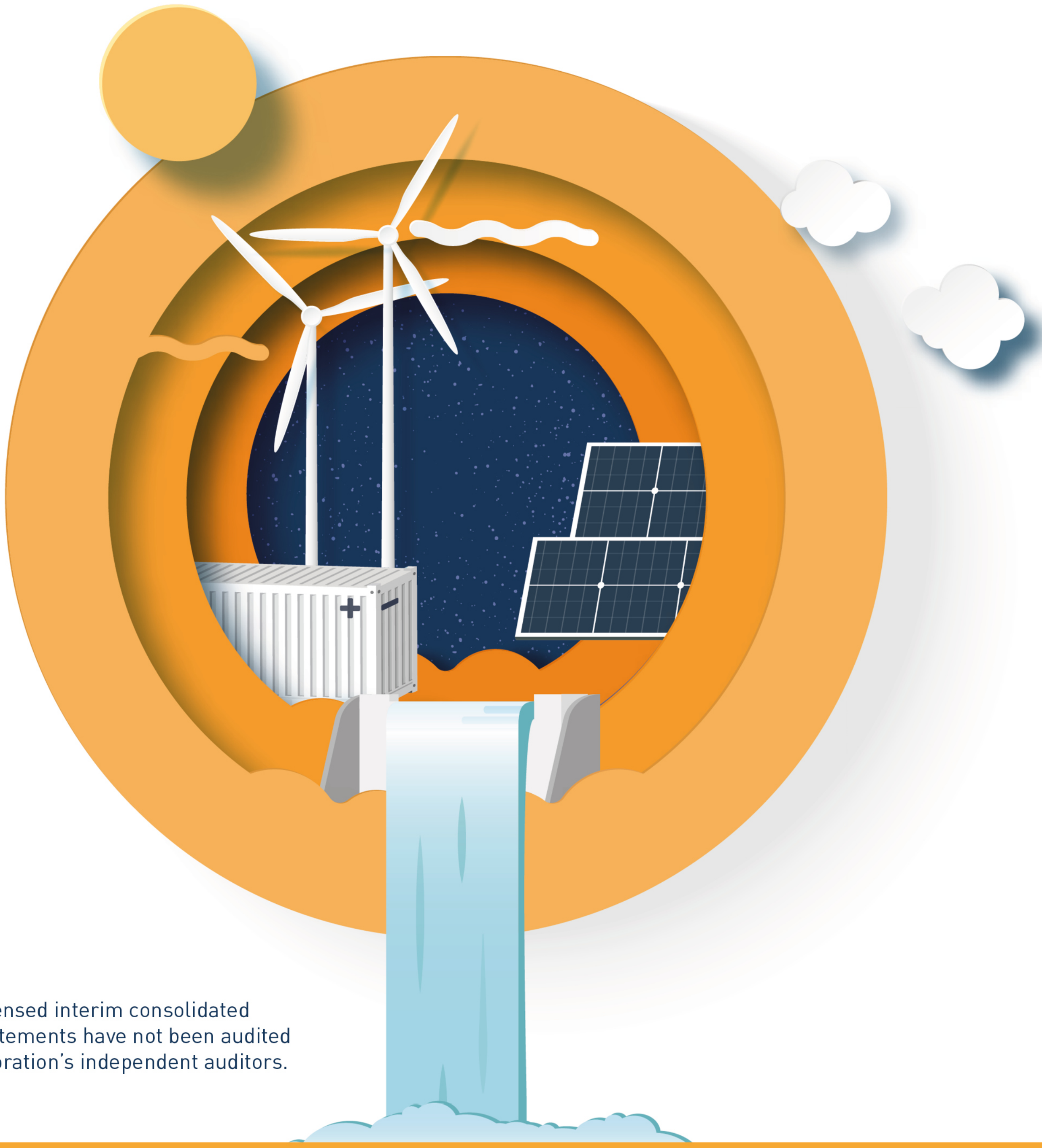
INNERGEX

Renewable Energy.
Sustainable Development.

QUARTERLY REPORT 2021

for the Period Ended September 30, 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 40 hydroelectric facilities drawing on 33 watersheds, 32 wind farms and 7 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.

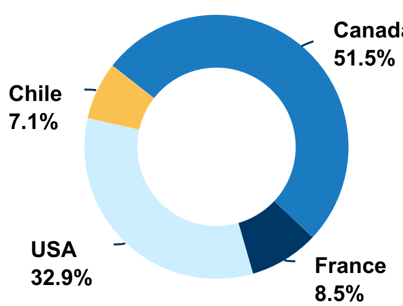
These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the “Non-IFRS Measures” section for more information.

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

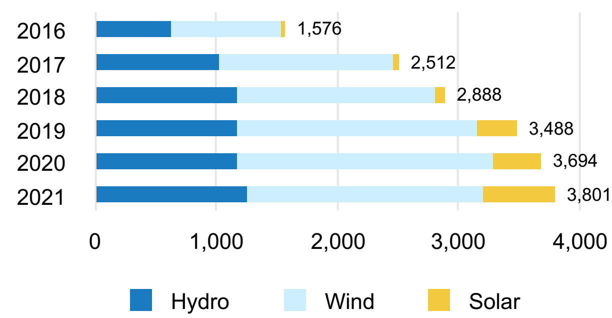
Operational Key Performance Indicators

As at November 9, 2021, the Corporation has four geographic segments and three operating segments.

Gross Installed Capacity by Country*



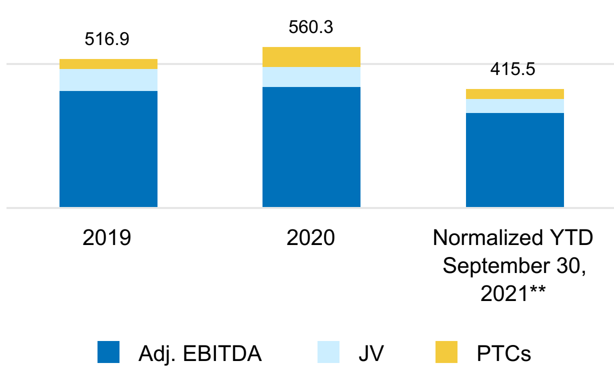
Gross Installed Capacity by Source of Energy (MW)*



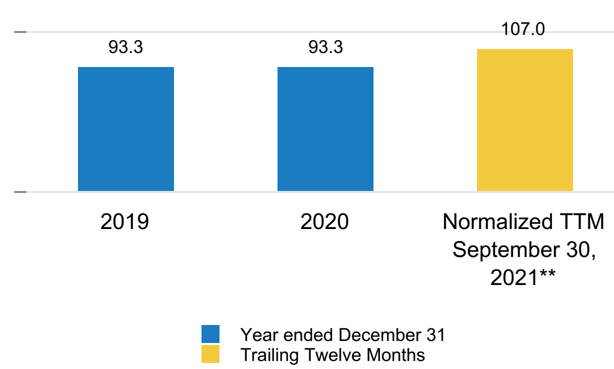
* Gross Installed Capacity for continued operations, including the Hillcrest solar facility for which PPA commercial operation was reached and excluding the Shannon and Flat Top facilities due to the projects' assets and liabilities being classified as disposal groups held for sale, following the February 2021 Texas Events.

Financial Key Performance Indicators

Adjusted EBITDA Proportionate ($M)



Free Cash Flow ($M)



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

INFORMATION ON COVID-19

The Corporation continues to closely monitor the impacts of COVID-19 and is actively managing its response by placing a priority on the health and safety of our employees, suppliers, business partners and the broader community. Innergex is adhering to pandemic response plans and is following guidance from government health departments with respect to conducting operations safely. To the extent possible, and as permitted by local guidelines, the Corporation is facilitating vaccination of its employees against COVID-19.

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. In addition to standard operating procedures designed to maintain safe operations, the Corporation has implemented additional measures including:

- work from home policy for all office employees, except essential tasks that must be achieved on-site;
- enhancing cleaning and disinfecting of facilities;
- limiting interactions between employees through social distancing and physical barriers;
- mandating the use of personal protective equipment by employees;
- revising and improving COVID-19 screening protocols and measures specifically for monitoring the health and safety of employees; and
- introducing specific instructions and guidance on COVID-19 health and safety measures.

The Corporation is engaged in ongoing communications with employees, apprising them on its response to the pandemic. Innergex believes that its employees and suppliers can access its facilities safely and in compliance with relevant directives.

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 November 9, 2021, the Corporation owns and operates 79 facilities in commercial operation (the "Operating Facilities"). Commissioned between 1986 and July 2021, the facilities have a weighted average age of approximately 9.2 years[1].

They mostly sell the generated power under long-term power purchase agreements, power hedge contracts[2] 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 14.2 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 mainly 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 Including the Hillcrest solar facility for which PPA commercial operation was reached.
2 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 November 9, 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	3	—	70	—	40	—	—	—
Chile	4	2	170	112	166	85	—	—
Subtotal	40	3	1,259	120	919	89	—	—
WIND								
Canada	8	—	908	—	714	—	—	—
France	16	1	324	9	226	2	—	—
United States	8	—	714	—	662	—	—	—
Subtotal	32	1	1,946	9	1,602	2	—	—
SOLAR								
Canada	1	—	27	—	27	—	—	—
United States	4	4	467	80	466	80	—	320 [5]
Chile	2	—	102	—	87	—	150 [4]	—
Subtotal	7	4	596	80	580	80	150	320
STORAGE								
France	—	1	—	—	—	—	—	9 [6]
Total	79	9	3,801	209	3,101	171	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 the three- and nine-month periods ended September 30, 2021, and reflects all material events up to November 9, 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- and nine-month periods ended September 30, 2021.

The unaudited condensed interim consolidated financial statements attached to this MD&A and the accompanying notes for the three- and nine-month periods ended September 30, 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 September 30		Nine months ended September 30			
	2021	2020	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized	2020
OPERATING RESULTS						
Production (MWh)	2,290,086	2,021,559	6,472,058	—	6,472,058	5,886,949
Revenues	184,564	162,651	544,820	(54,967)	489,853	445,280
Adjusted EBITDA[1]	122,522	108,524	388,326	(54,967)	333,359	304,279
Adjusted EBITDA Margin[1]	66.4 %	66.7 %	71.3 %	(3.2)%	68.1 %	68.3 %
Net Earnings (Loss)	(23,464)	7,492	(191,137)	64,219	(126,918)	(41,005)
Adjusted Net Earnings[1]	11,905	13,376	3,023	—	3,023	9,319
PROPORTIONATE						
Production Proportionate (MWh)[1]	2,538,645	2,471,149	7,177,192	—	7,177,192	7,016,780
Revenues Proportionate[1]	221,960	213,736	682,096	(95,273)	586,823	570,111
Adjusted EBITDA Proportionate[1]	155,938	151,433	510,791	(95,273)	415,518	407,398
Adjusted EBITDA Proportionate Margin[1]	70.3 %	70.9 %	74.9 %	(4.1)%	70.8 %	71.5 %
COMMON SHARES						
Dividends Declared on Common Shares	34,703	31,409	97,580	—	97,580	94,118
Weighted Average Number of Common Shares (in 000s)	182,692	173,858	177,044	—	177,044	169,048

	Trailing twelve months ended September 30			
	2021	February 2021 Texas Events (9 days)[4]	2021 Normalized	2020
CASH FLOW AND PAYOUT RATIO				
Cash Flow From Operating Activities[2]	267,354	17,093	284,447	229,152
Free Cash Flow[1,2]	91,211	15,789	107,000	95,612
Payout Ratio[1,2]	141 %	(20)%	121 %	124 %
Adjusted Payout Ratio[1,2]	96 %	— %	96 %	102 %

FINANCIAL POSITION As at	September 30, 2021	December 31, 2020
Total Assets	7,244,604	7,154,232
Total Liabilities	6,055,206	6,083,300
Non-Controlling Interests	57,991	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 nine months ended September 30, 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 September 30, 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 | Third Quarter 2021 – Operating Performance

For the quarter ended September 30, 2021, **Revenues** were up 13% to $184.6 million compared with the same quarter last year. The **hydroelectric** power generation segment recorded an increase in revenues mainly attributable to the acquisition of the remaining 50% interest in Energía Llaima, which is now included in Innergex's consolidated revenues, and to the Licán Acquisition. These items were partly offset by a lower contribution from the facilities in British Columbia due to the temporary shutdown at the Kwoiek Creek facility due to the wildfire that damaged the facility's transmission line and lower contribution from the facilities in Quebec due to lower revenues from lower production and lower selling prices. The increase in revenues in the **wind** power generation segment is mostly attributable to the commissioning of the Griffin Trail wind facility and to higher revenues at the wind facilities in France due to higher production. The increase was partly offset by lower revenues at the Quebec wind facilities due to lower production and by a lower contribution from the Foard City facility due to a combined effect of lower production and lower average selling prices. The increase in revenues from the **solar** power generation segment was due to liquidated damages due from the EPC contractor for loss of revenues caused by the delays in and the commissioning of the Hillcrest solar facility, higher selling prices at the Salvador facility and the acquisition of the remaining 50% interest in Energía Llaima. These items were partly offset by lower revenues at the Phoebe solar facility due to lower average selling prices. **Revenues Proportionate** were up at $222.0 million a 4% increase compared with the same period last year.

The **Adjusted EBITDA** was higher by 13% at $122.5 million compared with the same period last year. The increase is attributable to liquidated damages due from the EPC contractor for loss of revenue caused by the delays in and the commissioning of the Hillcrest solar facility, the acquisition of the remaining 50% interest in Energía Llaima, which is now included in Innergex's consolidated Adjusted EBITDA, higher selling prices at the Salvador facility, the commissioning of the Griffin Trail facility and the Licán Acquisition. These items were partly offset by lower revenues at the wind and hydro facilities in Quebec and higher operational expenses at the Quebec wind facilities. The **Adjusted EBITDA Proportionate** reached $155.9 million, a 3% increase compared with the same period last year.

Innergex recorded a **net loss** of $23.5 million ($0.10 loss per share - basic and diluted) for the quarter ended September 30, 2021, compared with **net earnings** of $7.5 million ($0.06 earnings per share - basic and diluted) for the same period in 2020. This was mainly due to the recognition of **impairment charges** related to the Phoebe solar facility in Texas, and to a minority equity investment in France, totaling $24.7 million and $5.9 million, respectively. An unfavourable $15.6 million unrealized change in **fair value of financial instruments,** mainly related to the increase in merchant price curves for the Phoebe power hedge, an increase in **finance costs** mainly related to the Griffin Trail wind facility, following its commissioning during the third quarter, and an **increase in inflation compensation interests** on the Harrison Hydro real return bonds, also contributed to the decrease in net earnings. These items were **partly offset** by a $17.1 million increase in **other income** mainly related to the production tax credits and tax attributes allocated to the tax equity investors at the Griffin Trail wind facility, following its commissioning during the third quarter.

1- HIGHLIGHTS | Third Quarter 2021 – Capital and Resource

The increase in total assets results largely from the Energía Llaima and Licán Acquisitions in the third quarter of 2021, as well as the construction activities at the Hillcrest solar and Griffin Trail wind facilities. This was partly offset by 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, as well as depreciation and amortization. Additionally, Innergex has acquired the remaining 50% interest in Energía Llaima, which triggered consolidation and concurrently reduced the investments in joint ventures.

The increase in long-term loans and borrowings, including the current portion thereof, results largely from the debt assumed in the Energía Llaima and Licán Acquisitions, and from the net draws made toward the construction of the Hillcrest and Griffin Trail facilities, partly offset by the proceeds received from the public offering of common shares and the Hydro-Québec Private Placement applied against the revolving credit facility.

The increase in equity attributable to owners is mainly attributable to the issuances of common shares upon acquisitions, public offering and Hydro-Québec Private Placement and as a result of the total comprehensive loss attributable to owners of the parent and dividends declared.

The increase in Free Cash Flow for the trailing twelve months ended September 30, 2021, is mainly due to the Salvador and Mountain Air Acquisitions achieved during the second and third quarters of 2020, and the Energía Llaima and Licán Acquisitions achieved during the third quarter of 2021, along with a decrease in interest payments on the revolving credit facility concurrent with the Hydro-Québec Private Placement in February 2020, and on the Alterra loans, following their reimbursement in January 2021.

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

Construction continued at the 7.5 MW **Innavik hydro project** in Quebec, Canada, which is expected to be commissioned in late 2022. In France, at the **Tonnerre standalone battery storage project,** all battery containers and converters have been installed on site.

Projects under development are progressing, including the **Hale Kuawehi solar and battery storage project** for which construction permitting activities applications and approvals are underway. Site mobilization is anticipated for Q4 2021. Progress is also being made at the **Paeahu, Barbers Point** and **Kahana solar and battery storage projects** in Hawaii. A new project in Chile was added to our development activities during the quarter.

The **Prospective projects** pipeline will allow several opportunities in the years to come, with 11 projects for a total 696 MW of installed capacity currently at an advanced stage.

Innergex Acquires Remaining Interests in Energía Llaima

Innergex has entered into a stock purchase agreement pursuant to which it has acquired, effective July 9, 2021, the remaining 50% interest in Energía Llaima SpA ("Energía Llaima"), a renewable energy company based in Chile, of which Innergex already owned 50%, for an aggregate consideration of US$75.0 million ($94.0 million), which includes a contingent consideration of US$3.7 million ($4.6 million).

As a consideration for this transaction, Innergex has issued to Energía Llaima's shareholders the number of Innergex common shares for an aggregate value of US$71.4 million at a price per share equal to the 10-day volume weighted average price prior to the closing of the acquisition, for a total of 4,048,215 shares issued.

Additionally, as part of the Investor Rights Agreement between Innergex and Hydro-Québec, Hydro-Québec owns a preferential subscription right allowing it to maintain its 19.9% ownership. Therefore, Hydro-Québec can subscribe to Innergex common shares in connection with any issuance at an equal price, including in the context of an acquisition. Hydro-Québec also has a subscription right to maintain its ownership following any annual issuance pursuant to equity securities, incentive securities or securities granted in connection with compensation. In that regard, Innergex has issued, concurrently with the closing of the transaction described above, 1,148,050 common shares, for total proceeds of $25.3 million, in order for Hydro-Québec to maintain its 19.9% ownership.

