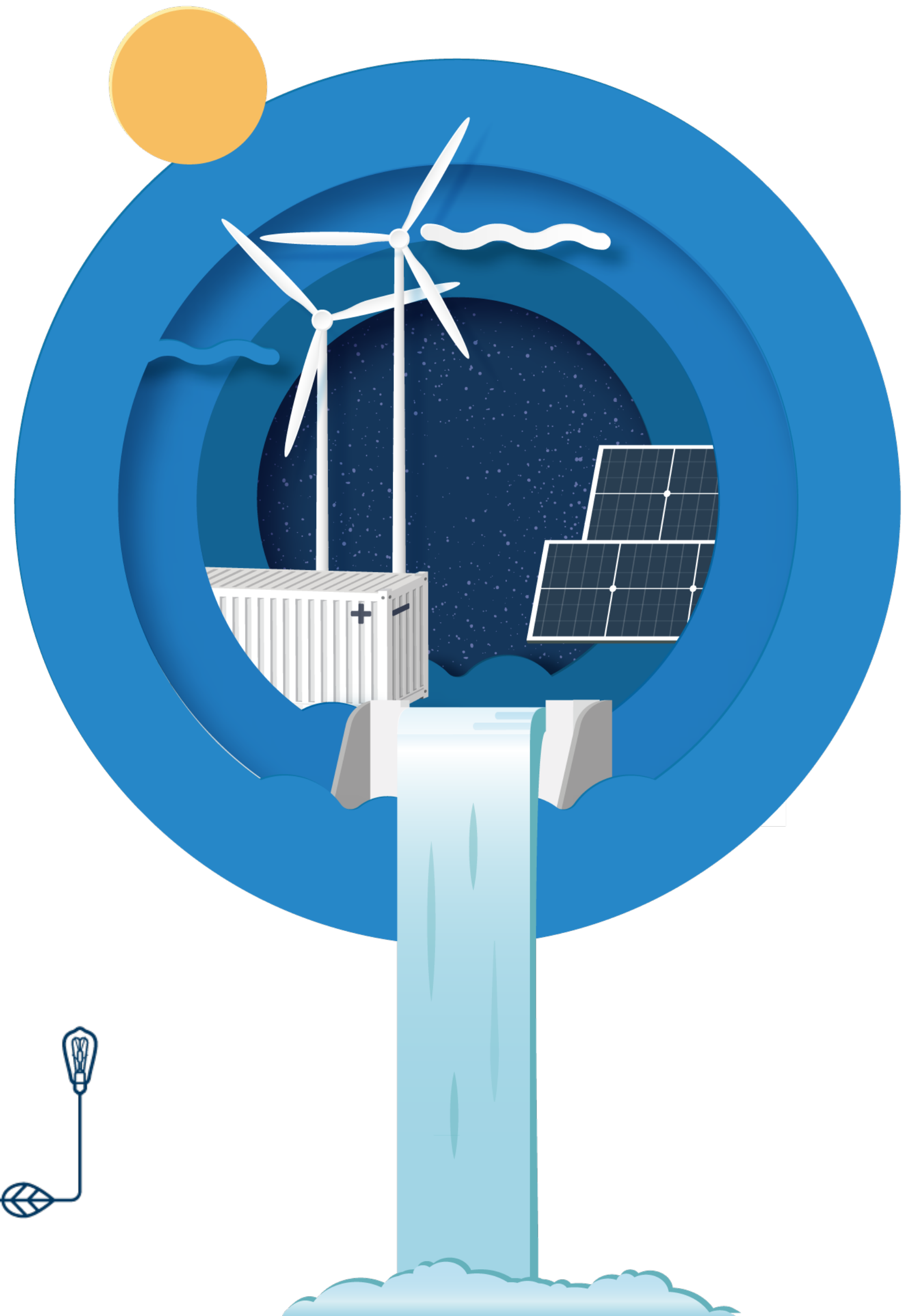
INNERGEX

Renewable Energy.
Sustainable Development.

Third Quarter 2021

Conference Call & Webcast

November 10, 2021



FORWARD-LOOKING INFORMATION

To inform readers of the Corporation's future prospects, this document 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 document.

