Renewable Energy.
Sustainable Development.

QUARTERLY REPORT 2021

for the Period Ended March 31, 2021

These condensed interim consolidated financial statements have not been audited by the Corporation's independent auditors.

For more than 30 years now, Innergex Renewable Energy Inc. has believed in a world where abundant renewable energy promotes healthier communities and creates shared prosperity. As an independent renewable power producer that develops, acquires, owns and operates hydroelectric facilities, wind farms, solar farms and energy storage facilities, Innergex is convinced that renewable energy will lead the way to a better world. Innergex operates in Canada, the United States, France and Chile and follows a sustainable development philosophy that balances people, our planet and prosperity. The Corporation's shares are listed on the Toronto Stock Exchange ("TSX") under the symbols INE, INE.PR.A and INE.PR.C and its convertible debentures are listed under the symbols INE.DB.B and INE.DB.C.

BUSINESS STRATEGY

Innergex develops, acquires, owns and operates renewable power-generating facilities with a focus on hydroelectric, wind and solar production as well as energy storage technologies.

The Corporation's fundamental goal is to create wealth by efficiently managing its high-quality renewable energy assets and successfully pursuing its growth.

Innergex is committed to producing energy from sustainable renewable sources exclusively and to providing energy storage capacity, guided by its philosophy that balances investing in people, caring for our planet and generating prosperity by sharing economic benefits with local communities and creating shareholder value.

Innergex is committed to developing, acquiring, owning and operating renewable energy facilities exclusively that generate sustainable cash flows, provide an attractive risk-adjusted return on invested capital and enable the distribution of a sustainable dividend.

By harnessing the power of the sun's rays, the natural flow of water and the motion of the air, we work with nature to generate clean energy for a brighter future.

Innergex owns interests in 37 hydroelectric facilities drawing on 31 watersheds, 33 wind farms and 6 solar farms. The expertise and innovation developed by our skilled team in various energies and different locations can be leveraged and shared among the Corporation to maximize returns from our high-quality assets.

KEY FIGURES

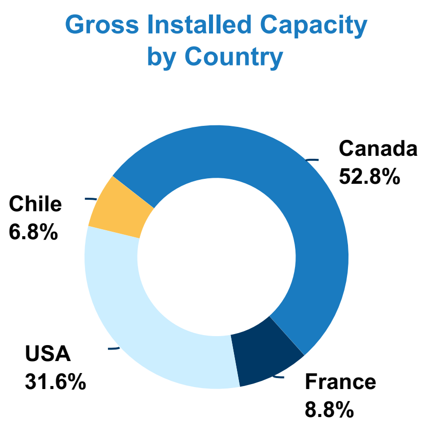
Innergex measures its performance using key performance indicators (“KPIs”). Innergex believes that these indicators are important, as they provide management and the reader with additional information about its production and cash generating capabilities, its ability to pay dividends and fund its growth.

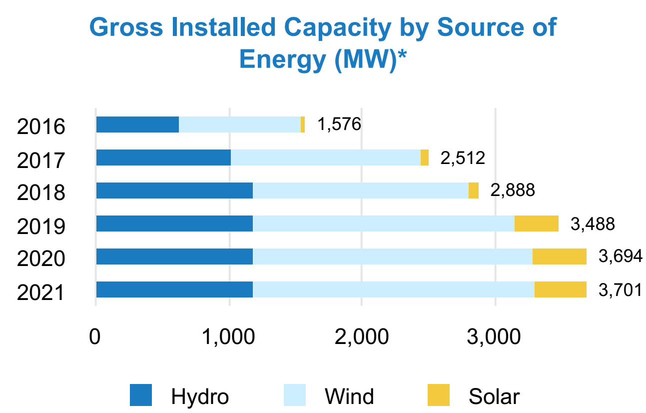
These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the “Non-IFRS Measures” section for more information.

Production KPIs	Financial KPIs
Production in comparison with Long-Term Average (" LTA") in megawatt/hours (“MWh”) and gigawatt/hours (“GWh”)	Revenues and Revenues Proportionate
Production and Production Proportionate	Adjusted EBITDA, Adjusted EBITDA Margin and Adjusted EBITDA Proportionate
	Adjusted Net Earnings (Loss)
	Free Cash Flow
	Payout Ratio

Operational Key Performance Indicators

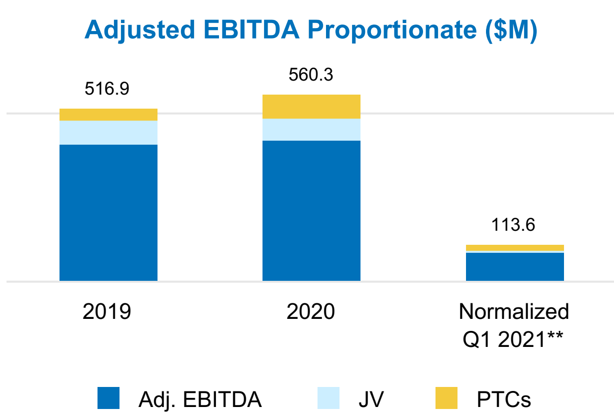
As at May 11, 2021, the Corporation has four geographic segments and three operating segments.

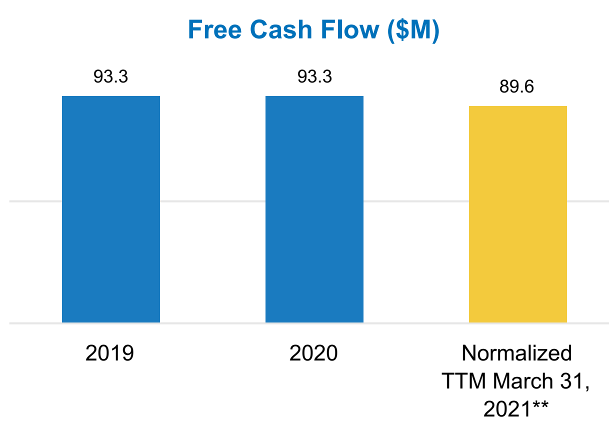




* Gross Installed Capacity for continued operations

Financial Key Performance Indicators





** Please refer to the "February 2021 Texas Events" section for more information.

FEBRUARY 2021 TEXAS EVENTS – SUPPLEMENTAL INFORMATION TO FIRST QUARTER RESULTS

All amounts are in thousands of Canadian dollars, unless otherwise indicated.

Innergex's Presence in Texas

Name	Location	Type	Status	Sponsor Equity Ownership %	Gross installed capacity (MW)	Contract Type
Foard City	Foard County	Wind	Operating	100	350.3	Power Purchase Agreement and Merchant Price
Phoebe	Winkler County	Solar	Operating	100	250.0	Power Hedge
Flat Top	Mills County	Wind	Operating	51	200.0	Power Hedge
Shannon	Clay County	Wind	Operating	50	204.0	Power Hedge
Griffin Trail	Knox and Baylor Counties	Wind	Under Construction	100	225.6	Merchant Price

1. TEXAS EVENTS DESCRIPTION

- In February 2021, unprecedented extreme winter weather conditions and related electricity market failure paralyzed the State of Texas, United States (unofficially referred to as Winter Storm Uri). These unprecedented extreme winter weather events pushed the Texas Government to declare a disaster and the US Government to declare a state of emergency.
- The storm disturbed production, transmission and distribution of power, severely impacting prices. Because of the disturbance, wholesale electricity prices in the Electric Reliability Council of Texas (ERCOT) reached their cap of US$9,000 per MWh and remained at such level for a prolonged period of time.
- The February 2021 Texas Events lasted from February 11 to February 19, 2021, and the figures provided hereinafter are normalized for this period.

1.1 Summary Impacts per Facility

The following table presents a reconciliation of the Production and financial impacts, before income tax, resulting from the February 2021 Texas Events, detailed by facility:

	For the 9-day period from February 11 to February 19, 2021							
	Production (MWh)	LTA (MWh)	Hedge obligation (MWh)[1]	Hedge price (US$)	Revenues	Power hedge	Basis hedge	Total Financial impacts
Consolidated facilities								
Foard City	29,464	35,175	N/A	18.13	16,801	—	—	16,801
Phoebe	5,996	14,550	13,473	33.10	38,166	(70,756)	(1,304)	(33,894)
Total - Consolidated facilities					54,967	(70,756)	(1,304)	(17,093)
Joint venture facilities								
Flat Top	2,046	24,507	19,152	22.60	15,316	(113,609)	—	(98,293)
Shannon	15,546	18,533	15,480	26.20	64,989	(93,123)	—	(28,134)
Total - Joint venture facilities								(126,427)
Total - Innergex's share of loss of the joint venture facilities								(64,197)
Total - Consolidated financial impact, before income tax								(81,290)

1. Hedge obligations are based on hourly commitments in MWh. Therefore, actual production is not always indicative of the hedge obligation fulfillment.

2. FINANCIAL IMPACTS AND NORMALIZED FINANCIAL INFORMATION

2.1 Impacts to Consolidated Statement of Earnings

The Phoebe, Shannon and Flat Top facilities are subject to power hedges. For facilities subject to power hedges, the power that is generated by the facility is delivered to the grid at the project's node (point of delivery) at the prevailing merchant prices. Production delivered at the node at merchant prices is recognized by Innergex as revenue. Under the power hedges, the hourly contracted energy is virtually purchased at the point of withdrawal on the grid ("hub"), subject to the prevailing merchant prices, and exchanged for the contractual fixed price per MWh. Settlements under the power hedges are recognized as change in fair value of financial instruments.

The following table presents a reconciliation of the February 2021 Texas Events' impacts to the Consolidated Statement of Earnings, for each line-item impacted by the events:

		Three months ended March 31, 2021		
		As presented	Impacts from the February 2021 Texas Events (9 days)	Normalized
1	Revenues	189,651	(54,967)	134,684
	Adjusted EBITDA	143,119	(54,967)	88,152
2	Change in fair value of financial instruments	(87,709)	72,060	(15,649)
3	Share of losses of joint ventures and associates	(207,984)	64,197	(143,787)
	Loss before income tax	(259,155)	81,290	(177,865)

(1) Although power generation was depressed by the weather, **revenues at the Foard City and Phoebe facilities were favourably impacted by the events**, with revenues of $16.8 million and $38.2 million, respectively, for an aggregate impact of $55.0 million, as a result of the unprecedented increase in market prices prevailing at the point of delivery on the grid ("Node").

(2) Conversely, the change in fair value of financial instruments was unfavourably impacted by a $70.8 million **realized loss on the Phoebe power hedge**, and $1.3 million on the Phoebe basis hedge, for an aggregate impact of $72.1 million, resulting from the unprecedented increase in market prices prevailing at the point of withdrawal on the grid ("Hub"), for the committed power hedge hourly volumes.

(3) The Flat Top and Shannon joint ventures were similarly impacted by an increase in their respective revenues and realized losses on their respective power hedges, resulting in a share of losses of joint ventures and associates of $50.1 million and $14.1 million for Flat Top and Shannon, respectively, aggregating to a net $64.2 million **unfavourable impact on the share of losses of joint ventures and associates**.

The following table presents a reconciliation of the February 2021 Texas Events' impacts to the segmented information:

	Three months ended March 31, 2021				
	Hydro	Wind	Solar	Unallocated	Total
Revenues	26,570	116,013	47,068	—	189,651
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Revenues	26,570	99,212	8,902	—	134,684
Revenues Proportionate	30,909	183,254	47,572	—	261,735
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Revenues Proportionate	30,909	126,147	9,406	—	166,462
Adjusted EBITDA	14,490	99,623	44,075	(15,069)	143,119
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Adjusted EBITDA	14,490	82,822	5,909	(15,069)	88,152
Adjusted EBITDA Proportionate	15,997	163,590	44,373	(15,069)	208,891
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Adjusted EBITDA Proportionate	15,997	106,483	6,207	(15,069)	113,618

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

2.2 Impacts to Free Cash Flow and Payout Ratio

The following table presents a reconciliation of the February 2021 Texas Events' cash impacts:

		For the 9-day period from February 11 to February 19, 2021		
Facility	Impact	Cash	Non-Cash	Total
Foard City	Revenues	16,801	—	16,801
Phoebe	Revenues	38,166	—	38,166
Phoebe	Power hedge	(70,756)	—	(70,756)
Phoebe	Basis hedge	(1,304)	—	(1,304)
Flat Top	Share of loss	—	(50,129)	(50,129)
Shannon	Share of loss	—	(14,068)	(14,068)
		(17,093)	(64,197)	(81,290)

For the trailing twelve months ended March 31, 2021, the February 2021 Texas Events, whose cash impacts are detailed above, have impacted the Free Cash Flow and Payout Ratio as follows:

		Trailing twelve months ended March 31, 2021		
		As presented	Impacts from the February 2021 Texas Events (9 days)	Normalized
1	Cash flows from operating activities before changes in non-cash operating working capital items	241,224	17,093	258,317
2	Realized loss on the Phoebe basis hedge	1,127	(1,304)	(177)
	Free Cash Flow	73,762	15,789	89,551
	Dividends declared on common shares	125,649	—	125,649
	Payout Ratio	170 %	(30)%	140 %

(1) Cash flows from operating activities before changes in non-cash operating working capital items were impacted by a net unfavourable amount of $17.1 million, representing the February 2021 Texas Events' **realized losses on the Phoebe power and basis hedges, partly offset by the favourable impact to the consolidated revenues**. The $64.2 million non-cash share of losses of joint ventures and associates does not directly impact cash flows from operating activities before changes in non-cash operating working capital items. It will, however, affect the joint ventures' future capacity to distribute cash to the Corporation.

(2) In the Free Cash Flow and Payout Ratio calculation, **Innergex reverses the impacts of the Phoebe basis hedge due to its limited occurrence** (over the remaining contractual period of nine months), which are deemed not to represent the long-term cash-generating capacity of Innergex. As such, $1.3 million is reversed from the recurring adjustment, representing the February 2021 Texas Events' related realized loss on the basis hedge.

2.3 Fiscal 2021 Projected Financial Performance

On a normalized basis, the 2021 Projected Financial Performance would remain as previously disclosed in the 2020 Annual Report.

3. IMPAIRMENT

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

Following the February 2021 Texas Events, which caused significant losses for facilities under power hedge contracts, a general increase in the assessed risk has been observed throughout the industry for facilities subject to shape risk[1] in this region. While the other key assumptions remained largely consistent as compared to December 31, 2020, these above factors contributed to increase discount rates to reflect higher risk premiums. On March 31, 2021, the Flat Top and Shannon joint ventures, each identified as separate cash generating units ("CGU"), recognized impairment charges of US$83.0 million ($105.4 million) and US$92.7 million ($117.7 million), respectively. The impairment charges were recognized by the Corporation through its share of loss of joint ventures and associates, at $53.8 million and $58.8 million, for Flat Top and Shannon, respectively.

The recoverable amount of each CGU was determined based on a value in use calculation which uses cash flow projections based on financial budgets approved by management covering a period extending to the period for which the Corporation owns its rights on the site, and discounted at a rate of 12%.

1. Shape risk exists when there is a mismatch, or a potential mismatch, between the volume commitment under a power hedge instrument, and the actual production of the facility at a given time. For various reasons, it may happen that a facility's electricity output at a given time is below the contractual volume. In such instance, the project cannot fully cover its hub purchases with its node sales and is therefore exposed to merchant prices on its purchases at the hub.

4. MANAGEMENT'S STRATEGIES

4.1 Procedures Initiated

Phoebe

- As a consequence of the February 2021 Texas Events, a claim of Force Majeure was notified to the counterparty of the power hedge of the Phoebe facility in February, which was rejected by the recipient. However, discussions are in progress with the counterparty of the power hedge.

Flat Top and Shannon

- As a consequence of the February 2021 Texas Events, a claim of Force Majeure was notified to the counterparty of the power hedges of the Flat Top and Shannon facilities in February, which were rejected by the recipient.
- To preserve the Corporation’s and its partners’ rights with regard to the Flat Top and Shannon facilities, court proceedings were initiated on April 21, 2021.
- On May 6, 2021, the Court heard the temporary injunction application to suspend all remedies, including foreclosure, against the Flat Top and Shannon facilities, arising from an alleged default of payment that was formally disputed and will render its decision by May 20, 2021. If the Court does deny the application, then the counterparty to the power hedges for the two facilities will not be precluded from exercising any of its remedies, including foreclosure.

4.2 Decisions and Actions

Phoebe

- Despite an increase in the discount rate, estimated future cash flows remain above the carrying value of the assets.
- Management is still in negotiation with all Phoebe's counterparts.

Flat Top and Shannon

- Should the District Court of Harris County, Texas, deny the temporary injunction mentioned above, the counterparty to the power hedges for the Flat Top and Shannon wind facilities will not be precluded from exercising any of its remedies, including foreclosure. The Corporation and its partners in the facilities are evaluating and considering all commercially reasonable options to enforce the rights of the facilities under the power hedges. Decisions made with regard to the facilities are dependent of the partners' agreements on the strategies.
- The carrying amount of the two facilities is higher than the current value of the estimated future cash flows due to an increase in the discount rates.
- Management does not consider these facilities to be viable in the long term in their current configuration.
- Given its understanding of currently available information and on the basis that the facilities are non-recourse to the Corporation, none of the remedies is expected to have an impact greater than the carrying amount of the Flat Top and Shannon equity investments which were nil at March 31, 2021, following the recognition of the aggregate $112.6 million non-cash impairment charges on these facilities, which has already been recognized in the 2021 First Quarter results. Following these impairments, the balance of the equity investments in Flat Top and Shannon is nil as March 31, 2021.
- The impact of the potential foreclosures on the Corporation's Free Cash Flow, based on the facilities' 2020 contribution, could represent a potential loss of approximately $4.2 million.
- The potential foreclosure of the Flat Top and Shannon facilities would also represent an avoided cash outflow of US$60.2 million ($75.7 million), representing the share of the invoiced amounts attributable to the Corporation, which Innergex would have funded through an equity contribution in the facilities, or US$118.8 million ($149.4 million) should the facilities' respective sponsor partners decide not to support the facilities.

- Should the District Court of Harris County, Texas, approve the temporary injunction mentioned above, the exercise of the remedies by the power hedge counterparty would be postponed and the impact mentioned above would also be delayed until a hearing on the dispute takes place.

INFORMATION ON COVID-19

COVID-19 has negatively impacted the global economy, disrupted financial markets and supply chains, significantly reduced travel and interrupted business activity. Federal, state and local governments have implemented mitigation measures, including travel restrictions, stay-at-home orders, border closings, social distancing, shelter-in-place restrictions and limitations on business policies.

Although our business is considered essential services, these government actions have already affected the ability of Innergex's employees, customers, suppliers and other business partners to conduct business activities as usual, and this could last for an extended period. This could have a material effect on our operating results, financial condition, liquidity, capital expenditures and the trading value of our securities, in particular:

- Impact of supply chain disruption on the construction activities
- Impact on employees and cybersecurity
- Impact on liquidity
- Impact on capital expenditures and costs
- Impact on general electricity demand
- Impact on merchant prices

The effects of COVID-19 on business may continue for an extended period, and the ultimate impact on the Corporation of the pandemic will depend on future developments that are uncertain and cannot be predicted including, and without limitations, the duration and severity of the pandemic, the duration of government mitigation measures, the effectiveness of the actions taken to contain and treat the disease, and the length of time it takes for normal economic and operating conditions to resume.

Power Production: an Essential Service

Power production activities have continued in all segments, as they have been deemed essential services in every region where the Corporation operates. Innergex's renewable power production is sold mainly through power purchase agreements, which include sufficient protection to prevent material reduction in demand, to financially solid counterparties, and no credit issues are anticipated. As such, the Corporation does not intend to make any changes to its workforce and intends to maintain salaries and benefits. Only BC Hydro sent curtailment notices for some hydro facilities which are disputed by the Corporation (please refer to the Capital and Liquidity section of the Management's Discussion and Analysis for more information).

Health and Safety of our Employees and Visitors

Since March 2020, Innergex has implemented numerous measures to protect employees, suppliers and business partners from COVID-19.

All Operations teams were split into segregated work groups to reduce risks of contamination across teams. Cleaning procedures were implemented and continue to be enforced to ensure common surfaces are disinfected. COVID-19 screening protocols and measures were revised and improved specifically for monitoring the health and safety of our employees. Specific instructions and guidance on COVID-19 health and safety measures were introduced.

All office employees were instructed to work from home. Office presence is limited to essential tasks.

Visitors and contractors must complete a questionnaire before accessing a site or an office and must respect additional hygiene measures.

IT systems have remained available remotely and multiple controls are in place to ensure overall security while working remotely.

PORTFOLIO OF ASSETS

The Corporation owns interests in three groups of projects at various stages: the Operating Facilities, the Development Projects and the Prospective Projects.

As at May 11, 2021, the Corporation owns and operates 76 facilities in commercial operation (the "Operating Facilities"). Commissioned between 1992 and March 2021, the facilities have a weighted average age of approximately 8.2 years.

