occur.

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

Dokie

The Corporation holds a 25.5% interest in the Dokie wind facility.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenue	5,089
Operating, general and administrative expenses	1,073
	4,016
Finance costs	1,699
Other net expenses	332
Depreciation and amortization	1,997
Net loss	(12)

Summary Statements of Financial Position

As at	March 31, 2018
Cash and cash equivalents	7,227
Other current assets	5,984
Current assets	13,211
Non-current assets	233,532
	246,743
Accounts payable and other payables	2,077
Other current liabilities	—
Current liabilities	2,077
Non-current liabilities	149,128
Partner's equity	95,538
	246,743

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	March 31, 2018
Net assets of the joint venture	95,538
Proportion of the Corporation's ownership interest in the joint venture	25.5%
Carrying amount of the Corporation's interest in the joint venture	24,362

Dokie's Debt

As of the date of the acquisition of Alterra, Dokie had total loan facilities of $149,265.

Dokie executed a credit agreement on December 7, 2009 for a $175,000 loan with an annual fixed interest rate of 7.243% and a maturity date of December 31, 2030. The principal repayments are set to $7,358 for the twelve month period following March 31, 2018.

Dokie is subject to certain covenants regarding its loan agreements and as at March 31, 2018 was in compliance with all debt covenants.

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

Jimmie Creek

The Corporation holds a 50.99% interest in the Jimmie Creek hydro facility.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenue	107
Operating, general and administrative expenses	659
	(552)
Finance costs	1,579
Other net revenues	(235)
Depreciation and amortization	809
Net loss and comprehensive loss	(2,705)

Summary Statements of Financial Position

As at	March 31, 2018
Cash and cash equivalents	3,066
Other current assets	3,057
Current assets	6,123
Non-current assets	234,794
	240,917
Accounts payable and other payables	2,318
Other current liabilities	586
Current liabilities	2,904
Non-current liabilities	166,842
Partner's equity	71,171
	240,917

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	March 31, 2018
Net assets of the joint venture	71,171
Proportion of the Corporation's ownership interest in the joint venture	50.99%
Carrying amount of the Corporation's interest in the joint venture	36,290

Jimmie Creek's Debt
As of the date of the acquisition of Alterra, Jimmie Creek had total loan facilities of $167,558.

Jimmie Creek executed a credit agreement in October 2014 for a $176,450, 42-year senior secured credit facility at a fixed interest rate, which corresponded with the two-year construction period, and a repayment period over the 40-year term (plus final 10% bullet payment due on maturity) of the Jimmie Creek project's PPA with BC Hydro. The annual interest rate on the loan is fixed at 5.255%. The principal repayments are set to $741 for the twelve month period following March 31, 2018.

Jimmie Creek is subject to certain covenants regarding its loan agreements and as at March 31, 2018 was in compliance with all debt covenants.

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

Umbata Falls

The Corporation holds a 49% interest in the Umbata Falls hydro facility.

Summary Statements of Earnings and Comprehensive Income

	Three months ended March 31	
	2018	2017
Revenue	1,681	2,208
Operating, general and administrative expenses	244	217
	1,437	1,991
Finance costs	569	601
Other net revenues	(17)	(8)
Depreciation and amortization	1,003	1,004
Unrealized net (gain) loss on derivative financial instruments	(411)	33
Net earnings and comprehensive income	293	361

Summary Statements of Financial Position

As at	March 31, 2018	December 31, 2017
Cash and cash equivalents	2,297	1,620
Other current assets	944	1,930
Current assets	3,241	3,550
Non-current assets	59,666	60,658
	62,907	64,208
Accounts payable and other payables	120	198
Other current liabilities	2,561	3,314
Current liabilities	2,681	3,512
Non-current liabilities	40,160	40,924
Partner's equity	20,066	19,772
	62,907	64,208

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	March 31, 2018	December 31, 2017
Net assets of the joint venture	20,066	19,772
Proportion of the Corporation's ownership interest in the joint venture	49%	49%
Carrying amount of the Corporation's interest in the joint venture	9,832	9,688

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

Viger-Denonville

The Corporation holds a 50% interest in the Viger-Denonville wind facility.