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 document, 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

The following table outlines the Forward-Looking Information contained in this document, 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"
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

FORWARD-LOOKING INFORMATION

Principal Assumptions	Principal Risks and Uncertainties
PROJECTED FREE CASH FLOW, PROJECTED FREE CASH FLOW PER SHARE AND INTENTION TO PAY DIVIDEND QUARTERLY The Corporation estimates Projected Free Cash Flow as projected cash flows, from operating activities before changes in non-cash operating working capital items, less estimated maintenance capital expenditures net of proceeds from disposals, scheduled debt principal payments, preferred share dividends declared and the portion of Free Cash Flow attributed to non-controlling interests, plus or minus other elements that are not representative of the Corporation's long-term cash generating capacity, such as transaction costs related to realized acquisitions (which are financed at the time of the acquisition), realized losses or gains on derivative financial instruments used to hedge the interest rate on project-level debt or the exchange rate on equipment purchases. The Corporation estimates the annual dividend it intends to distribute based on the Corporation's operating results, cash flows, financial conditions, debt covenants, long-term growth prospects, solvency test imposed under corporate law for declaration of dividends and other relevant factors.	See principal assumptions, risks and uncertainties identified under “Expected Production”, “Projected Revenues” and "Projected Adjusted EBITDA" Possibility that the Corporation may not declare or pay a dividend
ESTIMATED PROJECT COSTS, EXPECTED OBTAINMENT OF PERMITS, START OF CONSTRUCTION, WORK CONDUCTED AND START OF COMMERCIAL OPERATION FOR DEVELOPMENT PROJECTS OR PROSPECTIVE PROJECTS For each Development Project and Prospective Project, the Corporation may provide (where available) an estimate of potential installed capacity, estimated storage capacity, estimated project costs, project financing terms and each project’s development and construction schedule, based on its extensive experience as a developer, in addition to information directly related to incremental internal costs, site acquisition costs and financing costs, which are eventually adjusted for the projected costs and construction schedule provided by the engineering, procurement and construction (“EPC”) contractor retained for the project. The Corporation provides indications based on assumptions regarding its current strategic positioning and competitive outlook, as well as scheduling and construction progress, for its Development Projects and its Prospective Projects, which the Corporation evaluates based on its experience as a developer.	Uncertainties surrounding development of new facilities Performance of major counterparties, such as suppliers or contractors Delays and cost overruns in the design and construction of projects Ability to secure appropriate land Obtainment of permits Health, safety and environmental risks Ability to secure new PPAs or renew any PPA Higher-than-expected inflation Equipment supply Interest rate fluctuations and financing risk Risks related to U.S. PTCs and ITCs, changes in U.S. corporate tax rates and availability of tax equity financing Regulatory and political risks Natural disaster and force majeure Relationships with stakeholders Foreign market growth and development risks Social acceptance of renewable energy projects Ability of the Corporation to execute its strategy of building shareholder value Failure to realize the anticipated benefits of completed and future acquisitions Changes in governmental support to increase electricity to be generated from renewable sources by independent power producers COVID-19 restrictive measures
INTENTION TO RESPOND TO REQUESTS FOR PROPOSALS The Corporation provides indications of its intention to submit proposals in response to requests for proposals (“Request for Proposals” or “RFP”) based on the state of readiness of some of its Prospective Projects and their compatibility with the announced terms of these RFPs.	Regulatory and political risks Ability of the Corporation to execute its strategy for building shareholder value Ability to secure new PPAs Changes in governmental support to increase electricity to be generated from renewable sources by independent power producers Social acceptance of renewable energy projects Relationships with stakeholders

AGENDA

1. Q3 2021 Financial Highlights
2. Q3 2021 Results
3. Significant Financial Event
4. Growth and Development Initiatives
5. Construction Activities
6. Development Activities
7. Prospective Projects
8. Question Period

Appendix: Non-IFRS Measures

Note: All amounts in this presentation are in Canadian dollars, unless otherwise indicated

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Jean-François Neault
CPA, CMA, MBA

Chief Financial Officer

1. Q3 2021 FINANCIAL HIGHLIGHTS

In millions of Canadian dollars	Three Months Ended September 30			Nine Months Ended September 30				
CONSOLIDATED	**2021**	**2020**	**Change**	**2021 as reported**	**Texas[2]**	**2021 Norm.**	**2020**	**Change[3]**
Production (GWh)	2,290.1	2,021.6	13%	6,472.1	-	6,472.1	5,886.9	10%
Revenues	184.6	162.7	13%	544.8	(55.0)	489.9	445.3	10%
Adjusted EBITDA[1]	122.5	108.5	13%	388.3	(55.0)	333.4	304.3	10%
Adjusted EBITDA Margin[1]	66.4%	66.7%	-	71.3%	(3.2%)	68.1%	68.3%	-
PROPORTIONATE								
Production Proportionate[1] (GWh)	2,538.6	2,471.1	3%	7,177.2	-	7,177.2	7,016.8	2%
Revenues Proportionate[1]	222.0	213.7	4%	682.1	(95.3)	586.8	570.1	3%
Adjusted EBITDA Proportionate[1]	155.9	151.4	3%	510.8	(95.3)	415.5	407.4	2%

1. Adjusted EBITDA, Adjusted EBITDA Margin, Production Proportionate, Revenues Proportionate, 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 presentation for more information.
2. Normalized to exclude the impacts of the February 2021 Texas Events. Please refer to the "February 2021 Texas Events" section of the MD&A for more information.
3. Variation with 2021 Normalized results.