They mostly sell the generated power under long-term power purchase agreements, power hedge contracts[1] and short- and long-term industrial contracts (each, a "PPA") to rated public utilities or other creditworthy counterparties or on the open market. The PPAs have a weighted average remaining life of 14.3 years (weighted average based on gross long-term average production).

For most Operating Facilities in Canada and in France, PPAs include a base price and, in some cases, a price adjustment depending on the month, day and hour of delivery. For most Operating Facilities in the United States, power generated is sold through PPAs or on the open market supported by financial or physical power hedges. In Chile, Operating Facilities sell the power generated through PPAs to industrial customers or on the open market.

The Corporation also holds interests in projects under development that are either at an advanced development stage or under construction (the "Development Projects").

[1] A power hedge contract is deemed a PPA regardless of whether it is subjected to hedge accounting or accounted for as a financial derivative at fair value through earnings (loss).

The table below outlines Operating Facilities and Development Projects as at May 11, 2021.

	Number of Facilities[1]		Gross[2] Installed Capacity (MW)		Net[3] Installed Capacity (MW)		Storage Capacity (MWh)	
	Operating Facilities	Development Projects	Operating Facilities	Development Projects	Operating Facilities	Development Projects	Operating Facilities	Development Projects
HYDRO								
Canada	33	1	1,019	8	713	4	—	—
United States	1	—	10	—	10	—	—	—
Chile	3	1	152	109	74	41	—	—
Subtotal	37	2	1,181	117	797	45	—	—
WIND								
Canada	8	—	908	—	714	—	—	—
France	16	—	324	—	226	—	—	—
United States	9	1	892	226	640	226	—	—
Subtotal	33	1	2,124	226	1,580	226	—	—
SOLAR								
Canada	1	—	27	—	27	—	—	—
United States	3	5	267	280	266	280	—	320 [5]
Chile	2	—	102	—	77	—	150 [4]	—
Subtotal	6	5	396	280	370	280	150	320
STORAGE								
France	—	1	—	—	—	—	—	9 [6]
Total	76	9	3,701	623	2,747	551	150	329

1. The number of Operating Facilities includes all facilities owned and operated by the Corporation, including non-wholly owned subsidiaries and joint ventures and associates.
2. Gross installed capacity is the total capacity of all Operating Facilities of Innergex, including non-wholly owned subsidiaries and joint ventures and associates.
3. Net installed capacity is the proportional share of the total capacity attributable to Innergex based on its ownership interest in each facility.
4. Capacity related to the hot water storage of the Pampa Elvira thermal solar facility.
5. Battery storage capacity related to Hale Kuawehi (120 MWh), Paeahu (60 MWh), Kahana (80 MWh) and Barbers Point (60 MWh) solar projects.
6. Tonnerre Standalone battery storage project.

More information on the Corporation's Prospective Projects is available in the "Prospective Projects" section of the Management's Discussion and Analysis.

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

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 three-month period ended March 31, 2021, and reflects all material events up to May 11, 2021, the date on which this MD&A was approved by the Corporation's Board of Directors.

The MD&A should be read in conjunction with the unaudited condensed interim consolidated financial statements and the accompanying notes for the three-month period ended March 31, 2021.

The unaudited condensed interim consolidated financial statements attached to this MD&A and the accompanying notes for the three-month period ended March 31, 2021, along with the 2020 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 tabular 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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1- HIGHLIGHTS

	Three months ended March 31			
	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized	2020
OPERATING RESULTS				
Production (MWh)	1,785,947	—	1,785,947	1,679,598
Revenues	189,651	(54,967)	134,684	132,116
Adjusted EBITDA[1]	143,119	(54,967)	88,152	90,419
Adjusted EBITDA Margin[1]	75.5 %	(10.0)%	65.5 %	68.4 %
Net Loss	(217,872)	64,219	(153,653)	(46,931)
Adjusted Net Loss[1]	(27,540)	—	(27,540)	(9,503)
PROPORTIONATE				
Production Proportionate (MWh)[1]	2,049,621	—	2,049,621	1,969,766
Revenues Proportionate[1]	261,735	(95,273)	166,462	164,371
Adjusted EBITDA Proportionate[1]	208,891	(95,273)	113,618	116,014
Adjusted EBITDA Proportionate Margin[1]	79.8 %	(11.5)%	68.3 %	70.6 %
COMMON SHARES				
Dividends Declared on Common Shares	31,445	—	31,445	31,339
Weighted Average Number of Common Shares (in 000s)	174,111	—	174,111	159,682

	Trailing twelve months ended March 31			
	2021	February 2021 Texas Events (9 days)[4]	2021 Normalized	2020
CASH FLOW AND PAYOUT RATIO				
Cash Flow From Operating Activities[2]	276,045	(16,801)	259,244	206,480
Free Cash Flow[1,2]	73,762	15,789	89,551	91,447
Payout Ratio[1,2]	170 %	(30)%	140 %	113 %
Adjusted Payout Ratio[2]	111 %	— %	111 %	97 %

	As at	
FINANCIAL POSITION	March 31, 2021	December 31, 2020
Total Assets	6,909,097	7,154,232
Total Liabilities	6,044,499	6,083,300
Non-Controlling Interests	58,274	62,078

1. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production and Production Proportionate are key performance indicators for the Corporation that cannot be reconciled with an IFRS measure. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. For more information on the calculation and explanation, please refer to the "Free Cash Flow and Payout Ratio" section.
3. For the three months ended March 31, 2021, the operating results are normalized to exclude the impacts of the February 2021 Texas Events. Please refer to the "February 2021 Texas Events" section for more information.
4. For the trailing twelve months ended March 31, 2021, the Cash Flow From Operating Activities, Free Cash Flow and Payout Ratio are normalized to exclude the impacts of the February 2021 Texas Events. Please refer to the "February 2021 Texas Events" section for more information.

1- HIGHLIGHTS | First Quarter 2021 – Operating Performance

For the quarter ended March 31, 2021, **Revenues** were $189.7 million. Excluding the February 2021 Texas Events, on a normalized basis, Revenues were up 2% to $134.7 million. The **hydroelectric** power generation segment recorded a decrease in revenues mainly due to a combined effect of lower production in British Columbia and lower average selling price at some facilities in the same region, partly offset by higher revenues at the Quebec facilities due to higher production. The increase in revenues, on a normalized basis, in the **wind** power generation segment is mostly attributable to the Mountain Air Acquisition completed on July 15, 2020, and to the contribution of the Foard City facility due to higher production, partly offset by lower revenues at the France wind facilities due to lower production. The increase in revenues, on a normalized basis, from the **solar** power generation segment was due to the Salvador Acquisition completed on May 14, 2020, partly offset by lower revenue due to lower average selling price at the Phoebe solar facility. **Revenues Proportionate** were $261.7 million. Excluding the February 2021 Texas Events, on a normalized basis, Revenues Proportionate were up 1% to $166.5 million.

The **Adjusted EBITDA** was at $143.1 million. Excluding the February 2021 Texas Events, on a normalized basis, the Adjusted EBITDA was down to $88.2 million, a 3% decrease compared with the same period last year. The decrease, on a normalized basis, is mainly attributable to a lower contribution from wind facilities in France and hydroelectric facilities in British Columbia both due to lower revenues and by higher prospective expenses over lower general and administrative expenses. This decrease is partly offset by the contribution of the Mountain Air and Salvador Acquisitions. The **Adjusted EBITDA Proportionate** reached $208.9 million. Excluding the February 2021 Texas Events, on a normalized basis, the Adjusted EBITDA Proportionate reached to $113.6 million, a 2% decrease compared with the same period last year.

Innergex recorded a net loss of $217.9 million ($1.24 loss per share - basic and diluted) for the quarter ended March 31, 2021, compared with a **net loss** of $46.9 million ($0.35 loss per share - basic and diluted) for the same period in 2020. This was mainly due to the net unfavourable impacts of $81.3 million from the February 2021 Texas events, and the recognition of an aggregate $112.6 million share of **impairment charges** in the Flat Top and Shannon joint ventures. These items were **partly offset** by a a $40.5 million increase in **recovery of income tax**, and a favourable $21.0 million movement in the **realized portion of the change in fair value on the Phoebe basis hedge**, compared with the same period in 2020.

1- HIGHLIGHTS | First Quarter 2021 – Capital and Resource

The decrease in total assets results largely from the share of loss in joint ventures and associates due mainly to the February 2021 Texas Events and the impairment loss at the Shannon and Flat Top facilities.

The increase in long-term loans and borrowings, including the current portion thereof, results largely from the draws made toward the construction of the Griffin Trail project. In addition, the Corporate revolving credit facility was used for reimbursing the outstanding balance of the Alterra term loans on January 11, 2021.

The decrease in equity attributable to owners is mainly a result of dividends declared and the total comprehensive loss attributable to owners of the parent.

The decrease in Free Cash Flow for the trailing twelve months ended March 31, 2021, is mainly due to the February 2021 Texas Events (refer to the "February 2021 Texas Events" section of this MD&A for more information). Excluding those events, Free Cash Flow remained relatively stable. The Salvador and Mountain Air Acquisitions realized during the second and third quarter of 2020, along with a decrease in interest payments on the corporate revolving credit facility concurrent with the Hydro-Québec Private Placement, have contributed to improving cash flows from operating activities before changes in non-cash operating working capital items.

1- HIGHLIGHTS | First Quarter 2021 – Growth and Development Initiatives

On March 1, 2021, the 6.9 MW Yonne II wind farm located in France reached its **full commissioning**.

The Corporation is pursuing **construction** on three projects in 2021. The Corporation advanced the construction of the 200.0 MW Hillcrest solar project in Ohio, U.S. Despite some delays, the commissioning is still expected in Q2 2021. The 225.6 MW Griffin Trail wind project in Texas, U.S., should reach commercial operation in Q3 2021 and the 7.5 MW Innavik hydro project in Quebec, Canada, is expected to be commissioned in 2022.

Projects under development are progressing well. The Engineering, Procurement and Construction ("EPC") contractors were selected and Limited Notice to Proceed are in progress at both the **Paeahu and Hale Kuawehi solar and battery storage projects**. Environmental studies are ongoing as other permitting-related activities at both the **Barbers Point** and **Kahana solar and battery storage projects** in Hawaii. In France, for the **Tonnerre standalone battery storage project** the building permit was obtained in February 2021 and a supply, construction and maintenance agreement has been signed with the selected battery supplier, EVLO, a Hydro-Québec subsidiary.

The **Prospective projects** pipeline will allow several opportunities in the years to come, with 12 projects for a total 685 MW installed capacity currently at an advanced stage.

1-HIGHLIGHTS | Subsequent Events

Mesgi'g Ugju's'n letter of credit

In 2019, the service provider under the turbine supply agreement at Mesgi'g' Ugju's'n filed for bankruptcy. Certain of the performance obligations under the turbine supply agreement were covered, subject to terms and conditions precedent, by a $19.6 million letter of credit. The Corporation availed itself of the full amount on April 27, 2021. The proceeds will be used in the future to remediate to the unfulfilled performance obligations under the turbine supply agreement.

2- OVERVIEW OF OPERATIONS | Business Environment

Seasonality of Operations

The Corporation aims 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 and solar irradiation. Lower-than-expected resources in any given quarter could have an impact on the Corporation's revenues and hence on its profitability.

Fortunately, the complementary nature of hydroelectric, wind and solar energy production partially offsets any seasonal variations, as illustrated in the following table:

	Consolidated LTA and Quarterly Seasonality[1]									
In GWh and %	Q1		Q2		Q3		Q4		Total	
HYDRO	370	12 %	1,065	36 %	1,002	33 %	581	19 %	3,018	35 %
WIND	1,367	29 %	1,115	23 %	918	20 %	1,296	28 %	4,696	54 %
SOLAR	212	22 %	275	29 %	270	28 %	199	21 %	956	11 %
Total	1,949	22 %	2,455	29 %	2,190	25 %	2,076	24 %	8,670	100 %

1. The consolidated long-term average production is the annualized LTA for the facilities in operation as of May 11, 2021. 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. Production in comparison to the LTA is a key performance indicator for the Corporation. For more information, please refer to the “Key Figures” section.

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

2- OVERVIEW OF OPERATIONS | Operating Facilities

Energy segment	Location	Three months ended March 31, 2021		Three months ended March 31, 2020		Three months Production % change
		Production (MWh)	Production as a % of LTA	Production (MWh)	Production as a % of LTA	
HYDRO	Quebec	142,140	114 %	120,710	97 %	18 %
	Ontario	22,928	94 %	22,733	94 %	1 %
	British Columbia	143,613	67 %	162,093	76 %	(11)%
	United States	4,379	55 %	3,920	49 %	12 %
	Subtotal	**313,060**	**85 %**	**309,456**	**84 %**	**1 %**
WIND	Quebec	638,178	92 %	639,952	92 %	— %
	France	207,210	91 %	276,825	122 %	(25)%
	United States [2]	450,800	102 %	328,423	93 %	37 %
	Subtotal	**1,296,188**	**95 %**	**1,245,200**	**98 %**	**4 %**
SOLAR	Ontario	5,921	85 %	6,326	90 %	(6)%
	United States	122,296	80 %	118,616	78 %	3 %
	Chile[3]	48,482	92 %	—	— %	— %
	Subtotal	**176,699**	**83 %**	**124,942**	**78 %**	**41 %**
TOTAL PRODUCTION[1]		**1,785,947**	**92 %**	**1,679,598**	**93 %**	**6 %**
Innergex's share of production of joint venture and associates		263,674	92 %	290,168	101 %	(9)%
PRODUCTION PROPORTIONATE		**2,049,621**	**92 %**	**1,969,766**	**94 %**	**4 %**

1. Some facilities 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, their electricity production figures have been excluded from the production table.
2. The Mountain Air Acquisition was completed on July 15, 2020.
3. The Salvador Acquisition was completed on May 14, 2020.

Production for the three-month period ended March 31, 2021, was 92% of LTA. The variation is mostly explained by below-average water flows in British Columbia, below-average wind regime in Quebec and in France and by an unfavourable impact of curtailment required by the distribution network in Texas at the Phoebe facility. These items were partly offset by above-average water flows at some hydro facilities in Quebec and above-average wind regime at the Mountain Air facilities in the United States. Innergex's share of Production of joint ventures and associates was 92% of LTA, translating into a **Production Proportionate** at 92% of LTA.

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

2- OVERVIEW OF OPERATIONS | Construction Activities

The table below outlines the projects that are under construction as at the date of this MD&A.

Name (Location)	Type	Ownership %	Gross installed capacity (MW)	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project cost: Estimated[1] ($M)	Expected first 5-year average: Revenues Proportionate[1,2] ($M)	Expected first 5-year average: Adjusted EBITDA Proportionate[1,2] ($M)	Status	Expected COD
Hillcrest (Ohio, U.S.)	Solar	100	200.0	413.3	15	363.4 [3]	21.4 [3]	12.8 [4]	All major work activities are well underway and the project is approximately 95% complete. Tracker and module installation are nearly completed. Feeders 1, 2 & 3 have achieved mechanical completion. Commissioning work started in December. Full commercial operation is scheduled for Q2 2021.	2021
Innavik (QC, Canada)	Hydro	50	7.5	54.7	40	63.9 [4]	5.4 [4]	4.3 [4]	Residential bi-energy conversion RFP was released and results are expected soon. Bridge to give access to south shore was repaired and its installation is now completed. Transmission line design is completed.	2022
Griffin Trail (Texas, U.S.)	Wind	100	225.6	819.0	0 [5]	358.0 [6]	44.7 [6]	33.6 [6]	Construction progressed well on site in Q1 with completion of turbine deliveries, collection line installation, turbine foundations and O&M building construction. Significant progress on turbine installation was also achieved. The contractor has over 250 personnel on site performing the work. All of the turbine components have been received and approximately 60% of the turbines have been installed. Mechanical completion and pre-commissioning of the turbines are ongoing. Project financing was completed at the end of December 2020. Commercial operation is scheduled for Q3 2021.	2021
Total			433.1	1,287.0	55.0	785.3	71.5	50.7		

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 this MD&A.
2. Revenues Proportionate 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.
3. Total Estimated Project Cost at US$289.0 million, Expected Revenues at US$17.0 million and Expected Adjusted EBITDA at US$10.2 million translated at a rate of 1.2575.
4. Construction costs correspond to 100% of the expected costs for this facility. Revenues and Adjusted EBITDA are expected at $10.8 million and $8.6 million, respectively, or $5.4 million and $4.3 million on a proportionate basis, respectively.
5. Power to be sold on the open market.
6. Total Estimated Project Cost at US$284.7 million, Expected Revenues at US$13.3 million, Expected Revenues Proportionate at US$35.5 million, Expected Adjusted EBITDA at US$4.5 million, and Adjusted EBITDA Proportionate of US$26.7 million translated at a rate of 1.2575.

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

Contingency plans and measures are in place at all construction sites to address the COVID-19 pandemic. Unless a decree is issued to halt construction, all construction sites should continue as planned.

On March 1, 2021, the Corporation announced the full commissioning of the 6.9 MW Yonne II wind farm in France. Yonne II is expected to produce a gross estimated long-term average of 11.0 GWh, annual projected revenues of approximately €1.0 million ($1.5 million) and annual projected Adjusted EBITDA of approximately €0.8 million ($1.1 million). The budgeted construction costs amounted to €10.8 million ($15.9 million) and construction was achieved on-budget. Innergex owns a 69.55% interest in the wind farm and Desjardins Group Pension Plan ("RRMD") owns the remaining 30.45%.

2- OVERVIEW OF OPERATIONS | Development Activities

Innergex owns a portfolio of Development Projects with a gross installed capacity of approximately 189 MW. The table below outlines their status as at the date of this MD&A.

Name (Location)	Type	Gross installed capacity (MW)	Gross estimated LTA[1] (GWh)	PPA term (years)	Status	Expected COD
Frontera (Chile)	Hydro	109.0	464.0	— [2]	The financing process, the construction contract and permitting are progressing slowly due to the COVID-19 pandemic. Project schedule is under revision.	—
Hale Kuawehi (Hawaii, U.S.)	Solar	30.0 [3]	87.4 [5]	25	Environmental and technical studies are completed. EPC contractor selected and issued Limited Notice to Proceed ("LNTP").	2022
Paeahu (Hawaii, U.S.)	Solar	15.0 [3]	41.2 [5]	25	The PUC approved the PPA. EPC contractor final offer negotiation is underway and a LNTP with the EPC contractor is expected in Q2 2021. Maui County issued their notice of acceptance and completeness of application and has scheduled the application to be presented to the Planning Commission in Q2 2021. An appeal was filed in the Supreme Court of Hawaii regarding the PUC's approval of the PPA and PUC's denial of a Motion for Reconsideration.	2023
Kahana (Hawaii, U.S.)	Solar	20.0 [3]	74.6 [5]	25	Environmental studies are ongoing as well as are other permitting-related activities. 30% design engineering is completed. A contested case proceeding regarding the PUC's approval of the PPA is in process.	2023
Barbers Point (Hawaii, U.S.)	Solar	15.0 [3]	37.0 [5]	25	Environmental studies are ongoing as well as are other permitting-related activities. 30% design engineering is in progress.	2023
Tonnerre (France)	Storage	— [4]	—	— [6]	A supply, construction and maintenance agreement has been signed with the selected battery supplier, EVLO, a Hydro-Québec subsidiary. The building permit was obtained in February.	2021
TOTAL		189.0	704.2			

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 this MD&A.
2. Power to be sold on the open market or through PPAs yet to be signed.
3. Solar project with a battery storage capacity of 120 MWh for Hale Kuawehi, 60 MWh for Paeahu, 80 MWh for Kahana and 60 MWh for Barbers Point.
4. Standalone battery storage capacity of 9 MWh.
5. PPA is a fixed lump sum capacity payment for the availability of dispatchable energy.
6. The project has been awarded a 7-year Contract for Difference offering a fixed-price contract for capacity certificate. The French Energy Code sets forth a market-based premium regime. Under a Contract for Difference, the income of the producer relies on a price obtained on the market and an energy premium that corresponds to the difference between a reference tariff calculated on the basis of the average financing and operation costs for an efficient and representative installation and the average electricity and capacity market-based prices.

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

2- OVERVIEW OF OPERATIONS | Prospective Projects

Innergex owns interests in numerous prospective projects at various stages of development. Some projects have secured land rights, filed an investigative permit application or have submitted or could submit a proposal under a Request for Proposals or a Standing Offer Program (collectively the "Prospective Projects"). The list of Prospective Projects is revised quarterly to add or remove projects, according to their advancement potential. Prospective projects are categorized in different stages based on the items below. There is no certainty that any Prospective Project will be realized.

In order to define the stage of each prospective project, their progression is measured according to the permitting maturity phase leading to obtaining a final notice to proceed combined with a success probability factor that the project will reach the development stage. Prospective projects are segregated into three different stages, i.e. early, mid and advanced.