Summary Statements of Earnings and Comprehensive Income

	Three months ended March 31	
	2018	2017
Revenue	3,366	3,062
Operating, general and administrative expenses	528	514
	2,838	2,548
Finance costs	818	874
Other net revenues	(16)	(8)
Depreciation and amortization	627	730
Unrealized net gain on derivative financial instruments	(170)	(124)
Net earnings	1,579	1,076
Other comprehensive income (loss)	235	(129)
Total comprehensive income	1,814	947
Distributions received from the joint venture by the Corporation	663	290

Summary Statements of Financial Position

As at	March 31, 2018	December 31, 2017
Cash and cash equivalents	1,462	1,760
Other current assets	1,021	1,245
Current assets	2,483	3,005
Non-current assets	53,196	53,812
	55,679	56,817
Accounts payable and other payables	574	744
Other current liabilities	3,553	3,611
Current liabilities	4,127	4,355
Non-current liabilities	48,521	49,920
Partner's equity	3,031	2,542
	55,679	56,817

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	March 31, 2018	December 31, 2017
Net assets of the joint venture	3,031	2,542
Proportion of the Corporation's ownership interest in the joint venture	50%	50%
Carrying amount of the Corporation's interest in the joint venture	1,515	1,271

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

Spartan

The Corporation owns 100% of the sponsor equity interest in the Spartan solar facility and none of the tax equity interest which is owned by a third party.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenue	209
Operating, general and administrative expenses	41
	168
Finance costs	110
Other net expenses	29
Depreciation and amortization	228
Unrealized net gain on derivative financial instruments	(1)
Net loss	(198)
Other comprehensive income	260
Total comprehensive income	62
Net loss attributable to:	
Sponsor	(30)
Tax equity investor	(168)
	(198)
Total comprehensive income attributable to:	
Sponsor	(27)
Tax equity investor	89
	62

Summary Statements of Financial Position

As at	March 31, 2018
Cash and cash equivalents	38
Other current assets	1,929
Current assets	1,967
Non-current assets	27,615
	29,582
Accounts payable and other payables	362
Other current liabilities	1,462
Current liabilities	1,824
Non-current liabilities	12,458
Sponsor equity interest	3,129
Tax equity interest	12,171
	29,582

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

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	March 31, 2018
Net assets of the joint venture attributable to sponsor	3,129
Proportion of the Corporation's ownership interest in the joint venture	100%
Carrying amount of the Corporation's interest in the joint venture	3,129

As of the date of the acquisition of Alterra, Spartan had total loan facilities of US$10,029.

On December 22, 2017, Spartan entered into a US$10,200, 6 year senior secured term loan with a floating interest rate and a balloon payment based on a 6 year maturity and 20 year amortization. The floating interest rate is based on three month LIBOR plus a spread of 3.5% per annum. Concurrently, Spartan entered into an interest rate swap contract for the estimated operating term to effectively fix the interest rates on the term loan. Pursuant to the interest rate swap agreement, Spartan will receive interest on a notional amount at the three month LIBOR plus a spread of 3.5% per annum from the counterparty and will pay interest on the notional amount at an interest rate of 5.81% per annum. The notional amount is US$10,204 as at March 31, 2018 and is reduced in amounts based on the scheduled principal repayments on the term loan agreement over the life of the interest rate swap.

The principal repayments are set to US$379 for the twelve month period following March 31, 2018.

Spartan is subject to certain covenants regarding its loan agreements and as at March 31, 2018 was in compliance with all debt covenants.

Kokomo

The Corporation holds a 90% sponsor equity interest in the Kokomo solar facility, with the remaining 10% sponsor equity interest and tax equity interest held by third parties.

Summary Statements of Earnings and Comprehensive Income

	Period of 54 days ended March 31, 2018
Revenue	115
Operating, general and administrative expenses	26
	89
Finance costs	62
Other net expenses	14
Depreciation and amortization	111
Net loss	(98)
Other comprehensive income	135
Total comprehensive income	37
Net loss attributable to:	
Sponsors	(15)
Tax equity investor	(83)
	(98)
Total comprehensive income attributable to:	
Sponsors	(15)
Tax equity investor	52
	37

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

Summary Statements of Financial Position

As at	March 31, 2018
Cash and cash equivalents	65
Other current assets	73
Current assets	138
Non-current assets	13,021
	13,159
Accounts payable and other payables	143
Other current liabilities	413
Current liabilities	556
Non-current liabilities	5,687
Sponsors equity interest	2,186
Tax equity interest	4,730
	13,159

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	March 31, 2018
Net assets of the joint venture attributable to sponsors	2,186
Proportion of the Corporation's ownership interest in the joint venture	90%
Carrying amount of the Corporation's interest in the joint venture	1,967

As of the date of the acquisition of Alterra, Kokomo had total loan facilities of US$4,489.