Innergex Acquires an 18 MW Run-of-River Hydro Facility in Chile

On August 3, 2021, Innergex has acquired 100% of the shares of Empresa Eléctrica Licán S.A. ("Licán"), which owns and operates an 18 MW run-of-river hydro facility with a reservoir for daily regulation for up to 3.5 hours. The facility commissioned in 2011 is located on the Licán river, in the region of Los Rios in Chile. Licán was acquired for an aggregate consideration of US$16.6 million ($20.8 million), financed with cash held in Chile, broken down to payment to the shareholders and the partial repayment of the existing debt and other costs.

The facility is expected to produce a gross estimated long-term average of 77.8 GWh per year. The asset is expected to reach an Adjusted EBITDA of US$2.1 million ($2.7 million) on average for the first five full years.

Innergex Announces the acquisition of the 60 MW Curtis Palmer Run-of-River Hydroelectric Portfolio in the State of New York

On August 17, 2021, Innergex and HQI US Holding LLC, a subsidiary of Hydro-Québec, have entered into a Membership Interest Purchase Agreement with Atlantic Power to acquire Curtis Palmer, a 60 MW run-of-river hydroelectric portfolio located in Corinth, New York, consisting of the 12 MW Curtis Mills and 48 MW Palmer Falls facilities ("Curtis Palmer"). The acquisition closed subsequent to September 30, 2021 (please refer to the Subsequent Events section for more information).

This joint acquisition is the first under the Strategic Alliance formed by Innergex and Hydro-Québec in 2020. Upon closing, on October 25, 2021, Innergex owns indirectly a 50% interest in the Curtis Palmer facilities with Hydro-Québec indirectly owning the remaining 50% interest.

The Curtis Palmer facilities have a PPA for energy, RECs and capacity with Niagara Mohawk Power Corporation (A3 / BBB+) that expires upon the earlier of either December 31, 2027, or the delivery of cumulative 10,000 GWh (which is expected in 2026). Following the expiry of the PPA, it is expected that the Curtis Palmer facilities will sell energy, RECs and capacity in the NYISO market. The New York renewable energy market benefits from state programs that support existing renewables and can offer additional upside potential to the Curtis Palmer facilities, including the recent Tier 2 REC program, and the introduction of the social cost of carbon into energy markets.

The Curtis Palmer facilities have an attractive cash flow profile and are expected to generate an average annual Adjusted EBITDA of US$42.5 million ($54.1 million) and average annual Free Cash Flow of US$39.5 million ($50.3 million) through the end of the PPA on a 100% basis.

Innergex Closes $201 million Bought Deal Equity Financing and $50 million Concurrent Private Placement

On September 3, 2021, Innergex has completed a bought deal equity financing of common shares. The Corporation issued a total of 10,374,150 common shares, including 1,353,150 common shares issued as a result of the full exercise at closing of the over-allotment option granted to the syndicate of underwriters led by CIBC Capital Markets, National Bank Financial Inc., BMO Capital Markets and TD Securities Inc. (collectively the “Underwriters”), at an offering price of $19.40 per common share (the “Offering Price”) for aggregate gross proceeds of $201.3 million (the “Offering”).

As part of the Investor Rights Agreement between Innergex and HQI Canada Holding Inc., a wholly owned subsidiary of Hydro-Québec (“Hydro-Québec”), Hydro-Québec owns a preferential subscription right allowing it to maintain its 19.9% ownership of the common shares of Innergex. Therefore, it can subscribe to Innergex common shares in connection with any issuance at an equal price, including in the context of a bought deal equity financing. Concurrent with the Offering, Innergex also closed its previously announced Private Placement (the “Private Placement”) with Hydro-Québec. A total of 2,581,000 common shares were issued at the Offering Price for aggregate gross proceeds of $50.1 million in order to maintain Hydro-Québec’s 19.9% ownership. The common shares offered pursuant to the Private Placement were sold directly to Hydro-Québec, without an underwriter or placement agent.

The Corporation intends to use the net proceeds of the Offering and the Private Placement to fund the purchase price of the acquisition of Curtis Palmer, with the remainder of the net proceeds to be used for general corporate purposes including future growth initiatives.

1-HIGHLIGHTS | Subsequent Events

Completion of the Curtis Palmer Acquisition

On October 25, 2021 Innergex and HQI US Holding LLC, a subsidiary of Hydro-Québec, completed the acquisition of Curtis Palmer, a 60 MW run-of-river hydroelectric portfolio located in Corinth, New York, for a total consideration of US$318.4 million ($393.4 million), including US$9.2 million ($11.4 million) of cash and working capital adjustments. In addition, the acquisition is subject to an earn-out provision based on the evolution of the New York Independent System Operator ("NYISO") market pricing during calendar years 2023 and 2024, limited to US$30.0 million. Upon closing, the Corporation owns a 50% interest in the Facilities with Hydro-Québec indirectly owning the remaining 50% interest.

1- HIGHLIGHTS | Updated Projected Financial Performance

The Corporation makes projections using certain assumptions to provide readers with an indication of its business activities and operating performance. For 2021, projections were based on the commissioning of the Yonne II wind farm in the first quarter of 2021, the commissioning of the Hillcrest solar project in the second quarter of 2021 and the commissioning of the Griffin Trail wind project in the third quarter of 2021. It did not take into consideration potential acquisitions that could be achieved in 2021 nor the potential impact of the February 2021 Texas Events nor the potential impact of future waves of COVID-19.

Since the Corporation made these assumptions at the beginning of the year, the projections were revised in November 2021 to take into consideration the exclusion of the results from the Flat Top and Shannon joint venture facilities, from April 1, 2021 onwards, due to the projects' assets and liabilities being classified as disposal groups held for sale, following the February 2021 Texas Events. This exclusion impacts mostly the Adjusted EBITDA Proportionate as in addition to removing Innergex's share of joint ventures' and associates' Adjusted EBITDA from the two facilities, it also excludes the PTCs they generated. The projections were also revised to take into consideration the wildfire in British Columbia that damaged the Kwoiek Creek's transmission line and below-average water flows, wind regimes and solar irradiation in most regions. Finally, the new projections were positively impacted by the acquisition of the 50% remaining interest in Energía Llaima on July 9, 2021, the acquisition of Licán on August 3, 2021, and the acquisition of Curtis Palmer on October 25, 2021.

The following table summarizes the revised projections for 2021, excluding the impacts of the February 2021 Texas Events.

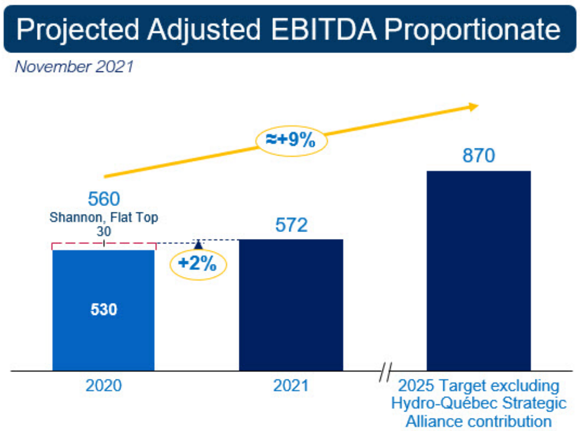
	February 2021		November 2021	
	Projected		Projected	
Revenues	approx.	+12%	approx.	+10%
Adjusted EBITDA	approx.	+12%	approx.	+10%
Adjusted EBITDA Proportionate	approx.	+12%	approx.	+2%

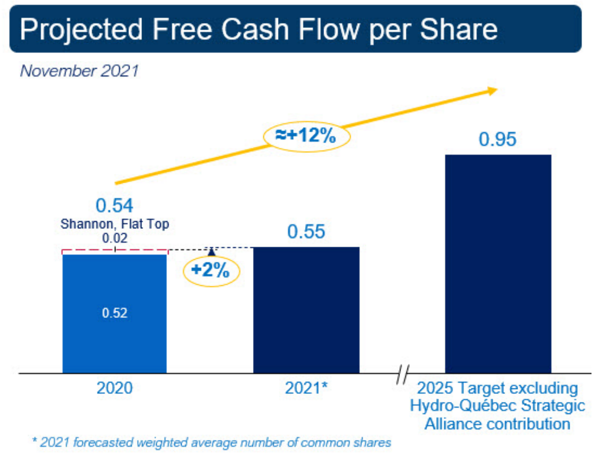
1 - HIGHLIGHTS | Strategic Plan 2020-2025

On September 15, 2021, the Corporation held its first Investor Day and provided an update on its 2020-2025 Strategic Plan and its projected financial growth. Despite lower financial projections for 2021, the targets provided in February 2021 for 2025 are expected to remain substantially the same after a revision in November 2021. The Adjusted EBITDA Proportionate is expected to achieve a compound annual growth rate of approximately 9% by 2025 to $870 million (10% projected in February 2021) and the Free Cash Flow per Share is expected to achieve a compound annual growth rate of approximately 12% by 2025 to $0.95 (12% projected in February 2021).

The following graphs present the targets for 2025, taking into consideration the revised projections for 2021, excluding the impacts of the February 2021 Texas Events.

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





Innergex's continued growth will come from a balanced strategy of developing greenfield projects with a deferred cash contribution profile and strategic acquisitions in current markets with nearer-term cash contributions. The projected figures above do not take into consideration potential transactions or projects that could be achieved or developed as part of the Strategic Alliance with Hydro-Québec.

The projections made above are based on certain key assumptions including 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. 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.

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	539	14 %	1,257	33 %	1,219	32 %	825	21 %	3,840	36 %
WIND	1,579	29 %	1,342	24 %	1,083	20 %	1,507	27 %	5,511	51 %
SOLAR	294	21 %	421	30 %	424	30 %	277	20 %	1,416	13 %
Total	2,412	22 %	3,021	28 %	2,725	26 %	2,609	24 %	10,767	100 %

1. The consolidated long-term average production is the annualized LTA for the facilities in operation as of November 9, 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 September 30, 2021		Three months ended September 30, 2020		Three months Production % change	Nine months ended September 30, 2021		Nine months ended September 30, 2020		Nine months Production % change
		Production (MWh)	Production as a % of LTA	Production (MWh)	Production as a % of LTA		Production (MWh)	Production as a % of LTA	Production (MWh)	Production as a % of LTA	
HYDRO	Quebec	163,024	90 %	181,050	100 %	(10)%	517,811	100 %	501,598	97 %	3 %
	Ontario	16,300	198 %	6,904	84 %	136 %	49,462	93 %	45,914	86 %	8 %
	British Columbia	630,122	79 %	663,946	83 %	(5)%	1,600,299	88 %	1,503,565	82 %	6 %
	United States	13,242	79 %	16,531	99 %	(20)%	35,347	85 %	39,386	95 %	(10)%
	Chile[5]	110,611	74 %	—	— %	— %	110,611	74 %	—	— %	— %
	Subtotal	**933,299**	**81 %**	**868,431**	**87 %**	**7 %**	**2,313,530**	**89 %**	**2,090,463**	**86 %**	**11 %**
WIND	Quebec	437,765	98 %	485,791	108 %	(10)%	1,537,997	93 %	1,693,988	103 %	(9)%
	France	111,831	79 %	101,934	73 %	10 %	472,722	89 %	503,002	96 %	(6)%
	United States[3]	430,748	99 %	314,987	99 %	37 %	1,294,013	98 %	993,938	97 %	30 %
	Subtotal	**980,344**	**96 %**	**902,712**	**100 %**	**9 %**	**3,304,732**	**94 %**	**3,190,928**	**100 %**	**4 %**
SOLAR	Ontario	13,020	107 %	12,804	105 %	2 %	33,236	107 %	33,311	107 %	— %
	United States	315,572	92 %	196,393	90 %	61 %	691,390	85 %	515,422	86 %	34 %
	Chile[4,5]	47,851	94 %	41,219	106 %	16 %	129,170	94 %	56,825	104 %	127 %
	Subtotal	**376,443**	**93 %**	**250,416**	**93 %**	**50 %**	**853,796**	**87 %**	**605,558**	**88 %**	**41 %**
TOTAL PRODUCTION[1]		**2,290,086**	**89 %**	**2,021,559**	**93 %**	**13 %**	**6,472,058**	**91 %**	**5,886,949**	**93 %**	**10 %**
Innergex's share of production of joint venture and associates		248,559	102 %	449,590	96 %	(45)%	705,134	96 %	1,129,831	96 %	(38)%
PRODUCTION PROPORTIONATE[1,2]		**2,538,645**	**90 %**	**2,471,149**	**93 %**	**3 %**	**7,177,192**	**92 %**	**7,016,780**	**93 %**	**2 %**

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 production and included in production proportionate.
2. The results from the Flat Top and Shannon joint venture facilities from April 1, 2021, onward were excluded due to the projects' assets and liabilities being classified as disposal groups held for sale, following the February 2021 Texas Events.
3. The Mountain Air Acquisition was completed on July 15, 2020.
4. The Salvador Acquisition was completed on May 14, 2020.
5. The acquisition of the remaining 50% interest in Energía Llaima was completed on July 9, 2021, and the Licán Acquisition was completed on August 3, 2021.

Production for the three-month period ended September 30, 2021, was 89% of LTA. The variation is mostly explained by lower production at the facilities in British Columbia from the temporary shutdown at the Kwoiek Creek facility due to the wildfire that damaged the facility's transmission line, below-average wind regimes at the facilities in France and at Foard City and by lower irradiation at the Phoebe facility. These items were partly offset by above-average wind regimes at the Griffin Trail facility in the United States. Innergex's share of production of joint ventures and associates was 102% of LTA, translating into a **Production Proportionate** at 90% of LTA.

Production for the nine-month period ended September 30, 2021, was 91% of LTA. The variation is mostly explained by lower production at the facilities in British Columbia, mostly due to the temporary shutdown at the Kwoiek Creek facility due to the wildfire that damaged the facility's transmission line, to below-average wind regimes at some Quebec facilities, at the Foard City facility and at facilities in France, and to the unfavourable impact of curtailment required by the distribution network in Texas along with lower irradiation at the Phoebe facility. These items were partly offset by above-average wind regimes at the Mountain Air and Griffin Trail facilities in the United States. Innergex's share of production of joint ventures and associates was 96% 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 | Commissioning Activities

The table below outlines the projects commissioned since the beginning of 2021.

Name (Location)	Type	Ownership %	Gross installed capacity (MW)	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project cost	Expected first 5-year average		Status
						Estimated[1] ($M)	Revenues Proportionate[1,2] ($M)	Adjusted EBITDA Proportionate[1,2] ($M)	
Hillcrest (Ohio, U.S.)	Solar	100	200	413.3	15	399.6 [3]	21.7 [3]	13.0 [3]	On May 11, 2021, the Hillcrest solar facility located in Ohio achieved PPA Commercial Operation. We expect to reach substantial completion and full commercial operation in Q4 2021. Total estimated costs have been revised to reflect some cost overruns and commercial close-out discussions with the EPC Contractor.
Griffin Trail (Texas, U.S.)	Wind	100	225.6	832.4	— [4]	362.7 [5]	49.8 [5]	38.6 [5]	On July 26, 2021, the Corporation completed the commissioning of the 225.6 MW Griffin Trail wind facility located in north Texas and concluded the tax equity funding on July 30, 2021.
Yonne II	Wind	69.55	6.9	11.0	20	15.9 [6]	1.5 [6]	1.1 [6]	On March 1, 2021, the Corporation completed the commissioning of the 6.9 MW Yonne II wind farm in France. Innergex owns a 69.55% interest in the wind farm and Desjardins Group Pension Plan ("RRMD") owns the remaining 30.45%.
Total			232.5	843.4	20.0	378.6	51.3	39.7	

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$313.6 million, Expected Revenues at US$17.0 million and Expected Adjusted EBITDA at US$10.2 million translated at a rate of 1.2741.
4. Power to be sold on the open market.
5. Total Estimated Project Cost at US$284.7 million, Expected Revenues at US$16.8 million, Expected Revenues Proportionate at US$39.1 million, Expected Adjusted EBITDA at US$8.1 million, and Adjusted EBITDA Proportionate of US$30.3 million translated at a rate of 1.2741.
6. Total Estimated Project Cost at €10.8 million, Expected Revenues at €1.0 million and Expected Adjusted EBITDA at €0.8 million translated at a rate of 1.4801.

(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
Innavik (QC, Canada)	Hydro	50	7.5	54.7	40	63.9 [3]	5.4 [3]	4.3 [3]	Spillway and diversion excavation is completed. Derivation structure concreting is completed up to level 38.0 metres. Cofferdam installation will go ahead in Q4 as scheduled. Powerhouse concrete work is completed up to level 26.3 metres. Powerhouse superstructure and envelope will be realized in Q4. Transmission line permit has been received and construction should start in Q2 of 2022. Conversion of the OMHK Residences has started and is progressing as per schedule. Total estimated costs do not reflect some cost overruns and ongoing commercial discussions with the EPC Contractor.	2022
Tonnerre (France)	Storage	100	Note [4]	—	— [5]	Note [6]	Note [6]	Note [6]	A supply, construction and maintenance agreement has been signed with the selected battery supplier, EVLO, a Hydro-Québec subsidiary. Construction at site in France is close to completion: all battery containers and converters have been delivered from Quebec and installed at site in France. Last missing components are the LV/MV transformers, which are on their way to France. Commissioning is expected in Q4 2021.	2021
Total			7.5	54.7	40.0	63.9	5.4	4.3		

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. 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.
4. Standalone battery storage capacity of 9 MWh.
5. 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.
6. Estimated Project Cost, Expected Revenues and Expected Adjusted EBITDA to be finalized. Figures to be disclosed at commissioning.

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 activities should continue as planned.