Early Stage	The prospective projects in this category have a **LOW** permitting maturity combined with a **LOW** success probability factor; or a **MID**-stage permitting maturity combined with a **LOW** success probability factor.
Mid Stage	The prospective projects in this category have a **MID**-stage permitting maturity combined with a **MEDIUM** success probability factor; or a **HIGH-**stage permitting maturity combined with a **MEDIUM** success probability factor.
Advanced Stage	The prospective projects in this category have a **HIGH** permitting maturity combined with a **HIGH** success probability factor; or a **MID-**stage permitting maturity combined with **HIGH** success probability factor.

	Early Stage		Mid Stage		Advanced Stage		Total Capacity[1] (in MW)	Total number of projects
	Capacity[1] (in MW)	Number of projects	Capacity[1] (in MW)	Number of projects	Capacity[1] (in MW)	Number of projects		
CANADA								
Hydro	500	7	—	—	—	—	500	7
Solar	300	8	—	—	—	—	300	8
Wind	3,443	20	500	3	—	—	3,943	23
Subtotal	4,243	35	500	3	—	—	4,743	38
UNITED STATES								
Solar	589	6	445	4	200	1	1,234	11
Wind	—	—	—	—	320	1	320	1
Subtotal	589	6	445	4	520	2	1,554	12
FRANCE								
Solar	60	1	—	—	—	—	60	1
Wind	69	7	120	7	162	9	351	23
Subtotal	129	8	120	7	162	9	411	24
CHILE								
Hydro	183	3	—	—	3	1	186	4
Solar	32	1	—	—	—	—	32	1
Wind	—	—	9	1	—	—	9	1
Subtotal	215	4	9	1	3	1	227	6
Total	5,176	53	1,074	15	685	12	6,935	80

1. Only Gross Installed Capacity is disclosed for Prospective Projects as the net capacity is not yet defined at this stage.

Compared to last quarter, a solar project was added to the list of prospective projects as an early stage project in France and one solar project in the US advanced from early stage to mid-stage

Strategic Alliance Pipeline

The Corporation formed a Strategic Alliance with Hydro-Québec on February 6, 2020, to leverage the strong Quebec know-how in renewable energy and power grid management into global opportunities. Hydro-Québec has committed an initial $500 million to the Strategic Alliance, which will be entirely and exclusively dedicated to co-investment projects with Innergex. Each party has also committed to presenting investment opportunities in targeted sectors outside of Quebec to each other exclusively for an initial 3-year period. Targeted areas for investment include wind and solar projects with battery storage or transmission, distributed generation, off-grid renewable energy networks, and other sectors as may be agreed by both parties.

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

In the first year of the Strategic Alliance, both entities worked together to build a team responsible for identifying opportunities to invest. Many opportunities have been assessed while many others are still under review. Both teams are collaborating on a daily basis to identify and assess the best opportunities for the Strategic Alliance. The current COVID-19 pandemic has slowed down the market but opportunities still exist and the team is evaluating all of those that make sense for the Strategic Alliance. In addition, the entities are targeting standalone energy storage facilities with the battery technology developed by Hydro-Québec, such as Innergex's Tonnerre battery project which is the first battery deployment for Hydro-Quebec.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS

	Three months ended March 31					
	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized	2020	Change	
Revenues	189,651	(54,967)	134,684	132,116	2,568	2 %
Operating expenses	30,993	—	30,993	27,547	3,446	13 %
General and administrative expenses	9,750	—	9,750	10,511	(761)	(7)%
Prospective project expenses	5,789	—	5,789	3,639	2,150	59 %
Adjusted EBITDA[1]	143,119	(54,967)	88,152	90,419	(2,267)	(3)%
Adjusted EBITDA margin[1]	75.5 %	(10.0)%	65.5 %	68.4 %		
Finance costs	59,600	—	59,600	60,330	(730)	(1)%
Other net income	(11,904)	—	(11,904)	(23,497)	11,593	(49)%
Depreciation and amortization	58,885	—	58,885	53,567	5,318	10 %
Share of losses of joint ventures and associates:						
Share of losses, before impairment charges [2]	95,375	(64,197)	31,178	20,054	11,124	55 %
Share of impairment charge [2]	112,609	—	112,609	—	112,609	— %
Change in fair value of financial instruments	87,709	(72,060)	15,649	27,709	(12,060)	(44)%
Income tax recovery	(41,283)	17,071	(24,212)	(813)	(23,399)	2,878 %
Net loss	(217,872)	64,219	(153,653)	(46,931)	(106,722)	227 %
Net loss attributable to:						
Owners of the parent	(214,161)	64,219	(149,942)	(53,740)	(96,202)	179 %
Non-controlling interests	(3,711)	—	(3,711)	6,809	(10,520)	(155)%
	(217,872)	64,219	(153,653)	(46,931)	(106,722)	227 %
Basic and diluted net loss per share attributable to owners ($)	(1.24)	0.37	(0.87)	(0.35)		
Basic and diluted net loss per share attributable to owners ($)	(1.24)	0.37	(0.87)	(0.35)		

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. Some facilities 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.
3. For the three months ended March 31, 2021, the Financial Performance and Operating Results are normalized to exclude the impacts of the February 2021 Texas Events. Please refer to the "February 2021 Texas Events" section for more information.

On a consolidated basis, the **Adjusted EBITDA Margin** was 75.5% for the three-month period ended on March 31, 2021. Excluding the February Texas Events, the Adjusted EBITDA Margin was down from 68.4% to 65.5%. This decrease is mainly explained by lower revenues in British Columbia, higher operating expenses at the Quebec hydroelectric facilities and higher prospective project expenses.

On a consolidated basis, **Adjusted EBITDA Proportionate Margin** was 79.8% for the three-month period ended on March 31, 2021. Excluding the February Texas Events, the Adjusted EBITDA Proportionate Margin was down from 70.6% to 68.3%. This decrease is mainly explained by lower Adjusted EBITDA margin and lower PTCs earned from lower production at the Shannon and Flat Top facilities.

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

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Hydroelectric Segment

Hydroelectric Segment	Three months ended March 31		
	2021	2020	Change
Production (MWh)	313,060	309,456	1 %
LTA (MWh)	369,682	369,682	— %
Revenues (In $M)	26,570	27,957	(5)%
Adjusted EBITDA (In $M)[1]	14,490	16,540	(12)%
Adjusted EBITDA Margin[1]	54.5 %	59.2 %	
PROPORTIONATE[1]			
Production Proportionate (MWh)	351,152	344,673	2 %
Revenues Proportionate (In $M)	30,909	32,748	(6)%
Adjusted EBITDA Proportionate (In $M)	15,997	17,867	(10)%
Adjusted EBITDA Margin Proportionate	51.8 %	54.6 %	

1. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production and Production Proportionate are key performance indicators for the Corporation that cannot be reconciled with an IFRS measure. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the three-month period ended March 31, 2021, the decrease of 12% in **Adjusted EBITDA** in the hydroelectric segment compared with the same quarter last year is mainly due to a lower contribution from the facilities in British Columbia, mainly attributable to lower revenues derived from lower production and lower average selling prices. This decrease is partly offset by higher revenues from higher production over higher operational expenses at the Quebec facilities. The **Adjusted EBITDA Margin** is down from 59.2% to 54.5%, which is mainly explained by higher operational expenses at the Quebec facilities and lower revenues in British Columbia.

The **joint ventures' and associates'** hydroelectric facilities contributed $1.5 million to the **Adjusted EBITDA Proportionate** for the three-month period ended March 31, 2021, compared with a contribution of $1.3 million for the same quarter last year, a 14% increase mainly due to a higher contribution from the Chile facilities derived from the impact of lower operating expenses over lower revenues due to lower average selling price, despite higher production. This increase is also explained by a higher contribution from facilities in British Columbia from lower operating expenses.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Wind Segment

Wind Segment	Three months ended March 31				
	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized	2020	Change
Production (MWh)	1,296,188	—	1,296,188	1,245,200	4 %
LTA (MWh)	1,364,691	—	1,364,691	1,274,681	7 %
Revenues (In $M)	116,013	(16,801)	99,212	95,805	4 %
Adjusted EBITDA (In $M)[1]	99,623	(16,801)	82,822	80,839	2 %
Adjusted EBITDA Margin[1]	85.9 %	(2.4)%	83.5 %	84.4 %	
PROPORTIONATE[1]					
Production Proportionate (MWh)	1,518,873	—	1,518,873	1,497,029	1 %
Revenues Proportionate (In $M)	183,254	(57,107)	126,147	122,686	3 %
Adjusted EBITDA Proportionate (In $M)	163,590	(57,107)	106,483	104,783	2 %
Adjusted EBITDA Margin Proportionate	89.3 %	(4.9)%	84.4 %	85.4 %	

1. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production and Production Proportionate are key performance indicators for the Corporation that cannot be reconciled with an IFRS measure. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. For the three months ended March 31, 2021, the Financial Performance and Operating Results are normalized to exclude the impacts of the February 2021 Texas Events. Please refer to the "February 2021 Texas Events" section for more information.

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

For the three-month period ended March 31, 2021, the **Adjusted EBITDA** in the wind power generation segment, excluding the February 2021 Texas Events, on a normalized basis, increased by 2% compared with the same quarter last year. This increase is mainly attributable to the Mountain Air Acquisition in Idaho completed on July 15, 2020, and to a higher contribution from the Foard City facility due to a combined effect of higher revenues from higher production and lower operational expenses. These items were partly offset by a lower contribution from the wind facilities in France explained by lower revenues due to lower wind regime. The **Adjusted EBITDA Margin,** excluding the February 2021 Texas Events, on a normalized basis, was down from 84.4% to 83.5%. This decrease is explained by the weight of recent acquisition in the United States for which margins are lower and lower revenues in France wind facilities. This decrease was partly offset by higher revenues over lower operational expenses at the Foard City facility.

The **joint ventures' and associates'** wind farms, excluding the February 2021 Texas Events, on a normalized basis, contributed $6.2 million to the **Adjusted EBITDA Proportionate** for the three-month period ended March 31, 2021, compared with a contribution of $5.8 million in the same quarter last year. This increase is mainly due to a higher contribution from the Shannon and Flat Top facilities due mostly to higher revenues explained by higher average selling prices despite lower production. The increase is also explained by a higher contribution of the Viger-Denonville wind facility in Quebec due to a combined effect of higher revenues from higher production and lower operational expenses.

The **proportional PTCs** generated by the wind farms contributed $17.4 million in the three-month period ended March 31, 2021, compared with an $18.1 million contribution in the same quarter last year. This decrease is due to lower PTCs earned from lower production at the Shannon and Flat Top facilities.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Solar Segment

	Three months ended March 31				
Solar Segment	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized	2020	Change
Production (MWh)	176,699	—	176,699	124,942	41 %
LTA (MWh)	212,520	—	212,520	159,872	33 %
Revenues (In $M)	47,068	(38,166)	8,902	8,354	7 %
Adjusted EBITDA (In $M)[1]	44,075	(38,166)	5,909	5,696	4 %
Adjusted EBITDA Margin[1]	93.6 %	(27.2)%	66.4 %	68.2 %	
PROPORTIONATE[1]					
Production Proportionate (MWh)	179,596	—	179,596	128,064	40 %
Revenues Proportionate (In $M)	47,572	(38,166)	9,406	8,937	5 %
Adjusted EBITDA Proportionate (In $M)	44,373	(38,166)	6,207	6,020	3 %
Adjusted EBITDA Margin Proportionate	93.3 %	(27.3)%	66.0 %	67.4 %	

1. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production and Production Proportionate are key performance indicators for the Corporation that cannot be reconciled with an IFRS measure. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. For the three months ended March 31, 2021, the Financial Performance and Operating Results are normalized to exclude the impacts of the February 2021 Texas Events. Please refer to the "February 2021 Texas Events" section for more information.

For the three-month period ended March 31, 2021, the **Adjusted EBITDA** in the solar power generation segment, excluding the February 2021 Texas Events, on a normalized basis, increased by 4% compared with the same quarter last year. This increase is mainly explained by the contribution of the Salvador Acquisition on May 14, 2020, partly offset by a lower contribution from the Phoebe solar facility attributable to a net unfavourable impact of lower revenues due to lower average selling prices over lower operational expenses. The **Adjusted EBITDA Margin,** excluding the February 2021 Texas Events, on a normalized basis, was down from 68.2% to 66.4% mainly explained by the weight of the recent acquisition in Chile for which margins are lower.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Net Loss

Net loss of $217.9 million ($1.24 loss per share - basic and diluted) for the three-month period ended March 31, 2021, compared with a net loss of $46.9 million ($0.35 loss per share - basic and diluted) for the corresponding period in 2020.

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

In addition to the hydroelectric, wind and solar segments' respective operating performance previously explained, the $170.9 million increase in net loss mainly stems from:

- the **February 2021 Texas Events**, resulting in a net unfavourable impact of $81.3 million (refer to the "February 2021 Texas Events" section of this MD&A for more information);
- the recognition of an aggregate $112.6 million in **impairment charges through the Corporation's share of loss of the Flat Top and Shannon joint ventures**, at $53.8 million and $58.8 million, respectively;
- an $11.6 million decrease in **other income mainly related to tax attributes allocated to the tax equity investors** at the Phoebe solar facilities, largely related to a decrease in tax depreciation, which was recognized primarily during the first two years of operations; and
- a $6.3 million unfavourable movement in the unrealized portion of change in fair value of financial instruments mainly related to **the Phoebe power hedge** and to an **unfavourable variation of foreign exchange rates on the foreign currency-denominated intragroup loans**.

These items were partly offset by:

- a $40.5 million increase in **recovery of income tax**, mainly related to the impacts of the February 2021 Texas Events, and from the Flat Top and Shannon impairment charges; and
- a favourable $21.0 million movement in the **realized portion of the change in fair value on the Phoebe basis hedge**, compared with the same period in 2020.

3- FINANCIAL PERFORMANCE ON OPERATING RESULTS | Adjusted Net Loss

The Adjusted Net Loss seeks to provide a measure that eliminates the earnings impacts of certain derivative financial instruments and non-recurring events, which do not represent the Corporation's operating performance. Adjusted Net Loss is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with measures presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information

References to "Adjusted Net Loss" are to net earnings or losses of the Corporation, to which the following elements are added (subtracted): unrealized portion of the change in fair value of financial instruments; realized portion of the change in fair value of the Phoebe basis hedge, realized loss on the termination of interest rate swaps, realized gain on foreign exchange forward contracts, impairment charges, specific unusual or non-recurring events such as the February 2021 Texas Events, the net income tax expense (recovery) related to these items, and the share of loss of joint ventures and associates (income) related to the above items, net of related tax.

The table below shows a summary statement of Adjusted Net Earnings (Loss) (Please refer to the "Non-IFRS Measures" for a reconciliation to the Consolidated Statements of Earnings):

	Three months ended March 31	
	2021	2020
Revenues	134,684	132,116
Expenses:		
Operating expenses	30,993	27,547
General and administrative expenses	9,750	10,511
Prospective project expenses	5,789	3,639
Adjusted EBITDA	88,152	90,419
Finance costs	59,600	60,330
Other net income	(11,589)	(23,497)
Depreciation and amortization	58,885	53,567
Share of (earnings) losses of joint ventures and associates	5,384	4,218
Realized (gains) losses on power hedges	(3,654)	(2,199)
Income tax expense	7,066	7,503
Adjusted Net Loss[1]	(27,540)	(9,503)

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 for more information.

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

Adjusted Net Loss of $27.5 million for the three-month period ended March 31, 2021, compared with an Adjusted Net Loss of $9.5 million for the corresponding period in 2020.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously explained, the $18.0 million increase in Adjusted Net Loss mainly stems from:

- an $11.9 million decrease in **other income mainly related to tax attributes allocated to the tax equity investors** at the Phoebe solar facility, largely related to a decrease in tax depreciation, which was recognized primarily during the first two years of operations; and
- a $5.3 million increase in **depreciation and amortization, mainly attributable to the Mountain Air and Salvador Acquisitions**.

3- FINANCIAL PERFORMANCE ON OPERATING RESULTS | Non-Controlling Interests

Attribution of loss of $3.7 million to non-controlling interests for the three-month period ended March 31, 2021, compared with a earnings of $6.8 million for the corresponding period in 2020

The $10.5 million increase in loss attributed to non-controlling interests is mainly due to an unfavourable variation of foreign exchange rates on the foreign currency-denominated intragroup loans in Innergex Europe. This was partly offset by the earnings allocated to non-controlling interests of Mountain Air, following its acquisition in the third quarter of 2020.

4- CAPITAL AND LIQUIDITY | Capital Structure

Our capital structure consists of the following components as shown below:

	As at March 31, 2021	As at December 31, 2020
Equity[1]		
Common shares[2]	3,837,985	4,778,325
Preferred shares[3]	105,760	99,364
Non-controlling interests	58,274	62,078
	4,002,019	4,939,767
Long-term loans and borrowings[1]		
Corporate revolving credit facility	340,769	182,996
Other corporate debt	150,000	266,627
Project-level debt	3,841,635	3,839,799
Tax Equity financing	308,647	315,958
Convertible debentures	278,477	280,075
Deferred financing costs	(65,875)	(71,574)
	4,853,653	4,813,881
	8,855,672	9,753,648

1. Common and preferred shares are presented at their market value as at March 31, 2021, and December 31, 2020, while non-controlling interests and long-term loans and borrowings are presented at their respective book value.
2. Consists of the number of common shares outstanding as at March 31, 2021, and December 31, 2020, multiplied by the prevailing share price of $21.97 (2020 - $27.37) at the close of markets.
3. Consists of the number of preferred shares outstanding as at March 31, 2021, and December 31, 2020, multiplied by the prevailing share price of $16.40 and $25.00 (2020 - $14.46 and $25.10), for the Series A and Series C preferred shares, respectively at the close of markets.

Innergex's strategy in managing its capital is: (i) to develop or acquire high-quality renewable power production facilities that generate sustainable and stable cash flows, with the objective of achieving a high return on invested capital, and (ii) to distribute a stable dividend.

Innergex determines the amount of capital required, and its allocation between debt and equity, for the acquisition and development of new electricity-generating facilities by considering the specific characteristics of stability and growth of each facility. This determination is made in order to distribute a stable dividend while maintaining an acceptable level of indebtedness. Generally, equity is the primary source of financing for the development of projects, while long-term loans and borrowings are used to finance the construction projects. The Corporation expects to finance 70% to 85% of its construction costs mostly through non-recourse long-term debt financing or tax equity financing for qualifying projects in the United States.

The common and preferred shares structure remained consistent, compared to December 31, 2020. The market value was therefore impacted mainly by a net unfavourable change in the share prices, partly offset by a slight increase in the number of common shares outstanding (refer to the "Information on Capital Stock" section of this MD&A for more information). The decrease in non-controlling interests stems principally from the unfavourable variation of foreign exchange rates on the foreign currency-denominated intragroup loans in Innergex Europe. The increase in long-term loans and borrowings mainly relates to the net draws, made mostly toward the construction of the Griffin Trail project, partly offset by the strengthening of the Canadian Dollar against the Euro.

The effective all-in interest rate on the Corporation's long-term loans and borrowings was 4.39% as at March 31, 2021 (4.50% as at December 31, 2020).

Credit Agreements – Material Financial and Non-Financial Conditions

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

As at March 31, 2021, the Corporation and its subsidiaries have met all material financial and non-financial conditions, unless indicated below, related to their credit agreements, trust indentures and PPAs. Were they not met, certain financial and non-financial covenants included in the credit agreements, trust indentures and PPAs entered into by various subsidiaries of the Corporation could limit the capacity of these subsidiaries to transfer funds to the Corporation. These restrictions could have a negative impact on the Corporation's ability to meet its obligations. The Mesgi'g Ugju's'n project was in breach of its credit agreement as at March 31, 2021, and December 31, 2020. The breach was triggered by the bankruptcy of a supplier considered a major project participant under the credit agreement. A waiver has been obtained and was subsequently extended until May 31, 2021. A plan was put in place to ensure the continuity of the operations of the project. Ongoing dialogue and reporting are provided to the project lenders until this situation is resolved. If the waiver is not renewed, the lenders would have the right to request repayment. As a result, the $215.8 million ($219.0 million in 2020) portion of the loan that would otherwise be classified as long-term was reallocated to the current portion of long-term loans and borrowings. As at March 31, 2021, and as at December 31, 2020, the project was in compliance with financial covenants.

The Montjean and Theil-Rabier facilities were not meeting their respective targeted debt coverage ratios as at March 31, 2021, and December 31, 2020, which triggered a breach under their respective credit agreement. This was due to two blade incidents, which caused business interruptions of both Montjean and Theil-Rabier facilities for an extended period, which were subsequently followed by several production restrictions. Assuming the situation is not resolved, the lenders would have the right to request repayment, and as a result, the €11.7 million ($17.2 million) portion of the loan that would otherwise be classified as long-term of each debt was reallocated to the current portion of long-term loans and borrowings.

The Mountain Air facilities were in breach under their credit agreements as at March 31, 2021, and December 31, 2020, due to a non-respect of a specific requirement of the insurance clause. A waiver was obtained until June 30, 2021. If the situation is not resolved and the waiver is not renewed, the lenders would have the right to request repayment, and as a result, the US$113.7 million ($143.0 million) portion of the loan that would otherwise be classified as long-term was reallocated to the current portion of long-term loans and borrowings.