On December 30, 2016, Kokomo entered into a US$5,000, 10 year senior secured term loan with a floating interest rate and a balloon payment based on a 10 year maturity and a 18 year amortization. The floating interest rate is based on three month LIBOR plus a spread of 3.5% per annum. Concurrently, Kokomo entered into an interest rate swap contract for the estimated operating term to effectively fix the interest rates on the term loan.

Pursuant to the interest rate swap agreement, Kokomo will receive interest on a notional amount at three month LIBOR plus a spread of 3.5% per annum from the counterparty and will pay interest on the notional amount at the interest rate of 5.35% per annum. The notional amount is US$4,760 as at March 31, 2018 and is reduced in amounts based on the scheduled principal repayments on the term loan agreement over the life of the interest rate swap.

The principal repayments are set to US$226 for the twelve month period following March 31, 2018.

Kokomo is subject to certain covenants regarding its loan agreements and as at March 31, 2018 was in compliance with all debt covenants.

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

Blue Lagoon

HS Orka hf ("HS Orka"), holds a 30% interest in Blue Lagoon hf, which operates the Blue Lagoon geothermal spa in Iceland.

Reconciliation of the carrying amount of the interest in the associate recognized in the consolidated financial statements:

As at	March 31, 2018
Opening Balance, January 1, 2018	—
Preliminary fair value pursuant to acquisition of Alterra	141,135
Share of comprehensive income	2,052
Foreign exchange	7,198
Ending Balance, March 31, 2018	150,385

7.2 Commitments of joint ventures and associates

As at March 31, 2018, the Corporation's share of the expected schedule of commitment payments for joint ventures and associates are as follows:

Years of	Wind Power Generation
2018	4,596
2019	7,067
2020	7,067
2021	7,067
2022	7,067
Thereafter	95,081
Total	127,945

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

8. DERIVATIVE FINANCIAL INSTRUMENTS

As part of the acquisition of Alterra, the Corporation acquired HS Orka which has two power purchase agreements that have embedded derivatives that are accounted for separately from the host contracts. HS Orka signed power sales agreements on power supply until the year 2026 and the sale of power until the year 2019. Payments under the agreements are made in USD and are linked to the price of aluminum. These long-term power sales agreements feature embedded derivatives, the value of which is adjusted upon changes in the future price of aluminum. In evaluating the value of embedded derivatives, generally accepted valuation methods are applied, as the market value is not available. The fair value is based on Level 2 valuation techniques. The fair value of the embedded derivatives are calculated on the basis of the forward price of aluminum. The expected present value of cash flows based on the reporting date is calculated on the basis of the registered forward price of aluminum on the London Metal Exchange (LME) over the remaining lifetime of the contracts. The embedded derivatives are recorded at fair value at inception and at each subsequent reporting period based on the expected present value of cash flows. The fair value change of the embedded derivatives is recognized in earnings or loss. When calculating the present value, the discount rate the Corporation uses is based on the current government yield curve for US sovereign strips plus applicable counterparty risk spread which is calculated based on the credit rating of the counterparty.

Alterra holds hedge agreements to mitigate the risk of fluctuations in the interest rates on its long-term debts. The fair value is based on Level 2 valuation techniques. Hedge accounting is applied on these contracts.

Contracts	Maturity	Early termination option	Notional Amounts March 31, 2018
Contracts used to hedge the interest rate risk			
Interest rate swap, 7.9%	2023	None	29,000
Interest rate swap, 8.1%	2023	None	49,000

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

9. EARNINGS PER SHARE

The net earnings per share is computed as follows:

	Three months ended March 31	
	2018	2017
		(Restated Note 2.2)
Net (loss) earnings attributable to owners of the parent	(6,617)	2,294
Dividends declared on preferred shares	(1,485)	(1,485)
Net (loss) earnings available to common shareholders	(8,102)	809
Weighted average number of common shares (in 000s)	122,593	108,341
Basic net (loss) earnings per share ($)	(0.07)	0.01
Weighted average number of common shares (in 000s)	122,593	108,341
Effect of dilutive elements on common shares (in 000s) (a)	719	954
Diluted weighted average number of common shares (in 000s)	123,312	109,295
Diluted net (loss) earnings per share ($)	(0.07)	0.01

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.