2. Q3 2021 RESULTS | SEGMENTED ADJUSTED EBITDA[1] BY ENERGY

In millions of Canadian dollars

	HYDRO		WIND		SOLAR	
CONSOLIDATED	**2021**	**Change**	**2021**	**Change**	**2021**	**Change**
Production (GWh)	933.3	7%	980.3	9%	376.4	50%
Revenues	78.4	3%	70.7	4%	35.5	89%
Adjusted EBITDA[1]	62.5	1%	45.6	(6%)	29.8	112%
Adjusted EBITDA Margin[1]	79.8%		64.5%		83.9%	

Hydro

\+
- Contribution from the Chilean facilities following the acquisition of the remaining interests in Energía Llaima
- Acquisition of Licán

\−
- Temporary shutdown at the Kwoiek Creek facility caused by wildfire damaging the transmission line
- Lower revenues from the facilities in Quebec due to lower production and lower selling prices

Wind

\+
- Commissioning of the Griffin Trail wind facility
- Higher revenues from higher production in France

\−
- Lower revenues in Quebec due to lower production and higher operating expenses
- Lower revenues at the Foard City facility from lower production and lower average selling prices

Solar

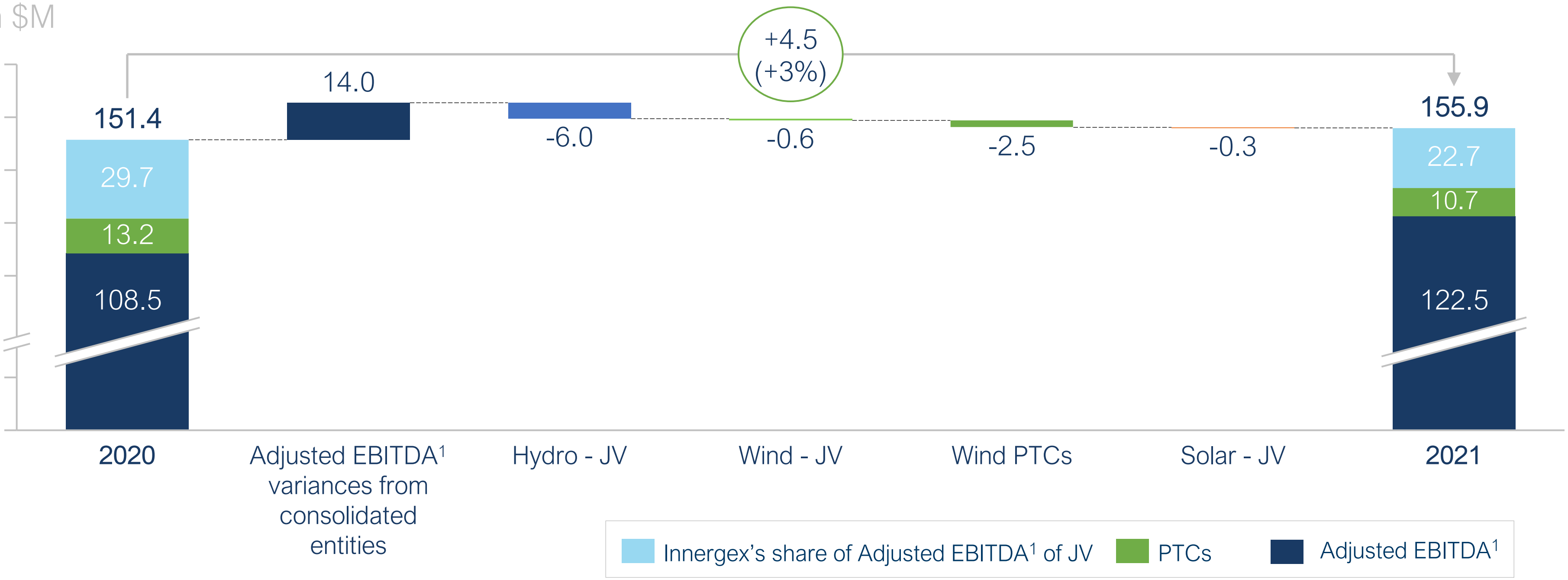
\+
- Liquidated damages due caused by delays in and the commissioning of the Hillcrest solar facility
- Higher selling prices at the Salvador facility
- Contribution of the Pampa Elvira facility following the acquisition of the remaining interests in Energía Llaima

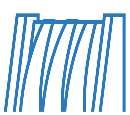
\−
- Lower revenues at the Phoebe facility due to lower average selling prices

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 presentation for more information.