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

2- OVERVIEW OF OPERATIONS | Development Activities

Innergex owns a portfolio of Development Projects with a gross installed capacity of approximately 201 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	0 [2]	The financing process, the construction contract and permitting are progressing slowly due to the COVID-19 pandemic. Project schedule is under revision.	—
Rucacura (Chile)	Hydro	3.0	12.4	0 [2]	Rucacura is a hydro project located in BioBio, Chile. This project will be an addition to the existing Ducqueco facilities. Negotiation of an agreement with the turbine supplier is underway. Limited Notice To Proceed ("LNTP") with contractor is under negotiation.	2023
Hale Kuawehi (Hawaii, U.S.)	Solar	30.0 [3]	87.4 [4]	25	90% design engineering is completed. Engineering, procurement and construction ("EPC") contractor was selected and an LNTP was issued at the end of Q1 2021. Final EPC contract is anticipated in early Q4 2021. Construction permitting applications and approval are underway. BESS supplier has notified the project of a 5-month delay of equipment which will impact the COD. Impact on the PPA should be covered mostly by the BESS supplier. Site mobilization is anticipated for Q4 2021.	2022
Paeahu (Hawaii, U.S.)	Solar	15.0 [3]	41.2 [4]	25	Final EPC contract is anticipated Q4 2021. Maui County Planning Commission approved the Special Use Permit and Project District Phase II Development Approval on May 25, 2021, for which an appeal by local opposition is underway in the Circuit Court of the Second Circuit State of Hawaii. However, this currently does not limit their effectiveness. Construction permitting applications are underway. The PPA is not in full effect until the PUC approves the overhead line extension. Approval schedule is still unknown.	2023
Kahana (Hawaii, U.S.)	Solar	20.0 [3]	74.6 [4]	25	Consultations with potential EPC contractors have commenced. The PPA is subject to approval by the Hawaii PUC and a contested case proceeding is being held by the PUC prior to a decision. The Hawaii PUC held a two-day evidentiary hearing in September, which was followed by a 30-day mediation period to resolve differing perspectives of the parties and participants. Mediation concluded with an agreement being reached.	2023
Barbers Point (Hawaii, U.S.)	Solar	15.0 [3]	37.0 [4]	25	Environmental studies are ongoing, as are other permitting-related activities including the publication of the Draft Environmental Assessment. Consultations with potential EPC contractors have commenced. PUC suspended the procedural schedule for PPA approval until the final environmental assessment is completed and filed at the end of Q1 2022.	2023
Lazenay (France)	Wind	9.0	27.8	—	Lazenay is a wind project located in Centre Val de Loire, of which the Corporation owns 25%. Environmental approval was received, the PPA approval by EDF-OA was approved and request for interconnection service agreement was initiated.	2023
TOTAL		201.0	744.4			

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. PPA is a fixed lump sum capacity payment for the availability of dispatchable energy.

(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	8	—	—	—	—	500	8
Solar	300	7	—	—	—	—	300	7
Wind	3,943	23	—	—	—	—	3,943	23
Subtotal	4,743	38	—	—	—	—	4,743	38
UNITED STATES								
Solar	639	7	730	4	200	1	1,569	12
Wind	—	—	—	—	332	1	332	1
Subtotal	639	7	730	4	532	2	1,901	13
FRANCE								
Solar	—	—	60	1	—	—	60	1
Wind	128	11	61	3	161	8	350	22
Subtotal	128	11	121	4	161	8	410	23
CHILE								
Hydro	183	3	—	—	3	1	186	4
Solar	32	1	—	—	—	—	32	1
Wind	9	1	—	—	—	—	9	1
Subtotal	224	5	—	—	3	1	227	6
Total	5,734	61	851	8	696	11	7,281	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, one new solar project in the United States progressed to the early stage. Also, in France, one wind project went from mid stage to advanced stage, while four wind projects in France and one wind project in Chile went from mid stage to early stage.

The advanced stage Boswell Springs wind project in Wyoming, USA, has been selected to PacifiCorp's 2020 All-Source Request for Proposal final shortlist. Therefore, the project is currently negotiating the terms of a busbar take-or-pay 30-year PPA with PacifiCorp.

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

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 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-Québec.

On October 25, 2021, the Corporation and HQI US Holding LLC, a subsidiary of Hydro-Québec, announced the completion of the 50-50 joint acquisition of the 60 MW Curtis Palmer hydroelectric portfolio in the state of New York. The Curtis Palmer facilities consist of two run-of-river hydroelectric facilities, Curtis Mills (12 MW) and Palmer Falls (48 MW). Curtis Palmer has a power purchase agreement for energy, RECs and capacity with Niagara Mohawk Power Corporation. The five employees currently working at the Curtis Palmer facilities are joining the Innergex team. This joint acquisition is the first under the Strategic Alliance.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS

	Three months ended September 30				Nine months ended September 30					
	2021	2020	Change		2021	February 2021 Texas Events (9 days)[3]	2021 Normalized	2020	Change	
Revenues	184,564	162,651	21,913	13 %	544,820	(54,967)	489,853	445,280	44,573	10 %
Operating expenses	45,395	37,040	8,355	23 %	106,551	—	106,551	94,932	11,619	12 %
General and administrative expenses	11,512	12,388	(876)	(7)%	32,285	—	32,285	32,969	(684)	(2)%
Prospective project expenses	5,135	4,699	436	9 %	17,658	—	17,658	13,100	4,558	35 %
Adjusted EBITDA[1]	122,522	108,524	13,998	13 %	388,326	(54,967)	333,359	304,279	29,080	10 %
Adjusted EBITDA margin[1]	66.4 %	66.7 %			71.3 %	(3.2)%	68.1 %	68.3 %		
Finance costs	66,519	60,122	6,397	11 %	184,838	—	184,838	175,700	9,138	5 %
Other net income	(33,827)	(16,725)	(17,102)	102 %	(55,056)	—	(55,056)	(58,250)	3,194	(5)%
Depreciation and amortization	59,838	59,368	470	1 %	177,892	—	177,892	170,061	7,831	5 %
Impairment of long-term assets	30,660	—	30,660	— %	36,974	—	36,974	—	36,974	— %
Share of (earnings) losses of joint ventures and associates:[2]										
Share of (earnings) losses, before impairment charges	(14,311)	(11,382)	(2,929)	26 %	78,071	(64,197)	13,874	21,398	(7,524)	(35)%
Share of impairment charges	—	—	—	— %	112,609	—	112,609	—	112,609	— %
Change in fair value of financial instruments	15,366	(1,859)	17,225	(927)%	107,533	(72,060)	35,473	24,835	10,638	43 %
Income tax expense (recovery)	21,741	11,508	10,233	89 %	(63,398)	17,071	(46,327)	11,540	(57,867)	(501)%
Net (loss) earnings	(23,464)	7,492	(30,956)	(413)%	(191,137)	64,219	(126,918)	(41,005)	(85,913)	210 %
(Net loss) earnings attributable to:										
Owners of the parent	(16,398)	11,740	(28,138)	(240)%	(189,457)	64,219	(125,238)	(44,548)	(80,690)	181 %
Non-controlling interests	(7,066)	(4,248)	(2,818)	66 %	(1,680)	—	(1,680)	3,543	(5,223)	(147)%
	(23,464)	7,492	(30,956)	(413)%	(191,137)	64,219	(126,918)	(41,005)	(85,913)	210 %
Basic and diluted net (loss) earnings per share attributable to owners ($)	(0.10)	0.06			(1.09)	0.36	(0.73)	(0.29)		

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 nine months ended September 30, 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)

During the quarter, revenues and operating expenses increased due to the commissioning of the Hillcrest and Griffin Trail facilities and the acquisitions of Energía Llaima and Licán. However, unfavourable weather conditions during the quarter at most of our facilities compared to the same period last year have more than offset the growth in revenues stemming from these newly commissioned and acquired facilities, leaving the operating expense increase unabsorbed by the increased revenues.

On a consolidated basis, the **Adjusted EBITDA Margin** was down from 66.7% to 66.4% for the three-month period ended on September 30, 2021. This decrease is mainly explained by lower revenues from Quebec hydro and wind facilities and from hydro facilities in British Columbia. This decrease was partly offset by the contribution of the Hillcrest solar facility and higher revenues at the Salvador solar facility due to higher selling prices.

On a consolidated basis, excluding the February 2021 Texas Events, the **Adjusted EBITDA Margin** was down from 68.3% to 68.1% for the nine-month period ended September 30, 2021. The decrease is explained by higher prospective expenses, lower revenues and higher operating expenses at the Quebec wind facilities and by the weight of the recent acquisition in the United States for which margins are lower. The decrease is partly offset by higher revenues from the hydro facilities in British Columbia, the contribution of the Hillcrest solar facility and higher revenues at the Salvador solar facility due to higher selling prices.

On a consolidated basis, **Adjusted EBITDA Proportionate Margin** was down from 70.9% to 70.3% for the three-month period ended on September 30, 2021. This decrease is explained by a lower Adjusted EBITDA margin and by lower PTCs due to the exclusion of the results from the Flat Top and Shannon joint venture facilities, from April 1, 2021 onwards, due to the projects' assets and liabilities being classified as disposal groups held for sale, following the February 2021 Texas Events and to lower PTCs earned at the Foard City wind facility due to lower production. This decrease was partly offset by the PTCs earned at the Griffin Trail facility following its commissioning on July 26, 2021.

On a consolidated basis, excluding the February 2021 Texas Events, the **Adjusted EBITDA Proportionate Margin** was down from 71.5% to 70.8% for the nine-month period ended September 30, 2021. The decrease is explained by a lower Adjusted EBITDA margin and by lower PTCs due to the exclusion of the results from the Flat Top and Shannon joint venture facilities, from April 1, 2021 onwards, due to the projects' assets and liabilities being classified as disposal groups held for sale, following the February 2021 Texas Events and to lower PTCs earned at the Foard City wind facility due to lower production. This decrease was partly offset by the PTCs earned at the Griffin Trail facility following its commissioning on July 26, 2021

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Hydroelectric Segment

Hydroelectric Segment	Three months ended September 30			Nine months ended September 30		
	2021	2020	Change	2021	2020	Change
Production (MWh)	933,299	868,431	7 %	2,313,530	2,090,463	11 %
LTA (MWh)	1,151,138	1,001,625	15 %	2,585,769	2,436,257	6 %
Revenues (In $M)	78,414	76,170	3 %	180,910	169,157	7 %
Adjusted EBITDA (In $M)[1]	62,546	61,847	1 %	140,063	130,368	7 %
Adjusted EBITDA Margin[1]	79.8 %	81.2 %		77.4 %	77.1 %	
PROPORTIONATE[1]						
Production Proportionate (MWh)	1,153,856	1,136,368	2 %	2,739,021	2,544,123	8 %
Revenues Proportionate (In $M)	101,885	106,691	(5)%	223,950	219,139	2 %
Adjusted EBITDA Proportionate (In $M)	82,924	88,249	(6)%	173,581	169,840	2 %
Adjusted EBITDA Margin Proportionate	81.4 %	82.7 %		77.5 %	77.5 %	

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 September 30, 2021, the increase of 1% in **Adjusted EBITDA** in the hydroelectric segment compared with the same quarter last year is mainly explained by the contribution from the Chilean facilities following the acquisition of the remaining 50% interest in Energía Llaima on July 9, 2021, and the Licán Acquisition closed on August 3, 2021. This increase was partly offset by the temporary shutdown at the Kwoiek Creek facility due to the wildfire that damaged the facility's transmission line and lower contribution from the facilities in Quebec due to lower revenues from lower production and lower selling prices.The **Adjusted EBITDA Margin** was down from 81.2% to 79.8%, mainly explained by lower revenues at the Kwoiek Creek facility, lower revenues from the facilities in Quebec and by the increased weight of the Chilean facilities following the recent acquisitions for which margins are lower.

The **joint ventures' and associates'** hydroelectric facilities contributed $20.4 million to the **Adjusted EBITDA Proportionate** for the three-month period ended September 30, 2021, compared with a contribution of $26.4 million for the same quarter last year, a 23% decrease explained by a lower contribution from the Chilean facilities since their results are now included in the Adjusted EBITDA, following the acquisition of the remaining 50% interest of Energía Llaima on July 9, 2021, and to a lower contribution from the Toba Montrose facility due to lower average selling prices, partly offset by a higher contribution from the Jimmie Creek facility due to higher revenues from higher production explained by lower 2020 figures that included the impact of the curtailment imposed by BC Hydro.

For the nine-month period ended September 30, 2021, the increase of 7% in **Adjusted EBITDA** in the hydroelectric segment compared with the same period last year was mainly due to the contribution from the Chilean facilities following the acquisition of the remaining 50% interest of Energía Llaima on July 9, 2021, and the Licán Acquisition closed on August 3, 2021. This increase is also explained by a higher contribution from the facilities in British Columbia mainly attributable to higher revenues from higher production explained by lower 2020 figures that included the impact of the curtailment imposed by BC Hydro for five facilities. This increase was partly offset by lower contribution from some Quebec hydro facilities due to lower revenues from the combined effect of lower production, lower selling prices and higher operating expenses at some facilities. The **Adjusted EBITDA Margin** was up from 77.1% to 77.4%, which is mainly explained by higher revenues from the British Columbia facilities but partly offset by lower revenues from the Quebec facilities and by the increased weight of Chilean facilities following the recent acquisitions for which margins are lower.

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

The **joint ventures' and associates'** hydroelectric facilities contributed $33.5 million to the **Adjusted EBITDA Proportionate** for the nine-month period ended September 30, 2021, compared with a contribution of $39.5 million for the same period last year, explained by a lower contribution from the Chilean facilities since their results are now included in the Adjusted EBITDA, following the acquisition of the remaining 50% interest of Energía Llaima on July 9, 2021, and to a lower contribution from facilities in British Columbia due to lower average selling prices, partly offset by a higher contribution from the Jimmie Creek facility due to higher revenues from higher production explained by lower 2020 figures that included the impact of the curtailment imposed by BC Hydro.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Wind Segment

	Three months ended September 30			Nine months ended September 30				
Wind Segment	2021	2020	Change	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized	2020	Change
Production (MWh)	980,344	902,712	9 %	3,304,732	—	3,304,732	3,190,928	4 %
LTA (MWh)	1,024,347	905,533	13 %	3,503,914	—	3,503,914	3,200,496	9 %
Revenues (In $M)	70,678	67,726	4 %	259,506	(16,801)	242,705	235,325	3 %
Adjusted EBITDA (In $M)[1]	45,582	48,431	(6)%	202,841	(16,801)	186,040	185,287	— %
Adjusted EBITDA Margin[1]	64.5 %	71.5 %		78.2 %	(9.2)%	76.7 %	78.7 %	
PROPORTIONATE[1]								
Production Proportionate (MWh)	1,008,346	1,081,146	(7)%	3,578,835	—	3,578,835	3,857,814	(7)%
Revenues Proportionate (In $M)	84,603	87,887	(4)%	352,857	(57,107)	295,750	308,754	(4)%
Adjusted EBITDA Proportionate (In $M)	58,620	64,664	(9)%	291,234	(57,107)	234,127	248,098	(6)%
Adjusted EBITDA Margin Proportionate	69.3 %	73.6 %		82.5 %	(10.1)%	79.2 %	80.4 %	

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 nine months ended September 30, 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 September 30, 2021, the **Adjusted EBITDA** in the wind power generation segment decreased by 6% compared with the same quarter last year. This decrease is mainly attributable to the lower contribution from the Quebec facilities due to a combined effect of lower revenues from lower production and higher operating expenses and to the Foard City facility due to a combined effect of lower revenues from lower production and lower average selling prices. This decrease was partly offset by the commissioning of the Griffin Trail wind facility on July 26, 2021 and by a higher contribution from the facilities in France due to higher revenues from higher production. The **Adjusted EBITDA Margin** was down from 71.5% to 64.5%. This decrease is explained by the combined effect of lower revenues from lower production and higher operating expenses at the Quebec wind facilities.

The **joint ventures' and associates'** wind farms contributed $2.3 million to the **Adjusted EBITDA Proportionate** for the three-month period ended September 30, 2021, compared with a contribution of $3.0 million in the same quarter last year. This decrease is mainly attributable to the exclusion of the results from the Flat Top and Shannon joint venture facilities, from April 1, 2021 onward, due to the projects' assets and liabilities being classified as disposal groups held for sale, following the February 2021 Texas Events. The decrease is also explained by a lower contribution from the Viger-Denonville facility in Quebec due to lower revenues from lower production.

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

The **proportional PTCs** generated by the wind farms contributed $10.7 million in the three-month period ended September 30, 2021, compared with a $13.2 million contribution in the same quarter last year. This decrease is mainly attributable to the exclusion of the results from the Flat Top and Shannon joint venture facilities, from April 1, 2021 onward, due to the projects' assets and liabilities being classified as disposal groups held for sale, following the February 2021 Texas Events and to lower PTCs earned at the Foard City facility due to lower production. This decrease was partly offset by the PTCs earned at the Griffin Trail facility following its commissioning on July 26, 2021.

For the nine-month period ended September 30, 2021, the **Adjusted EBITDA** in the wind power generation segment, excluding the February 2021 Texas Events, on a normalized basis was stable at $186.0 million, compared with the same period last year, mainly due to the Mountain Air Acquisition in Idaho, completed on July 15, 2020, and the contribution from the Griffin Trail facility, following its commissioning on July 26, 2021. These factors were offset by lower contributions from the Quebec wind facilities due to lower revenues from lower production and higher operating expenses and by lower contributions from the facilities in France from lower revenues due to lower production at some facilities. The **Adjusted EBITDA Margin,** excluding the February 2021 Texas Events, on a normalized basis, was down from 78.7% to 76.7%. This decrease is explained by lower revenues from the facilities in Quebec and France.

The **joint ventures' and associates'** wind farms, excluding the February 2021 Texas Events, on a normalized basis, contributed $10.5 million to the **Adjusted EBITDA Proportionate** for the nine-month period ended September 30, 2021, compared with a contribution of $12.0 million in the same period last year. This decrease is mainly attributable to the exclusion of the results from the Flat Top and Shannon joint venture facilities, from April 1, 2021 onward, due to the projects' assets and liabilities being classified as disposal groups held for sale, following the February 2021 Texas Events. This decrease is also explained by a lower contribution from the Dokie wind facility in British Columbia due to a combined effect of lower revenues from lower selling prices and higher operating expenses.

The **proportional PTCs** generated by the wind farms contributed $37.6 million for the nine-month period ended September 30, 2021, compared with a $50.8 million contribution in the same period last year. This decrease is mainly attributable to the exclusion of the results from the Flat Top and Shannon joint venture facilities, from April 1, 2021 onward, due to the projects' assets and liabilities being classified as disposal groups held for sale, following the February 2021 Texas Events and to lower PTCs earned at the Foard City facility due to lower production. This decrease was partly offset by the PTCs earned at the Griffin Trail facility following its commissioning on July 26, 2021.