	Three months ended March 31	
	2018	2017
Shares that are excluded from the dilutive elements on common shares that can be issued from (in 000s):		
Stock options	203	126
Convertible debentures	6,667	6,667

10. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facility	Geothermal facilities	Facilities under construction	Other equipments	Total
Cost								
As at January 1, 2018	3,055	2,081,857	1,410,294	124,322	—	—	14,476	3,634,004
Additions	71	170	65	98	4,749	3,053	472	8,678
Business acquisitions (Note 3)	—	—	—	—	430,305	56,250	1,052	487,607
Dispositions	—	(175)	(143)	—	—	—	—	(318)
Other changes	—	—	—	—	—	—	(5)	(5)
Net foreign exchange differences	13	216	40,579	—	25,513	3,115	74	69,510
As at March 31, 2018	3,139	2,082,068	1,450,795	124,420	460,567	62,418	16,069	4,199,476
Accumulated depreciation								
As at January 1, 2018	—	(230,616)	(172,439)	(33,733)	—	—	(8,978)	(445,766)
Depreciation	—	(9,730)	(14,198)	(1,490)	(2,639)	—	(481)	(28,538)
Dispositions	—	5	4	—	—	—	—	9
Other changes	—	—	—	—	—	—	7	7
Net foreign exchange differences	—	(84)	(1,521)	—	(83)	—	(6)	(1,694)
As at March 31, 2018	—	(240,425)	(188,154)	(35,223)	(2,722)	—	(9,458)	(475,982)
Carrying amount as at March 31, 2018	3,139	1,841,643	1,262,641	89,197	457,845	62,418	6,611	3,723,494

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

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 credit facilities are capitalized for the portion of the financing actually used for a specific property, plant and equipment. Additions in the current period include $72 of capitalized financing costs incurred prior to commissioning.

The cost of the facilities were reduced by investment tax credits of $3,003 ($3,003 as at December 31, 2017).

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

11. LONG-TERM DEBT

(references to US$, € and ISK are in thousands)

a. Increase to the revolving credit facilities

On February 6, 2018 the Corporation announced that it had increased its revolving credit facilities by $225,000 to $700,000 and added a new lender to the syndicate of lenders. The maturity of the revolving credit facilities remains December 2022.

b. Alterra

As part of the acquisition of Alterra, the Corporation assumed the related loan facilities for a total value of $305,045.

- A $112,991 holding company loan facility with 3 tranches. The loan facility has no scheduled payments of principal prior to maturity. The loan facility is secured by future cash flow, and indirect equity investments in Toba Montrose, Dokie, Jimmie Creek and Flat Top.
- A $76,919 (€49,641) HS Orka corporate loan. The loan carries an initial term of five years with options to extend the loan's term up to 18 years. The interest rate on the facility is the Euro Interbank Offered Rate ("EURIBOR") plus 3.15%. Primary uses of loan proceeds include construction of the Brúarvirkjun hydro project, drilling and other field development activities at Reykjanes. The loan will fund in tranches upon the fulfillment of certain conditions precedent. The loan was accounted for at its fair market value of $79,784 for an effective rate of 3.6%. The loan is secured by the operating assets of HS Orka, Reykjanes expansion and the Brúarvirkjun project.
- A $2,864 (ISK230,618) HS Orka corporate loan with an interest rate of 5.6% maturing in 2031. The loan was accounted for at its fair value of $2,805.
- A $48,155 (US$38,431) holding company bond owed by the subsidiary Magma Energy Sweden A.B ('Magma Sweden'). Under the terms of the bond, it became immediately payable upon the delisting of Alterra shares from the TSX as a result of the acquisition. Consequently the bond was settled in full on February 6, 2018 following completion of the acquisition of Alterra.
- A $44,010 (US$35,124) holding company bond owed by Magma Sweden. The holding company bond is secured by shares in HS Orka, has an interest rate of 8.5% per annum and a maturity date of October 23, 2021. The bond was repaid in full during the quarter. (See note 15)
- A $17,300 short-term revolving credit facility. The facility has a borrowing amount of $20,000 with funds made available on a revolving basis at an interest rate of 8% per annum compounded and payable monthly. The amount borrowed was repaid in full during the quarter and the facility expired on March 31, 2018. (See note 15)

	Interest rate 2018	Maturity	March 31, 2018
Alterra			
Holding company loan facility	7.30%-8.07%	2023	87,113
Holding company loan facility (US 20,714)	7.34%	2023	26,708
HS Orka loans (Euro 52,559)	3.60%	2022	83,093
HS Orka loans (Icelandic Krona 215,243)	5.60%	2031	2,831

Subordinated unsecured term loan

Concurrently to the closing of the acquisition of Alterra, Innergex has closed a $150,000 subordinated unsecured 5-year term loan at a 5.13% interest rate.