The Phoebe Solar Facility received from its lenders a notice of a potential event of default. Such potential default is related to certain unpaid amounts following the February 2021 Texas Events, which are under dispute for correctness as the Corporation seeks an adjustment for the portion that relates to a claimed force majeure event. The Corporation believes that no default exists under these circumstances and responded accordingly. While discussions are ongoing, the US$104.2 million ($131.1 million) portion of the loan that would otherwise be classified as long-term was reallocated to the current portion of long-term loans and borrowings.

The Fitzsimmons Creek facility did not meet the minimum working capital requirement as at March 31, 2021, which triggered a breach under its credit agreement. Assuming the situation is not resolved, the lenders would have the right to request repayment, and as a result, the $18.2 million portion of the loan that would otherwise be classified as long-term was reallocated to the current portion of long-term loans and borrowings.

The Corporation believes these breaches, and cures thereof, are substantially under its control and lenders request for repayment are very unlikely to occur.

4- CAPITAL AND LIQUIDITY | Tax Equity Investment

The Corporation owns equity interests in some facilities that are eligible for tax incentives available for renewable energy facilities in the United States. With its current portfolio of renewable energy facilities, Innergex cannot fully monetize such tax incentives. To take full advantage of these incentives, the Corporation partners with Tax Equity Investors (“TEI”) who invest in these facilities in exchange for a share of the tax credits.

Some TEI financing structures include a partial pay as you go ("Pay-go") funding arrangement under which, when the actual annual MWh production exceeds a certain production threshold, the TEI are obligated to make a cash contribution (“Pay-go Contribution”) to the Corporation. The Pay-go arrangement results in a lower initial investment by the TEI and provides them with some protection from potential underperformance of the asset.

Innergex recognizes the TEI contributions as long-term loans and borrowings, at an amount representing the proceeds received from the TEI in exchange for shares of the subsidiary, net of the following elements:

Elements affecting amortized cost of the tax equity financing	Description
Production Tax Credits ("PTC")	Allocation of PTCs to the TEI derived from the power generated during the period and recognized in other net income as earned and as a reduction in tax equity financing
Investment Tax Credits ("ITC")	Allocation of ITCs to the TEI stemming from the construction activities and recognized as a reduction in both the cost of the assets to which they relate and the tax equity financing
Taxable income (loss), including tax attributes such as accelerated tax depreciation	Allocation of taxable income and other tax attributes to the TEI recognized in other net income as earned and as a reduction in tax equity financing
Interest expense	Interest expense using the effective interest rate method recognized in finance costs as incurred and as an increase in tax equity financing
Pay-go contributions	Additional cash contributions made by the TEI when the annual production exceeds the contractually determined threshold and recognized as an increase in tax equity financing
Cash distributions	Cash allocation to the TEI, recognized as a reduction in tax equity financing

Production Tax Credit Program ("PTC")
Current United States tax law allows wind energy projects to receive tax credits that are earned for each MWh of generation during the first 10 years of the projects' operation. The TEIs are allocated a portion of the renewable energy facility's taxable income (losses) and PTCs produced and a portion of the cash generated by the facility until they achieve an agreed-upon after-tax investment return ("Flip Point"). After the Flip Point, TEIs will retain a lesser portion of the cash and the taxable income (losses) generated by the facility.

	Commercial Operation Date	Expected TEI Flip Point	TEI Investment (M$)	Expected Annual PTC Generation[3] (M$)	Expected Annual Pay-go Contribution[4] (M$)	TEI Allocation of Taxable Income (Loss) and PTCs (Pre-Flip Point)	TEI Allocation of Cash Distributions (Pre-Flip Point)
Shannon[1,2,5]	2015	Under review[5]	274.2	22.4	—	99.00 %	64.10 %
Flat Top[1,2,5]	2018	Under review[5]	267.2	27.4	—	99.00 %	21.97 %
Foard City[1,2,4]	2019	2029	372.7	41.0	4.4	99.00 %	5.00 %

1. Before the Flip Point, TEI cash distributions are based on a quarterly test measurement of cumulative generation for the project since commercial operations date. Lower production could result in a higher cash allocation to the TEI or a change to the Flip Point. Figures provided are for the period ended March 31, 2021.
2. TEIs in U.S. projects generally require certain sponsor guarantees as a condition for their investment. To support the tax equity investments at Shannon, Flat Top and Foard City, Alterra, a subsidiary of Innergex, executed a guarantee indemnifying the TEIs against certain breaches of project-level representations, warranties and covenants. The Corporation believes these indemnifications cover matters that are substantially within its control, and are very unlikely to occur.
3. Based on the gross estimated LTA and the current credit of US$25/MWh generated for the period from COD to Flip Point, translated into Canadian dollars at 1.2575. PTCs generation will vary depending on actual production.
4. Average annual Pay-go Contributions estimate is based on PTCs generated on gross estimated LTA for each year from COD to Flip Point, translated into Canadian dollars at 1.2575. Pay-go Contributions will be earned on actual production in excess of a specified annual threshold, subject to a contractual cumulative maximum.
5. Due to the adverse financial impacts of the February 2021 Texas Events (refer to the "February 2021 Texas Events" section of this MD&A for more information), the Corporation is currently assessing the impacts on the TEI Flip Point dates of its Texas facilities subject to power hedges.

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

Investment Tax Credit Program (“ITC”)

Current United States tax law allows wind and solar facilities to receive a one-time federal tax credit, calculated on the basis of the facility's capital cost. Projects that began construction through 2019 are eligible for 30% ITC. This credit steps down to 26% for facilities that began construction in 2021 and 2022, 22% in 2023 and 10% thereafter.

	Commercial Operation Date	Expected TEI Flip Point	TEI Investment (M$)	TEI Allocation of Taxable Income (Loss) and ITC (Pre-Flip Point)	TEI Preferred Allocation of Cash (Pre-Flip Point)
Phoebe [1,2,3,7]	2019	Under review[7]	244.3	67.00 %	10.62% in excess of priority distribution
Hillcrest [1,4,5,6]	2021	2028	29.8	99.00 %	4.23 %

1. TEIs in U.S. projects generally require certain sponsor guarantees as a condition for their investment. To support the tax equity investments at Phoebe, Alterra, a subsidiary of Innergex, executed a guarantee indemnifying the TEIs against certain breaches of project-level representations, warranties and covenants. The Corporation believes these indemnifications cover matters that are substantially within its control, and are very unlikely to occur.
2. Phoebe’s cash distribution amounts to the TEI are fixed and defined within the TEI partnership agreement. All amounts of distributable cash in excess of this defined threshold are distributed at the rate of 10.62% and 89.38% to the TEI and Innergex respectively.
3. TEI Allocation of taxable income (loss) and ITC are 99% until February 15, 2020, down to 67.00% from February 15, 2020, to December 31, 2024, and then back to 99.00% until TEI Flip Point.
4. Hillcrest Solar Partners received US$22.4 million ($29.8 million) from the TEI in return for its Class A membership interest, representing 20% of the TEI's total investment. The remaining funding of US$89.7 million ($112.7 million) is to be received upon commissioning of the project.
5. Hillcrest allocation of taxable income (loss) and ITCs is 99.00% to the TEI. From January 1, 2025, to December 31, 2025, allocation of taxable income (loss) to the TEI will be 67.00%, and 5.00% thereafter.
6. Hillcrest’s cash distribution amounts to the TEI are fixed and defined within the partnership agreement. All amounts of distributable cash above these fixed and defined distributions are distributed at the rate of 4.23% to the TEI, until the Flip Point date.
7. Due to the adverse financial impacts of the February 2021 Texas Events (refer to the "February 2021 Texas Events" section of this MD&A for more information), the Corporation is currently assessing the impacts on the TEI Flip Point dates of its Texas facilities subject to power hedges.

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

4- CAPITAL AND LIQUIDITY | Financial Position

As at	March 31, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	181,390	161,465
Restricted cash	66,202	67,477
Investment tax credits recoverable	109,471	106,353
Other current assets	122,392	117,157
Total current assets	479,455	452,452
Non-current assets		
Property, plant and equipment	5,038,284	5,053,125
Intangible assets	885,048	919,323
Investments in joint ventures and associates	235,982	446,837
Goodwill	74,069	75,932
Other non-current assets	196,259	206,563
Total non-current assets	6,429,642	6,701,780
Total assets	6,909,097	7,154,232
LIABILITIES		
Current liabilities	1,207,149	1,036,730
Non-current liabilities		
Long-term loans and borrowings	3,955,642	4,046,714
Other non-current liabilities	881,708	999,856
Total non-current liabilities	4,837,350	5,046,570
Total liabilities	6,044,499	6,083,300
SHAREHOLDERS' EQUITY		
Equity attributable to owners	806,324	1,008,854
Non-controlling interests	58,274	62,078
Total shareholders’ equity	864,598	1,070,932
	6,909,097	7,154,232

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

Working Capital Items

As at March 31, 2021, working capital was negative at $727.7 million, from negative $584.3 million in 2020, mainly explained by:

Current assets amounted to $479.5 million as at March 31, 2021, an increase of $27.0 million compared with December 31, 2020, mainly due to a $19.9 million increase in cash and cash equivalents resulting from the Foard City facility being favourably impacted by the February 2021 Texas Events. In addition, there was a $3.1 million increase in investment tax credits recoverable relating to the Hillcrest construction activities.

Current liabilities amounted to $1,207.1 million as at March 31, 2021, an increase of $170.4 million compared with December 31, 2020, mainly due to a $130.3 million increase in the current portion of long-term debts, which primarily relates to the classification of the Phoebe and Fitzsimmons Creek long-term debt as current following the notice from its lenders of a potential event of default, and not meeting the minimum working capital requirement, respectively.

Derivative financial instruments also contributed favourably to the working capital balance (please refer to the "Financial Position – Derivative Financial Instruments and Risk Management" subsection below for more information).

The Corporation considers its current level of working capital to be sufficient to meet its needs, considering a total amount of $542.5 million of the loan that would otherwise be classified as long-term was reallocated to the current portion of long-term loans and borrowings (see the "Capital Structure" section of this MD&A for more information). As at March 31, 2021, the Corporation had $700.0 million in revolving term credit facilities and had drawn $340.8 million as cash advances, while $59.0 million had been used to issue letters of credit, leaving $300.2 million available.

Non-current assets

Non-current assets amounted to $6,429.6 million as at March 31, 2021, a decrease of $272.1 million compared with December 31, 2020, mainly due to a $210.9 million decrease in investments in joint ventures and associates. The Corporation's total share of losses of joint ventures and associates is $208.0 million, which is mainly the consequence of the February 2021 Texas Events, aggregating to a share of losses of $64.2 million for Innergex, and impairment charges recognized by the Flat Top and Shannon facilities through the Corporation's share of losses of joint ventures and associates, at $53.8 million and $58.8 million for Flat Top and Shannon, respectively.

The net decreases of $34.3 million in intangibles and $14.8 million in property, plant and equipment, are mostly due to $58.9 million of depreciation and amortization, and a strengthening of the Canadian dollar against the Euro. The decrease in property, plant and equipment is partly offset by additions during the period, related primarily to the Hillcrest and Griffin Trail projects under construction, aggregating to $99.8 million, net of the ITC recoverable recognized against the Hillcrest construction costs.

Derivative financial instruments also contributed to decreasing non-current assets (please refer to the "Financial Position – Derivative Financial Instruments and Risk Management" subsection below for more information).

Non-current liabilities

Non-current liabilities amounted to $4,837.4 million as at March 31, 2021, a decrease of $209.2 million compared with December 31, 2020, mainly due to a $91.1 million decrease in long-term loans and borrowings, which primarily relates to the classification of the Phoebe and Fitzsimmons Creek long-term debt as current following the notice from its lenders of a potential event of default, and not meeting the minimum working capital requirement, respectively. In addition, the decrease is also explained by a strengthening of the Canadian dollar against the Euro, partly offset by the net draws, made mostly toward the construction of the Griffin Trail project.

Derivative financial instruments also contributed to decreasing non-current liabilities (please refer to the "Financial Position – Derivative Financial Instruments and Risk Management" subsection below for more information).

Shareholders' Equity

As at March 31, 2021, Shareholders' equity decreased by $206.3 million compared with December 31, 2020, mainly due to the dividends declared on common and preferred shares totaling $32.9 million, and the total comprehensive loss of $172.5 million.

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, to manage its exposure to exchange rate fluctuations on the future repatriation of cash flows from its French operations, and to reduce exposure to the risk of decreasing power prices.

The aggregate fair value of derivative financial instruments amounted to a net liability of $79.3 million as at March 31, 2021, from a net liability of $151.0 million as at December 31, 2020. The increase in fair value is mainly due to an upward shift in interest rate curves, which favourably impacted the interest rate swaps portfolio, an upward shift in the EUR-CAD forward curve, which favourably impacted the foreign exchange forward contracts portfolio, and a decrease in the estimated basis difference, combined with the passage of time, which favourably impacted the Phoebe basis hedge. These increases in fair value were partly offset by a decrease in the fair value of the Phoebe power hedge, following an increase in the merchant price curves.

Contingencies

February 2021 Texas Events

In February 2021, unprecedented extreme winter weather conditions and related electricity market failure paralyzed the state of Texas, United States. These unprecedented extreme winter weather events pushed the Texas Government to declare a disaster and the US Government to declare a state of emergency. The storm disturbed production, transmission and distribution of power, severely impacting prices. Because of the disturbance, wholesale electricity prices in the Electric Reliability Council of Texas (ERCOT) reached their cap of US$9,000 per MWh and remained at such a level for a prolonged period of time. The February 2021 Texas Events lasted from February 11 to February 19, 2021. The combined effect of supply interruptions, abnormal market pricing conditions and contractual obligations to supply a predetermined daily generation under the power hedges, have had a net unfavourable impact at the Corporation's Phoebe solar facility located in Winkler County, Flat Top wind facility in Mills County, and Shannon wind facility in Clay County.

Phoebe

As a consequence of the February 2021 Texas Events, a claim of Force Majeure was notified to the counterparty of the power hedge of the Phoebe facility in February, which was rejected by the recipient. Discussions are in progress with the counterparty of the power hedge.

Flat Top and Shannon

As a consequence of the February 2021 Texas Events, a claim of Force Majeure was notified to the counterparty of the power hedges of the Flat Top and Shannon facilities in February, which were rejected by the recipient. To preserve the Corporation’s and its partners’ rights with regard to the Flat Top and Shannon facilities, court proceedings were initiated on April 21, 2021. On May 6, 2021, the Court heard the temporary injunction application to suspend all remedies, including foreclosure, against the Flat Top and Shannon facilities, arising from an alleged default of payment that was formally disputed and will render its decision by May 20, 2021. If it does deny the application, then the counterparty to the power hedges for the two facilities will not be precluded from exercising any of its remedies, including foreclosure. The Corporation and its partners in the Flat Top and Shannon projects are now evaluating and considering all commercially reasonable options to enforce the rights of the projects under the power hedges.

Given its understanding of currently available information and on the basis that the projects are non-recourse to the Corporation, the financial exposure of the Corporation is limited to the non-cash impacts, if any, on the Corporation's provision for income taxes and potential reversal of exchange differences in accumulated other comprehensive income related to these two projects, as the carrying amount of its equity investments in Flat Top and Shannon was nil as at March 31, 2021, following the $53.8 million and $58.8 million respective impairment charges recognized by the Corporation through its share of loss of joint ventures and associates during the three-month period ended March 31, 2021.

Harrison Hydro L.P. Water Rights

On March 23, 2017, the Comptroller of the Water Rights issued adjusted rental statements to the Harrison Hydro L.P. and its subsidiaries for the years 2011 and 2012 for an amount of $3.2 million in aggregate regarding water rental rates to be charged under the Water Act. The amount claimed was paid under protest and Harrison Hydro L.P. and its subsidiaries filed a notice of appeal of the decision to the Environmental Appeal Board.

On July 26, 2019, the Environmental Appeal Board of British Columbia rendered a decision granting the appeal and ordering the Comptroller of Water Rights to reimburse to each of the Limited Partnerships its proportionate share of the adjusted water rental amounts of $3.2 million overcharged to Harrison Hydro L.P. and its subsidiaries for the years 2011 and 2012. On November 22, 2019, the Environmental Appeal Board of British Columbia rendered another decision confirming that the sum will accrue interest starting June 28, 2017 until the date it is refunded. On January 20, 2020, the Comptroller of Water Rights filed with the Supreme Court of British Columbia a petition for judicial review of the Environmental Appeal Board’s order to return the amount in water rental fees to Harrison Hydro L.P. and its subsidiaries, with interest. The Corporation recognized a receivable in the amount of $3.2 million during the year ended December 31, 2019. On January 31, 2020, the Comptroller of Water Rights transferred an amount equal to the receivable recorded, representing the principal of $3.2 million with interest accrued between June 28, 2017, and January 31, 2020, to a trust account established by Harrison Hydro L.P. and its subsidiaries’ external legal counsel, bearing interest in favour of the Appellants. The Limited Partnerships have filed their response to petition on April 14, 2020. The hearing took place in Victoria in the last week of September 2020. A decision was rendered on February 9, 2021, by the Supreme Court of British Columbia, which concluded that the Environmental Appeal Board's decision was reasonable, and dismissed the Comptroller of Water Rights' petition accordingly. In March 2021, the Comptroller of Water Rights informed the Corporation that it will appeal the decision of the British Columbia Supreme Court.

BC Hydro Curtailment Notices

In May 2020, Innergex received notices from BC Hydro in relation to six of the Corporation’s hydroelectric facilities in British Columbia stating that BC Hydro would not accept and purchase energy under the applicable electricity purchase agreements (“EPAs”) above a specified curtailment level for the period from May 22, 2020, to July 20, 2020. The specified curtailment levels were 0.0 MW/h for the Jimmie Creek (accounted for using the equity method), Upper Lillooet River, Northwest Stave River, and Boulder Creek facilities, 2.0 MW/h for the Tretheway Creek facility and 4.0 MW/h for the Big Silver Creek facility.

BC Hydro cites the current COVID-19 pandemic and related governmental measures taken in response to it as constituting a “force majeure” event under the EPAs, and resulting in a situation in which BC Hydro is unable to accept or purchase energy under the EPAs. The notices to Innergex follow public statements by BC Hydro regarding measures it is taking to address the reduced electricity demand during the COVID-19 pandemic and related challenges to the safe operation of its hydroelectric system.

Innergex disputes that the current pandemic and related governmental measures in any way prevent BC Hydro from fulfilling its obligations to accept and purchase energy under the EPAs or enable it to invoke “force majeure” provisions under the EPAs to suspend these obligations. Innergex acknowledges that BC Hydro retains “turn-down” rights under the EPAs, which enable it to require Innergex to turn down or shut off its facilities in certain circumstances, including in order to avoid a safety or stability risk. Where BC Hydro exercises this right, it is required under the EPAs to compensate Innergex for energy that would have been produced at the facilities in the absence of the curtailment. Innergex has complied with BC Hydro’s curtailment request, but has done so under protest and seeks to enforce its rights under the EPAs on the basis described above. For the period from May 22, 2020, to July 20, 2020, actual eligible energy revenue that would have been produced at the facilities in the absence of the curtailment amounts to $13.0 million ($14.8 million on a Revenues Proportionate[1] basis).

1. Revenues Proportionate 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.

Off-Balance-Sheet Arrangements

As at March 31, 2021, the Corporation had issued letters of credit totaling $240.8 million, including $59.0 million from its available corporate facilities, to meet its obligations under its various PPAs and other agreements. These letters of credit were issued as payment securities for various projects under construction and as performance or financial guarantees under PPAs and other contractual obligations. As at that date, Innergex had also issued a total of $57.6 million in corporate guaranties used mainly to guarantee certain activities of prospective projects. The corporate guaranties were also used to support the long-term currency hedging instruments of its operations in France, and the performance of the Brown Lake and Miller Creek hydroelectric facilities.

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, Flat Top, Kokomo, Spartan, Foard City, Phoebe, Hillcrest, Griffin Trail and Mountain Air, Alterra Power Corp, a subsidiary of Innergex, has executed guaranties 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. With respect to the Phoebe facility, Alterra has also provided guarantees in favor of the project, which will become effective only in the unlikely event that the Phoebe tax equity investors call upon their corresponding guarantee.