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Solar Segment

Solar Segment	Three months ended September 30			Nine months ended September 30				
	2021	2020	Change	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized	2020	Change
Production (MWh)	376,443	250,416	50 %	853,796	—	853,796	605,558	41 %
LTA (MWh)	404,765	270,448	50 %	986,076	—	986,076	687,583	43 %
Revenues (In $M)	35,472	18,755	89 %	104,404	(38,166)	66,238	40,798	62 %
Adjusted EBITDA (In $M)[1]	29,777	14,034	112 %	93,295	(38,166)	55,129	31,079	77 %
Adjusted EBITDA Margin[1]	83.9 %	74.8 %		89.4 %	(10.4)%	83.2 %	76.2 %	
PROPORTIONATE[1]								
Production Proportionate (MWh)	376,443	253,635	48 %	859,336	—	859,336	614,843	40 %
Revenues Proportionate (In $M)	35,472	19,158	85 %	105,289	(38,166)	67,123	42,218	59 %
Adjusted EBITDA Proportionate (In $M)	29,777	14,308	108 %	93,849	(38,166)	55,683	31,915	74 %
Adjusted EBITDA Margin Proportionate	83.9 %	74.7 %		89.1 %	(10.3)%	83.0 %	75.6 %	

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.
2. For the nine months ended September 30, 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 September 30, 2021, the **Adjusted EBITDA** in the solar power generation segment increased by 112% compared with the same quarter last year. This increase is mainly explained by the liquidated damages due from the EPC contractor for loss of revenue caused by the delays in and the commissioning of the Hillcrest solar facility, higher selling prices at the Salvador facility and by the contribution of the Pampa Elvira facility following the acquisition of the remaining 50% interest in Energía Llaima on July 9, 2021. The increase was partly offset by a lower contribution from the Phoebe facility due to lower revenues from lower average selling prices. The **Adjusted EBITDA Margin** was up from 74.8% to 83.9% mainly explained by the contribution of the Hillcrest and Salvador solar facilities.

For the nine-month period ended September 30, 2021, the **Adjusted EBITDA** in the solar power generation segment, excluding the February 2021 Texas Events, on a normalized basis, increased by 77% compared with the same period last year. This increase is mainly explained by the liquidated damages due from the EPC contractor for loss of revenue caused by the delays in and the commissioning of the Hillcrest solar facility and the contribution of the Salvador Acquisition on May 14, 2020. The **Adjusted EBITDA Margin,** excluding the February 2021 Texas Events, on a normalized basis, was up from 76.2% to 83.2% mainly explained by the contribution of the Hillcrest solar facility and higher selling prices at the Salvador facility.

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

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Net Earnings (Loss)

Net loss of $23.5 million ($0.10 loss per share - basic and diluted) for the three-month period ended September 30, 2021, compared with net earnings of $7.5 million ($0.06 earnings per share - basic and diluted) for the corresponding period in 2020.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously explained, the $31.0 million decrease in net earnings mainly stems from:

- the recognition of **impairment charges** related to the Phoebe solar facility in Texas, and to a minority equity investment in France, totalling $24.7 million and $5.9 million, respectively;
- a $10.2 million increase in income tax expense mainly due to **tax attributes being allocated to tax equity investors**, namely the accelerated tax depreciation and PTCs at the Griffin Trail facility;
- an unfavourable $15.6 million unrealized change in **fair value of financial instruments, mainly related to the increase in merchant power curves for the Phoebe power hedge**, compared with the same period in 2020; and
- a $6.4 million increase in **finance costs mainly related to the Griffin Trail wind facility**, following its commissioning during the third quarter, and an increase in inflation compensation interests on the Harrison Hydro real return bonds.

These items were partly offset by:
- a $17.1 million increase in **other income mainly related to the production tax credits and tax attributes allocated to the tax equity investors** at the Griffin Trail wind facility, following its commissioning during the third quarter.

Net loss of $191.1 million ($1.09 loss per share - basic and diluted) for the nine-month period ended September 30, 2021, compared with a net loss of $41.0 million ($0.29 loss per share - basic and diluted) for the corresponding period in 2020.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously explained, the $150.1 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 venture facilities**, at $53.8 million and $58.8 million, respectively;
- the recognition of **impairment charges** related to the Phoebe solar facility in Texas reflecting an outlook of lower than expected congestion charges, the previously owned Energía Llaima investment in light of the purchase price for the remaining interests, and a minority equity investment in France, totalling $24.7 million, $6.3 million, and $5.9 million, respectively;
- an unfavourable $21.5 million unrealized change in **fair value of financial instruments, mainly related to the increase in merchant power curves for the Phoebe power hedge**, compared with the same period in 2020;
- a $9.1 million increase in **finance costs mainly related to the Griffin Trail wind facility**, following its commissioning during the third quarter, and an increase in inflation compensation interests on the Harrison Hydro real return bonds;
- a $7.8 million increase in **depreciation and amortization, mainly attributable to the Mountain Air and Salvador Acquisitions;** and
- a $3.5 million decrease in **other income mainly related to a decrease in the 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, partly offset by **the production tax credits and tax attributes allocated to the tax equity investors at the Griffin Trail wind facility**, following its commissioning during the third quarter.

These items were partly offset by:
- a favourable $13.7 million movement on the **realized portion of financial instruments, mainly related to the Phoebe basis hedge**, compared with the same period in 2020; and
- a $74.9 million increase in **recovery of income tax**, mainly related to the impacts of the February 2021 Texas Events and the reversal of deferred tax liabilities related to the Flat Top and Shannon joint venture facilities, due to the projects' assets and liabilities being classified as disposal groups held for sale, partly offset by the **tax attributes being allocated to tax equity investors**, namely the accelerated tax depreciation and PTCs at the Griffin Trail facility.

3- FINANCIAL PERFORMANCE ON OPERATING RESULTS | Adjusted Net Earnings

The Adjusted Net Earnings 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 Earnings 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 Earnings" 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 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 losses of joint ventures and associates 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 September 30		Nine months ended September 30	
	2021	2020	2021	2020
Revenues	184,564	162,651	489,853	445,280
Expenses:				
Operating expenses	45,395	37,040	106,551	94,932
General and administrative expenses	11,512	12,388	32,285	32,969
Prospective project expenses	5,135	4,699	17,658	13,100
Adjusted EBITDA	122,522	108,524	333,359	304,279
Finance costs	66,519	60,122	184,838	175,700
Other net income	(32,694)	(15,970)	(53,175)	(56,670)
Depreciation and amortization	59,838	59,368	177,892	170,061
Share of losses of joint ventures and associates	(14,070)	(17,078)	(12,151)	(8,817)
Realized losses (gains) on power hedges	1,139	(2,447)	1,230	(7,414)
Income tax expense	29,885	11,153	31,702	22,100
Adjusted Net Earnings[1]	11,905	13,376	3,023	9,319

1. Adjusted Net Earnings 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.

Adjusted Net Earnings of $11.9 million for the three-month period ended September 30, 2021, compared with an Adjusted Net Earnings of $13.4 million for the corresponding period in 2020.

The $1.5 million decrease in Adjusted Net Earnings mainly stems from:
- an $18.7 million increase in income tax expense mainly due to **tax attributes being allocated to tax equity investors**, namely the accelerated tax depreciation and PTCs at the Griffin Trail facility; and
- a $6.4 million increase in **finance costs mainly related to the Griffin Trail wind facility**, following its commissioning during the third quarter, and an increase in inflation compensation interests on the Harrison Hydro real return bonds.

This item was partly offset by:
- the hydroelectric, wind and solar segments' respective operating performance previously explained; and
- a $16.7 million increase in **other income mainly related to the production tax credits and tax attributes allocated to the tax equity investors** at the Griffin Trail wind facility, following its commissioning during the third quarter.

Adjusted Net Earnings of $3.0 million for the nine-month period ended September 30, 2021, compared with an Adjusted Net Earnings of $9.3 million for the corresponding period in 2020.

The $6.3 million decrease in Adjusted Net Earnings mainly stems from:
- a $9.6 million increase in income tax expense mainly due to **tax attributes being allocated to tax equity investors**, namely the accelerated tax depreciation and PTCs at the Griffin Trail facility;

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- a $9.1 million increase in **finance costs mainly related to the Griffin Trail wind facility**, following its commissioning during the third quarter, and an increase in inflation compensation interests on the Harrison Hydro real return bonds;
- a $7.8 million increase in **depreciation and amortization, mainly attributable to the Mountain Air and Salvador Acquisitions**;
- an unfavourable $8.6 million movement in the **realized portion of the power hedges**, compared with the same period in 2020; and
- a $3.5 million decrease in **other income mainly related to a decrease in the 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, partly offset by **the production tax credits and tax attributes allocated to the tax equity investors at the Griffin Trail wind facility**, following its commissioning during the third quarter.

These items were partly offset by:
- the hydroelectric, wind and solar segments' respective operating performance previously explained.

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

Attribution of loss of $7.1 million to non-controlling interests for the three-month period ended September 30, 2021, compared with an attribution of loss of $4.2 million for the corresponding period in 2020

The $2.8 million increase in loss attributed to non-controlling interests for the three-month period ended September 30, 2021, is mainly due to the temporary shutdown at the Kwoiek Creek facility due to the wildfire that damaged the facility's transmission line.

Attribution of loss of $1.7 million to non-controlling interests for the nine-month period ended September 30, 2021, compared with an attribution of earnings of $3.5 million for the corresponding period in 2020

The $5.2 million decrease in earnings attributed to non-controlling interests for the nine-month period ended September 30, 2021, is mainly due to:
- a higher allocation of losses to the non-controlling interests of Harrison Hydro, largely due to an increase in the inflation compensation interest on the real return bonds, compared with the same period last year; and
- the temporary shutdown at the Kwoiek Creek facility due to the wildfire that damaged the facility's transmission line.

These items were partly offset by:
- a contractual increase in the percentage of allocation to the non-controlling interests of Mesgi'g Ugju's'n; and
- the earnings allocated to the non-controlling interests in 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 September 30, 2021	As at December 31, 2020
Equity[1]		
Common shares[2]	3,913,697	4,778,325
Preferred shares[3]	110,710	99,364
Non-controlling interests	57,991	62,078
	4,082,398	4,939,767
Long-term loans and borrowings[1]		
Corporate revolving credit facility	277,732	182,996
Other corporate debt	150,000	266,627
Project-level debt	3,737,449	3,839,799
Tax Equity financing	465,272	315,958
Convertible debentures	279,653	280,075
Deferred financing costs	(65,335)	(71,574)
	4,844,771	4,813,881
	8,927,169	9,753,648

1.Common and preferred shares are presented at their market value as at September 30, 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 September 30, 2021, and December 31, 2020, multiplied by the prevailing share price of $20.30 (2020 - $27.37) at the close of markets.
3.Consists of the number of preferred shares outstanding as at September 30, 2021, and December 31, 2020, multiplied by the prevailing share price of $17.65 and $25.35 (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 fair value of common shares was impacted mainly by share issuances upon acquisitions, public offering and Hydro-Québec Private Placement (refer to the "Information on Capital Stock" section of this MD&A for more information), partly offset by a net unfavourable change in the share prices. The preferred shares structure remained consistent compared to December 31, 2020. The fair value was therefore impacted mainly by a net favourable change in the preferred shares prices. The decrease in non-controlling interests stems from the distributions made in excess of the allocation of earnings to the non-controlling interests. The increase in long-term loans and borrowings mainly relates to the net draws, made mostly toward the construction of the Hillcrest and Griffin Trail projects, partly offset by the strengthening of the Canadian Dollar.

The effective all-in interest rate on the Corporation's long-term loans and borrowings was 4.68% as at September 30, 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 September 30, 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. When they are 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 Montjean and Theil-Rabier facilities were not meeting their respective targeted debt coverage ratios as at December 31, 2020, which triggered a breach under their respective credit agreement. This was due to two blade incidents, which caused business interruptions at both Montjean and Theil-Rabier facilities for an extended period, which were subsequently followed by several production restrictions. In July 2021, the lenders waived their right to request repayment related to the non-achievement of the minimum debt coverage ratios as at December 31, 2020.

The Phoebe solar facility was in breach of its credit agreement as at September 30, 2021. The US$103.2 million ($131.5 million) portion of the loan that would otherwise be classified as long-term was reclassified to the current portion of long-term loans and borrowings. Ongoing dialogue and reporting are provided to the facility lenders until this situation is resolved.

The Duqueco facility was in breach of its credit agreement following the acquisition of the remaining 50% interest in Energía Llaima since the former Chilean equity investors ceased to jointly hold direct ownership of fifty percent of the company's shares. The US$109.9 million ($140.0 million) portion of the loan that would otherwise be classified as long-term was reclassified to the current portion of long-term loans and borrowings. Negotiations are currently underway to resolve this situation.

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

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

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)
Foard City[1,2]	2019	2029	372.7	41.5	4.5	99.00 %	5.00 %
Griffin Trail[1,2]	2021	2031	210.6	26.5	4.7	82.50 %	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 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 1.2741. 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 1.2741. Pay-go Contributions will be earned on actual production in excess of a specified annual threshold, subject to a contractual cumulative maximum.

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 decreases 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% in excess of priority distribution

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 these fixed and defined distributions are distributed at the rate of 10.62% to the TEI, until the Flip Point date.
3. TEI Allocation of taxable income (loss) and ITC are 67.00% until December 31, 2024, and up to 99.00% thereafter, 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 ($114.2 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 TEI partnership agreement. All amounts of distributable cash in excess of 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	September 30, 2021	December 31, 2020
ASSETS		
Current assets		
Cash and cash equivalents	175,050	161,465
Restricted cash	70,555	67,477
Investment tax credits recoverable	89,345	106,353
Other current assets	167,978	117,157
Total current assets	502,928	452,452
Non-current assets		
Property, plant and equipment	5,367,171	5,053,125
Intangible assets	902,400	919,323
Investments in joint ventures and associates	137,370	446,837
Goodwill	74,325	75,932
Other non-current assets	260,410	206,563
Total non-current assets	6,741,676	6,701,780
Total assets	7,244,604	7,154,232
LIABILITIES		
Current liabilities	909,020	1,036,730
Non-current liabilities		
Long-term loans and borrowings	4,236,492	4,046,714
Other non-current liabilities	909,694	999,856
Total non-current liabilities	5,146,186	5,046,570
Total liabilities	6,055,206	6,083,300
SHAREHOLDERS' EQUITY		
Equity attributable to owners	1,131,407	1,008,854
Non-controlling interests	57,991	62,078
Total shareholders' equity	1,189,398	1,070,932
	7,244,604	7,154,232

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

Working Capital Items

As at September 30, 2021, working capital was negative at $406.1 million, from negative $584.3 million in 2020, mainly explained by:

- Current assets amounted to $502.9 million as at September 30, 2021, an increase of $50.5 million compared with December 31, 2020, mainly due to a $36.8 million increase in accounts receivable attributable to higher revenues from higher production from the hydroelectric facilities. Additionally, the increase is due to the accounts receivables acquired from the business acquisitions.

- Current liabilities amounted to $909.0 million as at September 30, 2021, a decrease of $127.7 million compared with December 31, 2020, mainly due to a $159.2 million decrease in the current portion of long-term loans and borrowings which primarily relates to the resolution of breaches of the Mesgi'g Ugju's'n and Mountain Air respective credit agreements, partly offset by the classification of the Phoebe project loan as current following the breach of its credit agreement as at September 30, 2021 and by the classification of the Duqueco facility as current following the breach of its credit agreement following the acquisition of the remaining 50% interest in Energía Llaima since the former Chilean equity investors ceased to jointly hold direct ownership of fifty percent of the company's shares.

- 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 that a total amount of $271.5 million that would otherwise be classified as long-term was reclassified to the current portion of long-term loans and borrowings (see the "Capital Structure" section of this MD&A for more information). As at September 30, 2021, the Corporation had $700.0 million in revolving term credit facilities and had drawn $277.7 million as cash advances, while $61.4 million had been used to issue letters of credit, leaving $360.9 million available.

Non-Current Assets

Non-current assets amounted to $6,741.7 million as at September 30, 2021, an increase of $39.9 million compared with December 31, 2020. The increase is mainly due to the Energía Llaima and Licán Acquisitions in the third quarter of 2021. Moreover, the construction activities, mainly related to the Hillcrest and Griffin Trail facilities, contributed to increasing property, plant and equipment by an aggregate amount of $192.4 million, net of the ITC recoverable recognized against the Hillcrest construction costs. In addition, other non-current assets increased following proceeds received from a $19.6 million letter of credit that the Corporation availed itself of following the bankruptcy of the service provider under the turbine supply agreement at Mesgi'g Ugju's'n. The proceeds are to be used in the future to remediate the unfulfilled performance obligations under the turbine supply agreement.

These items were partly offset by a $24.7 million impairment charge related to the Phoebe solar facility in Texas, reflecting an outlook of higher than expected congestion charges, the strengthening of the Canadian dollar against the Euro, depreciation and amortization of $177.9 million, and a decrease in investments in joint ventures and associates. The decrease in investments in joint ventures and associates is related mainly to the impacts of the February 2021 Texas Events on the Flat Top and Shannon joint ventures, aggregating to a share of losses of $64.2 million for Innergex, impairment charges of $53.8 million and $58.8 million for Flat Top and Shannon, respectively, and to the acquisition of the remaining interests in Energía Llaima which was previously presented as an equity accounted investment.

Non-Current Liabilities

Non-current liabilities amounted to $5,146.2 million as at September 30, 2021, an increase of $99.6 million compared with December 31, 2020. The increase is mainly due to the Energía Llaima and Licán Acquisitions in the third quarter of 2021. Moreover, the reclassification of project loans as non-current following the resolution of breaches of the Mesgi'g Ugju's'n, Montjean/Theil-Rabier and Mountain Air credit agreements contributed to increasing the non-current portion of long-term loans and borrowings, as well as the net draws made toward the construction of the Hillcrest and Griffin Trail facilities. In addition, other liabilities increased following proceeds received from a $19.6 million letter of credit that the Corporation availed itself of following the bankruptcy of the service provider under the turbine supply agreement at Mesgi'g Ugju's'n.

These increases were partly offset by the strengthening of the Canadian dollar against the Euro, scheduled principal repayments, the classification of the Phoebe project loan and Duqueco project loan as current (see the "Capital Structure" section of this MD&A for more information), and the proceeds received from the public offering of common shares and the Hydro-Québec Private Placement applied against the revolving credit facility.

Shareholders' Equity

As at September 30, 2021, Shareholders' equity increased by $118.5 million compared with December 31, 2020, mainly attributable to the issuances upon acquisitions, public offering and the Hydro-Québec Private Placement (refer to the "Information on Capital Stock" section of this MD&A for more information), and due to the total comprehensive loss of $133.1 million, the dividends declared on common and preferred shares totaling $101.8 million, and $13.3 million in distributions to non-controlling interest.