12. SHAREHOLDERS' CAPITAL

a) Buyback of common shares

On August 15, 2017, Innergex announced that it has received approval from the Toronto Stock Exchange (TSX) to proceed with a normal course issuer bid on its common shares (the Bid). Under the Bid, the Corporation may purchase for cancellation up to 2,000,000 of its common shares, representing approximately 1.84% of the 108,640,790 issued and outstanding common shares of the Corporation as at August 14, 2017. The Bid commenced on August 17, 2017 and will terminate on August 16, 2018. As at December 31, 2017, 56,082 common shares have been purchased and cancelled at an average price of $13.85. During the 3 month period ended March 31, 2018, an additional 697,212 common shares have been purchased and cancelled at an average price of $13.60.

b) Issuance of common shares

As part of the Alterra acquisition, the Corporation issued 24,327,225 common shares at a price of $13.59 for a value of $330,607. (see note 3)

13. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Three months ended March 31	
	2018	2017
Accounts receivable and income tax receivable	28,519	(5,842)
Prepaid and others	(1,132)	(2,648)
Accounts payable and other payables and income tax payable	(16,619)	(1,817)
	10,768	(10,307)

b. Additional information

	Three months ended March 31	
	2018	2017
Interest paid (including $nil capitalized interest ($5,676 in 2017))	35,930	30,894
Non-cash transactions		
in unpaid property, plant and equipment	(9,758)	(14,106)
in shares vested in PSP plan	948	—
distribution unpaid to non-controlling interests in subsidiaries	2,535	—
variation in discounted rates in asset retirement obligations	(167)	—
in common shares issued through dividend reinvestment plan	(1,191)	(2,695)
in common shares issued upon the acquisition of Alterra	(330,607)	—
in investment from non-controlling interests in subsidiaries	218	—

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

c. Changes in liabilities arising from financing activities

	Three months ended March 31	
	2018	2017
Long-term debt at beginning of the period	3,157,458	2,606,633
Increase of long-term debt	302,086	88,856
Repayment of long-term debt	(166,104)	(19,119)
Payment of deferred financing costs	(2,614)	(476)
Business acquisitions (Note 3)	305,045	101,287
Other changes	(4,284)	2,149
Net foreign exchange differences	38,846	2,609
Long-term debt at end of the period	3,630,433	2,781,939

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

14. SUBSIDIARIES

HS Orka hf

As part of the acquisition of Alterra, the Corporation owns a 53.9% ownership interest in HS Orka hf which owns two operating geothermal power plants in Iceland; Svartsengi and Reykjanes.

The summarized financial information below represents amounts before intragroup eliminations.

As at	March 31, 2018
Summary Statement of Financial Position	
Current assets	23,133
Non-current assets	893,756
	916,889
Current liabilities	38,571
Non-current liabilities	211,548
Equity attributable to owners of the parent	359,389
Non-controlling interest	307,381
	916,889

	Period of 54 days ended March 31, 2018
Summary Statement of Earnings and Comprehensive loss	
Revenues	16,417
Expenses [1]	19,254
Net loss	(2,837)
Other comprehensive income	36,805
Total comprehensive income	33,968
Net loss attributable to:	
Owners of the parent	(1,529)
Non-controlling interests	(1,308)
	(2,837)
Total comprehensive income attributable to:	
Owners of the parent	18,309
Non-controlling interests	15,659
	33,968

1. Expenses also include non-cash expenses such as depreciation and amortization totalling $3,270 and unrealized net loss on financial instruments related to embedded derivatives totalling $9,859.

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

15. RELATED PARTY TRANSACTIONS

Related party transactions conducted in the normal course of operations are measured at fair value which is the amount established and agreed to by the related parties, unless specific requirements within IFRS require different treatment.