4- CAPITAL AND LIQUIDITY | Cash Flows

	Three months ended March 31			
	2021	February 2021 Texas Events (9 days)[1]	2021 Normalized	2020
OPERATING ACTIVITIES				
Cash flows from operating activities	59,970	(16,801)	43,169	19,033
FINANCING ACTIVITIES				
Cash flows from financing activities	45,185	—	45,185	133,207
INVESTING ACTIVITIES				
Cash flows used in investing activities	(81,884)	—	(81,884)	(49,617)
Effects of exchange rate changes on cash and cash equivalents	(3,346)	—	(3,346)	12,161
Net change in cash and cash equivalents	19,925	(16,801)	3,124	114,784
Cash and cash equivalents, beginning of period	161,465	—	161,465	145,635
Cash and cash equivalents, end of period	181,390	(16,801)	164,589	260,419

1. Please refer to the "February 2021 Texas Events.

Cash Flows from Operating Activities

For the three-month period ended March 31, 2021, cash flows from operating activities totalled $60.0 million, compared with $19.0 million in the same period last year. The February 2021 Texas Events contributed to a $16.8 million increase in cash flows from operating activities. Excluding the impacts from the February 2021 Texas Events, the increase relates primarily to a favourable $21.0 million change in the realized loss on the Phoebe basis hedge, and the contribution from the Salvador and Mountain Air facilities following their acquisition during the second and third quarter of 2020, respectively.

Cash Flows from Financing Activities

For the three-month period ended March 31, 2021, cash flows from financing activities totalled $45.2 million, compared with $133.2 million in the same period last year. The decrease stems mainly from the $659.9 million cash inflow last year from the Hydro-Québec Private Placement, partly offset by the increase in proceeds received from construction loan draws, net of long term debt repayment for a total of $84.0 million in 2021 compared with a net repayment of long-term debt of $496.4 million in 2020.

Cash Flows Used in Investing Activities

For the three-month period ended March 31, 2021, cash flows used in investing activities totalled $81.9 million, compared with $49.6 million in the same period last year. The increase is mainly due to the additions to property, plant, and equipment related the Hillcrest and Griffin Trail projects under construction.

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

4- CAPITAL AND LIQUIDITY | Free Cash Flow and Payout Ratio

Free Cash Flow and Payout Ratio calculation[1]	Trailing twelve months ended March 31			
	2021	February 2021 Texas Events (9 days)[5]	2021 Normalized	2020
Cash flows from operating activities	276,045	(16,801)	259,244	206,480
Add (Subtract) the following items:				
Changes in non-cash operating working capital items	(34,821)	33,894	(927)	(14,741)
Maintenance capital expenditures, net of proceeds from disposals	(3,531)	—	(3,531)	(6,894)
Scheduled debt principal payments	(151,609)	—	(151,609)	(134,127)
Free Cash Flow attributed to non-controlling interests[2]	(15,701)	—	(15,701)	(7,929)
Dividends declared on Preferred shares	(5,865)	—	(5,865)	(5,942)
Add (subtract) the following non-recurring elements:				
Realized loss on contingent considerations	3,568	—	3,568	—
Realized loss on termination of interest rate swaps	2,885	—	2,885	4,145
Transaction costs related to realized acquisitions	1,664	—	1,664	264
Realized loss on the Phoebe basis hedge[3]	1,127	(1,304)	(177)	31,355
Income tax paid on realized intercompany gain	—	—	—	10,594
Recovery of maintenance capital expenditures and prospective project expenses on sale of HS Orka, net of attribution to non-controlling interests[4]	—	—	—	8,242
Free Cash Flow[5]	73,762	15,789	89,551	91,447
Dividends declared on common shares	125,649	—	125,649	103,025
Payout Ratio[5]	170 %	(30)%	140 %	113 %
Adjust for the following items:				
Prospective projects expenses			18,858	12,113
Adjusted Free Cash Flow			108,409	103,560
Dividends declared on common shares - DRIP adjusted			120,224	99,969
Adjusted Payout Ratio			111 %	97 %

1. Free Cash Flow, Adjusted Free Cash Flow, Payout Ratio and Adjusted 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 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. Due to their limited occurrence (over the remaining contractual period of 9 months), gains and losses on the Phoebe basis hedge are deemed not to represent the long-term cash-generating capacity of Innergex.
4. The sale of HS Orka has allowed for the recovery of maintenance capital expenditures and prospective project expenses incurred thereon since the acquisition of the project in February 2018, totaling $5.7 million and $9.6 million, respectively. An amount of $7.1 million was deducted from the total recovery as it pertains to non-controlling interests.
5. For the trailing twelve months ended March 31, 2021, the Free Cash Flow and Payout Ratio are normalized to exclude the impacts of the February 2021 Texas Events. Please refer to the "February 2021 Texas Events" section for more information.

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

Free Cash Flow

For the trailing twelve months ended March 31, 2021, the Corporation generated Free Cash Flow of $73.8 million. Excluding the impacts from the February 2021 Texas Events (refer to the "February 2021 Texas Events" section of this MD&A for more information), the Corporation generated Normalized Free Cash Flow of $89.6 million, compared with $91.4 million for the corresponding period last year.

Normalized Free Cash Flow remained relatively consistent compared with the comparative trailing twelve months. The decrease in Normalized Free Cash Flow is mainly due to:

- an increase in debt principal payments stemming from the Phoebe and Foard City facilities, commissioned in late-2019, and from the Mountain Air Acquisition from mid-2020;
- the BC Hydro-imposed curtailment in mid-2020, citing the COVID-19 pandemic; and
- the recovery of maintenance capital expenditures and prospective project expenses following the sale of HS Orka in 2019.

These items were partly offset by:

- the contribution to cash flows from operating activities before changes in non-cash operating working capital items from the Phoebe and Foard City facilities, commissioned in late-2019, and from the Salvador and Mountain Air Acquisitions from mid-2020; and
- a decrease in interest payments on the corporate revolving credit facility concurrent with the Hydro-Québec Private Placement.

Payout Ratio

For the trailing twelve months ended March 31, 2021, the dividends on common shares declared by the Corporation amounted to 170% of Free Cash Flow. Excluding the impacts from the February 2021 Texas Events (refer to the "February 2021 Texas Events" section of this MD&A for more information), the dividends on common shares declared by the Corporation amounted to 140% of Normalized Free Cash Flow, compared with 113% for the corresponding period last year.

4- CAPITAL AND LIQUIDITY | Information on Capital Stock

The Corporation's Equity Securities

	As at		
	May 10, 2021	March 31, 2021	March 31, 2020
Number of common shares	174,807,444	174,692,091	174,104,754
Number of 4.75% convertible debentures	148,023	148,023	150,000
Number of 4.65% convertible debentures	142,056	142,056	143,750
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	262,784	262,784	642,933

As at the closing of the market on May 10, 2021, and since March 31, 2021, the increase in the number of common shares of the Corporation is attributable mainly to the issuance of 115,353 common shares related to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at March 31, 2021, the increase in the number of common shares since March 31, 2020, was attributable mainly to the conversion of a portion of the 4.65% Convertible Debentures into 73,969 common shares and the conversion of a portion of the 4.75% Convertible Debentures into 98,850 common shares. In addition, the increase was attributable to the issuance of 141,665 common shares following the cashless exercise of 411,721 options and to the issuance of 272,853 common shares related to the DRIP.

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	
	2021	2020
Dividends declared on common shares[1]	31,445	31,339
Dividends declared on common shares ($/share)	0.180	0.180
Dividends declared on Series A Preferred Shares	689	766
Dividends declared on Series A Preferred Shares ($/share)	0.202750	0.225500
Dividends declared on Series C Preferred Shares	719	719
Dividends declared on Series C Preferred Shares ($/share)	0.359375	0.359375

1. The increase in dividends declared on common shares was attributable to the increase in quarterly dividend, the issuance of common shares following the exercise of options and to the issuance of shares under the DRIP.

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

The Corporation announced on January 8, 2021, that the applicable dividend rates for its Cumulative Rate Reset Preferred Shares, Series A and Cumulative Floating Rate Preferred Shares, Series B were reset. For Series A shares, the dividend rate for the five-year period commencing on January 15, 2021, to but excluding January 15, 2026, will be 3.244% per annum, or $0.202750 per share per quarter. For Series B shares, the dividend rate for the Quarterly Floating Rate Period commencing on January 15, 2021, to but excluding April 15, 2021, will be equal to 2.91% per annum, or $0.181875 per share per quarter. As at March 31, 2021, there were no outstanding Series B Preferred Shares.

The following dividends will be paid by the Corporation on July 15, 2021:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
May 11, 2021	June 30, 2021	July 15, 2021	$0.180	$0.202750	$0.359375

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

5- 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 these indicators are important, as they provide management and the reader with additional information about Innergex's production and cash generation capabilities, its ability to sustain current dividends and its ability to fund its growth. These indicators also facilitate the comparison of results over different periods. Innergex's share of Revenues of joint ventures and associates, Revenues Proportionate, Adjusted EBITDA, Adjusted EBITDA Margin, Innergex's share of Adjusted EBITDA of joint ventures and associates, Adjusted EBITDA Proportionate, Adjusted EBITDA Margin Proportionate, Adjusted Net Earnings (Loss), Free Cash Flow, Adjusted Free Cash Flow, Payout Ratio and Adjusted Payout Ratio, are not measures recognized by IFRS and have no standardized meaning prescribed by IFRS.

Production, Revenues, Adjusted EBITDA, and corresponding Margin and Proportionate measures

References in this document to "Innergex's share of Production of the joint ventures and associates" are to Innergex's equity interest in the joint ventures' and associates' Production.

References in this document to "Innergex's share of Revenues of joint ventures and associates" are to Innergex's equity interest in the joint ventures' and associates' Revenues. References in this document to "Revenues Proportionate" are to Revenues, plus Innergex's share of Revenues of the joint ventures and associates, other income related to PTCs, and Innergex's share of the operating joint ventures' and associates' other income related to PTCs.

References in this document to “Adjusted EBITDA” are to net earnings (loss), to which are added (deducted) provision (recovery) for income tax expense, finance costs, depreciation and amortization, other net income, share of (earnings) loss of joint ventures and associates and unrealized net (gain) loss on financial instruments. References in this document to "Innergex's share of Adjusted EBITDA of joint ventures and associates" are to Innergex's equity interest in the joint ventures' and associates' Adjusted EBITDA. 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, other income related to PTCs, and Innergex's share of other income related to PTCs of the joint ventures and associates.

References in this document to "Adjusted EBITDA Margin" are to Adjusted EBITDA divided by revenues. References in this document to "Adjusted EBITDA Margin Proportionate" are to Adjusted EBITDA Proportionate, divided by Revenues Proportionate.

Innergex believes that the presentation of these measures enhances the understanding of the Corporation's operating performance. Readers are cautioned that Innergex's share of Revenues of joint ventures and associates, and Revenues Proportionate, should not be construed as an alternative to Revenues, as determined in accordance with IFRS. Readers are also cautioned that Adjusted EBITDA, Innergex's share of Adjusted EBITDA of joint ventures and associates, Adjusted EBITDA Proportionate, Adjusted EBITDA Margin, and Adjusted EBITDA Margin Proportionate, should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Financial Performance and Operating Results" section for more information.

	Three months ended March 31					
	2021			2020		
	Production (MWh)	Revenues	Adjusted EBITDA	Production (MWh)	Revenues	Adjusted EBITDA
Consolidated	1,785,947	189,651	143,119	1,679,598	132,116	90,419
Innergex's share of joint ventures and associates:						
Hydro	38,092	4,339	1,507	35,217	4,791	1,327
Wind	222,685	49,818	46,544	251,829	8,742	5,805
Solar	2,897	504	298	3,122	583	324
	263,674	54,661	48,349	290,168	14,116	7,456
PTCs and Innergex's share of PTCs generated:						
Foard City		11,389	11,389		10,931	10,931
Shannon (50%)		2,767	2,767		3,155	3,155
Flat Top (51%)		3,267	3,267		4,053	4,053
		17,423	17,423		18,139	18,139
Proportionate	2,049,621	261,735	208,891	1,969,766	164,371	116,014
Adjusted EBITDA Margin			75.5 %			68.4 %
Adjusted EBITDA Margin Proportionate			79.8 %			70.6 %

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

Below is a reconciliation of the non-IFRS measures to their closest IFRS measures:

	Three months ended March 31	
	2021	2020
Revenues	189,651	132,116
Innergex's share of Revenues of joint ventures and associates	54,661	14,116
PTCs and Innergex's share of PTCs generated	17,423	18,139
Revenues Proportionate	261,735	164,371
Net loss	(217,872)	(46,931)
Income tax expense	(41,283)	(813)
Finance costs	59,600	60,330
Depreciation and amortization	58,885	53,567
EBITDA	(140,670)	66,153
Other net income	(11,904)	(23,497)
Share of losses of joint ventures and associates	207,984	20,054
Change in fair value of financial instruments	87,709	27,709
Adjusted EBITDA	143,119	90,419
Innergex's share of Adjusted EBITDA of joint ventures and associates	48,349	7,456
PTCs and Innergex's share of PTCs generated	17,423	18,139
Adjusted EBITDA Proportionate	208,891	116,014
Adjusted EBITDA Margin	75.5 %	68.4 %
Adjusted EBITDA Margin Proportionate	79.8 %	70.6 %

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

Adjusted Net Loss

References to "Adjusted Net Loss" are to net earnings or losses of the Corporation, to which the following elements are added (subtracted): unrealized portion of the change in fair value of financial instruments; realized portion of the change in fair value of the Phoebe basis hedge, realized loss on the termination of interest rate swaps, realized gain on foreign exchange forward contracts, impairment charges, specific unusual or non-recurring events such as the February 2021 Texas Events, the net income tax expense (recovery) related to these items, and the share of loss of joint ventures and associates (income) related to the above items, net of related tax.

The Adjusted Net Loss seeks to provide a measure that eliminates the earnings impacts of certain derivative financial instruments and non-recurring events, which do not represent the Corporation's operating performance. Innergex uses derivative financial instruments to hedge its exposure to various risks. Accounting for derivatives requires that all derivatives are marked-to-market. When hedge accounting is not applied, changes in the fair value of the derivatives is recognized directly in net earnings (loss). Such unrealized changes have no immediate cash effect, may or may not reverse by the time the actual settlements occur and do not reflect the Corporation's business model toward derivatives, which are held for their long-term cash flows, over the whole life of a project. In addition, the Corporation uses foreign exchange forward contracts to hedge its net investment in its French subsidiaries. Management therefore believes realized gains (losses) on such contracts does not reflect the operations of Innergex.

Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Readers are cautioned that Adjusted Net Loss should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Operating Results" section for reconciliation of the Adjusted Net Loss.

Below is a reconciliation of Adjusted Net Loss to its closest IFRS measure:

Adjusted Net Earnings (Loss)	Three months ended March 31	
	2021	2020
Net loss	(217,872)	(46,931)
Add (Subtract):		
February 2021 Texas Events:		
Revenues	(54,967)	—
Power hedge	70,756	—
Share of loss of Flat Top and Shannon	64,197	—
Share of impairment of Flat Top and Shannon	112,609	—
Share of unrealized portion of the change in fair value of financial instruments of joint ventures and associates, net of related income tax	20,437	12,509
Unrealized portion of the change in fair value of financial instruments	16,523	10,250
Realized loss on termination of interest rate swaps	2,885	—
Realized portion of the change in fair value of the Phoebe basis hedge	1,199	19,658
Realized gain on foreign exchange forward contracts	(315)	—
Income tax recovery related to above items	(42,992)	(4,989)
Adjusted net loss	(27,540)	(9,503)

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

Below is a reconciliation of Adjusted Net Loss adjustments to each line item of the consolidated statements of earnings:

	Three months ended March 31					
	2021			2020		
	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS
Revenues	189,651	(54,967)	134,684	132,116	—	132,116
Operating expenses	30,993	—	30,993	27,547	—	27,547
General and administrative expenses	9,750	—	9,750	10,511	—	10,511
Prospective project expenses	5,789	—	5,789	3,639	—	3,639
Adjusted EBITDA	143,119	(54,967)	88,152	90,419	—	90,419
Finance costs	59,600	—	59,600	60,330	—	60,330
Other net income	(11,904)	315	(11,589)	(23,497)	—	(23,497)
Depreciation and amortization	58,885	—	58,885	53,567	—	53,567
Share of (earnings) losses of joint ventures and associates	207,984	(202,600)	5,384	20,054	(15,836)	4,218
Change in fair value of financial instruments	87,709	(91,363)	(3,654)	27,709	(29,908)	(2,199)
Income tax (recovery)	(41,283)	48,349	7,066	(813)	8,316	7,503
Net loss	(217,872)	190,332	(27,540)	(46,931)	37,428	(9,503)

Free Cash Flow and Payout Ratio

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, the portion of Free Cash Flow attributed to non-controlling interests, and preferred share dividends declared, plus or minus other elements that are not representative of the Corporation's long-term cash-generating capacity, such as gains and losses on the Phoebe basis hedge due to their limited occurrence over the next 12 months, realized gains and losses on contingent considerations related to past business acquisitions, transaction costs related to realized acquisitions, 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.

The Payout Ratio is a measure of the Corporation's ability to sustain current dividends as well as its ability to fund its growth. The Payout Ratio level reflects the Corporation's decision to invest yearly in advancing the development of its Prospective Projects, for 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. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's cash generation capabilities, its ability to sustain current dividends 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 for the reconciliation of Free Cash Flow.

References to "Adjusted Free Cash Flow" are to Free Cash Flow excluding prospective project expenses.

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 as well as its ability to fund its growth.

References to "Adjusted Payout Ratio" are to dividends declared on common shares divided by Adjusted Free Cash Flow after the impact of the DRIP.

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

6- ADDITIONAL CONSOLIDATED INFORMATION | Geographic Segments – Non-current Assets

	As at	
	March 31, 2021	December 31, 2020
Non-current assets, excluding derivative financial instruments and deferred tax assets[1]		
Canada	3,449,400	3,504,403
United States	1,853,889	1,990,997
France	861,955	922,330
Chile	163,395	166,881
	6,328,639	6,584,611

1. Includes the investments in joint ventures and associates.

6- ADDITIONAL CONSOLIDATED INFORMATION | Geographic Segments – Revenues

	Three months ended March 31	
	2021	2020
Revenues		
Canada	83,150	83,875
United States	76,033	11,851
France	28,368	36,390
Chile	2,100	—
	189,651	132,116

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

6- ADDITIONAL CONSOLIDATED INFORMATION | Historical Quarterly Financial Information

	Three months ended							
(in millions of dollars, unless otherwise stated)	March 31, 2021	Dec 31, 2020	Sept 30, 2020	June 30, 2020	March 31, 2020	Dec 31, 2019	Sept 30, 2019	June 30, 2019
Production (MWh)	1,785,947	2,186,961	2,021,559	2,185,793	1,679,598	1,793,803	1,665,362	1,741,953
Revenues	189.7	167.9	162.7	150.5	132.1	143.1	142.8	144.7
Adjusted EBITDA[1]	143.1	117.8	108.5	105.3	90.4	103.3	107.4	105.2
Net (loss) earnings	(217.9)	11.9	7.5	(1.6)	(46.9)	(47.4)	9.7	7.3
Net (loss) earnings from continuing operations attributable to owners of the parent	(214.2)	11.9	11.7	(2.5)	(53.7)	(46.8)	14.3	(7.8)
Net (loss) earnings from continuing operations attributable to owners of the parent ($ per share – basic and diluted)	(1.24)	0.06	0.06	(0.02)	(0.35)	(0.35)	0.10	(0.07)
Net (loss) earnings attributable to owners of the parent	(214.2)	11.9	11.7	(2.5)	(53.7)	(46.2)	14.1	10.8
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(1.24)	0.06	0.06	(0.02)	(0.35)	(0.35)	0.09	0.07
Dividends declared on common shares	31.4	31.4	31.4	31.4	31.3	24.4	23.9	23.4
Dividends declared on common shares, $ per share	0.180	0.180	0.180	0.180	0.180	0.175	0.175	0.175

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 for more information.

The Corporation's production, revenues, net earnings and cash flows are variable with each season, depending on the geography and source of energy. Please refer to the "Overview of Operations | Business Environment - Seasonality of Operations" section of this MD&A for more information on seasonality.

7- ACCOUNTING POLICIES AND DISCLOSURE CONTROLS | Significant Accounting Policies

New Accounting Standards and Interpretations Adopted During the Year

On January 1, 2021, the Corporation adopted the following new standards and interpretations:

Interest Rate Benchmark Reform — Phase 2 (Amendments to IFRS 9, IFRS 7, and IFRS 16)

On August 27, 2020, the IASB finalized its response to the ongoing reform of inter-bank offered rates and other interest rate benchmarks by issuing a package of amendments to IFRS Standards. The amendments complement those issued in 2019 as part of Phase 1 amendments and mainly relate to:

- changes to contractual cash flows: a company will not have to derecognize the carrying amount of financial instruments for changes required by the reform, but will instead update the effective interest rate to reflect the change to the alternative benchmark rate;
- hedge accounting: a company will not have to discontinue its hedge accounting solely because it makes changes required by the reform, if the hedge meets other hedge accounting criteria; and
- disclosures: a company will be required to disclose information about new risks arising from the reform and how it manages the transition to alternative benchmark rates.

The amendments are effective for annual periods beginning on or after January 1, 2021. Additional disclosures have been included to the financial statements.

Definition of Accounting Estimates (Amendments to IAS 8)

On February 12, 2021, the IASB issued Definition of Accounting Estimates (Amendments to IAS 8).