2. Q3 2021 RESULTS | ADJUSTED EBITDA PROPORTIONATE[1]

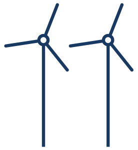
In $M





+ Higher revenues from higher production at Jimmie Creek facility due to lower 2020 figures in relation to the BC Hydro curtailment

− Lower contribution from facilities in Chile now included in the Adj. EBITDA
− Lower contribution from Toba Montrose due to lower average selling prices

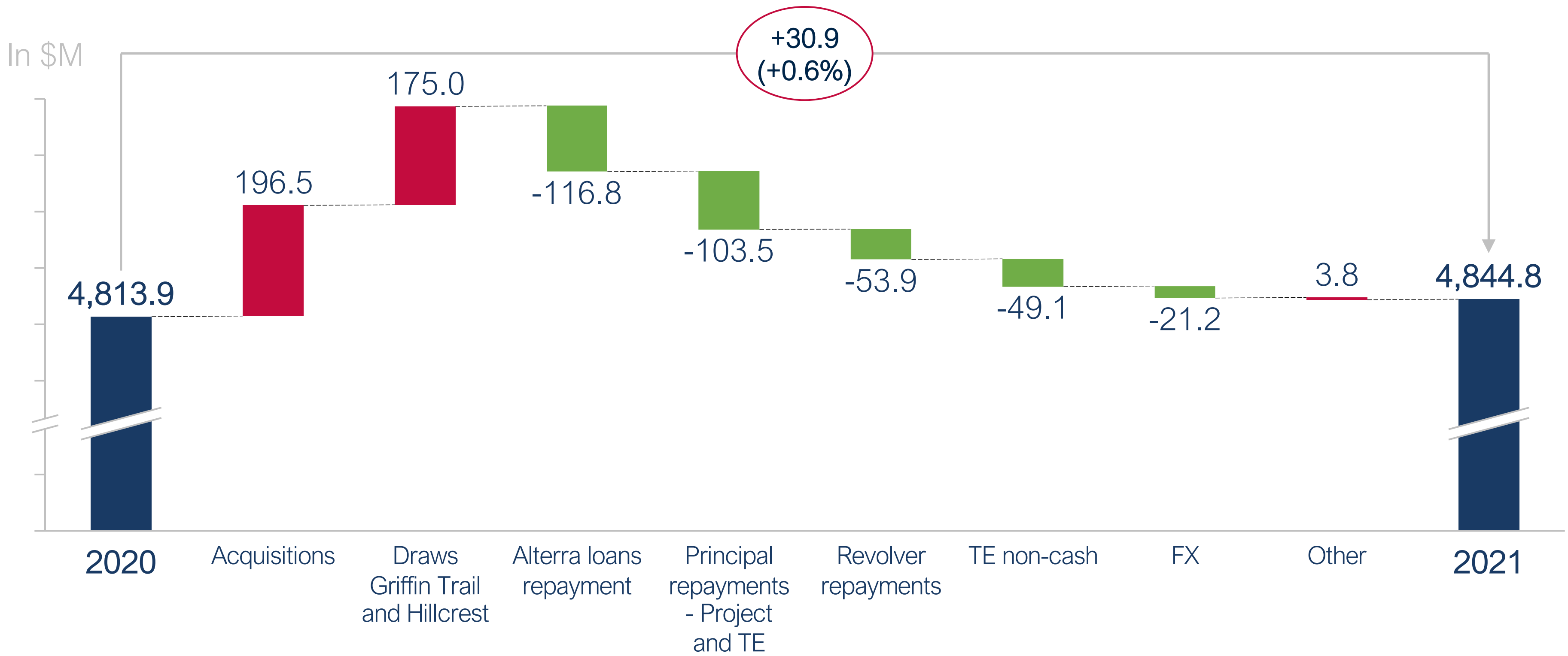


+ PTCs earned at the Griffin Trail facility following its commissioning

− Exclusion of the results from the Flat Top and Shannon joint venture facilities
− Lower revenues at Viger-Denonville due to lower production
− Lower PTCs earned at Foard City due to lower production

1. Adjusted EBITDA and Adjusted EBITDA Proportionate are not recognized measures under IFRS and therefore may not be comparable to the ones presented by other issuers. Please refer to the "Non-IFRS Measures" section of this presentation for more information.