As part of the Alterra acquisition, the following debts were assumed: (i) in 2011, Ross J. Beaty, chairman of the Board of directors and a large shareholder of Alterra, entered into a revolving credit facility with Alterra (the "Credit Facility"). The Credit Facility had a borrowing capacity amount of $20,000 and made funds available to Alterra on a revolving basis at an interest rate of 8% per annum, compounded and payable monthly. In addition, a standby fee in the amount of 0.75% of the Credit Facility, and a drawdown fee in the amount of 1.5% of amounts advanced, were payable in cash. The Credit Facility matured on March 31, 2018. Alterra had borrowed $17,300 under the Credit Facility; and (ii) in October 2016, Ross J. Beaty loaned through a five-year term bond US$35,700 to Alterra's subsidiary Magma Energy Sweden A.B (the "Bond"). The Bond paid interest at 8.5% per annum with an upfront fee of 2% of the principal which was paid at closing of the financing. The Bond was collateralized by 15% of the outstanding shares in HS Orka. In order to optimize its treasury management, the Corporation repaid both the Credit Facility and the Bond in the first quarter. (See note 11)

16. SEGMENT INFORMATION

Geographic segments

As at March 31, 2018, excluding its investments in joint ventures and associates, the Corporation had interests in 29 hydroelectric facilities, six wind farms and one solar farm in Canada, 15 wind farms in France, one hydroelectric facility in the United States and two geothermal facilities in Iceland. The Corporation operates in four principal geographical areas, which are detailed below:

	Three months ended March 31	
	2018	2017
Revenues		
Canada	68,431	64,489
France	32,219	9,480
Iceland	16,417	—
United States	814	558
	117,881	74,527

As at	March 31, 2018	December 31, 2017
Non-current assets, excluding derivatives financial instruments and deferred tax assets		
Canada	3,159,307	2,977,859
France	1,003,446	973,740
Iceland	899,096	—
United States	186,271	7,052
	5,248,120	3,958,651

Operating segments

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

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

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

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, impairment of project development costs, other net (revenues) expenses , share of (earnings) loss of joint ventures and associates and unrealized net (gain) loss 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, geothermal 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.

Three months ended March 31, 2018						
Operating segments	Hydroelectric	Wind	Geothermal	Solar	Site development	Total
Revenues	34,663	64,051	16,417	2,750	—	117,881
Expenses:						
Operating	9,855	7,429	8,519	169	—	25,972
General and administrative	2,657	2,622	2,345	34	—	7,658
Prospective projects	—	—	—	—	4,908	4,908
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses, share of earnings of joint ventures and associates and unrealized net loss on financial instruments	22,151	54,000	5,553	2,547	(4,908)	79,343
Finance costs						45,671
Other net expenses						2,188
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and associates unrealized net loss on financial instruments						31,484
Depreciation						28,538
Amortization						10,634
Share of earnings of joint ventures and associates						(3,096)
Unrealized net loss on financial instruments						12,143
Loss before income taxes						(16,735)

As at March 31, 2018						
Goodwill	15,180	41,894	42,762	303	5	100,144
Total assets	2,525,449	1,899,336	932,785	106,408	69,550	5,533,528
Total liabilities	2,186,081	1,618,357	460,430	112,966	85,732	4,463,566
Acquisition of property, plant and equipment during the period	401	153	7,803	98	223	8,678

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

Three months ended March 31, 2017					
Operating segments	Hydroelectric	Wind	Solar	Site development	Total
					Restated Note 2.2
Revenues	34,358	36,892	3,277	—	74,527
Expenses:					
Operating	10,739	5,175	175	—	16,089
General and administrative	2,765	1,422	55	336	4,578
Prospective projects	—	—	—	2,918	2,918
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and associates and unrealized net gain on financial instruments	20,854	30,295	3,047	(3,254)	50,942
Finance costs					29,518
Other net revenues					(360)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and associates and unrealized net gain on financial instruments					21,784
Depreciation					21,817
Amortization					7,765
Share of earnings of joint ventures and associates					(715)
Unrealized net gain on financial instruments					(5,075)
Loss before income taxes					(2,008)

As at December 31, 2017 (Restated Note 2.2)					
Goodwill	8,269	30,311	—	—	38,580
Total assets	2,425,646	1,651,537	101,449	11,824	4,190,456
Total liabilities	2,093,158	1,515,468	99,902	25,803	3,734,331
Acquisition of property, plant and equipment during the year	18,804	352,968	12	185,884	557,668