The amendments introduce a new definition for accounting estimates, clarifying that they are monetary amounts in the financial statements that are subject to measurement uncertainty. The amendments also clarify the relationship between accounting policies and accounting estimates by specifying that a company develops an accounting estimate to achieve the objective set out by an accounting policy. The Corporation early adopted the amendments on January 1, 2021, with no impact to the financial statements.

7- ACCOUNTING POLICIES AND DISCLOSURE CONTROLS | Disclosure Controls and Procedures

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 annual filings are being prepared; and (ii) the information required to be disclosed by the Corporation in its annual filings, interim filings and other reports filed or submitted by it under 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.

During the period from January 1, 2021, to March 31, 2021, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

8- 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 projected financial performance, power production, prospective projects, successful development, construction and financing (including tax equity funding) of the projects under construction and the advanced-stage prospective projects, sources and impact of funding, project acquisitions, execution of non-recourse project-level financing (including the timing and amount thereof), and strategic, operational and financial benefits and accretion expected to result from such acquisitions, business strategy, future development and growth prospects (including expected growth opportunities under the Strategic Alliance with Hydro-Québec), 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", "would", “plans”, “potential”, "project", “anticipates”, “estimates”, “scheduled” or “forecasts”, or other comparable terms 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, including information regarding the Corporation's expected production, the estimated project costs, projected revenues, projected Revenues Proportionate, projected Adjusted EBITDA and projected Adjusted EBITDA Proportionate, Projected Free Cash Flow, Projected Free Cash Flow per Share and intention to pay dividend quarterly, the estimated project size, costs and schedule, including obtainment of permits, start of construction, work conducted and start of commercial operation for Development Projects and Prospective Projects, the Corporation's intent to submit projects under Requests for Proposals, the qualification of U.S. projects for PTCs and ITCs and other statements that are not historical facts. Such information is intended to inform readers of the potential financial impact of expected results, of the expected commissioning of Development Projects, of the potential financial impact of completed and future acquisitions, of the Corporation's ability to sustain current dividends and to fund its growth and of the possible outcomes of the proceedings initiated in Texas with regard to the Flat Top and Shannon facilities. Such information may not be appropriate for other purposes.

Assumptions: Forward-Looking Information is based on certain key assumptions made by the Corporation, including, without restriction, those concerning hydrology, wind regimes and solar irradiation, performance of operating facilities, project performance, economic, financial and financial market conditions, the Corporation’s success in developing and constructing new facilities, expectations and assumptions concerning availability of capital resources and timely performance by third parties of contractual obligations and receipt of regulatory approvals.

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 "Risks and Uncertainties" section of the Annual Report and include, without limitation: the variability in hydrology, wind regimes and solar irradiation; the delays and cost overruns in the design and construction of projects; health, safety and environmental risks, equipment failure or unexpected operations and maintenance activity; the variability of installation performance and the related penalties; the performance of major counterparties; equipment supply; the regulatory and political risks; the increase in water rental cost or the changes to regulations applicable to water use; the availability and the reliability of the transmission systems; the assessment of water, wind and solar and the associated electricity production; global climate change; natural disasters and force majeure; pandemics, epidemics or other public health emergencies; cybersecurity; the reliance on shared transmission and interconnection infrastructure; the ability of the Corporation to execute its strategy for building shareholder value; the ability to raise additional capital and the state of the capital market; the ability to secure new PPAs or renew any PPA; the fluctuations affecting prospective power prices; uncertainties surrounding development of new facilities; the obtainment of permits; the failure to realize the anticipated benefits of completed and future acquisitions; the integration of the completed and future acquisitions; the changes in governmental support to increase electricity to be generated from renewable sources by independent power producers; social acceptance of renewable energy projects; the relationships with stakeholders; the ability to secure appropriate land; foreign market growth and development risks; the liquidity risks related to derivative financial instruments; the interest rate fluctuations and refinancing risk; the financial leverage and restrictive covenants governing current and future indebtedness; the changes in general economic conditions; the foreign exchange fluctuations; the risks related to U.S. production and investment tax credits, changes in U.S. corporate tax Rates and availability of tax equity financing; the possibility that the Corporation may not declare or pay a dividend; the ability to attract new talent or to retain officers or key employees; litigation; the exposure to many different forms of taxation in various jurisdictions; the reliance on various forms of PPAs; the sufficiency of insurance coverage; the credit rating not reflecting the actual performance of the Corporation or a lowering (downgrade) of the credit rating; the variation of the revenues from certain facilities based on the market (or spot) price of electricity; the host country economic, social and political conditions; the adverse claims to property title; unknown liabilities; the reliance on intellectual property and confidential agreements to protect the Corporation’s rights and confidential information; the reputational risks arising from misconduct of representatives of the Corporation.

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 provided as at the date of this MD&A, and the Corporation does not undertake any obligation to update or revise any Forward-Looking Information, whether as a result of events or circumstances occurring after the date hereof, unless so required by law.

Forward-Looking Information in this MD&A

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

Principal Assumptions	Principal Risks and Uncertainties
Expected production For each facility, the Corporation determines a long-term average annual level of electricity production ("LTA") over the expected life of the facility, based on engineers' studies that take into consideration a number of important factors: for hydroelectricity, the historically observed flows of the river, the operating head, the technology employed and the reserved aesthetic and ecological flows; for wind energy, the historical wind and meteorological conditions and turbine technology; and for solar energy, the historical solar irradiation conditions, panel technology and expected solar panel degradation. Other factors considered 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 LTA. On a consolidated basis, the Corporation estimates its LTA by adding together the expected LTAs of all the Operating Facilities that it consolidates. This consolidation excludes, however, the facilities that are accounted for using the equity method.	Improper assessment of water, wind and solar resources and associated electricity production Variability in hydrology, wind regimes and solar irradiation resources Equipment supply risk, including failure or unexpected operations and maintenance activity Natural disasters and force majeure Regulatory and political risks affecting production Health, safety and environmental risks affecting production Variability of installation performance and related penalties Availability and reliability of transmission systems Litigation
Projected revenues and Projected Revenues Proportionate For each facility, expected annual revenues are estimated by multiplying the LTA by a price for electricity stipulated in the PPA secured with a public utility or other creditworthy counterparty. In most cases, these PPAs stipulate a base price for electricity produced and, in some cases, a price adjustment depending on the month, day and hour of its delivery. This excludes facilities that receive revenues based on the market (or spot) price for electricity, including the Foard City, Shannon and Flat Top wind farms, the Phoebe and Salvador solar farms and the Miller Creek hydroelectric facility, which receives a price based on a formula using the Platts Mid-C pricing indices; and the Horseshoe Bend hydroelectric facility, for which 85% of the price is fixed and 15% is adjusted annually as determined by the Idaho Public Utility Commission. In most cases, PPAs 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 the Operating Facilities that it consolidates. The consolidation excludes, however, the facilities that are accounted for using the equity method.	See principal assumptions, risks and uncertainties identified under "Expected Production" Reliance on PPAs Revenues from certain facilities will vary based on the market (or spot) price of electricity Fluctuations affecting prospective power prices Changes in general economic conditions Ability to secure new PPAs or renew any PPA
Projected Adjusted EBITDA For each facility, the Corporation estimates annual operating earnings by adding (deducting) to net earnings (loss) income tax expense (recovery), finance costs, depreciation and amortization, other net income, share of (earnings) loss of joint ventures and associates and change in fair value of financial instruments.	See principal assumptions, risks and uncertainties identified under "Expected Production" and "Projected Revenues" Unexpected maintenance expenditures
Projected Adjusted EBITDA Proportionate On a consolidated basis, the Corporation estimates annual Adjusted EBITDA Proportionate by adding to the projected Adjusted EBITDA Innergex's share of Adjusted EBITDA of the operating joint ventures and associates, other income related to PTCs, and Innergex's share of the other net income of the operating joint ventures and associates related to PTCs.	See principal assumptions, risks and uncertainties identified under "Expected Production", "Projected Revenues" and "Projected Adjusted EBITDA"

Principal Assumptions	Principal Risks and Uncertainties
Projected Free Cash Flow, Projected Free Cash Flow per Share and Intention to pay dividend quarterly The Corporation estimates Projected Free Cash Flow as projected cash flows, from operating activities before changes in non-cash operating working capital items, less estimated maintenance capital expenditures net of proceeds from disposals, scheduled debt principal payments, preferred share dividends 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. The Corporation estimates the annual dividend it intends to distribute based on the Corporation's operating results, cash flows, financial conditions, debt covenants, long-term growth prospects, solvency test imposed under corporate law for declaration of dividends and other relevant factors.	See principal assumptions, risks and uncertainties identified under “Expected Production”, “Projected Revenues” and "Projected Adjusted EBITDA". Possibility that the Corporation may not declare or pay a dividend
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 and Prospective Project, the Corporation may provide (where available) an estimate of potential installed capacity, estimated storage capacity, estimated project costs, project financing terms and each project’s development and construction schedule, based on its extensive experience as a developer, in addition to information directly related to incremental internal costs, site acquisition costs and financing costs, which are eventually adjusted for the projected costs and construction schedule provided by the engineering, procurement and construction (“EPC”) contractor retained for the project. The Corporation provides indications based on assumptions regarding its current strategic positioning and competitive outlook, as well as scheduling and construction progress, for its Development Projects and its Prospective Projects, which the Corporation evaluates based on its experience as a developer.	Uncertainties surrounding development of new facilities Performance of major counterparties, such as suppliers or contractors Delays and cost overruns in the design and construction of projects Ability to secure appropriate land Obtainment of permits Health, safety and environmental risks Ability to secure new PPAs or renew any PPA Higher-than-expected inflation Equipment supply Interest rate fluctuations and financing risk Risks related to U.S. PTCs and ITCs, changes in U.S. corporate tax rates and availability of tax equity financing Regulatory and political risks Natural disaster and force majeure Relationships with stakeholders Foreign market growth and development risks Social acceptance of renewable energy projects Ability of the Corporation to execute its strategy of building shareholder value Failure to realize the anticipated benefits of completed and future acquisitions Changes in governmental support to increase electricity to be generated from renewable sources by independent power producers COVID-19 restrictive measures
Intention to respond to requests for proposals The Corporation provides indications of its intention to submit proposals in response to requests for proposals (“Request for Proposals” or “RFP”) based on the state of readiness of some of its Prospective Projects and their compatibility with the announced terms of these RFPs.	Regulatory and political risks Ability of the Corporation to execute its strategy for building shareholder value Ability to secure new PPAs Changes in governmental support to increase electricity to be generated from renewable sources by independent power producers Social acceptance of renewable energy projects Relationships with stakeholders

Principal Assumptions	Principal Risks and Uncertainties
Qualification for PTCs and ITC and expected tax equity investment Flip Point 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 a basis. To assess the potential qualification of a project, the Corporation takes into account the construction work performed and the timing of such work. The expected Tax Equity Flip Point for tax equity investment is determined according to the LTAs and revenues of each such project and is subject in addition to the related risks mentioned above.	Risks related to U.S. PTCs and ITC, changes in U.S. corporate tax 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

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

	Notes	Three months ended March 31 2021	2020
Revenues		189,651	132,116
Expenses			
Operating		30,993	27,547
General and administrative		9,750	10,511
Prospective projects		5,789	3,639
Earnings before the following:		143,119	90,419
Depreciation	8	44,297	43,121
Amortization		14,588	10,446
Earnings before the following:		84,234	36,852
Finance costs	3	59,600	60,330
Other net income	4	(11,904)	(23,497)
Share of losses of joint ventures and associates:			
Share of losses, before impairment charges	5	95,375	20,054
Share of impairment charge	5	112,609	—
Change in fair value of financial instruments	6b)	87,709	27,709
Loss before income tax		(259,155)	(47,744)
Recovery of income tax		(41,283)	(813)
Net loss		(217,872)	(46,931)
Net loss attributable to:			
Owners of the parent		(214,161)	(53,740)
Non-controlling interests		(3,711)	6,809
		(217,872)	(46,931)
Loss per share attributable to owners:			
Basic net loss per share ($)	7	(1.24)	(0.35)
Diluted net loss per share ($)	7	(1.24)	(0.35)
Loss per share attributable to owners:			
Basic net loss per share ($)	7	(1.24)	(0.35)
Diluted net loss per share ($)	7	(1.24)	(0.35)

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

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

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Notes	Three months ended March 31 2021	2020
Net loss		(217,872)	(46,931)
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:			
Foreign currency translation differences for foreign operations		(16,668)	71,617
Change in fair value of financial instruments designated as net investment hedges	6	1,682	1,024
Change in fair value of financial instruments designated as cash flow hedges	6	74,339	(92,521)
Change in fair value of financial instruments of joint ventures and associates designated as cash flow hedges		5,176	(5,892)
Related deferred income tax		(19,109)	24,168
Other comprehensive income (loss)		45,420	(1,604)
Total comprehensive loss		(172,452)	(48,535)
Total comprehensive loss attributable to:			
Owners of the parent		(169,539)	(57,190)
Non-controlling interests		(2,913)	8,655
		(172,452)	(48,535)

The accompanying notes are an integral part of these unaudited condensed interim consolidated 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, 2021	December 31, 2020
ASSETS			
Current assets			
Cash and cash equivalents		181,390	161,465
Restricted cash		66,202	67,477
Accounts receivable		93,418	92,746
Derivative financial instruments	6	10,449	9,039
Investment tax credits recoverable	8	109,471	106,353
Prepaid and other		18,525	15,372
Total current assets		479,455	452,452
Non-current assets			
Property, plant and equipment	8	5,038,284	5,053,125
Intangible assets		885,048	919,323
Project development costs		21,947	14,092
Investments in joint ventures and associates	5	235,982	446,837
Derivative financial instruments	6	72,095	92,040
Deferred tax assets		28,908	25,129
Goodwill		74,069	75,932
Other long-term assets		73,309	75,302
Total non-current assets		6,429,642	6,701,780
Total assets		6,909,097	7,154,232
LIABILITIES			
Current liabilities			
Accounts payable and other payables		251,437	190,333
Derivative financial instruments	6	51,949	72,958
Current portion of long-term loans and borrowings and other liabilities		903,763	773,439
Total current liabilities		1,207,149	1,036,730
Non-current liabilities			
Derivative financial instruments	6	109,884	179,154
Long-term loans and borrowings		3,955,642	4,046,714
Other liabilities		370,575	397,513
Deferred tax liabilities		401,249	423,189
Total non-current liabilities		4,837,350	5,046,570
Total liabilities		6,044,499	6,083,300
SHAREHOLDERS' EQUITY			
Equity attributable to owners		806,324	1,008,854
Non-controlling interests		58,274	62,078
Total shareholders' equity		864,598	1,070,932
Total liabilities and shareholders' equity		6,909,097	7,154,232

The accompanying notes are an integral part of these unaudited condensed interim consolidated 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, 2021	Equity attributable to owners								
	Common share capital account	Contributed surplus	Preferred shares	Convertible debentures	Deficit	Accumulated other comprehensive loss	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2021	4,185	2,026,415	131,069	2,843	(1,043,962)	(111,696)	1,008,854	62,078	1,070,932
Net loss	—	—	—	—	(214,161)	—	(214,161)	(3,711)	(217,872)
Other comprehensive income	—	—	—	—	—	44,622	44,622	798	45,420
Total comprehensive (loss) income	—	—	—	—	(214,161)	44,622	(169,539)	(2,913)	(172,452)
Common shares issued through dividend reinvestment plan	154	—	—	—	—	—	154	—	154
Share-based payments and Performance Share Plan	—	478	—	—	—	—	478	—	478
Convertible debentures converted into common shares and redemption	2,330	—	—	(24)	—	—	2,306	—	2,306
Shares vested - Performance Share Plan	3,174	(6,250)	—	—	—	—	(3,076)	—	(3,076)
Dividends declared on common shares (Note 10)	—	—	—	—	(31,445)	—	(31,445)	—	(31,445)
Dividends declared on preferred shares (Note 10)	—	—	—	—	(1,408)	—	(1,408)	—	(1,408)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(891)	(891)
Balance March 31, 2021	9,843	2,020,643	131,069	2,819	(1,290,976)	(67,074)	806,324	58,274	864,598

The accompanying notes are an integral part of these unaudited condensed interim consolidated 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, 2020	Equity attributable to owners								
	Common shares capital account	Contributed surplus	Preferred shares	Convertible debentures	Deficit	Accumulated other comprehensive (loss) income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2020	97,215	1,268,311	131,069	2,869	(879,849)	(15,231)	604,384	10,942	615,326
Net (loss) earnings	—	—	—	—	(53,740)	—	(53,740)	6,809	(46,931)
Other comprehensive (loss) income	—	—	—	—	—	(3,450)	(3,450)	1,846	(1,604)
Total comprehensive (loss) income	—	—	—	—	(53,740)	(3,450)	(57,190)	8,655	(48,535)
Common shares issued on February 6, 2020: private placement	660,870	—	—	—	—	—	660,870	—	660,870
Issuance fees (net of $536 of deferred income tax)	(1,469)	—	—	—	—	—	(1,469)	—	(1,469)
Common shares issued through dividend reinvestment plan	203	—	—	—	—	—	203	—	203
Share-based payments	—	18	—	—	—	—	18	—	18
Stock options exercised	137	(649)	—	—	—	—	(512)	—	(512)
Shares vested - Performance Share Plan	1,046	—	—	—	—	—	1,046	—	1,046
Shares purchased - Performance Share Plan	(3,104)	—	—	—	—	—	(3,104)	—	(3,104)
Dividends declared on common shares (Note 10)	—	—	—	—	(31,339)	—	(31,339)	—	(31,339)
Dividends declared on preferred shares (Note 10)	—	—	—	—	(1,485)	—	(1,485)	—	(1,485)
Balance March 31, 2020	754,898	1,267,680	131,069	2,869	(966,413)	(18,681)	1,171,422	19,597	1,191,019

The accompanying notes are an integral part of these unaudited condensed interim consolidated 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	
		2021	2020
OPERATING ACTIVITIES	Notes		
Net loss		(217,872)	(46,931)
Items not affecting cash:			
Depreciation and amortization		58,885	53,567
Share of loss of joint ventures and associates		207,984	20,054
Unrealized portion of change in fair value of financial instruments	6	16,523	10,250
Production tax credits and tax attributes allocated to tax equity investors	4	(11,196)	(17,282)
Other		992	18
Finance costs		59,600	60,330
Finance costs paid	11 b)	(38,622)	(37,315)
Distributions received from joint ventures and associates		6,414	5,124
Recovery of income tax		(41,283)	(813)
Income tax received (paid)		33	(1,520)
Effect of exchange rate fluctuations		(278)	(2,653)
		41,180	42,829
Changes in non-cash operating working capital items	11 a)	18,790	(23,796)
		59,970	19,033
FINANCING ACTIVITIES			
Dividends paid on common and preferred shares		(32,756)	(25,678)
Distributions to non-controlling interests		(891)	—
Increase in long-term debt, net of deferred financing costs	11 c)	271,898	70,925
Repayment of long-term debt	11 c)	(187,880)	(567,358)
Payment of other liabilities		(2,110)	(443)
Net proceeds from issuance of common shares		—	658,865
Purchase of common shares under the Performance Share Plan		—	(3,104)
Payment of payroll withholding on exercise of stock options and Performance Share Plan		(3,076)	—
		45,185	133,207
INVESTING ACTIVITIES			
Change in restricted cash		622	4,070
Additions to property, plant and equipment, net		(76,331)	(49,854)
Additions to project development costs		(7,027)	(1,813)
Investments in joint ventures and associates		(65)	—
Change in other long-term assets		917	(2,020)
		(81,884)	(49,617)
Effects of exchange rate changes on cash and cash equivalents		(3,346)	12,161
Net change in cash and cash equivalents		19,925	114,784
Cash and cash equivalents, beginning of period		161,465	145,635
Cash and cash equivalents, end of period		181,390	260,419

Additional information is presented in Note 11.
The accompanying notes are an integral part of these unaudited condensed interim consolidated 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, and its shares and convertible debentures are listed on the Toronto Stock Exchange. The Corporation is a developer, acquirer, owner and operator of renewable power-generating and energy storage facilities, essentially focused on the hydroelectric, wind and solar power sectors. The Corporation's head office is located at 1225 St-Charles Street West, 10th floor, Longueuil, QC, J4K 0B9, Canada.

These unaudited condensed interim consolidated financial statements were approved by the Board of Directors on May 11, 2021.

The Corporation's revenues are variable with each season and are normally at their highest in the second quarter and at their lowest in the first quarter. 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

Statement of Compliance

These unaudited condensed interim consolidated financial statements have been prepared in accordance with International Financial Reporting Standards (“IFRS”), as issued by the International Accounting Standards Board (“IASB”). The condensed interim 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 interim consolidated financial statements do not include all disclosures required under IFRS and, accordingly, should be read in conjunction with the audited consolidated financial statements and the notes thereto included in the Corporation’s latest annual report.

Basis of Measurement

The unaudited condensed interim consolidated financial statements have been prepared on a historical cost basis, except for certain financial instruments. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

Functional Currency and Presentation Currency

These unaudited condensed interim consolidated financial statements are presented in Canadian dollars, which is the Corporation’s functional currency.