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 $95.6 million as at September 30, 2021, from a net liability of $151.0 million as at December 31, 2020. The favourable unrealized change in fair value relates mainly to the interest hedging derivatives, favourably impacted by an upward shift in interest rate curves, and by the Phoebe basis hedge, mainly stemming from a decrease in the estimated basis difference, combined with the passage of time. These items were partly offset by the unfavourable change in 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.

On July 19, 2021, Innergex reached an agreement to settle the amounts that remained unpaid by the Phoebe solar facility following the February 2021 Texas Events. The aggregate cash disbursement of US$24.0 million ($29.7 million) comprises the agreed-upon settlement payment for the amounts disputed following the February 2021 Texas Events, and a payment on the project's tracking account balance[1], net of unpaid energy sold by the project during the negotiation process.

1. Renewable energy projects selling energy under a power hedge structure are exposed to mismatch risk mainly driven by: (1) volume/shape risk, which represents the risk of a shortfall in the actual energy produced in comparison to the contractual hourly quantities; and (2) basis risk, which represents a price differential risk between hub and node per MWh of contracted energy. To cover for temporary unfavourable mismatches, counterparties provide projects with a tracking account; a working capital loan that is repaid with subsequent favourable mismatches or cash payments.

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 20, 2021, the District Court of Harris County, Texas denied the temporary injunction application, directing the counterparty to the power hedges for the Flat Top and Shannon wind facilities to suspend all remedies against the projects, including foreclosure, arising from an alleged default of payment that was formally disputed by Innergex, following the February 2021

Texas Events. As a result of the Court’s decision, the counterparty to the power hedges for the projects will not be precluded from exercising any of its remedies, including foreclosure.

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 on the reversal of exchange differences in accumulated other comprehensive income related to these two projects. As at September 30, 2021, the carrying amount of the Corporation's equity investments in Flat Top and Shannon was nil, 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. In addition, as at September 30, 2021, the deferred tax liabilities related to the Corporation's equity investments in Flat Top and Shannon were nil following the $24.4 million and $15.1 million respective deferred tax recoveries upon reclassification of the projects' assets and liabilities as disposal groups held for sale during the period ended June 30, 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. 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 would appeal the decision of the Supreme Court of British Columbia. The Comptroller of Water Rights filed the appeal documents on June 21, 2021.The hearing before the British Columbia Court of Appeal took place in Vancouver on October 21 and October 22, 2021. The Court of Appeal’s decision is expected to be rendered within 60 to 90 days following the hearing.

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 $12.5 million ($14.2 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 September 30, 2021, the Corporation had issued letters of credit totaling $241.3 million, including $61.4 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 $64.3 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 a guarantee in favour of the project, which will become effective only in the unlikely event that the Phoebe tax equity investors call upon their guarantee.

4- CAPITAL AND LIQUIDITY | Cash Flows

	Three months ended September 30		Nine months ended September 30			
	2021	2020	2021	February 2021 Texas Events (9 days)[1]	2021 Normalized	2020
OPERATING ACTIVITIES						
Cash flows from operating activities	80,052	64,912	189,661	17,093	206,754	157,416
FINANCING ACTIVITIES						
Cash flows from financing activities	6,348	118,382	47,849	—	47,849	394,497
INVESTING ACTIVITIES						
Cash flows used in investing activities	(66,421)	(252,890)	(220,971)	—	(220,971)	(555,805)
Effects of exchange rate changes on cash and cash equivalents	1,426	(3,022)	(2,954)	—	(2,954)	4,028
Net change in cash and cash equivalents	21,405	(72,618)	13,585	17,093	30,678	136
Cash and cash equivalents, beginning of period	153,645	228,978	161,465	—	161,465	156,224
Cash and cash equivalents, end of period	175,050	156,360	175,050	17,093	192,143	156,360

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

Cash Flows from Operating Activities

For the three-month period ended September 30, 2021, cash flows from operating activities totalled $80.1 million, compared with $64.9 million in the same period last year. The increase relates primarily to the contribution to operating cash flows from the Energía Llaima and Licán facilities following their acquisition during the third quarter of 2021, as well as the commissioning of the Hillcrest solar and Griffin Trail wind facilities.

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

For the nine-month period ended September 30, 2021, cash flows from operating activities totalled $189.7 million, compared with $157.4 million in the same period last year. The February 2021 Texas Events contributed to a $17.1 million decrease in cash flows from operating activities. Excluding the impacts from the February 2021 Texas Events, the increase relates primarily to a favourable $20.8 million change in the realized loss on the Phoebe basis hedge, an increase in revenues from the hydroelectric facilities in British Columbia explained by the lower 2020 figures that included the impact of the curtailment imposed by BC Hydro for five facilities, the contribution from the Salvador and Mountain Air facilities following their acquisition during the second and third quarter of 2020, respectively, the commissioning of the Hillcrest solar facility, and the contribution from the Energía Llaima and Licán facilities, following their acquisition during the third quarter of 2021.

Cash Flows from Financing Activities

For the three-month period ended September 30, 2021, cash flows from financing activities totalled $6.3 million, compared with $118.4 million in the same period last year. The decrease stems mainly from the net repayments on long term loans and borrowings, totalling $224.8 million in 2021, mainly related to repayments made from $195.0 million and $75.3 million proceeds from the public offering of common shares and the Hydro-Québec Private Placement, respectively, partly offset by net draws made toward the construction of the Griffin Trail wind facility. This compares with net draws of $153.1 million in 2020, mainly related to the Hillcrest construction and the Mountain Air Acquisition. The net repayments in long-term loans and borrowings were offset by the proceeds received from the public offering of common shares and the Hydro-Québec Private Placement (nil during the same quarter of 2020).

For the nine-month period ended September 30, 2021, cash flows from financing activities totalled $47.8 million, compared with $394.5 million in the same period last year.

The decrease stems mainly from the $658.4 million cash inflow last year from the Hydro-Québec Private Placement compared with the $195.0 million and $75.3 million proceeds from the public offering of common shares and the Hydro-Québec Private Placement, respectively.

The decrease was also attributable to net repayment on long-term loans and borrowings, totalling $99.2 million in 2021, mainly related to the repayments made from the proceeds received from the public offering of common shares and the Hydro-Québec Private Placement, partly offset by net draws made toward the construction of the Hillcrest solar and the Griffin Trail wind facilities. This compares with a net repayment of $151.0 million in 2020, mainly related to the repayment of revolving term credit facility.

Cash Flows Used in Investing Activities

For the three-month period ended September 30, 2021, cash flows used in investing activities totalled $66.4 million, compared with $252.9 million in the same period last year. The decrease is mainly due to a decrease in additions to property, plant and equipment and project development costs, mainly due to timing and status of the construction activities, as well as to a higher cash contribution made toward the Salvador Acquisition in 2020 compared to the Licán Acquisition in 2021, while the Energía Llaima Acquisition was entirely financed through equity.

For the nine-month period ended September 30, 2021, cash flows used in investing activities totalled $221.0 million, compared with $555.8 million in the same period last year. The decrease is mainly due to a higher cash contribution made toward the Salvador and Mountain Air Acquisitions in 2020 compared to the Licán Acquisition in 2021, while the Energía Llaima Acquisition was entirely financed through equity. Also, the variation is attributable to a decrease in additions to property, plant and equipment and project development costs, mainly due to the timing and status of the construction activities.

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

Free Cash Flow and Payout Ratio calculation[1]	Trailing twelve months ended September 30			
	2021	February 2021 Texas Events (9 days)[4]	2021 Normalized	2020
Cash flows from operating activities	267,354	17,093	284,447	229,152
Add (Subtract) the following items:				
Changes in non-cash operating working capital items	(2,754)	—	(2,754)	(4,510)
Maintenance capital expenditures, net of proceeds from disposals	(5,455)	—	(5,455)	(3,428)
Scheduled debt principal payments	(155,072)	—	(155,072)	(144,261)
Free Cash Flow attributed to non-controlling interests[2]	(13,787)	—	(13,787)	(11,617)
Dividends declared on Preferred shares	(5,710)	—	(5,710)	(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	1,640	—	1,640	923
Realized (gain) loss on the Phoebe basis hedge[3]	(1,458)	(1,304)	(2,762)	31,150
Free Cash Flow[4]	91,211	15,789	107,000	95,612
Dividends declared on common shares	129,005	—	129,005	118,514
Payout Ratio[4]	141 %	(20)%	121 %	124 %
Adjust for the following items:				
Prospective projects expenses			21,266	15,340
Adjusted Free Cash Flow			128,266	110,952
Dividends declared on common shares - DRIP adjusted			123,266	113,084
Adjusted Payout Ratio			96 %	102 %

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 3 months), gains and losses on the Phoebe basis hedge are deemed not to represent the long-term cash-generating capacity of Innergex.
4. For the trailing twelve months ended September 30, 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 September 30, 2021, the Corporation generated Free Cash Flow of $91.2 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 $107.0 million, compared with $95.6 million for the corresponding period last year.

Normalized Free Cash Flow increased $11.4 million compared with the comparative trailing twelve months, mainly due to:

- the contribution to cash flows from operating activities before changes in non-cash operating working capital items from the Salvador and Mountain Air Acquisitions achieved during mid-2020, the Energía Llaima and Licán Acquisitions achieved during the third quarter of 2021 and the Hillcrest and Griffin Trail facilities, which commenced delivering energy during the second quarter of 2021;
- a decrease in interest payments on the corporate revolving credit facility concurrent with the Hydro-Québec Private Placement in the first quarter of 2020 and in the third quarter of 2021, and a decrease in interest payments related to the Alterra loans reimbursed in full in January 2021;
- an increase in revenues from the facilities affected by the BC Hydro-imposed curtailment, citing the COVID-19 pandemic, which mainly impacted the second quarter of 2020; and
- an increase in distributions from joint ventures and associates, primarily due to a distribution received from Energía Llaima in the second quarter of 2021.

These items were partly offset by:

- an increase in debt principal payments stemming from the Mountain Air Acquisition in the third quarter of 2020, and the Energía Llaima Acquisition in the third quarter of 2021;
- an increase in Free Cash Flow attributed to non-controlling interests, stemming mainly from the Mountain Air Acquisition; and
- a decrease in cash flows from operating activities before changes in non-cash operating working capital items from the Phoebe facility, due mostly to an unfavourable difference between sales at the Phoebe node and purchases at the ERCOT South hub, compared with a favourable difference in the comparative period.

Payout Ratio

For the trailing twelve months ended September 30, 2021, the dividends on common shares declared by the Corporation amounted to 141% 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 121% of Normalized Free Cash Flow, compared with 124% for the corresponding period last year.

4- CAPITAL AND LIQUIDITY | Information on Capital Stock

The Corporation's Equity Securities

	As at		
	November 8, 2021	September 30, 2021	September 30, 2020
Number of common shares	192,804,589	192,792,970	174,495,317
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	265,570	265,570	266,143

As at the closing of the market on November 8, 2021, and since September 30, 2021, the increase in the number of common shares of the Corporation is attributable mainly to the issuance of 11,619 common shares related to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at September 30, 2021, the increase in the number of common shares since September 30, 2020, was mainly due to the following:

– the issuance of 4,048,215 common shares following the acquisition of Energía Llaima on July 9, 2021. Concurrently, with the closing of the acquisition, the Corporation issued 1,148,050 common shares, in order for Hydro-Québec to maintain its 19.9% ownership;
– the issuance of 10,374,150 common shares following the agreement with a syndicate of underwriters on August 23, 2021. Concurrently, with this agreement, the Corporation issued 2,581,000 common shares, in order for Hydro-Québec to maintain its 19.9% ownership;
– 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;
– the issuance of 10,194 common shares following the cashless exercise of 411,721 options; and
– the issuance of 143,827 common shares related to the DRIP.

Theses items were partly offset by:

– the 180,602 common shares purchased and cancelled by the Corporation under the Normal Course Issuer Bid terminated on May 23, 2021 at an average price of $18.90 for a total cash consideration of $3.4 million.

Normal Course Issuer Bid renewal

The Corporation received the approval from the Toronto Stock Exchange ("TSX") to proceed with a normal course issuer bid on its common shares (the "New Bid"). Under the New Bid, the Corporation could purchase for cancellation up to 2,000,000 of its common shares, representing approximately 1.15% of the 174,692,091 issued and outstanding common shares of the Corporation as at May 11, 2021. The New Bid commenced on May 24, 2021 and will terminate on May 23, 2022.

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

4- CAPITAL AND LIQUIDITY | 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 September 30	
	2021	2020
Dividends declared on common shares[1]	34,703	31,409
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 issuances of common shares upon acquisitions, public offering and Hydro-Québec Private Placement and to the issuance of common shares under the DRIP.

The following dividends will be paid by the Corporation on January 17, 2022:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
November 09, 2021	December 31, 2021	January 17, 2022	$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) income tax expense (recovery), finance costs, depreciation and amortization, impairment charges, other net income, share of (earnings) loss of joint ventures and associates, and change in fair value of 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 September 30						Nine months ended September 30					
	2021			2020			2021			2020		
	Production (MWh)	Revenues	Adjusted EBITDA	Production (MWh)	Revenues	Adjusted EBITDA	Production (MWh)	Revenues	Adjusted EBITDA	Production (MWh)	Revenues	Adjusted EBITDA
Consolidated[1]	2,290,086	184,564	122,522	2,021,559	162,651	108,524	6,472,058	544,820	388,326	5,886,949	445,280	304,279
Innergex's share of joint ventures and associates:												
Hydro[3]	220,557	23,471	20,378	267,937	30,521	26,402	425,491	43,040	33,518	453,660	49,982	39,472
Wind[2]	28,002	3,227	2,340	178,434	6,917	2,989	274,103	55,737	50,779	666,886	22,597	11,979
Solar	—	—	—	3,219	403	274	5,540	885	554	9,285	1,420	836
	248,559	26,698	22,718	449,590	37,841	29,665	705,134	99,662	84,851	1,129,831	73,999	52,287
PTCs and Innergex's share of PTCs generated:												
Foard City		7,241	7,241		8,229	8,229		28,123	28,123		31,281	31,281
Griffin Trail		3,457	3,457		—	—		3,457	3,457		—	—
Shannon (50%)[2]		—	—		2,054	2,054		2,767	2,767		8,486	8,486
Flat Top (51%)[2]		—	—		2,961	2,961		3,267	3,267		11,065	11,065
		10,698	10,698		13,244	13,244		37,614	37,614		50,832	50,832
Proportionate	2,538,645	221,960	155,938	2,471,149	213,736	151,433	7,177,192	682,096	510,791	7,016,780	570,111	407,398
Adjusted EBITDA Margin			66.4 %			66.7 %			71.3 %			68.3 %
Adjusted EBITDA Margin Proportionate			70.3 %			70.9 %			74.9 %			71.5 %

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 production and included in production proportionate.
2. The results from the Flat Top and Shannon joint venture facilities from April 1, 2021 onward were excluded due to the projects' assets and liabilities being classified as disposal groups held for sale, following the February 2021 Texas Events.
3.Innergex has acquired, effective July 9, 2021, the remaining 50% interest in Energía Llaima; therefore gaining control over the investee, which triggered consolidation and concurrently results are excluded from share of joint ventures.

(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 September 30		Nine months ended September 30	
	2021	2020	2021	2020
Revenues	184,564	162,651	544,820	445,280
Innergex's share of revenues of joint ventures and associates	26,698	37,841	99,662	73,999
PTCs and Innergex's share of PTCs generated	10,698	13,244	37,614	50,832
Revenues Proportionate	221,960	213,736	682,096	570,111
Net (loss) earnings	(23,464)	7,492	(191,137)	(41,005)
Income tax expense (recovery)	21,741	11,508	(63,398)	11,540
Finance costs	66,519	60,122	184,838	175,700
Depreciation and amortization	59,838	59,368	177,892	170,061
Impairment of long-term assets	30,660	—	36,974	—
EBITDA	155,294	138,490	145,169	316,296
Other net income	(33,827)	(16,725)	(55,056)	(58,250)
Share of (earnings) losses of joint ventures and associates	(14,311)	(11,382)	190,680	21,398
Change in fair value of financial instruments	15,366	(1,859)	107,533	24,835
Adjusted EBITDA	122,522	108,524	388,326	304,279
Innergex's share of Adjusted EBITDA of joint ventures and associates	22,718	29,665	84,851	52,287
PTCs and Innergex's share of PTCs generated	10,698	13,244	37,614	50,832
Adjusted EBITDA Proportionate	155,938	151,433	510,791	407,398
Adjusted EBITDA Margin	66.4 %	66.7 %	71.3 %	68.3 %
Adjusted EBITDA Margin Proportionate	70.3 %	70.9 %	74.9 %	71.5 %

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

Adjusted Net Earnings

References to "Adjusted Net Earnings" 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 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 (income) of joint ventures and associates related to the above items, net of related income tax.

The Adjusted Net Earnings 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 Earnings 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 Earnings.

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

Adjusted Net Earnings (Loss)	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Net (loss) earnings	(23,464)	7,492	(191,137)	(41,005)
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	(178)	4,850	20,603	23,655
Unrealized portion of the change in fair value of financial instruments	15,572	(23)	34,253	12,796
Impairment of long-term assets	30,660	—	36,974	—
Realized loss on termination of interest rate swaps	—	—	2,885	—
Realized (gain) loss on the Phoebe basis hedge	(1,345)	611	(1,591)	19,453
Realized gain on foreign exchange forward contracts	(1,133)	(755)	(1,881)	(1,580)
Income tax (recovery) expense related to above items	(8,207)	1,201	(89,678)	(4,000)
Adjusted Net Earnings	11,905	13,376	3,023	9,319

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

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

	Three months ended September 30						Nine months ended September 30					
	2021			2020			2021			2020		
	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS
Revenues	184,564	—	184,564	162,651	—	162,651	544,820	(54,967)	489,853	445,280	—	445,280
Operating expenses	45,395	—	45,395	37,040	—	37,040	106,551	—	106,551	94,932	—	94,932
General and administrative expenses	11,512	—	11,512	12,388	—	12,388	32,285	—	32,285	32,969	—	32,969
Prospective project expenses	5,135	—	5,135	4,699	—	4,699	17,658	—	17,658	13,100	—	13,100
Adjusted EBITDA	122,522	—	122,522	108,524	—	108,524	388,326	(54,967)	333,359	304,279	—	304,279
Finance costs	66,519	—	66,519	60,122	—	60,122	184,838	—	184,838	175,700	—	175,700
Other net income	(33,827)	1,133	(32,694)	(16,725)	755	(15,970)	(55,056)	1,881	(53,175)	(58,250)	1,580	(56,670)
Depreciation and amortization	59,838	—	59,838	59,368	—	59,368	177,892	—	177,892	170,061	—	170,061
Impairment of long-term assets	30,660	(30,660)	—	—	—	—	36,974	(36,974)	—	—	—	—
Share of (earnings) losses of joint ventures and associates	(14,311)	241	(14,070)	(11,382)	(5,696)	(17,078)	190,680	(202,831)	(12,151)	21,398	(30,215)	(8,817)
Change in fair value of financial instruments	15,366	(14,227)	1,139	(1,859)	(588)	(2,447)	107,533	(106,303)	1,230	24,835	(32,249)	(7,414)
Income tax expense (recovery)	21,741	8,144	29,885	11,508	(355)	11,153	(63,398)	95,100	31,702	11,540	10,560	22,100
Net (loss) earnings	(23,464)	35,369	11,905	7,492	5,884	13,376	(191,137)	194,160	3,023	(41,005)	50,324	9,319

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

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.