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

17. SUBSEQUENT EVENTS

a. Dividends declared by the Board of Directors

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
05/15/2018	06/29/2018	07/16/2018	0.1700	0.2255	0.359375

b. Petition filed for permission to appeal on water rights

On January 14, 2014, Harrison Hydro Project Inc., Fire Creek Project Limited Partnership, Lamont Creek Project Limited Partnership, Stokke Creek Project Limited Partnership, Tipella Creek Project Limited Partnership and Upper Stave Project Limited Partnership (the "Appellants") filed appeals with the Environmental Appeal Board challenging a determination by the Comptroller of the Water Rights respecting the water rental rates to be charged under the Water Act R.S.B.C. 1996, c. 483 in respect of the Fire Creek Facility, Lamont Creek Facility, Stokke Creek Facility, Tipella Creek Facility and Upper Stave River Facility. On December 8, 2015, the Environmental Appeal Board Decision issued its decision rejecting the appeal. On January 20, 2016, an application for judicial review was filed to the British Columbia Supreme Court ("BCSC"). On February 27, 2017, the BCSC declined to set aside the Environmental Appeal Board Decision. On March 21, 2017, the Appellants filed an appeal of the BCSC decision and on February 8, 2018, in a split decision, the British Columbia Court of Appeal refused to set aside the BCSC decision. The Appellants have filed a petition for permission to appeal to the Supreme Court of Canada on April 3, 2018. The outcome of the judicial review could affect the expenses of these entities on an annual basis going forward which would represent approximately $1,600 aggregate annual increase for water rights. The amount for such potential increase water rights rentals was recorded in the years 2013, 2014, 2015, 2016 and 2017 results of the Corporation, which owns a 50.0024% indirect interest in those facilities.

In addition, on March 23, 2017, the Comptroller of the Water Rights issued adjusted rental statements to the Appelants for years 2011 and 2012 for an amount of $3,287 in aggregate. The amount claimed was paid under protest and the Appelants have filed a Notice of Appeal of that decision to the Environmental Board of Appeal, which is stayed until the British Columbia Court of Appeal appeal mentioned in the preceding paragraph is resolved

c. Electricity purchase agreements renewed with BC Hydro

On April 16, 2018, Innergex announced the renewal of the electricity purchase agreement for the Brown Lake hydro facility. The renewed agreement is for a 40-year term and is effective as of April 1, 2018. The agreement is subject to approval by the British Columbia Utilities Commission.

On April 16, 2018, Innergex and Sekw'el'was Cayoose Creek Band announced the renewal of the electricity purchase agreement for the Walden North hydro facility. The renewed agreement is for a 40-year term and is effective as of April 1, 2018. The agreement is subject to approval by the British Columbia Utilities Commission.

d. First Court rules in favor of HS Orka

On April 17, 2018, the First Court of Iceland ruled in favor of HS Orka in a matter opposing the company to HS Veitur hf. In February 2016 HS Orka issued a legal letter to HS Veitur hf demanding full payment of the long-term receivable in relation to the shared pension liability. This was following receipt of a termination notice by HS Veitur of an agreement regarding payments of the pension liability, sent on December 31, 2015. The two companies had reached an agreement in 2011 on HS Veitur's share and HS Orka considers its claim on the basis of that agreement to be fully valid. Negotiations have not settled the matter. The court proceedings took place in March 2018. HS Veitur has 30 days from April 17, 2018 to file an appeal to the Supreme Court. A claim for $9,900 was filed and is included in accounts receivable on the balance sheet.

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

e. Extension of foreign exchange forward contracts

On April 23, 2018, the Corporation extended all of its foreign exchange forward contracts which hedge its exposure to foreign exchange rate on its investment in France. The contracts have been extended for a period of two years following their original expiry date ranging from April 2018 to August 2019.