2. SIGNIFICANT ACCOUNTING POLICIES

Changes in accounting policies

On January 1, 2021, the Corporation adopted the following new standards and interpretations which did not have a significant impact on these unaudited condensed interim consolidated financial statements:

Interest Rate Benchmark Reform - Phase 2 (Amendments to IFRS 9, IAS 39, IFRS 7, and IFRS 16)

On August 27, 2020, the IASB finalized its response to the ongoing reform of inter-bank offered rates and other interest rate benchmarks by issuing a package of amendments to IFRS Standards. The amendments complement those issued in 2019 as part of Phase 1 amendments and mainly relate to:

- changes to contractual cash flows: a company will not have to derecognize the carrying amount of financial instruments for changes required by the reform, but will instead update the effective interest rate to reflect the change to the alternative benchmark rate;
- hedge accounting: a company will not have to discontinue its hedge accounting solely because it makes changes required by the reform, if the hedge meets other hedge accounting criteria; and
- disclosures: a company will be required to disclose information about new risks arising from the reform and how it manages the transition to alternative benchmark rates.

The amendments are effective for annual periods beginning on or after January 1, 2021. Additional disclosures have been included in note 12.

Definition of Accounting Estimates (Amendments to IAS 8)

On February 12, 2021, the IASB issued Definition of Accounting Estimates (Amendments to IAS 8).

The amendments introduce a new definition for accounting estimates, clarifying that they are monetary amounts in the financial statements that are subject to measurement uncertainty. The amendments also clarify the relationship between accounting policies and accounting estimates by specifying that a company develops an accounting estimate to achieve the objective set out by an accounting policy. The Corporation early adopted the amendments on January 1, 2021, with no impact to the financial statements.

3. FINANCE COSTS

	Three months ended March 31	
	2021	2020
Interest expense on long-term corporate and project loans	43,050	43,251
Interest expense on tax equity financing	5,686	6,456
Interest expense on convertible debentures	3,395	3,478
Amortization of financing fees	2,001	2,425
Accretion expenses on other liabilities	1,255	1,322
Interest on lease liabilities	1,015	1,204
Inflation compensation interest	1,384	416
Accretion of long-term loans and borrowings	158	681
Other	1,656	1,097
	59,600	60,330

4. OTHER NET INCOME

	Three months ended March 31	
	2021	2020
Production tax credits	(11,389)	(10,931)
Tax attributes allocated to tax equity investors	193	(6,351)
Liquidated damages	(378)	(701)
Loss on repayment of loans	1,125	—
Realized loss on contingent considerations	547	—
Professional and other fees - February 2021Texas Events	311	—
Others, net	(2,313)	(5,514)
	(11,904)	(23,497)

Professional and other fees - February 2021Texas Events

During February 2021, the Corporation's facilities in Texas experienced unprecedented extreme winter weather conditions, which had an impact on their ability to produce electricity. While some power generation continued throughout the events, the combined effect of supply interruptions, abnormal market pricing conditions and contractual obligations to supply a predetermined hourly generation under the power hedges, had a net unfavourable impact at the Corporation's Flat Top wind facility in Mills County, the Shannon wind facility in Clay County, and the Phoebe solar facility located in Winkler County.

The professional and other fees represent mainly legal fees incurred following the February 2021 Texas Events for the period ended March 31, 2021.

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

5. INVESTMENTS IN JOINT VENTURES AND ASSOCIATES

Flat Top and Shannon

Following the February 2021 Texas Events, which caused important losses for facilities under power hedge contracts, a general increase in the assessed risk has been observed throughout the industry for facilities subject to shape risk[1] in this region. These factors contributed to increase discount rates to reflect higher risk premiums. On March 31, 2021, the Flat Top and Shannon joint ventures, each identified as separate cash generating units ("CGU"), recognized impairment charges of US$83,005 ($105,408) and US$92,686 ($117,702), respectively. The impairment charges were recognized by the Corporation through its share of loss of joint ventures and associates, at $53,758 and $58,851, for Flat Top and Shannon, respectively.

The recoverable amount of each CGU was determined based on a value in use calculation which uses cash flow projections based on financial budgets approved by management covering a period extending to the period for which the Corporation owns its rights on the site, and discounted at a rate of 12%.

Key assumptions used to determine the recoverable amount of assets are the following:
- the discount rate considers the weighted average between the consolidated cost of debt and the consolidated cost of equity, adjusted with alpha factors specific to the operating segment and country in which the facility operates;
- the expected selling price of electricity once the power purchase agreements and power hedges are renewed, or on the spot market;
- a cash-generating unit is an individual facility; and
- the future expected cash flows are based on the budgets before debt service and income tax of each cash-generating unit. The budgets have been built using long-term averages of expected production. These long-term averages are expected to approximate actual results.

1. Shape risk exists when there is a mismatch, or a potential mismatch, between the volume commitment under a power hedge instrument, and the actual production of the facility at a given time. For various reasons, it may happen that a facility's electricity output at a given time is below the contractual volume. In such instance, the project cannot fully cover its hub purchases with its node sales and is therefore exposed to merchant prices on its purchases at the hub.

The summarized financial information below represents amounts shown in the joint ventures' and associates' financial statements prepared in accordance with IFRS adjusted for fair value adjustments at acquisition and differences in accounting policies.

Summary Statements of Earnings (Loss) and Comprehensive Income (Loss)

	Three months ended March 31, 2021							
	Energía Llaima	Toba Montrose	Shannon	Flat Top	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville
Revenues	8,579	590	68,908	20,271	12,928	424	1,303	3,459
Operating, general and administrative expenses	3,993	2,914	2,770	2,174	2,312	808	377	381
	4,586	(2,324)	66,138	18,097	10,616	(384)	926	3,078
Finance costs	1,911	5,712	3,459	3,734	1,607	2,333	588	736
Production tax credits	—	—	(5,533)	(6,406)	—	—	—	—
Tax attributes allocated to tax equity investors	—	—	745	186	—	—	—	—
Other net expenses (income)	420	(31)	506	448	(372)	8	(4)	(4)
Depreciation and amortization	3,515	5,113	3,257	3,628	3,506	1,086	1,011	465
Impairment of property, plant and equipment	—	—	117,702	105,408	—	—	—	—
Change in fair value of financial instruments	—	(838)	114,615	143,380	—	—	(1,303)	(181)
Provision for income taxes	1,462	—	—	—	—	—	—	—
Net (loss) earnings	(2,722)	(12,280)	(168,613)	(232,281)	5,875	(3,811)	634	2,062
Other comprehensive loss	—	10,872	—	—	—	—	—	1,653
Total comprehensive (loss) income	(2,722)	(1,408)	(168,613)	(232,281)	5,875	(3,811)	634	3,715
Net (loss) earnings attributable to Innergex	(1,199)	(4,912)	(84,306)	(118,463)	1,498	(1,944)	311	1,031
Total comprehensive (loss) income attributable to Innergex	—	4,349	—	—	—	—	—	827
Total	(1,199)	(563)	(84,306)	(118,463)	1,498	(1,944)	311	1,858

(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 ventures and associates recognized in the consolidated financial statements:

	For the period ended March 31, 2021									
	Energía Llaima	Toba Montrose	Shannon	Flat Top	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Others	Total
Balance January 1, 2021	108,977	72,533	84,490	118,651	23,900	32,572	4,950	381	383	446,837
Increase in investment	—	—	—	—	—	—	—	—	65	65
Share of (loss) earnings	(1,199)	(4,912)	(84,306)	(118,463)	1,498	(1,944)	311	1,031	—	(207,984)
Share of other comprehensive loss	—	4,349	—	—	—	—	—	827	—	5,176
Foreign currency translation differences	(1,332)	—	(184)	(188)	—	—	—	—	6	(1,698)
Distributions received	—	(3,200)	—	—	(2,614)	—	—	(600)	—	(6,414)
Balance March 31, 2021	106,446	68,770	—	—	22,784	30,628	5,261	1,639	454	235,982

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

6. DERIVATIVE FINANCIAL INSTRUMENTS

a) Financial position

The following table shows a reconciliation from the opening balances to the closing balances for the derivative financial instruments (refer to Note 12 – Financial risk management and fair value disclosures for details about key inputs, judgements, assumptions and estimates involved in calculating fair values):

Financial assets (liabilities)	Foreign exchange forwards (Level 2)	Interests hedging derivatives (Level 2)	Power and basis hedges (Level 3)	Currency translation of intragroup loans[1]	Total
As at January 1, 2021	(37,113)	(168,002)	54,082	—	(151,033)
Unrealized portion of change in fair value recognized in earnings (loss) [2]	1,123	4,389	(11,212)	(10,823)	(16,523)
Change in fair value recognized in other comprehensive income (loss)	1,682	75,102	(763)	—	76,021
Amortization of accumulated other comprehensive income recognized in revenue	—	—	763	—	763
Net foreign exchange differences	—	1,217	(557)	10,823	11,483
As at March 31, 2021	(34,308)	(87,294)	42,313	—	(79,289)

1. A loss of $10,823 results from the revaluation, into Canadian dollars, of foreign currency-denominated intragroup loans. On consolidation, although the intragroup loans are eliminated from the consolidated statement of financial position, the foreign subsidiaries' financial positions, including their loan balances towards the Corporation, are converted into Canadian dollars, with currency translation differences being recorded within other comprehensive (loss) income, therefore not eliminating the gain recognized in earnings (loss).
2. Refer to Note 6 b) for a reconciliation to the change in fair value recognized in earnings (loss).

Reported in the consolidated statements of financial position:

As at	March 31, 2021	December 31, 2020
Current assets	10,449	9,039
Non-current assets	72,095	92,040
Current liabilities	(51,949)	(72,958)
Non-current liabilities	(109,884)	(179,154)
	(79,289)	(151,033)

b) Change in fair value of financial instruments recognized in the consolidated statements of earnings (loss)

Recognized in the consolidated statements of earnings (loss):

	Three months ended March 31	
	2021	2020
Unrealized portion of change in fair value of financial instruments	16,523	10,250
Realized portion of change in fair value of financial instruments:		
Realized loss on the interest rate swaps	2,885	—
Realized loss (gain) on the power hedges	67,102	(2,199)
Realized loss on Phoebe basis hedge	1,199	19,658
Change in fair value of financial instruments	87,709	27,709

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

7. EARNINGS (LOSS) PER SHARE

Basic	Three months ended March 31 2021	2020
Net loss attributable to owners of the parent	(214,161)	(53,740)
Dividends declared on preferred shares	(1,408)	(1,485)
Net loss available to common shareholders	(215,569)	(55,225)
Weighted average number of common shares	174,110,971	159,682,130
Basic net loss per share ($)	(1.24)	(0.35)

Diluted	Three months ended March 31 2021	2020
Net loss attributable to common shareholders	(215,569)	(55,225)
Diluted weighted average number of common shares	174,110,971	159,682,130
Diluted net loss per share ($)	(1.24)	(0.35)

	Three months ended March 31 2021	2020
Instruments that are excluded from the dilutive elements:		
Stock options	263	643
Shares held in trust related to the Performance Share Plan	426	401
Convertible debentures	13,604	13,777
	14,293	14,821

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

8. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facilities	Facilities under construction	Other	Total
Cost							
As at January 1, 2021	176,831	2,091,345	2,596,633	516,989	529,484	33,970	5,945,252
Additions [1]	—	194	1,028	—	104,236	1,260	106,718
Investment tax credits [2]	—	—	—	—	(4,473)	—	(4,473)
Transfer of assets upon commissioning	—	—	14,351	—	(14,351)	—	—
Dispositions	—	—	(472)	—	—	(181)	(653)
Other changes	199	8	(13,861)	(1,303)	—	1,256	(13,701)
Net foreign exchange differences	(3,039)	(116)	(50,117)	(5,212)	(7,732)	(172)	(66,388)
As at March 31, 2021	173,991	2,091,431	2,547,562	510,474	607,164	36,133	5,966,755
Accumulated depreciation							
As at January 1, 2021	(10,482)	(348,109)	(445,896)	(69,382)	—	(18,258)	(892,127)
Depreciation [3]	(1,647)	(9,569)	(28,285)	(4,314)	—	(977)	(44,792)
Dispositions	—	—	184	—	—	181	365
Net foreign exchange differences	236	92	7,442	275	—	38	8,083
As at March 31, 2021	(11,893)	(357,586)	(466,555)	(73,421)	—	(19,016)	(928,471)
Carrying amounts as March 31, 2021	162,098	1,733,845	2,081,007	437,053	607,164	17,117	5,038,284

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

1. 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 $3,390 of capitalized financing costs incurred prior to commissioning.
2. The Corporation accrued for US$3,523 ($4,473) in investment tax credits recoverable in relation to the construction of the Hillcrest solar project, which were recognized as a reduction in the cost of the Hillcrest property, plant and equipment. As at March 31, 2021, the balance of investments tax credits recoverable amounts to US$87,055 ($109,471).
3. An amount of $495 of the depreciation expense for the land leases is capitalized as a construction cost in facilities under construction.

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

9. LONG-TERM LOANS AND BORROWINGS

As at March 31, 2021, the Corporation and its subsidiaries have met all material financial and non-financial conditions related to their credit agreements, except for the following:

- the Mesgi'g Ugju's'n project was in breach of its credit agreement as at March 31, 2021 and December 31, 2020. The breach was triggered by the bankruptcy of a supplier considered a major project participant under the credit agreement. A waiver has been obtained and was subsequently extended until May 31, 2021. A plan was put in place to ensure the continuity of the operations of the project. Ongoing dialogue and reporting are provided to the project lenders until this situation is resolved. If the waiver is not renewed, the lenders would have the right to request repayment. As a result, the $215,814 ($219,007 in 2020) portion of the loan that would otherwise be classified as long-term was reallocated to the current portion of long-term loans and borrowings. As at March 31, 2021 and as at December 31, 2020 the project was in compliance with financial covenants;
- the Montjean and Theil-Rabier facilities were not meeting their respective targeted debt coverage ratios as at March 31, 2021 and December 31, 2020, which triggered a breach under their respective credit agreement. This was due to two blade incidents, which caused business interruptions of both Montjean and Theil-Rabier facilities for an extended period, which were subsequently followed by several production restrictions. Assuming the situation is not resolved, the lenders would have the right to request repayment, and as a result, the €11,675 ($17,232) portion of the loan that would otherwise be classified as long-term of each debt was reallocated to the current portion of long-term loans and borrowings.
- the Mountain Air facilities were in breach under their credit agreements as at March 31, 2021 and December 31, 2020, due to a non respect of a specific requirement of the insurance clause. A waiver was obtained until June 30, 2021. If the situation is not resolved and the waiver is not renewed, the lenders would have the right to request repayment, and as a result, the US$113,712 ($142,993) portion of the loan that would otherwise be classified as long-term was reallocated to the current portion of long-term loans and borrowings.
- the Phoebe Solar Facility received from its lenders a notice of a potential event of default. Such potential default is related to certain unpaid amounts following the February 2021 Texas Events, which are under dispute for correctness as the Corporation seeks an adjustment for the portion that relates to a claimed force majeure event. The Corporation believes that no default exists under these circumstances and responded accordingly. While discussions are ongoing, the US$104,244 ($131,087) portion of the loan that would otherwise be classified as long-term was reallocated to the current portion of long-term loans and borrowings.
- the Fitzsimmons Creek facility did not meet minimum working capital requirement as at March 31, 2021, which triggered a breach under its credit agreement. Assuming the situation is not resolved, the lenders would have the right to request repayment, and as a result, the $18,178 portion of the loan that would otherwise be classified as long-term was reallocated to the current portion of long-term loans and borrowings.

Repayment of Alterra loans

On January 11, 2021, the Corporation reimbursed the outstanding balance of the Alterra term loans, which included a CAD and a USD tranche, for an amount of $90,839 and US$21,359 ($26,725) of principal and accrued interests, respectively. A loss of $1,125 was recognized in Other net income. Also, on the same day, two related interest rate swaps were unwound for a net cash outflow of $3,154, comprising a realized loss of $2,885 on the terminal value of the derivatives recognized in Change in fair value of financial instruments, and accrued interests.

10. SHAREHOLDERS' CAPITAL

Equity-based compensation

a) Stock option plan

Granted
During the three months ended March 31, 2021, 29,245 options were granted. The options granted vest in four equal tranches until March 1, 2025 and must be exercised before March 1, 2028 at an exercise price of $24.49.

Fair value is determined at the date of the grant and each tranche is recognized on a graded-vesting basis over the period during which the options vest and is measured using the Black-Scholes pricing model taking into account the terms and conditions upon which the options were granted.

The following assumptions were used to estimate the fair value of the options issued to grantees during the year:

	March 31, 2021
Risk-free interest rate	0.97 %
Expected annual dividend per common share	$ 0.72
Expected life of options	6
Expected volatility	26.03 %

Expected volatility is estimated by considering historic average share price volatility.

A compensation expense of $19 was recorded during the first quarter of 2021 with respect to the stock option plan.

b) Performance Share Plan (the "PSP") and Deferred Share Unit Plan (the “DSU”)

Performance Share Plan

During the three months ended March 31, 2021, 281,313 performance share rights vested.

In addition, 157,339 share rights were granted in March 2021. The performance share rights vest on December 31, 2023.

Deferred Share Unit Plan

During the three months ended March 31, 2021, 21,611 units were granted.

A compensation expense of $336 was recorded during the first quarter of 2021 with respect to the PSP and DSU plan.

Dividends

a) Dividend Declared

The applicable dividend rates for the Corporation's Series A and Series B preferred shares were reset during the three months ended March 31, 2021. For Series A preferred shares, the dividend rate for the five-year period commencing on January 15, 2021, to but excluding January 15, 2026, is 3.244% per annum, or $0.202750 per share per quarter. For Series B shares, the dividend rate for the Quarterly Floating Rate Period commencing on January 15, 2021, to but excluding April 15, 2021, is equal to 2.91% per annum, or $0.181875 per share per quarter. As at March 31, 2021, there were no outstanding Series B Preferred Shares.

The following dividends were declared by the Corporation:

	Three months ended March 31			
	2021		2020	
	($/share)	Total	($/share)	Total
Dividends declared on common shares	0.180	31,445	0.180	31,339
Dividends declared on Series A preferred shares	0.202750	689	0.225500	766
Dividends declared on Series C preferred shares	0.359375	719	0.359375	719

Dividend Declared not recognized at the end of the reporting period

The following dividends will be paid by the Corporation on July 15, 2021:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
May 11, 2021	June 30, 2021	July 15, 2021	$ 0.180	$ 0.202750	$ 0.359375

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

11. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Three months ended March 31	
	2021	2020
Accounts receivable	(1,992)	1,474
Prepaids and other	(3,366)	(2,370)
Accounts payable and other payables	24,148	(22,900)
	18,790	(23,796)

b. Additional information

	Three months ended March 31	
	2021	2020
Finance costs paid relative to operating activities before interest on leases	(37,893)	(36,305)
Interest on leases paid relative to operating activities	(729)	(1,010)
Capitalized interest relative to investing activities	(1,029)	(428)
Capitalized interest on leases relative to investing activities	(578)	—
Total finance costs paid	(40,229)	(37,743)
Non-cash transactions:		
Change in unpaid property, plant and equipment	28,466	(10,780)
Investment tax credits	4,473	—
Change in long-term assets	14	—
Change in unpaid project development costs	1,061	—
Remeasurement of other liabilities	(21,577)	(34,438)
Initial measurement of other liabilities	(370)	52,034
Common shares issued through the conversion of convertible debentures	2,306	—
Common shares issued through equity based compensation	3,174	1,695
Common shares issued through dividend reinvestment plan	154	203

(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	
	2021	2020
Changes in long-term debt		
Long-term debt at beginning of period	4,533,806	4,412,842
Increase in long-term debt	271,898	70,925
Repayment of long-term debt	(187,880)	(567,358)
Tax attributes	193	(6,351)
Production tax credits	(11,389)	(10,931)
Other non-cash finance costs	11,536	9,469
Net foreign exchange differences	(42,988)	85,673
Long-term debt at end of period	4,575,176	3,994,269
Changes in convertible debentures		
Convertible debentures at beginning of period	280,075	278,827
Convertible debentures converted into common shares	(2,306)	—
Accretion of convertible debentures	708	611
Convertible debentures at end of period	278,477	279,438

12. FINANCIAL RISK MANAGEMENT AND FAIR VALUE DISCLOSURES

Fair value disclosures

Interest rate swaps

The fair value is calculated as the present value of the estimated future cash flows. Estimated cash flows are discounted using a yield curve constructed from similar sources and that reflects the relevant benchmark interbank rate used by market participants for this purpose when pricing interest rate swaps. The fair value estimate is subject to a credit risk adjustment that reflects the credit risk of the Corporation and of the counterparty.