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

	As at	
	September 30, 2021	December 31, 2020
Non-current assets, excluding derivative financial instruments and deferred tax assets[1]		
Canada	3,416,659	3,504,403
United States	1,942,670	1,990,997
France	839,674	922,330
Chile	428,354	166,881
	6,627,357	6,584,611

1. Includes the investments in joint ventures and associates.

6- ADDITIONAL CONSOLIDATED INFORMATION | Geographic Segments – Revenues

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Revenues				
Canada	109,990	120,038	312,706	320,958
United States	43,516	27,274	145,840	54,738
France	15,644	13,938	64,844	67,063
Chile	15,414	1,401	21,430	2,521
	184,564	162,651	544,820	445,280

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

6- ADDITIONAL CONSOLIDATED INFORMATION | Historical Quarterly Financial Information

(in millions of dollars, unless otherwise stated)	Three months ended							
	Sept 30, 2021	June 30, 2021	March 31, 2021	Dec 31, 2020	Sept 30, 2020	June 30, 2020	March 31, 2020	Dec 31, 2019
Production (MWh)	2,290,086	2,396,027	1,785,947	2,186,961	2,021,559	2,185,793	1,679,598	1,793,803
Revenues	184.6	170.6	189.7	167.9	162.7	150.5	132.1	143.1
Adjusted EBITDA[1]	122.5	122.7	143.1	117.8	108.5	105.3	90.4	103.3
Net (loss) earnings	(23.5)	50.2	(217.9)	11.9	7.5	(1.6)	(46.9)	(47.4)
Net (loss) earnings from continuing operations attributable to owners of the parent	(16.4)	41.1	(214.2)	11.9	11.7	(2.5)	(53.7)	(46.8)
Net (loss) earnings from continuing operations attributable to owners of the parent ($ per share – basic and diluted)	(0.10)	0.23	(1.24)	0.06	0.06	(0.02)	(0.35)	(0.35)
Net (loss) earnings attributable to owners of the parent	(16.4)	41.1	(214.2)	11.9	11.7	(2.5)	(53.7)	(46.2)
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(0.10)	0.23	(1.24)	0.06	0.06	(0.02)	(0.35)	(0.35)
Dividends declared on common shares	34.7	31.4	31.4	31.4	31.4	31.4	31.3	24.4
Dividends declared on common shares, $ per share	0.180	0.180	0.180	0.180	0.180	0.180	0.180	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.

FEBRUARY 2021 TEXAS EVENTS – SUPPLEMENTAL INFORMATION TO THIRD 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	Operating	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 disrupted 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:

		Nine months ended September 30, 2021		
		As presented	Impacts from the February 2021 Texas Events (9 days)	Normalized
1	Revenues	544,820	(54,967)	489,853
	Adjusted EBITDA	388,326	(54,967)	333,359
2	Change in fair value of financial instruments	(107,533)	72,060	(35,473)
3	Share of losses (earnings) of joint ventures and associates	(190,680)	64,197	(126,483)
	(Loss) Earnings before income tax	(254,535)	81,290	(173,245)

(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**.

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

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

	Nine months ended September 30, 2021				
	Hydro	Wind	Solar	Unallocated	Total
Revenues	180,910	259,506	104,404	—	544,820
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Revenues	180,910	242,705	66,238	—	489,853
Revenues Proportionate	223,950	352,857	105,289	—	682,096
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Revenues Proportionate	223,950	295,750	67,123	—	586,823
Adjusted EBITDA	140,063	202,841	93,295	(47,873)	388,326
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Adjusted EBITDA	140,063	186,040	55,129	(47,873)	333,359
Adjusted EBITDA Proportionate	173,581	291,234	93,849	(47,873)	510,791
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Adjusted EBITDA Proportionate	173,581	234,127	55,683	(47,873)	415,518

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 September 30, 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 September 30, 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	264,600	17,093	281,693
2	Realized loss on the Phoebe basis hedge	(1,458)	(1,304)	(2,762)
	Free Cash Flow	91,211	15,789	107,000
	Dividends declared on common shares	129,005	—	129,005
	Payout Ratio	141 %	(20)%	121 %

(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

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

$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

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 increased 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.
- On July 19, 2021, Innergex reached an agreement to settle the amounts that remained unpaid by the Phoebe solar facility following the February 2021 Texas Events. The aggregate cash disbursement of US$24.0 million ($29.7 million) comprises the agreed-upon settlement payment for the amounts disputed following the February 2021 Texas Events, and a payment on the project's tracking account balance, net of unpaid energy sold by the project during the negotiation process.

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 20, 2021, the District Court of Harris County, Texas denied the temporary injunction application, directing the counterparty to the power hedges for the Flat Top and Shannon wind facilities to suspend all remedies against the projects, including foreclosure, arising from an alleged default of payment that was formally disputed by Innergex, following the February 2021 Texas Events. As a result of the Court's decision, the counterparty to the power hedges for the projects will not be precluded from exercising any of its remedies, including foreclosure.

4.2 Decisions and Actions

Phoebe

- As at September 30, 2021, an impairment charge of $24.7 million was recognized, reflecting an outlook of higher than expected congestion charges, combined with a higher discount rate to reflect higher risk premiums for facilities under power hedge contracts in Texas.

Flat Top and Shannon

- Management does not consider these facilities to be viable in the long term in their current configuration.
- During the quarter ended June 30, 2021, the assets and liabilities of the Flat Top and Shannon facilities were classified as disposal groups held for sale, as the carrying amount of their respective Class B shares will be recovered principally through a sale transaction. As required, the disposal groups are measured at the lower of their respective carrying amounts and fair values less costs to sell, which is estimated to be nil, on a net basis, as at September 30, 2021.
- Given its understanding of currently available information and on the basis that the facilities are non-recourse to the Corporation, the financial exposure of the Corporation is limited to the non-cash impacts on the reversal of exchange differences in accumulated other comprehensive income related to these two projects. As at September 30, 2021, the carrying amount of the Corporation's equity investments in Flat Top and Shannon was nil, following aggregate $112.6 million non-cash impairment charges on these facilities as at March 31, 2021. In addition, as at September 30, 2021, the deferred tax liabilities related to the Corporation's equity investments in Flat Top and Shannon were nil following the aggregate $39.5 million deferred tax recovery upon reclassification of the projects' assets and liabilities as disposal groups held for sale during the period ended June 30, 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.

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 condensed interim consolidated 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 condensed interim consolidated 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 July 1, 2021, to September 30, 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 resources 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. In most cases, PPAs also contain an annual inflation adjustment based on a portion of the Consumer Price Index. This excludes facilities that receive revenues based on the market (or spot) price for electricity. For these facilities, expected annual revenues are estimated by multiplying the LTA with forward market prices, which are based on observable market data or constructed using various assumptions depending on historical market prices, supply, demand and congestion volumes observed, as well as econometric models. 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

Principal Assumptions	Principal Risks and Uncertainties
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
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 September 30 2021	Three months ended September 30 2020	Nine months ended September 30 2021	Nine months ended September 30 2020
Revenues		184,564	162,651	544,820	445,280
Expenses					
Operating		45,395	37,040	106,551	94,932
General and administrative		11,512	12,388	32,285	32,969
Prospective projects		5,135	4,699	17,658	13,100
Earnings before the following:		122,522	108,524	388,326	304,279
Depreciation	10	44,027	45,226	133,184	134,748
Amortization		15,811	14,142	44,708	35,313
Impairment of long-term assets	6,8,10	30,660	—	36,974	—
Earnings before the following:		32,024	49,156	173,460	134,218
Finance costs	4	66,519	60,122	184,838	175,700
Other net income	5	(33,827)	(16,725)	(55,056)	(58,250)
Share of (earnings) losses of joint ventures and associates:					
Share of (earnings) losses, before impairment charges	6	(14,311)	(11,382)	78,071	21,398
Share of impairment charges	6	—	—	112,609	—
Change in fair value of financial instruments	7 b)	15,366	(1,859)	107,533	24,835
(Loss) earnings before income tax		(1,723)	19,000	(254,535)	(29,465)
Income tax expense (recovery)		21,741	11,508	(63,398)	11,540
Net (loss) earnings		(23,464)	7,492	(191,137)	(41,005)
(Net loss) earnings attributable to:					
Owners of the parent		(16,398)	11,740	(189,457)	(44,548)
Non-controlling interests		(7,066)	(4,248)	(1,680)	3,543
		(23,464)	7,492	(191,137)	(41,005)
(Loss) earnings per share attributable to owners:					
Basic net (loss) earnings per share ($)	9	(0.10)	0.06	(1.09)	(0.29)
Diluted net (loss) earnings per share ($)	9	(0.10)	0.06	(1.09)	(0.29)

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 September 30 2021	Three months ended September 30 2020	Nine months ended September 30 2021	Nine months ended September 30 2020
Net (loss) earnings		(23,464)	7,492	(191,137)	(41,005)
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:					
Foreign currency translation differences for foreign operations		23,126	(21,589)	246	16,378
Change in fair value of financial instruments designated as net investment hedges	7	(699)	587	4,126	1,834
Change in fair value of financial instruments designated as cash flow hedges	7	10,966	4,589	70,212	(111,237)
Change in fair value of financial instruments of joint ventures and associates designated as cash flow hedges		789	598	5,569	(5,788)
Related deferred income tax		(3,972)	(1,241)	(22,112)	27,863
Other comprehensive income (loss)		30,210	(17,056)	58,041	(70,950)
Total comprehensive income (loss)		6,746	(9,564)	(133,096)	(111,955)
Total comprehensive income (loss) attributable to:					
Owners of the parent		13,521	(5,804)	(133,290)	(115,881)
Non-controlling interests		(6,775)	(3,760)	194	3,926
		6,746	(9,564)	(133,096)	(111,955)

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	September 30, 2021	December 31, 2020
ASSETS			
Current assets			
Cash and cash equivalents		175,050	161,465
Restricted cash		70,555	67,477
Accounts receivable		129,508	92,746
Derivative financial instruments	7	9,546	9,039
Investment tax credits recoverable	10	89,345	106,353
Prepaid and other		28,924	15,372
Total current assets		502,928	452,452
Non-current assets			
Property, plant and equipment	10	5,367,171	5,053,125
Intangible assets		902,400	919,323
Project development costs		48,550	14,092
Investments in joint ventures and associates	6	137,370	446,837
Derivative financial instruments	7	38,039	92,040
Deferred tax assets		76,280	25,129
Goodwill		74,325	75,932
Other long-term assets		97,541	75,302
Total non-current assets		6,741,676	6,701,780
Total assets		7,244,604	7,154,232
LIABILITIES			
Current liabilities			
Accounts payable and other payables		239,470	190,333
Derivative financial instruments	7	55,348	72,958
Current portion of long-term loans and borrowings and other liabilities		614,202	773,439
Total current liabilities		909,020	1,036,730
Non-current liabilities			
Derivative financial instruments	7	87,824	179,154
Long-term loans and borrowings		4,236,492	4,046,714
Other liabilities		418,303	397,513
Deferred tax liabilities		403,567	423,189
Total non-current liabilities		5,146,186	5,046,570
Total liabilities		6,055,206	6,083,300
SHAREHOLDERS' EQUITY			
Equity attributable to owners		1,131,407	1,008,854
Non-controlling interests		57,991	62,078
Total shareholders’ equity		1,189,398	1,070,932
Total liabilities and shareholders’ equity		7,244,604	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 nine-month period ended September 30, 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	—	—	—	—	(189,457)	—	(189,457)	(1,680)	(191,137)
Other comprehensive income	—	—	—	—	—	56,167	56,167	1,874	58,041
Total comprehensive (loss) income	—	—	—	—	(189,457)	56,167	(133,290)	194	(133,096)
Common shares issued on July 9, 2021: upon acquisition (Note 3)	89,437	—	—	—	—	—	89,437	—	89,437
Issuance fees (net of $47 of deferred income tax)	(129)	—	—	—	—	—	(129)	—	(129)
Common shares issued on Sept 3, 2021 : public offering (Note 13)	201,259	—	—	—	—	—	201,259	—	201,259
Issuance fees (net of $2,282 of deferred income tax)	(6,272)	—	—	—	—	—	(6,272)	—	(6,272)
Common shares issued on Private Placement (Note 13)	75,396	—	—	—	—	—	75,396	—	75,396
Issuance fees (net of $25 of deferred income tax)	(70)	—	—	—	—	—	(70)	—	(70)
Business acquisition	—	—	—	—	—	—	—	8,989	8,989
Common shares issued through dividend reinvestment plan	3,074	—	—	—	—	—	3,074	—	3,074
Buyback of common shares	(3,414)	—	—	—	—	—	(3,414)	—	(3,414)
Share-based payments and Performance Share Plan	—	1,554	—	—	—	—	1,554	—	1,554
Convertible debentures converted into common shares and redemption	2,330	—	—	(24)	—	—	2,306	—	2,306
Shares vested - Performance Share Plan	3,174	(6,320)	—	—	—	—	(3,146)	—	(3,146)
Shares purchased - Performance Share Plan	(2,622)	274	—	—	—	—	(2,348)	—	(2,348)
Dividends declared on common shares (Note13)	—	—	—	—	(97,580)	—	(97,580)	—	(97,580)
Dividends declared on preferred shares (Note13)	—	—	—	—	(4,224)	—	(4,224)	—	(4,224)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(13,270)	(13,270)
Balance September 30, 2021	366,348	2,021,923	131,069	2,819	(1,335,223)	(55,529)	1,131,407	57,991	1,189,398

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

	Equity attributable to owners								
For the nine-month period ended September 30, 2020	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	—	—	—	—	(44,548)	—	(44,548)	3,543	(41,005)
Other comprehensive (loss) income	—	—	—	—	—	(71,333)	(71,333)	383	(70,950)
Total comprehensive (loss) income	—	—	—	—	(44,548)	(71,333)	(115,881)	3,926	(111,955)
Common shares issued on February 6, 2020: Private Placement	660,870	—	—	—	—	—	660,870	—	660,870
Issuance fees (net of $672 of deferred income tax)	(1,842)	—	—	—	—	—	(1,842)	—	(1,842)
Business acquisition	—	—	—	—	—	—	—	63,169	63,169
Common shares issued through dividend reinvestment plan	5,247	—	—	—	—	—	5,247	—	5,247
Reduction of capital on common shares	(754,355)	754,355	—	—	—	—	—	—	—
Share-based payments	—	58	—	—	—	—	58	—	58
Stock options exercised	363	(2,226)	—	—	—	—	(1,863)	—	(1,863)
Shares vested - Performance Share Plan	1,046	—	—	—	—	—	1,046	—	1,046
Shares purchased - Performance Share Plan	(6,008)	—	—	—	—	—	(6,008)	—	(6,008)
Dividends declared on common shares (Note 13)	—	—	—	—	(94,118)	—	(94,118)	—	(94,118)
Dividends declared on preferred shares (Note 13)	—	—	—	—	(4,456)	—	(4,456)	—	(4,456)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(8,799)	(8,799)
Balance September 30, 2020	2,536	2,020,498	131,069	2,869	(1,022,971)	(86,564)	1,047,437	69,238	1,116,675

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 September 30		Nine months ended September 30	
		2021	2020	2021	2020
OPERATING ACTIVITIES	Notes				
Net (loss) earnings		(23,464)	7,492	(191,137)	(41,005)
Items not affecting cash:					
Depreciation and amortization		59,838	59,368	177,892	170,061
Impairment of long-term assets		30,660	—	36,974	—
Share of (earnings) losses of joint ventures and associates		(14,311)	(11,382)	190,680	21,398
Unrealized portion of change in fair value of financial instruments	7	15,572	(23)	34,253	12,796
Production tax credits and tax attributes allocated to tax equity investors	5	(31,418)	(12,532)	(53,367)	(47,014)
Other		(117)	(2,777)	796	(2,565)
Finance costs	4	66,519	60,122	184,838	175,700
Finance costs paid	14 b)	(39,832)	(37,755)	(130,993)	(127,306)
Distributions received from joint ventures and associates		8,139	11,249	21,636	19,394
Income tax (recovery) expense		21,741	11,508	(63,398)	11,540
Income tax paid		(1,141)	(4,745)	(4,223)	(7,407)
Effect of exchange rate fluctuations		818	689	1,039	(2,328)
		93,004	81,214	204,990	183,264
Changes in non-cash operating working capital items	14 a)	(12,952)	(16,302)	(15,329)	(25,848)
		80,052	64,912	189,661	157,416
FINANCING ACTIVITIES					
Dividends paid on common and preferred shares		(34,363)	(29,663)	(95,529)	(85,673)
Distributions to non-controlling interests		(1,302)	(3,177)	(12,885)	(8,799)
Increase in long-term debt, net of deferred financing costs	14 c)	404,760	195,194	793,331	500,871
Repayment of long-term debt	14 c)	(629,518)	(42,121)	(892,525)	(661,142)
Payment of other liabilities		(1,156)	(1,145)	(3,465)	(1,700)
Net proceeds from issuance of common shares		267,830	(150)	267,830	658,356
Purchase of common shares under the Performance Share Plan		97	—	(2,348)	(6,008)
Repurchase of common shares		—	—	(3,414)	—
Payment of payroll withholding on exercise of stock options and Performance Share Plan		—	(556)	(3,146)	(1,408)
		6,348	118,382	47,849	394,497
INVESTING ACTIVITIES					
Business acquisitions, net of cash acquired		1,391	(72,011)	1,391	(161,792)
Change in restricted cash		(717)	66	(584)	6,971
Additions to property, plant and equipment, net		(62,812)	(181,027)	(204,081)	(352,259)
Additions to intangible assets		(8)	—	(8)	—
Additions to project development costs		(5,426)	(2,031)	(17,520)	(25,667)
Investments in joint ventures and associates		—	—	(65)	—
Change in other long-term assets		1,151	2,113	(104)	(23,058)
		(66,421)	(252,890)	(220,971)	(555,805)
Effects of exchange rate changes on cash and cash equivalents		1,426	(3,022)	(2,954)	4,028
Net change in cash and cash equivalents		21,405	(72,618)	13,585	136
Cash and cash equivalents, beginning of period		153,645	228,978	161,465	156,224
Cash and cash equivalents, end of period		175,050	156,360	175,050	156,360

Additional information is presented in Note 14.
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 November 9, 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.