Contracts	Maturity	Early termination option	Notional Amounts April 23, 2018
Contracts used to hedge the foreign exchange risk			
Foreign exchange forwards amortizing until 2041, allowing translation at a fixed rate of CAD 1.7332/Euro (before 1.7575/Euro)	2020 (before 2018)	none	159,344
Foreign exchange forwards amortizing until 2042, allowing translation at a fixed rate of CAD 1.7340/Euro (before 1.7588/Euro)	2020 (before 2018)	none	49,957
Foreign exchange forwards amortizing until 2041, allowing translation at a fixed rate of CAD 1.6850/Euro (before 1.7150)	2021 (before 2019)	none	111,945
Foreign exchange forwards amortizing until 2043, allowing translation at a fixed rate of CAD 1.7654/Euro (before 1.7890)	2021 (before 2019)	none	167,963
Foreign exchange forwards amortizing until 2043, allowing translation at a fixed rate of CAD 1.7804/Euro (before 1.8011)	2021 (before 2019)	none	80,941

f. Power purchase agreement signed for a wind project in Texas, USA

On May 7, 2018, Innergex announced that it has signed a 12-year power purchase agreement for 300 MW of wind energy from its 350 MW Foard City development project. Sales under the power purchase agreement will start upon the facility reaching commercial operation. The project located in Texas, USA, has also executed an interconnection agreement with Electric Transmission Texas, LLC. On-site activities intended to qualify the Foard City wind project for US renewable tax incentives (PTCs) were performed since 2016. Full notice to proceed with construction is expected to be issued in the fourth quarter of 2018 to achieve commercial operation in the third quarter of 2019.

g. Acquisition of remaining interests in three hydro facilities

On May 15, 2018, Innergex announced that it has acquired Ledcor Power Ltd,'s 33.3% interest in Creek Power Inc., a company that indirectly owns the Fitzsimmons Creek (7.5 MW), Boulder Creek (25.3 MW) and Upper Lillooet River (81.4 MW) hydro facilities located in British Columbia as well as a portfolio of prospective projects. Innergex already owned the other 67.7% interest in Creek Power Inc. Innergex also owned all the preferred equity for an amount of $98,443 bearing an annualized after-tax return of 12.9%.

h. Partnership and acquisition in Chile

On May 15, 2018, Innergex and Energía Llaima, a renewable energy company located in Chile, are pleased to announce that they have been selected in a bid process to acquire in partnership the Duqueco hydro project (140 MW) which includes two hydro facilities in Chile. The acquisition is subject to certain regulatory approvals in Chile and to reaching a final partnership agreement between the parties. In addition, Innergex has signed an exclusivity agreement with Energía Llaima for a joint venture partnership to acquire a 50% stake in the company. Final agreements should be reached in the coming weeks in respect to this venture.

The Duqueco hydro project includes two hydro facilities commissioned in 2001, Peuchen (85 MW) and Mampil (55 MW). Innergex is expecting an Adjusted EBITDA of approximately US$21,000 ($26,827) annually for the Duqueco project. The purchase price, net of an estimated US$10,000 ($12,775) of cash, is approximately US$210,000 ($268,275), subject to certain adjustments and a financing of US$140,000 ($178,850) is to be granted by a South America bank, Itaú, to cover a portion of the purchase price. Innergex's net share of the remaining purchase price will amount to about US $80,000 ($102,200). In addition, the Corporation made a deposit to secure financing of US$10,000 ($12,775). Both amounts will be paid through available funds under its corporate revolving credit facility.

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

Energía Llaima owns interest in two facilities in operations, a run-of-river hydro facility (12 MW) and a solar thermal facility (34 MW), two run-of-river hydro facilities in development (125 MW) and other early development stage projects. Upon signing a final partnership agreement, Innergex would own 50% of Energía Llaima for a total commitment of US $110,000 ($140,525) to be invested in the next three years. In addition to the investment in the Duqueco project, Innergex will invest an additional US$10,000 ($12,775) in Energia Llaima to contribute to its working capital. With these investments, Innergex's commitment would almost be reached.

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Series A Preferred Shares - TSX: INE.PR.A

Series C Preferred Shares - TSX: INE.PR.C

Convertible Debentures - TSX: INE.DB.A

Credit Rating by Standard & Poor's

Innergex Renewable Energy Inc.	BBB-
Series A Preferred Shares	P-3
Series C Preferred Shares	P-3

Dividend Reinvestment Plan (DRIP)

Innergex Renewable Energy Inc. offers a Dividend Reinvestment Plan (DRIP) for its shareholders of common shares. This plan 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 at innergex.com or contact the DRIP administrator: Computershare Trust Corporation of Canada. Please note that if you wish to enrol in the DRIP but own your shares indirectly through a broker or financial institution, you must contact this intermediary and ask them to enrol in the DRIP on your behalf.

Transfer Agent and Registrar

For information concerning share certificates, dividend payments, a change of address, or electronic delivery of shareholder documents, please contact:

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