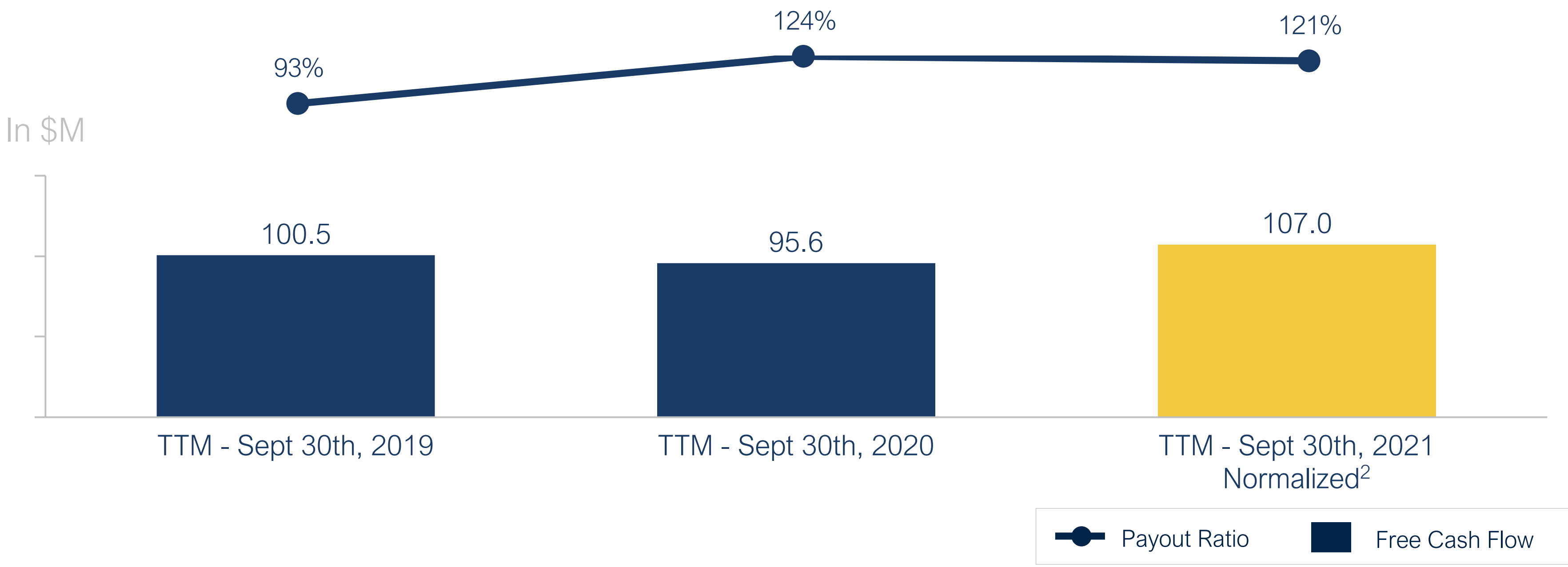
2. Q3 2021 RESULTS | LONG-TERM DEBT



2. Q3 2021 RESULTS | FINANCIAL POSITION HIGHLIGHTS

As at In millions of Canadian dollars	SEPT 30, 2021	DEC 31, 2020
Total Assets	7,244.6	7,154.2
Total Liabilities	6,055.2	6,083.3
Non-Controlling Interests	58.0	62.1
Equity Attributable to Owners	1,131.4	1,008.8

2. Q3 2021 RESULTS | FREE CASH FLOW[1] & PAYOUT RATIO[1]



Free Cash Flow[1]

+

- Contribution of recently acquired and commissioned projects
- Lower interest payment on the corporate revolving facilities following Hydro-Québec Private Placements and on the Alterra loans reimbursed
- Increase in revenues from the B.C. facilities affected by the 2020 BC Hydro curtailment
- Increase in distribution received from JV and associates, mainly from Energía Llaima

−

- Increase in debt principal payments from acquisition projects
- Increase in Free Cash Flow attributed to non-controlling interests stemming mainly from the Mountain Air Acquisition
- Decrease in cash flows from operating activities from the Phoebe facility

Payout Ratio[1]

+

- Increase of normalized free cash flow

−

- Increase in quarterly dividends following Hydro-Québec Private Placements, the bought deal equity financing and the acquisition of Energía Llaima

1. Free Cash Flow and Payout Ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this presentation for more information.
2. Normalized to exclude the impacts of the February 2021 Texas Events. Please refer to the "February 2021 Texas Events" section in the MD&A for more information.