Foreign exchange forwards

The fair value is calculated as the present value of the estimated future cash flows, representing the differential between the value of the contract at maturity and the value determined using the exchange rate the financial institution would use if the same contract was renegotiated at the statement of financial position date. The fair value estimate is subject to a credit risk adjustment that reflects the credit risk of the Corporation and of the counterparty, considering the offsetting agreements, as applicable.

Power hedges

The fair values of the power and basis hedges are calculated using a discounted cash flow model. The fair value calculation of power and basis hedges gives rise to measurement uncertainty as the power price curves are constructed using various methodologies and assumptions, which consider certain unobservable inputs. As at March 31, 2021, the forward power prices used in the calculation of fair value were as follows:

With respect to the Phoebe power hedge, ERCOT South Hub forward power prices are expected to be in a range of US$13.57 to US$79.29 per MWh between April 1, 2021 and June 30, 2031.

With respect to the Salvador power hedges, Polpaico node future power prices are expected to be in a range of US $4.99 to US$67.03 per MWh between April 1, 2021 and December 31, 2030.

With respect to the Phoebe basis hedge, ERCOT South Hub forward power prices are expected to be in a range of US$13.57 to US$79.29 per MWh between April 1, 2021 and December 31, 2021, while Phoebe node forward power prices are derived using a historical spread against the ERCOT South Hub of US$2.37 per MWh.

Further information is provided below with regard to the methodology for constructing the forward power price curves.

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

Phoebe power hedge: The fair value of the power hedge is derived from forward power prices that are not based on observable market data for the entirety of the contracted period. The power ERCOT South Hub forward price curves are constructed using various assumptions depending on the following observable market data available as of the valuation date: (1) a combination of observable exchange prices and over-the-counter broker quotes obtained through February 2031; (2) for the four remaining months until June 2031, extrapolated prices based on the growth rate implicit in traded NYMEX Natural Gas Futures prices.

Salvador power hedges: The fair value of the power hedges is derived from future power price forecasts that are not based on observable market data. Such forecasts are constructed using various assumptions depending on historical market prices, supply, demand and congestion volumes observed on the Chilean grid, as well as econometric models. In addition, as the notional volume of the power hedges is not contractually fixed, the estimated volume is determined using various assumptions such as the expected demand and volume of power to be successfully settled through the market bidding process.

Phoebe basis hedge: The fair value of the basis hedge is derived from observable forward power prices at the ERCOT South Hub for the remaining duration of the contract period and a Phoebe node forward price curve constructed using various assumptions depending on the following observable market data available as of the valuation date: (1) forward power prices at the ERCOT South Hub for the remaining duration of the contract period; and (2) historical spread between the ERCOT South Hub and the Phoebe node prices from April 2020 onwards.

The fair value estimates are subject to a credit risk adjustment that reflects the credit risk of the Corporation or of the counterparty.

The changes in the fair value of the derivative instrument are recognized in the consolidated statements of earnings (loss), as change in fair value of financial instruments.

Interest rate benchmark reform

The Corporation holds interest rate swaps for risk management purposes that are designated in cash flow hedging relationships. The interest rate swaps have floating legs that are indexed to either LIBOR, CDOR, or EURIBOR.

London Interbank Offered Rate ("LIBOR")

On March 5, 2021, the Financial Conduct Authority (UK), announced that all LIBOR settings for all currencies will either cease or no longer be representative after i) December 31, 2021, for Sterling, Euro, Swiss Franc and Japanese Yen LIBOR settings, and certain USD LIBOR tenors; and ii) June 30, 2023 for the USD LIBOR 1-month, 3-month, 6-month and 12-month tenors. The Corporation's LIBOR swaps and cash flow hedging relationships extend beyond the anticipated cessation date for LIBOR.

The Corporation has evaluated the extent to which its cash flow hedging relationships are subject to uncertainty driven by the IBOR reform. The Corporation's hedged items and hedging instruments continue to be indexed to LIBOR. The benchmark rates are quoted each day and the LIBOR cash flows are exchanged with counterparties as usual.

There is uncertainty about when and how replacement may occur with respect to the relevant hedged items and hedging instruments. Such uncertainty may impact the hedging relationship, which may experience ineffectiveness attributable to market participants' expectations of when the shift from the existing IBOR benchmark rate to an alternative benchmark interest rate will occur. This transition may occur at different times for the hedged item and hedging instrument, which may lead to hedge ineffectiveness. The Corporation has measured its hedging instruments indexed to LIBOR using available quoted market rates for LIBOR-based instruments of the same tenor and similar maturity and has measured the cumulative change in the present value of hedged cash flows attributable to changes in LIBOR on a similar basis. The Corporation's notional amount exposure to LIBOR designated in hedging relationships is US$224,154 ($281,874) as at March 31, 2021.

Canadian Dollar Offered Rate ("CDOR")

While CDOR is not anticipated to immediately be retired, the Bank of Canada expects its relevance to decline, like other credit-based benchmarks, as markets globally move to risk-free rates. While the 1-month, 2-month and 3-month tenors are not expected to be affected for the foreseeable future, the calculation and publication of the 6-month and 12-month CDOR tenors will cease from May 17, 2021 onwards, with no impact for the Corporation.

Euro Interbank Offered Rate ("EURIBOR")

In 2019, the EURIBOR has been authorized by the competent authority under the European Union Benchmarks Regulation. This allows market participants to continue to use EURIBOR for both existing and new contracts and the Corporation expects that EURIBOR will continue to exist as a benchmark rate for the foreseeable future.

Financial risk management

The Corporation is exposed to a variety of financial risks: market risk (e.g. interest rate, foreign exchange, and power price and others), credit risk and liquidity risk. The Corporation's objective with respect to financial risk management is to secure the long-term internal rate of return of its energy projects by mitigating uncertainty related to the fluctuation of certain key variables.

Management is responsible for establishing controls and procedures to ensure that financial risks are managed within acceptable levels. The Corporation does not use derivative financial instruments for speculative purposes.

a. Market risk

Market risk is related to fluctuations in the fair value or future cash flows of a financial instrument because of market price variations. Market risk includes interest rate, foreign exchange, and power price risks.

Most sales of electricity are made pursuant to long-term agreements where the offtakers are committed to take and pay for the total production at pre-determined prices, up to certain annual limits and generally subject to annual inflation. For some of the Corporation's facilities, power generated is sold on the open market and supported by power hedges to address market price risk exposure.

13. CONTINGENCIES

The Corporation is subject to various claims that arise in the normal course of business. Management believes that adequate provisions have been made in the accounts where required. Although it is not possible to estimate the extent of potential costs and losses, if any, management believes that the ultimate resolution of such contingencies will not have an adverse effect on the financial position of the Corporation.

February 2021 Texas Events

In February 2021, unprecedented extreme winter weather conditions and related electricity market failure paralyzed the state of Texas, United States. These unprecedented extreme winter weather events pushed the Texas Government to declare disaster and the US Government to declare a state of emergency. The storm disturbed production, transmission and distribution of power, severely impacting prices. Because of the disturbance, wholesale electricity prices in the Electric Reliability Council of Texas (ERCOT) reached their cap of US$9,000 per MWh and remained at such a level for a prolonged period of time. The February 2021 Texas Events lasted from February 11 to February 19, 2021. The combined effect of supply interruptions, abnormal market pricing conditions and contractual obligations to supply a predetermined daily generation under the power hedges, have had a net unfavourable impact at the Corporation's Phoebe solar facility located in Winkler County, Flat Top wind facility in Mills County, and Shannon wind facility in Clay County.

Phoebe
As a consequence of the February 2021 Texas Events, a claim of Force Majeure was notified to the counterparty of the power hedge of the Phoebe facility in February, which was rejected by the recipient. Discussions are in progress with the counterparty of the power hedge.

Flat Top and Shannon
As a consequence of the February 2021 Texas Events, a claim of Force Majeure was notified to the counterparty of the power hedges of the Flat Top and Shannon facilities in February, which were rejected by the recipient. To preserve the Corporation's and its partners' rights with regard to the Flat Top and Shannon facilities, court proceedings were initiated on April 21, 2021. On May 6, 2021, the Court heard the temporary injunction application to suspend all remedies, including foreclosure, against the Flat Top and Shannon facilities, arising from an alleged default of payment that was formally disputed and will render its decision by May 20, 2021. If it does deny the application, then the counterparty to the power hedges for the two facilities will not be precluded from exercising any of its remedies, including foreclosure. The Corporation and its partners in the Flat Top and Shannon projects are now evaluating and considering all commercially reasonable options to enforce the rights of the projects under the power hedges.

Given its understanding of currently available information and on the basis that the projects are non-recourse to the Corporation, the financial exposure of the Corporation is limited to the non-cash impacts, if any, on the Corporation's provision for income taxes and potential reversal of exchange differences in accumulated other comprehensive income related to these two projects, as the carrying amount of its equity investments in Flat Top and Shannon was nil as at March 31, 2021, following the $53,758 and $58,851 respective impairment charges recognized by the Corporation through its share of loss of joint ventures and associates during the three-month period ended March 31, 2021.

Harrison Hydro L.P. Water Rights

On March 23, 2017, the Comptroller of the Water Rights issued adjusted rental statements to the Harrison Hydro L.P. and its subsidiaries for the years 2011 and 2012 for an amount of $3,181 in aggregate regarding water rental rates to be charged under the Water Act. The amount claimed was paid under protest and Harrison Hydro L.P. and its subsidiaries filed a notice of appeal of the decision to the Environmental Appeal Board.

On July 26, 2019, the Environmental Appeal Board of British Columbia rendered a decision granting the appeal and ordering the Comptroller of Water Rights to reimburse to each of the Limited Partnerships its proportionate share of the adjusted water rental amounts of $3,181 overcharged to Harrison Hydro L.P. and its subsidiaries for the years 2011 and 2012. On November 22, 2019, the Environmental Appeal Board of British Columbia rendered another decision confirming that the sum will accrue interest starting June 28, 2017 until the date it is refunded. On January 20, 2020, the Comptroller of Water Rights filed with the Supreme Court of British Columbia a petition for judicial review of the Environmental Appeal Board’s order to return the amount in water rental fees to Harrison Hydro L.P. and its subsidiaries, with interest. The Corporation recognized a receivable in the amount of $3,181 during the year ended December 31, 2019. On January 31, 2020, the Comptroller of Water Rights transferred an amount equal to the receivable recorded, representing the principal of $3,181 with interest accrued between June 28, 2017 and January 31, 2020, to a trust account established by Harrison Hydro L.P. and its subsidiaries’ external legal counsel, bearing interest in favour of the Appellants. The Limited Partnerships have filed their response to petition on April 14, 2020. The hearing took place in Victoria in the last week of September 2020. A decision was rendered on February 9, 2021 by the Supreme Court of British Columbia, which concluded that the Environmental Appeal Board's decision was reasonable, and dismissed the Comptroller of Water Rights' petition accordingly. In March 2021, the Comptroller of Water Rights informed the Corporation that it will appeal the decision of the British Columbia Supreme Court.

BC Hydro curtailment notices

In May 2020, Innergex received notices from BC Hydro in relation to six of the Corporation’s hydroelectric facilities in British Columbia stating that BC Hydro would not accept and purchase energy under the applicable electricity purchase agreements (“EPAs”) above a specified curtailment level for the period from May 22, 2020 to July 20, 2020. The specified curtailment levels were 0.0 MW/h for the Jimmie Creek (accounted for using the equity method), Upper Lillooet River, Northwest Stave River, and Boulder Creek facilities, 2.0 MW/h for the Tretheway Creek facility and 4.0 MW/h for the Big Silver Creek facility.

BC Hydro cites the current COVID-19 pandemic and related governmental measures taken in response to it as constituting a “force majeure” event under the EPAs, and resulting in a situation in which BC Hydro is unable to accept or purchase energy under the EPAs. The notices to Innergex follow public statements by BC Hydro regarding measures it is taking to address the reduced electricity demand during the COVID-19 pandemic and related challenges to the safe operation of its hydroelectric system.

Innergex disputes that the current pandemic and related governmental measures in any way prevent BC Hydro from fulfilling its obligations to accept and purchase energy under the EPAs or enable it to invoke “force majeure” provisions under the EPAs to suspend these obligations. Innergex acknowledges that BC Hydro retains “turn-down” rights under the EPAs, which enable it to require Innergex to turn down or shut off its facilities in certain circumstances, including in order to avoid a safety or stability risk. Where BC Hydro exercises this right, it is required under the EPAs to compensate Innergex for energy that would have been produced at the facilities in the absence of the curtailment. Innergex has complied with BC Hydro’s curtailment request, but has done so under protest and seeks to enforce its rights under the EPAs on the basis described above. For the period from May 22, 2020 to July 20, 2020, actual eligible energy revenue that would have been produced at the facilities in the absence of the curtailment amounts to $13,031 ($14,758 on a Revenues Proportionate[1] basis), respectively.

1. Revenues Proportionate is not a recognized measure under IFRS and therefore, may not be comparable to those presented by other issuers. Please refer to Note 15, Segment Information, for more information.

14. COVID-19

To combat the spread of the COVID-19, authorities in all regions where the Corporation operates have put in place restrictive measures for businesses. However, with the exception of the curtailment notices received from BC Hydro, as described in Note 13, Contingencies, these measures have not impacted the Corporation in a material way to date, as electricity production has been deemed an essential service in every region where the Corporation operates. The renewable power production is sold mainly through power purchase agreements with public utilities and corporate entities with high credit ratings.

It is not excluded that current or future restrictive measures might have an adverse effect on the financial stability of the Corporation’s suppliers and other partners, or on the Corporation’s operating results, financial position, liquidity or capital expenditures. The issuance of permits and authorizations, negotiations and finalizations of agreements with regard to development and acquisition projects, construction activities and procurement of equipment could be adversely impacted by the COVID-19 restrictive measures. The full potential impact of COVID-19 on the Corporation's business is unknown as it may continue for an extended period and will depend on future developments that are uncertain and cannot be predicted including, and without limitations, the duration and severity of the pandemic, the duration of government mitigation measures, the effectiveness of the actions taken to contain and treat the disease, and the length of time it takes for normal economic and operating conditions to resume.

15. SEGMENT INFORMATION

Operating segments

The Corporation produces and sells electricity generated by its hydroelectric, wind and solar facilities to publicly-owned utilities or other creditworthy counterparties. The Corporation's Management analyzes the results and manages operations based on the type of technology, resulting in different cost structures and skill set requirements for the operating teams. The Corporation consequently has three operating segments: (a) hydroelectric power generation (b) wind power generation and (c) solar power generation.

"Revenues Proportionate" are Revenues plus Innergex's share of Revenues of the operating joint ventures and associates, other incomes related to PTCs, and Innergex's share of the operating joint ventures and associates' other incomes related to PTCs. "Adjusted EBITDA" represents net earnings (loss) before income tax expense, finance costs, depreciation and amortization, adjusted to exclude other net income, share of earnings (loss) of joint ventures and associates, and change in fair value of financial instruments. "Adjusted EBITDA Proportionate" represents Adjusted EBITDA plus Innergex's share of Adjusted EBITDA of the operating joint ventures and associates, other incomes related to PTCs, and Innergex's share of the operating joint ventures and associates' other incomes related to PTCs. Revenues Proportionate, Adjusted EBITDA and Adjusted EBITDA Proportionate are not recognized measures under IFRS and have no standardized meaning prescribed by IFRS. They may therefore not be comparable to similar measures presented by other issuers. Readers are cautioned that Revenues Proportionate, Adjusted EBITDA and Adjusted EBITDA Proportionate should not be construed as an alternative to net earnings (loss), as determined in accordance with IFRS.

Except for Revenues Proportionate, Adjusted EBITDA and Adjusted EBITDA Proportionate described above, the accounting policies for these segments are the same as those described in the significant accounting policies. The Corporation accounts for inter-segment and management sales at the carrying amount.

Three months ended March 31, 2021 Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	26,570	116,013	47,068	189,651
Innergex's share of revenues of joint ventures and associates	4,339	49,818	504	54,661
PTCs and Innergex's share of PTCs generated	—	17,423	—	17,423
Segment Revenues Proportionate	30,909	183,254	47,572	261,735
Segment Adjusted EBITDA	14,490	99,623	44,075	158,188
Innergex's share of Adjusted EBITDA of joint ventures and associates	1,507	46,544	298	48,349
PTCs and Innergex's share of PTCs generated	—	17,423	—	17,423
Segment Adjusted EBITDA Proportionate	15,997	163,590	44,373	223,960
Segment Adjusted EBITDA Margin	55 %	86 %	94 %	83 %

As at March 31, 2021	Hydroelectric	Wind	Solar	Segment totals [1]
Investments in joint ventures and associates	168,364	24,425	13,474	206,263
Transfer of assets upon commissioning	—	14,351	—	14,351
Acquisition of property, plant and equipment during the year	194	1,028	—	1,222

1. Segment totals include only operating projects.

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

Three months ended March 31, 2020				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	27,957	95,805	8,354	132,116
Innergex's share of revenues of joint ventures and associates	4,791	8,742	583	14,116
PTCs and Innergex's share of PTCs generated	—	18,139	—	18,139
Segment Revenues Proportionate	32,748	122,686	8,937	164,371
Segment Adjusted EBITDA	16,540	80,839	5,696	103,075
Innergex's share of Adjusted EBITDA of joint ventures and associates	1,327	5,805	324	7,456
PTCs and Innergex's share of PTCs generated	—	18,139	—	18,139
Segment Adjusted EBITDA Proportionate	17,867	104,783	6,020	128,670
Segment Adjusted EBITDA Margin	59 %	84 %	68 %	78 %

As at March 31, 2020	Hydroelectric	Wind	Solar	Segment totals [1]
Acquisition of property, plant and equipment during the year	237	194	52,420	52,851

1. Segment totals include only operating projects.

The following table presents a reconciliation of the non-IFRS measures to their closest IFRS measures:

	Three months ended March 31	
	2021	2020
Revenues	189,651	132,116
Innergex's share of Revenues of joint ventures and associates	54,661	14,116
PTCs and Innergex's share of PTCs generated	17,423	18,139
Revenues Proportionate	261,735	164,371
Net loss	(217,872)	(46,931)
Recovery of income tax	(41,283)	(813)
Finance costs	59,600	60,330
Depreciation and amortization	58,885	53,567
EBITDA	(140,670)	66,153
Other net income	(11,904)	(23,497)
Share of losses of joint ventures and associates	207,984	20,054
Change in fair value of financial instruments	87,709	27,709
Adjusted EBITDA	143,119	90,419
Unallocated expenses:		
General and administrative	9,280	9,017
Prospective projects	5,789	3,639
Segment Adjusted EBITDA	158,188	103,075
Innergex's share of Adjusted EBITDA of joint ventures and associates	48,349	7,456
PTCs and Innergex's share of PTCs generated	17,423	18,139
Segment Adjusted EBITDA Proportionate	223,960	128,670
Segment Adjusted EBITDA Margin	85.6 %	78.3 %

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

Geographic segments

As at March 31, 2021, excluding its investments in joint ventures and associates which are accounted for as equity method, the Corporation had interests in the following operating assets: 33 hydroelectric facilities, eight wind farms and one solar farm in Canada, 16 wind farms in France, and one hydroelectric facility, nine wind farms and three solar farms in the United States, and three hydroelectric facilities and two solar farm in Chile. The Corporation operates in four principal geographical areas, which are detailed below:

	Three months ended March 31	
	2021	2020
Revenues		
Canada	83,150	83,875
United States	76,033	11,851
France	28,368	36,390
Chile	2,100	—
	189,651	132,116

As at	March 31, 2021	December 31, 2020
Non-current assets, excluding derivative financial instruments and deferred tax assets [1]		
Canada	3,449,400	3,504,403
United States	1,853,889	1,990,997
France	861,955	922,330
Chile	163,395	166,881
	6,328,639	6,584,611

1. Includes the investments in joint ventures and associates

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

16. SUBSEQUENT EVENTS

Mesgi'g Ugju's'n letter of credit

During 2019, the service provider under the turbine supply agreement at Mesgi'g' Ugju's'n filed for bankruptcy. Certain of the performance obligations under the turbine supply agreement were covered, subject to terms and conditions precedent, by a $19,642 letter of credit. The Corporation availed itself of the full amount on April 27, 2021. The proceeds will be used in the future to remediate the unfulfilled performance obligations under the turbine supply agreement.

17. COMPARATIVE FIGURES

Certain reclassifications have been made to the prior quarter's consolidated financial statements to enhance comparability with the current quarter's consolidated financial statements.

As a result, certain line items have been amended in the consolidated statement of cash flows and the related notes to the financial statements. Comparative figures have been adjusted to conform to the current quarter's presentation.

SHAREHOLDER INFORMATION

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Common Shares - TSX: INE

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

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

Convertible Debentures - TSX: INE.DB.B

Convertible Debentures - TSX: INE.DB.C

Credit Rating by Standard & Poor's

Innergex Renewable Energy Inc.	BB+
Series A Preferred Shares	B+/P-4 (High)
Series C Preferred Shares	B+/P-4 (High)

Credit Rating by Fitch Rating

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

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 Company 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.

Independent Auditor

KPMG LLP

Ce document est disponible en français.
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