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 condensed interim consolidated financial statements.

3. BUSINESS ACQUISITIONS

a. Acquisition of Licán

The Corporation acquired an 18 MW run-of-river hydro facility in Chile ("Licán"), on August 3, 2021, for an aggregate consideration of US$16,563 ($20,778).

The following table reflects the preliminary amounts recognized for the assets acquired and liabilities assumed, on a fair value basis, at the acquisition date:

	Acquisition accounting	
	US$	CA$
Cash and cash equivalents	341	428
Restricted cash	274	344
Accounts receivable	1,196	1,500
Prepaid and other	5	6
Property, plant and equipment	36,481	45,765
Intangible assets	295	370
Deferred tax assets	4,491	5,634
Accounts payable and other payables	(520)	(652)
Long-term debt	(26,000)	(32,617)
Net assets acquired	16,563	20,778

The acquisition gave rise to transaction costs of $66 which were expensed as incurred in other net income in the consolidated statements of earnings (loss).

The investment was accounted for as a business combination and the results have been included in the consolidated statements of earnings (loss) since the date of the acquisition. The revenues and net earnings included in the consolidated statements of earnings (loss) are $1,770 and $1,340, respectively for the 58-day period ended September 30, 2021. Had the acquisition taken place on January 1, 2021, revenues and net earnings for the period from January 1, 2021 to September 30, 2021 would have been $4,073 and $855 higher, respectively.

b. Acquisition of remaining interests in Energía Llaima

Innergex has entered into a stock purchase agreement pursuant to which it has acquired, effective July 9, 2021, the remaining 50% interest in Energía Llaima SpA ("Energía Llaima"), a renewable energy company based in Chile, of which Innergex already owned 50%, for an aggregate consideration of US$75,000 ($94,012), which includes a contingent consideration of US$3,650 ($4,575).

As a consideration for this transaction, Innergex has issued to Energía Llaima's shareholders the number of Innergex common shares for an aggregate value of US$71,350 ($89,437) at a price per share equal to the 10-day volume weighted average price prior to the closing of the acquisition, for a total of 4,048,215 shares issued.

Concurrently with the closing of the financing, the corporation issued 1,148,050 common shares, for total proceeds of $25,325, in order for Hydro-Québec to maintain its 19.9% ownership.

The purchase prise has been calculated as follows:

	US$	CA$
Shares issued	71,350	89,437
Contingent consideration	3,650	4,575
	75,000	94,012

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

The acquisition gave rise to transaction costs of $184 which were expensed as incurred in other net income in the consolidated statements of earnings (loss).

The investment was accounted for as a business combination and the results have been included in the consolidated statements of earnings (loss) since the date of the acquisition. The revenues and net loss included in the consolidated statements of earnings (loss) are $8,722 and $1,418, respectively for the 83-day period ended September 30, 2021. Had the acquisition taken place on January 1, 2021, revenues and net loss for the period from January 1, 2021 to September 30, 2021 would have been $12,472 and $3,415 higher, respectively.

The following table reflects the preliminary amounts recognized for the assets acquired and liabilities assumed, on a fair value basis, at the acquisition date:

	Acquisition accounting	
	US$	CA$
Cash and cash equivalents	17,344	21,741
Restricted cash	1,156	1,449
Accounts receivable	10,297	12,907
Prepaid and other	494	619
Property, plant and equipment	202,613	253,975
Intangible assets	35,046	43,930
Project development costs	13,157	16,492
Derivative financial instruments	2,184	2,738
Deferred tax assets	21,924	27,482
Other long-term asset	7,076	8,870
Accounts payable and other payables	(9,923)	(12,438)
Long-term loans and borrowings	(130,744)	(163,888)
Other liabilities	(1,805)	(2,263)
Deferred tax liabilities	(11,648)	(14,601)
Non-controlling interests	(7,171)	(8,989)
Total net assets	150,000	188,024
Previously held equity interest	75,000	94,012
Net assets acquired	75,000	94,012

The fair value of the intangible assets related to power purchase agreements has been established using a with-or-without approach by calculating the excess of the power purchase agreement prices over the merchant prices for the generation that would have otherwise been sold in the market. The fair value of the intangible assets related to operating licenses and permits, was calculated using a discounted cash flow approach. The fair value of property, plant and equipment was established using a discounted cash flow approach.

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

4. FINANCE COSTS

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Interest expense on long-term corporate and project loans	44,210	42,873	128,169	129,399
Interest expense on tax equity financing	8,522	6,118	18,617	19,106
Interest expense on convertible debentures	3,409	3,488	10,214	10,362
Amortization of financing fees	2,115	2,339	5,767	7,120
Accretion expenses on other liabilities	1,384	1,413	3,975	3,892
Interest on lease liabilities	1,125	1,054	3,159	3,319
Inflation compensation interest	3,898	3,007	9,415	1,212
Accretion of long-term loans and borrowings	(25)	733	249	2,082
Interest income on preferred shares of equity-accounted investees	(235)	(1,252)	(464)	(4,214)
Other	2,116	349	5,737	3,422
	66,519	60,122	184,838	175,700

5. OTHER NET INCOME

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Production tax credits	(10,698)	(8,229)	(31,580)	(31,281)
Tax attributes allocated to tax equity investors	(20,720)	(4,303)	(21,787)	(15,733)
Liquidated damages	—	(3,235)	(229)	(5,307)
Restructuring costs	—	707	—	1,157
Realized loss (gain) on contingent considerations	—	—	547	(945)
Transaction costs related to business acquisitions	841	527	841	868
Professional and other fees - February 2021 Texas Events	130	—	1,308	—
Loss on repayment of loans	—	—	1,317	—
Others, net	(3,380)	(2,192)	(5,473)	(7,009)
	(33,827)	(16,725)	(55,056)	(58,250)

Professional and other fees - February 2021 Texas 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 periods ended September 30, 2021.

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

6. INVESTMENTS IN JOINT VENTURES AND ASSOCIATES

Flat Top and Shannon

In February 2021, unprecedented extreme winter weather conditions and related electricity market failure paralyzed the State of Texas, United States (the “February 2021 Texas Events”). 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. Depressed power generation, combined with the unprecedented increase in merchant market prices, yielded important losses, due to the committed hourly volumes under the projects’ respective power hedges.

i) Impairment

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. During the first quarter ended 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 USD$42,333 ($53,758) and USD$46,343 ($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.

ii) Classification as held for sale

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 20, 2021, the District Court of Harris County, Texas denied the temporary injunction application, directing the counterparty to the power hedges for the Flat Top and Shannon wind facilities to suspend all remedies against the projects, including foreclosure, arising from an alleged default of payment that was formally disputed by Innergex, following the February 2021 Texas Events. As a result of the Court’s decision, the counterparty to the power hedges for the projects will not be precluded from exercising any of its remedies, including foreclosure.

During the quarter ended June 30, 2021, the underlying assets and liabilities of the Flat Top and Shannon investments were classified as disposal groups held for sale, as the carrying amount of their respective Class B shares will be recovered principally through a sale transaction. As required, the disposal groups are measured at the lower of their respective carrying amounts and fair values less costs to sell, which is estimated to be nil, on a net basis, as at September 30, 2021.

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

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. The below results exclude results from the Shannon and Flat Top facilities, from April 1, 2021 onwards, as a result of the projects' assets and liabilities being classified as disposal groups held for sale, and Energia Llaima, following the acquisition of the remaining interest:

	Three months ended September 30, 2021					
	Toba Montrose	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Total
Revenues	40,447	8,730	13,652	675	2,001	65,505
Operating, general and administrative expenses	5,783	2,845	1,015	537	323	10,503
	34,664	5,885	12,637	138	1,678	55,002
Finance costs	5,714	1,569	2,326	620	720	10,949
Other net income	(13)	(51)	—	(3)	(233)	(300)
Depreciation and amortization	4,928	3,508	1,073	1,002	681	11,192
Change in fair value of financial instruments	153	—	—	(477)	(135)	(459)
Net earnings (loss)	23,882	859	9,238	(1,004)	645	33,620
Other comprehensive income	2,011	—	—	—	228	2,239
Total comprehensive income (loss)	25,893	859	9,238	(1,004)	873	35,859
Net earnings (loss) attributable to Innergex	9,552	219	4,711	(492)	321	14,311
Other comprehensive income attributable to Innergex	675	—	—	—	114	789
Total	10,227	219	4,711	(492)	435	15,100

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

	Nine months ended September 30, 2021								
	Energía Llaima (180-day period)	Toba Montrose	Shannon (90-day period)	Flat Top (90-day period)	Dokie	Jimmie Creek	Umbata Falls	Viger-Denonville	Total
Revenues	14,123	61,771	68,908	20,271	27,524	18,802	4,035	7,854	223,288
Operating, general and administrative expenses	5,828	11,999	2,770	2,174	7,474	2,599	1,610	1,118	35,572
	8,295	49,772	66,138	18,097	20,050	16,203	2,425	6,736	187,716
Finance costs	3,248	17,149	3,459	3,734	4,792	6,986	1,808	2,178	43,354
Production tax credits	—	—	(5,533)	(6,406)	—	—	—	—	(11,939)
Tax attributes allocated to tax equity investors	—	—	745	186	—	—	—	—	931
Other net expenses (income)	760	(56)	506	448	(364)	17	(270)	(241)	800
Depreciation and amortization	6,064	14,955	3,257	3,628	10,524	3,217	3,002	2,049	46,696
Impairment of property, plant and equipment	—	—	117,702	105,408	—	—	—	—	223,110
Net loss (gain) on financial instruments	—	1,081	—	—	—	—	(2,104)	(467)	(1,490)
Change in fair value of financial instruments	—	—	114,615	143,380	—	—	—	—	257,995
Provision for income taxes	(145)	—	—	—	—	—	—	—	(145)
Net (loss) earnings	(1,632)	16,643	(168,613)	(232,281)	5,098	5,983	(11)	3,217	(371,596)
Other comprehensive income	—	11,887	—	—	—	—	—	1,630	13,517
Total comprehensive (loss) income	(1,632)	28,530	(168,613)	(232,281)	5,098	5,983	(11)	4,847	(358,079)
Net (loss) earnings attributable to Innergex	(522)	6,656	(84,306)	(118,463)	1,300	3,051	(5)	1,609	(190,680)
Other comprehensive income attributable to Innergex	—	4,754	—	—	—	—	—	815	5,569
Total	(522)	11,410	(84,306)	(118,463)	1,300	3,051	(5)	2,424	(185,111)

(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 September 30, 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
Business acquisitions (note 3)	(94,012)	—	—	—	—	—	—	—	—	(94,012)
Share of (loss) earnings	(522)	6,656	(84,306)	(118,463)	1,300	3,051	(5)	1,609	—	(190,680)
Share of other comprehensive income	—	4,754	—	—	—	—	—	815	—	5,569
Impairment of equity accounted investment	(6,314)	—	—	—	—	—	—	—	—	(6,314)
Foreign currency translation differences	(2,066)	—	(184)	(188)	—	—	—	—	(21)	(2,459)
Distributions received	(6,063)	(8,400)	—	—	(4,654)	(1,020)	—	(1,499)	—	(21,636)
Balance September 30, 2021	—	75,543	—	—	20,546	34,603	4,945	1,306	427	137,370

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

7. 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 15 – 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)
Business acquisitions (Note 3)	—	2,738	—	—	2,738
Unrealized portion of change in fair value recognized in earnings (loss) [2]	13,812	6,015	(43,792)	(10,288)	(34,253)
Change in fair value recognized in other comprehensive income (loss)	4,126	72,918	(2,706)	—	74,338
Amortization of accumulated other comprehensive income recognized in revenue	—	—	2,706	—	2,706
Net foreign exchange differences	—	758	(1,129)	10,288	9,917
As at September 30, 2021	(19,175)	(85,573)	9,161	—	(95,587)

1. A loss of $10,288 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 7 b) for a reconciliation to the change in fair value recognized in earnings (loss).

Reported in the consolidated statements of financial position:

As at	September 30, 2021	December 31, 2020
Current assets	9,546	9,039
Non-current assets	38,039	92,040
Current liabilities	(55,348)	(72,958)
Non-current liabilities	(87,824)	(179,154)
	(95,587)	(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 September 30		Nine months ended September 30	
	2021	2020	2021	2020
Unrealized portion of change in fair value of financial instruments	15,572	(23)	34,253	12,796
Realized portion of financial instruments:				
Realized loss on the interest rate swaps	—	—	2,885	—
Realized (gain) loss on the power hedges	1,139	(2,447)	71,986	(7,414)
Realized (gain) loss on Phoebe basis hedge	(1,345)	611	(1,591)	19,453
Change in fair value of financial instruments	15,366	(1,859)	107,533	24,835

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

8. OTHER LONG-TERM ASSETS

As at September 30, 2021, the Corporation recognized an impairment charge related to a minority equity investment in France, totaling $5,931.

9. EARNINGS (LOSS) PER SHARE

	Three months ended September 30		Nine months ended September 30	
Basic	2021	2020	2021	2020
Net (loss) earnings attributable to owners of the parent	(16,398)	11,740	(189,457)	(44,548)
Dividends declared on preferred shares	(1,408)	(1,485)	(4,224)	(4,456)
Net (loss) earnings attributable to common shareholders	(17,806)	10,255	(193,681)	(49,004)
Weighted average number of common shares	182,691,797	173,858,483	177,043,601	169,048,260
Basic net loss per share ($)	(0.10)	0.06	(1.09)	(0.29)

	Three months ended September 30		Nine months ended September 30	
Diluted	2021	2020	2021	2020
Net (loss) earnings attributable to common shareholders	(17,806)	10,255	(193,681)	(49,004)
Diluted weighted average number of common shares	182,691,797	174,493,663	177,043,601	169,048,260
Diluted net (loss) earnings per share ($)	(0.10)	0.06	(1.09)	(0.29)

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Instruments that are excluded from the dilutive elements:				
Stock options	265,570	—	265,570	266,143
Shares held in trust related to the Performance Share Plan	541,261	—	541,261	557,091
Convertible debentures	13,604,473	13,777,293	13,604,473	13,777,293
	14,411,304	13,777,293	14,411,304	14,600,527

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

10. 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	1,411	10,392	—	204,510	5,830	222,337
Investment tax credits [2]	—	—	—	—	(12,752)	—	(12,752)
Business acquisitions (Note 3)	21,247	267,938	—	10,039	—	516	299,740
Transfer of assets upon commissioning	—	—	357,458	—	(357,502)	44	—
Transfer from project development costs	—	—	—	—	682	—	682
Reclassification	—	—	—	(644)	104	540	—
Dispositions	—	—	(957)	—	—	(267)	(1,224)
Other changes	1,237	8	(9,131)	(1,898)	—	2,273	(7,511)
Net foreign exchange differences	(1,132)	4,377	(37,313)	255	(594)	(94)	(34,501)
As at September 30, 2021	198,377	2,365,079	2,917,082	524,741	363,932	42,812	6,412,023
Accumulated depreciation							
As at January 1, 2021	(10,482)	(348,109)	(445,896)	(69,382)	—	(18,258)	(892,127)
Depreciation [3]	(4,927)	(30,688)	(81,012)	(14,937)	—	(3,072)	(134,636)
Reclassification	—	—	—	249	—	(249)	—
Dispositions	—	—	332	—	—	298	630
Impairment charge	—	—	—	(24,729)	—	—	(24,729)
Net foreign exchange differences	113	(29)	6,356	(447)	—	17	6,010
As at September 30, 2021	(15,296)	(378,826)	(520,220)	(109,246)	—	(21,264)	(1,044,852)
Carrying amounts as at September 30, 2021	183,081	1,986,253	2,396,862	415,495	363,932	21,548	5,367,171

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 $8,620 of capitalized financing costs incurred prior to commissioning.
2. The Corporation accrued for US$10,092 ($12,752) 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 September 30, 2021, the balance of investments tax credits recoverable amounts to US$70,124 ($89,345).
3. An amount of $1,452 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)

Impairment of Phoebe

As at September 30, 2021, the carrying value of Phoebe solar facility, located in Texas, exceeded its estimated recoverable amount resulting in an impairment charge of US$19,622 ($24,729), reflecting an outlook of higher than expected congestion charges.

The Phoebe solar facility recoverable amount of $260,521 as at September 30, 2021 was determined using VIU, which was calculated based on projected future cash flows utilizing the latest information available and Management’s estimates, including; Energy production, revenues, operating costs, general and administrative costs, energy price forecasts and foreign exchange rates.

These projected cash flows were prepared using a 2% inflation estimate and discounted using a post-tax discount rate of 8.5% representing the estimated weighted average cost of capital.

Sensitivities

The projected cash flows and estimated VIU can be affected by any one or more changes in the estimates used. Changes in discount rate, energy price forecasts and inflation rate have the most substantial influence on Phoebe’s valuation. A 1% change in inflation rate would change VIU by approximately $26,100, while a 0.5% increment in the discount rate would change VIU by approximately $11,700 and a change of one dollar in energy price would change the VIU by approximately $8,300.

11. LONG-TERM LOANS AND BORROWINGS

As at September 30, 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 Phoebe solar facility was in breach of its credit agreement. The US$103,212 ($131,502) portion of the loan that would otherwise be classified as long-term was reclassified to the current portion of long-term loans and borrowings. Ongoing dialogue and reporting are provided to the facility lenders until this situation is resolved.