3. SIGNIFICANT FINANCIAL EVENT

Closing of $201 million Bought Deal Equity Financing and $50 million Concurrent Private Placement

Bought Deal Equity Financing

- On September 3, 2021, Innergex completed a bought deal equity financing of common shares.
- **10,374,150 common shares were issued**:
  - 1,353,150 common shares as a result of the over-allotment.
  - Offering price of $19.40 per common share for **aggregate gross proceeds of $201.3 million**.

Private placement with Hydro-Québec

- A total of **2,581,000 common shares issued** at the offering price for **aggregate gross proceeds of $50.1 million**
  - in order to maintain Hydro-Québec's 19.9% ownership.

Use of proceeds

- Net proceeds were used to fund the acquisition of Curtis Palmer, with the remainder to be used for general corporate purposes including future growth initiatives.

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Michel Letellier, MBA

President and Chief Executive Officer

4. GROWTH AND DEVELOPMENT INITIATIVES

Innergex acquired remaining interests in Energía Llaima in Chile

- On July 9, 2021, acquisition of the remaining 50% interest in Energía Llaima in Chile, of which Innergex already owned 50%, for an aggregate consideration of US$75.0 million ($94.0 million).
- As a consideration for this transaction, Innergex has issued to Energía Llaima's shareholders 4,048,215 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.
- Innergex has also issued 1,148,050 common shares to Hydro-Québec for total proceeds of $25.3 million, in order for Hydro-Quebec to maintain its 19.9% ownership.

Acquisition of Licán hydro facility, 18 MW – Chile

- Acquisition of 100% of the shares of Empresa Eléctrica Licán S.A., which owns and operates Licán in Chile, an 18 MW run-of-river hydro facility with a reservoir for daily regulation for up to 3.5 hours.
- 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.
- Licán is expected to produce a gross estimated long-term average of 77.8 GWh per year and reach an Adjusted EBITDA of US$2.1 million ($2.7 million) on average for the first five full years.

4. GROWTH AND DEVELOPMENT INITIATIVES

Acquisition of the Curtis Palmer hydro portfolio, 60 MW – New York, U.S.

- On August 17, 2021, Innergex and HQI US Holding LLC, a subsidiary of Hydro-Québec have entered into a Membership Interest Purchase Agreement to purchase the 60 MW Curtis Palmer run-of-river hydro portfolio in New York State, consisting of Curtis Mills (12 MW) and Palmer Falls (48 MW).
- The acquisition was closed on October 25, 2021 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.
- This 50-50 joint acquisition is the first under the Strategic Alliance formed by Innergex and Hydro-Québec in 2020.
- Both facilities have a PPA for energy, RECs and capacity with Niagara Mohawk Power Corporation that expires upon the earlier of either December 31, 2027 or the delivery of cumulative 10,000 GWh.
- The facilities are expected to generate average annual Adjusted EBITDA of $54.1 million and average annual Free Cash Flow of $50.3 million through the end of the PPA on a 100% basis.
- The acquisition is also subject to an earn-out provision based on the evolution of the NYISO market pricing during 2023 and 2024, limited to US$30.0 million.

Full commissioning of Griffin Trail, 225.6 MW – Texas, U.S.

- On July 26, 2021, Innergex completed the commissioning of the 225.6 MW Griffin Trail wind facility and concluded the tax equity funding on July 30, 2021.
- Total construction costs were slightly under budget.
- The construction loan of US$256.2 million ($319.0 million) was repaid by a US$169.2 million ($210.6 million) tax equity investment, while the Corporation contributed US$115.5 million ($143.8 million) in sponsor equity.
- Griffin Trail should generate a projected Adjusted EBITDA of US$8.1 million ($10.1 million) and a projected Adjusted EBITDA Proportionate with PTCs of approximately US$30.3 million ($37.8 million) per year on average for the first five years of operations.

5. CONSTRUCTION ACTIVITIES

Innavik, 7.5 MW – Quebec, Canada

- 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 envelop 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.

Tonnerre, 9 MWh storage – France

- Construction at site in France is close to completion: all battery containers and converters have been delivered from Québec 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.
- A supply, construction and maintenance agreement has been signed with the selected battery supplier, EVLO, a Hydro-Québec subsidiary.

6. DEVELOPMENT ACTIVITIES

Hale Kuawehi, 30 MW (120 MWh storage) – Hawaii, U.S.

- 90% design engineering is completed and final EPC contract anticipated in Q4 2021.
- Construction permitting applications and approval are underway.
- Notification of a 5-month equipment delay which will impact the COD, the impacts on the PPA should be covered mostly by the BESS supplier.
- Site mobilization is anticipated for Q4 2021.

Paeahu, 15 MW (60 MWh storage) – Hawaii, U.S.

- Final EPC contract is anticipated Q4 2021.
- Maui County Planning Commission approved the Special Use Permit and Project District Phase II Development Approval for which an appeal was filed, but without limiting their effectiveness.
- Construction permitting applications are underway.
- The PPA is not in full effect until the PUC approves the overhead line extension, the approval schedule is still unknown.

Kahana, 20 MW (80 MWh storage) – Hawaii, U.S.

- Consultations with potential EPC contractors have commenced.
- The PPA is subject to approval by the PUC and a contested case proceeding is being held. The PUC held a two-day evidentiary hearing in September followed by a 30-day mediation period at the term of which an agreement was reached.

Barbers Point, 15 MW (60 MWh storage) – Hawaii, U.S.

- Environmental studies are ongoing as well as are other permitting-related activities including the publication of the Draft Environmental Assessment.
- Consultation with potential EPC contractors have commenced.
- Procedural schedule for PPA approval suspended by the PUC until the final environmental assessment is completed and filed at the end of Q1 2022.

6. DEVELOPMENT ACTIVITIES

Frontera, 109 MW – Chile

- The financing process, construction contract and permitting are progressing slowly due to the COVID-19 pandemic.

Rucacura, 3 MW – Chile

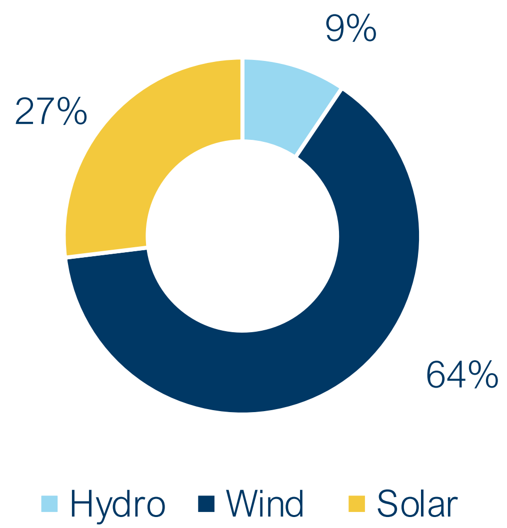
- Rucacura is an hydro project located in BioBio in Chile.
- This project will be an addition to the existing Ducqueco facility.
- Negotiation of an agreement with the turbine supplier is underway.
- Limited Notice To Proceed with contractor is under negotiation.

Lazenay, 9 MW – France

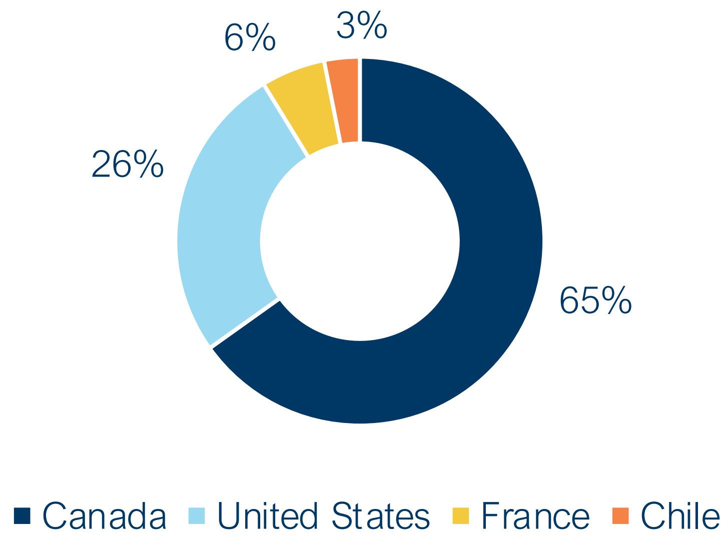
- Lazenay is a wind project located in Centre Val de Loire, of which the Corporation owns 25%.
- Environmental approval was received, the PPA was approved by EDF-OA and request for interconnection service agreement was initiated.