- the Duqueco facility was in breach of its credit agreement following the acquisition of the remaining 50% interest in Energia Llaima since the former Chilean equity investors ceased to jointly hold direct ownership of fifty percent of the company's shares. The US$109,887 ($140,006) portion of the loan that would otherwise be classified as long-term was reclassified to the current portion of long-term loans and borrowings. Negotiations are currently underway to resolve this situation.

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 $1,317 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.

Commissioning Activities - Griffin Trail Wind Facility

The construction loan of US$256,201 ($318,970) was repaid on July 30, 2021 by a US$169,155 ($210,598) tax equity investment, while the Corporation contributed US$115,512 ($143,812) in sponsor equity. The excess contribution of the tax and sponsor equity funding will be used to fund construction related spending and for holdback amounts following the end of the construction activities.

Acquisition of Energía Llaima

As part of the acquisition of the remaining 50% interest in Energía Llaima, the Corporation assumed the related loan facilities for a total fair value of US$130,744 ($163,888) which are comprised mainly of:

- US$110,502 ($138,514) term loan bearing interest at Libor 180 days + 3.5% payable semi-annually and maturing in March 2033.
- US$9,503 ($11,912) term loan bearing interest at Libor 180 days + 3.9%
- US$5,151 ($6,457 term loan bearing interest at 3.2%
- US$3,168 ($3,971) term loan bearing interest at Libor 180 days + 2.65%
- US$2,420 ($3,034) term loan bearing interest at 3.2%

The outstanding balance as at September 30, 2021 is US$130,129 ($165,797).

Acquisition of Licán

As part of the acquisition of Licán, the Corporation assumed the related loan facility for a total fair value of US$26,000 ($32,617). The term loan bears interest at Libor 180 days + 3.1% and matures in September 2026.

12. OTHER LIABILITIES

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 are subject to restrictions under the Mesgi'g Ugju's'n credit agreement and as such, have been recognized as other long-term assets and the associated obligation as other non-current liabilities. The proceeds are to be used in the future to remediate the unfulfilled performance obligations under the turbine supply agreement. During the three and nine months ended September 30, 2021, an amount of $1,013 of the liability was amortized in relation to remediation work performed.

13. SHAREHOLDERS' CAPITAL

Common Shares

Issuance of common shares

As part of the Energia Lliama acquisition on July 9, 2021, the Corporation issued 4,048,215 common shares at a price of $22.09 for a value of $89,437 (see note 3b). Concurrently with the closing of the acquisition, the Corporation issued 1,148,050 common shares, for total proceeds of $25,325, in order for Hydro-Québec to maintain its 19.9% ownership.

As part of the public offering in September 2021, the Corporation issued 10,374,150 common shares at a price of $19.40 for cash proceeds of $201,259. Concurrently with the closing of the public offering, Hydro-Québec subscribed 2,581,000 common shares of the common shares of the Corporation for cash proceeds of $50,071, in order for Hydro-Québec to maintain its 19.9% ownership of the Corporation's common shares.

Buyback of common shares and preferred shares

During the nine-month period ended September 30, 2021, 180,602 common shares have been purchased and cancelled under the normal course issuer bid terminated May 23, 2021, at an average price of $18.90.

Normal course issuer bid renewal

The Corporation received the approval from the Toronto Stock Exchange ("TSX") to proceed with a normal course issuer bid on its common shares (the "New Bid"). Under the New Bid, the Corporation could purchase for cancellation up to 2,000,000 of its common shares, representing approximately 1.15% of the 174,692,091 issued and outstanding common shares of the Corporation as at May 11, 2021. The New Bid commenced on May 24, 2021 and will terminate on May 23, 2022.

Equity-based compensation

a) Stock option plan

Granted

During the nine months ended September 30, 2021, 32,031 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:

	September 30, 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 $65 was recorded during the first nine months 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 nine months ended September 30, 2021, 281,313 performance share rights vested.

In addition, 157,339 share rights were granted during the first nine months of 2021. The performance share rights vest on December 31, 2023.

Deferred Share Unit Plan

During the nine months ended September 30, 2021, 21,611 units were granted.

A compensation expense of $1,625 was recorded during the first nine months of 2021 with respect to the PSP and DSU plans.

Dividends

a) Dividend Declared

The applicable dividend rates for the Corporation's Series A and Series B preferred shares were reset during the nine months ended September 30, 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 each quarterly period commencing on January 15, 2021, is equal to the sum of the T-Bill Rate plus 2.79% per annum, calculated on a quarterly basis. As at September 30, 2021, there were no outstanding Series B Preferred Shares.

The following dividends were declared by the Corporation:

	Nine months ended September 30			
	2021		2020	
	($/share)	Total	($/share)	Total
Dividends declared on common shares	0.5400	97,580	0.5400	94,118
Dividends declared on Series A preferred shares	0.6083	2,068	0.6765	2,300
Dividends declared on Series C preferred shares	1.0781	2,156	1.0781	2,156

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

Dividend Declared subsequent to period end and ninnot recognized at the end of the reporting period

The following dividends will be paid by the Corporation on January 17, 2022:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
November 09, 2021	December 31, 2021	January 17, 2022	$ 0.180	$ 0.202750	$ 0.359375

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

14. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a) Changes in non-cash operating working capital items

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Accounts receivable	6,809	(29,992)	(22,058)	(26,107)
Prepaids and other	(5,756)	(6,033)	(11,979)	(12,048)
Accounts payable and other payables	(14,005)	19,723	18,708	12,307
	(12,952)	(16,302)	(15,329)	(25,848)

b) Additional information

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Finance costs paid relative to operating activities before interest on leases	(39,120)	(37,261)	(127,848)	(125,778)
Interest on leases paid relative to operating activities	(712)	(494)	(3,145)	(1,528)
Capitalized interest relative to investing activities	(496)	(3,272)	(2,506)	(4,780)
Capitalized interest on leases relative to investing activities	(632)	(521)	(1,815)	(1,052)
Total finance costs paid	(40,960)	(41,548)	(135,314)	(133,138)
Non-cash transactions:				
Change in unpaid property, plant and equipment	(4,308)	(19,111)	3,685	(13,773)
Investment tax credits	8,279	19,403	12,752	96,156
Change in other long-term assets	28	11,521	12	11,521
Change in unpaid project development costs	447	266	738	266
Remeasurement of other liabilities	(1,068)	3,207	(14,448)	6,061
Initial measurement of other liabilities	1,538	22,494	8,417	75,270
New obligation under financing agreement	—	—	19,642	—
Common shares issued through the conversion of convertible debentures	—	—	2,306	—
Common shares issued through equity based compensation	—	568	3,174	1,864
Unpaid distributions to non-controlling interests in subsidiaries	385	—	385	—
Common shares issued through dividend reinvestment plan	327	2,552	3,074	5,247
Common shares issued upon acquisition	89,437	—	89,437	—

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

c) Changes in liabilities arising from financing activities

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Changes in long-term debt				
Long-term debt at beginning of period	4,600,233	4,133,473	4,533,806	4,412,842
Increase in long-term debt	404,760	195,194	793,331	510,127
Repayment of long-term debt	(629,518)	(42,121)	(892,525)	(661,142)
Payment of deferred financing costs	—	—	—	(9,256)
Business acquisitions (Note 3)	196,505	172,252	196,505	172,252
Investment tax credits	(29,617)	—	(29,617)	—
Tax attributes	(20,720)	(4,303)	(21,787)	(15,733)
Production tax credits	(10,698)	(8,229)	(31,580)	(31,281)
Other non-cash finance costs	14,294	11,794	38,148	28,093
Net foreign exchange differences	39,879	(5,500)	(21,163)	46,658
Long-term debt at end of period	4,565,118	4,452,560	4,565,118	4,452,560
Changes in convertible debentures				
Convertible debentures at beginning of period	279,112	280,057	280,075	278,827
Convertible debentures converted into common shares	—	—	(2,306)	—
Accretion of convertible debentures	541	662	1,884	1,892
Convertible debentures at end of period	279,653	280,719	279,653	280,719

15. 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 September 30, 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$21.24 to US$81.65 per MWh between October 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$5.79 to US$87.58 per MWh between October 1, 2021 and December 31, 2030.

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

With respect to the Phoebe basis hedge, ERCOT South Hub forward power prices are expected to be in a range of US$58.46 to US$59.24 per MWh between October 1, 2021 and December 31, 2021, while Phoebe node forward power prices are derived using a historical spread against the ERCOT South Hub of nil per MWh.

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

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 May 2031; (2) for the remaining month 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 for the period from January 1, 2021 to September 30, 2021.

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$220,668 ($281,153) as at September 30, 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 ceased 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 market risk (e.g. interest rate, foreign exchange, and power price and others). 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.

16. 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.

On July 19, 2021, Innergex reached an agreement to settle the amounts that remained unpaid by the Phoebe solar facility following the February 2021 Texas Events. The aggregate cash disbursement of US$23,956 ($29,691) comprises the agreed-upon settlement payment for the amounts disputed following the February 2021 Texas Events, and a payment on the project's tracking account balance[1], net of unpaid energy sold by the project during the negotiation process.

1. Renewable energy projects selling energy under a power hedge structure are exposed to mismatch risk mainly driven by: (1) volume/shape risk, which represents the risk of a shortfall in the actual energy produced in comparison to the contractual hourly quantities; and (2) basis risk, which represents a price differential risk between hub and node per MWh of contracted energy. To cover for temporary unfavourable mismatches, counterparties provide projects with a tracking account; a working capital loan that is repaid with subsequent favourable mismatches or cash payments

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 20, 2021, the District Court of Harris County, Texas denied the temporary injunction application, directing the counterparty to the power hedges for the Flat Top and Shannon wind facilities to suspend all remedies against the projects, including foreclosure, arising from an alleged default of payment that was formally disputed by the Innergex, following the February 2021 Texas Events. As a result of the Court's decision, the counterparty to the power hedges for the projects will not be precluded from exercising any of its remedies, including foreclosure.

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 on the reversal of exchange differences in accumulated other comprehensive income related to these two projects. As at September 30, 2021, the carrying amount of the Corporation's equity investments in Flat Top and Shannon was nil, 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. In addition, as at September 30, 2021, the deferred tax liabilities related to the Corporation's equity investments in Flat Top and Shannon were nil following the $24,390 and $15,101 respective deferred tax recoveries upon reclassification of the projects' assets and liabilities as disposal groups held for sale during the period ended June 30, 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. 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 would appeal the decision of the Supreme Court of British Columbia. The Comptroller of Water Rights filed the appeal documents on June 21, 2021.The hearing before the British Columbia Court of Appeal took place in Vancouver on October 21 and October 22, 2021. The Court of Appeal's decision is expected to be rendered within 60 to 90 days following the hearing.

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 $12,456 ($14,183 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 18, Segment Information, for more information.

17. 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 16, 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.

18. 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 income related to PTCs, and Innergex's share of the operating joint ventures and associates' other income related to PTCs. “Adjusted EBITDA” represents net earnings (loss), to which are added (deducted) income tax expense (recovery), finance costs, depreciation and amortization, impairment charges, 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 income related to PTCs, and Innergex's share of the operating joint ventures and associates' other income 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.

The below segment results exclude results from the Shannon and Flat Top joint venture facilities, from April 1, 2021 onwards, as a result of the projects' assets and liabilities being classified as disposal groups held for sale.

Three months ended September 30, 2021 Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	78,414	70,678	35,472	184,564
Innergex's share of revenues of joint ventures and associates	23,471	3,227	—	26,698
PTCs and Innergex's share of PTCs generated	—	10,698	—	10,698
Segment Revenues Proportionate	101,885	84,603	35,472	221,960
Segment Adjusted EBITDA	62,546	45,582	29,777	137,905
Innergex's share of Adjusted EBITDA of joint ventures and associates	20,378	2,340	—	22,718
PTCs and Innergex's share of PTCs generated	—	10,698	—	10,698
Segment Adjusted EBITDA Proportionate	82,924	58,620	29,777	171,321
Segment Adjusted EBITDA Margin	80 %	64 %	84 %	75 %

Nine months ended September 30, 2021 Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	180,910	259,506	104,404	544,820
Innergex's share of revenues of joint ventures and associates	43,040	55,737	885	99,662
PTCs and Innergex's share of PTCs generated	—	37,614	—	37,614
Segment Revenues Proportionate	223,950	352,857	105,289	682,096
Segment Adjusted EBITDA	140,063	202,841	93,295	436,199
Innergex's share of Adjusted EBITDA of joint ventures and associates	33,518	50,779	554	84,851
PTCs and Innergex's share of PTCs generated	—	37,614	—	37,614
Segment Adjusted EBITDA Proportionate	173,581	291,234	93,849	558,664
Segment Adjusted EBITDA Margin	77 %	78 %	89 %	80 %

As at September 30, 2021	Hydroelectric	Wind	Solar	Segment totals [1]
Investments in joint ventures and associates	115,093	21,852	—	136,945
Property, plant and equipment acquired through business acquisitions	273,327	—	10,069	283,396
Transfer of assets upon commissioning	—	357,502	—	357,502
Acquisition of property, plant and equipment during the year	2,113	9,157	788	12,058

1. Segment totals include only operating projects.

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

Three months ended September 30, 2020				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	76,170	67,726	18,755	162,651
Innergex's share of revenues of joint ventures and associates	30,521	6,917	403	37,841
PTCs and Innergex's share of PTCs generated	—	13,244	—	13,244
Segment Revenues Proportionate	106,691	87,887	19,158	213,736
Segment Adjusted EBITDA	61,847	48,431	14,034	124,312
Innergex's share of Adjusted EBITDA of joint ventures and associates	26,402	2,989	274	29,665
PTCs and Innergex's share of PTCs generated	—	13,244	—	13,244
Segment Adjusted EBITDA Proportionate	88,249	64,664	14,308	167,221
Segment Adjusted EBITDA Margin	81 %	72 %	75 %	76 %

Nine months ended September 30, 2020				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	169,157	235,325	40,798	445,280
Innergex's share of revenues of joint ventures and associates	49,982	22,597	1,420	73,999
PTCs and Innergex's share of PTCs generated	—	50,832	—	50,832
Segment Revenues Proportionate	219,139	308,754	42,218	570,111
Segment Adjusted EBITDA	130,368	185,287	31,079	346,734
Innergex's share of Adjusted EBITDA of joint ventures and associates	39,472	11,979	836	52,287
PTCs and Innergex's share of PTCs generated	—	50,832	—	50,832
Segment Adjusted EBITDA Proportionate	169,840	248,098	31,915	449,853
Segment Adjusted EBITDA Margin	77 %	79 %	76 %	78 %

As at September 30, 2020	Hydroelectric	Wind	Solar	Segment totals [1]
Property, plant and equipment acquired through business acquisitions	—	24,328	61,022	85,350
Acquisition of property, plant and equipment during the year	311	1,927	1,473	3,711

1. Segment totals include only operating projects.

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

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

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Revenues	184,564	162,651	544,820	445,280
Innergex's share of revenues of joint ventures and associates	26,698	37,841	99,662	73,999
PTCs and Innergex's share of PTCs generated	10,698	13,244	37,614	50,832
Revenues Proportionate	221,960	213,736	682,096	570,111
Net (loss) earnings	(23,464)	7,492	(191,137)	(41,005)
Income tax (recovery) expense	21,741	11,508	(63,398)	11,540
Finance costs	66,519	60,122	184,838	175,700
Depreciation and amortization	59,838	59,368	177,892	170,061
Impairment of long-term assets	30,660	—	36,974	—
EBITDA	155,294	138,490	145,169	316,296
Other net income	(33,827)	(16,725)	(55,056)	(58,250)
Share of (earnings) losses of joint ventures and associates	(14,311)	(11,382)	190,680	21,398
Change in fair value of financial instruments	15,366	(1,859)	107,533	24,835
Adjusted EBITDA	122,522	108,524	388,326	304,279
Unallocated expenses:				
General and administrative	10,248	11,089	30,215	29,355
Prospective projects	5,135	4,699	17,658	13,100
Segment Adjusted EBITDA	137,905	124,312	436,199	346,734
Innergex's share of Adjusted EBITDA of joint ventures and associates	22,718	29,665	84,851	52,287
PTCs and Innergex's share of PTCs generated	10,698	13,244	37,614	50,832
Segment Adjusted EBITDA Proportionate	171,321	167,221	558,664	449,853
Segment Adjusted EBITDA Margin	74.7 %	76.4 %	80.1 %	77.9 %

Geographic segments

As at September 30, 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, 8 wind farms and 1 solar farm in Canada, 16 wind farms in France, and 3 hydroelectric facility, 8 wind farms and 4 solar farms in the United States, and 3 hydroelectric facilities and 2 solar farm in Chile. The Corporation operates in four principal geographical areas, which are detailed below:

	Three months ended September 30		Nine months ended September 30	
	2021	2020	2021	2020
Revenues				
Canada	109,990	120,038	312,706	320,958
United States	43,516	27,274	145,840	54,738
France	15,644	13,938	64,844	67,063
Chile	15,414	1,401	21,430	2,521
	184,564	162,651	544,820	445,280

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

As at	September 30, 2021	December 31, 2020
Non-current assets, excluding derivative financial instruments and deferred tax assets [1]		
Canada	3,416,659	3,504,403
United States	1,942,670	1,990,997
France	839,674	922,330
Chile	428,354	166,881
	6,627,357	6,584,611

1. Includes the investments in joint ventures and associates

19. SUBSEQUENT EVENTS

On October 25, 2021 Innergex and HQI US Holding LLC, a subsidiary of Hydro-Québec, have acquired Curtis Palmer, a 60 MW run-of-river hydroelectric portfolio located in Corinth, New York, consisting of the 12 MW Curtis Mills and 48 MW Palmer Falls facilities for a total consideration of US$318,369 ($393,409), including US$9,195 ($11,362) of cash and working capital adjustments. In addition, the acquisition is subject to an earn-out provision based on the evolution of the New York Independent System Operator ("NYISO") market pricing during calendar years 2023 and 2024, limited to US$30,000. Upon closing, the Corporation owns a 50% interest in the Facilities with Hydro-Québec indirectly owning the remaining 50% interest. This acquisition was partly financed with the proceeds of the September 2021 share issuances described in Note 13.

The acquisition gave rise to transaction costs of $591 incurred in the period ended September 30, 2021 which were expensed as incurred in other net income in the consolidated statements of earnings (loss).

20. 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.

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

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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