7. PROSPECTIVE PROJECTS

Prospective projects by energy



Prospective projects by region



	Stage of project development (in MW)			Total
	Advanced Stage	Mid Stage	Early Stage	
Hydro	3	0	683	**686**
Wind	493	61	4,080	**4,634**
Solar	200	790	971	**1,961**
Total	**696**	**851**	**5,734**	**7,281**

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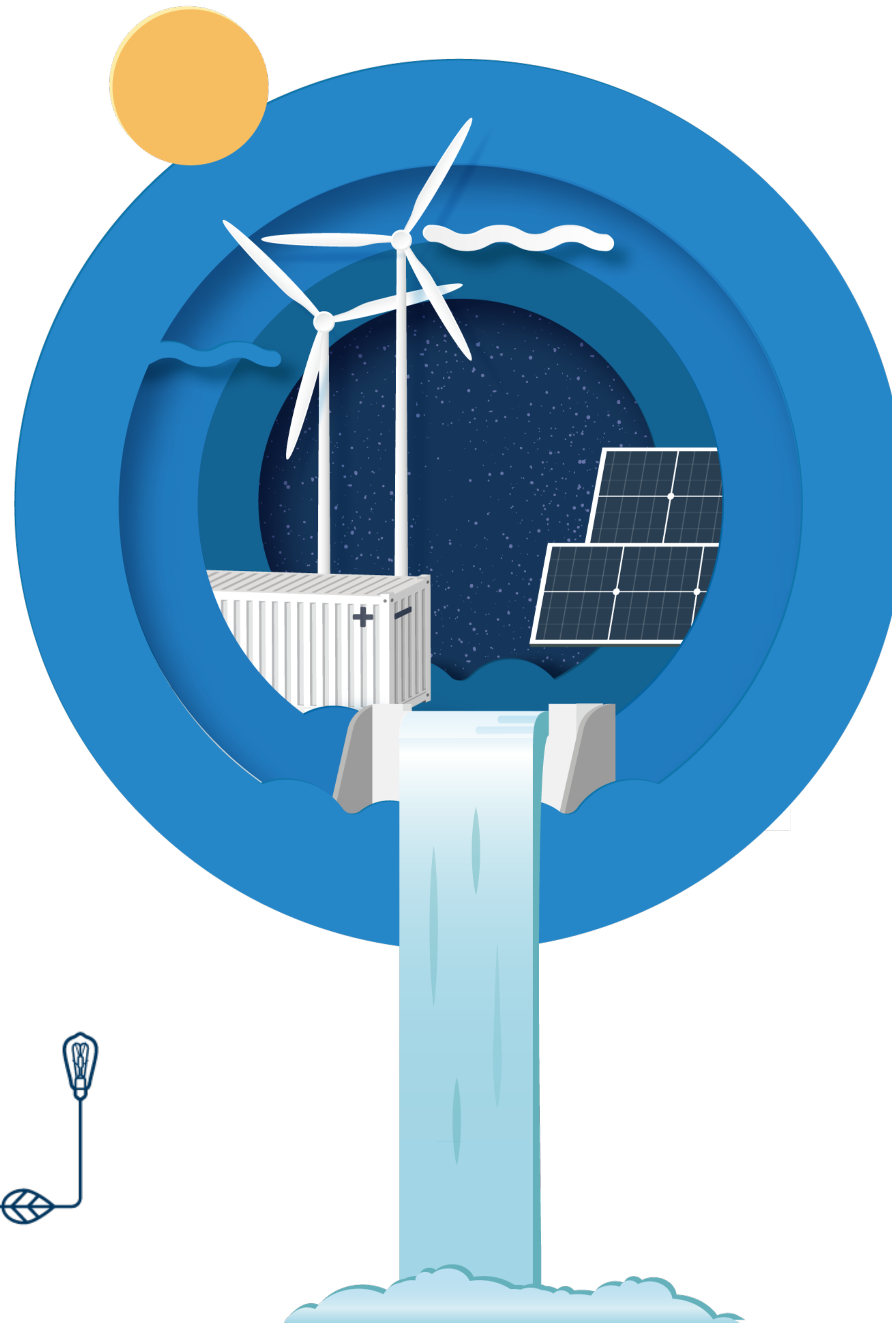

Question period

NON-IFRS MEASURES

This document has been prepared in accordance with IFRS. However, some measures referred to in this document 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.

NON-IFRS MEASURES

	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 onwards 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.

NON-IFRS MEASURES

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%

NON-IFRS MEASURES

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

NON-IFRS MEASURES

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		
	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

NON-IFRS MEASURES

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.