INNERGEX

Renewable Energy.
Sustainable Development.

Q1

Quarterly Report

For the Period Ended March 31, 2022

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.

KEY FIGURES

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

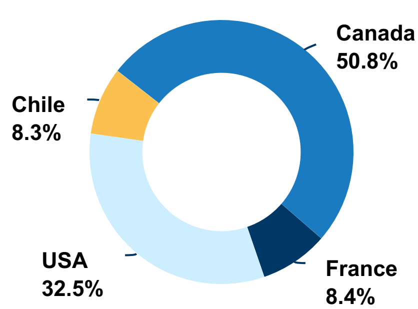
These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

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

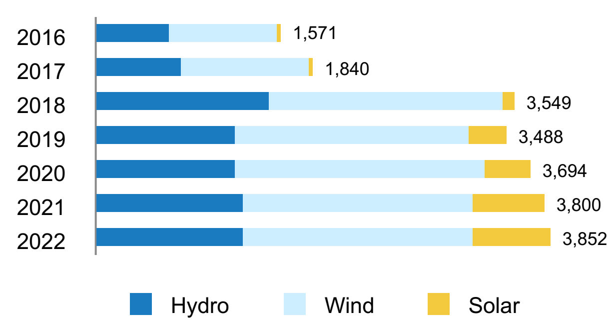
Operational Key Performance Indicators

As at May 10, 2022, the Corporation has four geographic segments and three operating segments.

Gross Installed Capacity by Country



Gross Installed Capacity by Source of Energy (MW)*



* For 2021, Gross Installed Capacity for continued operations, excluding the Shannon facility due to the project's assets and liabilities being classified as disposal group held for sale, following the February 2021 Texas Events.

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.

Innergex owns interests in 40 hydroelectric facilities drawing on 33 watersheds, 32 wind farms and 8 solar farms. The expertise and innovation developed by our skilled team in various energies and different locations can be leveraged and shared across the Corporation to maximize returns from our high-quality assets.

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 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 in May 2020 for six hydro facilities that were disputed by the Corporation on the basis that, under its Electricity Purchase Agreements with BC Hydro, BC Hydro can exercise this right but is required to compensate Innergex for energy that would have been produced at the facilities in the absence of the curtailment. 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 basis). The dispute was settled in the first quarter of 2022 to Innergex's satisfaction ("BC Hydro Curtailment Payment") (please refer to the "Capital and Liquidity" section of the Management's Discussion and Analysis for more information).

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

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

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

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 Communicable Disease Prevention Plans in each of its locations to provide guidance on health and safety measures to adopt regarding the COVID-19 pandemic. 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 May 10, 2022, the Corporation owns and operates 80 facilities in commercial operation (the "Operating Facilities"). Commissioned between 1986 and July 2021, the facilities have a weighted average age of approximately 9.6 years.

They mostly sell the generated power under long-term power purchase agreements, power hedge contracts[1] and short- and long-term industrial contracts (each, a "PPA") to rated public utilities or other creditworthy counterparties or on the open market. The PPAs have a weighted average remaining life of 13.9 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. A power hedge contract is deemed a PPA regardless of whether it is subjected to hedge accounting or accounted for as a financial derivative at fair value through earnings (loss).

The table below outlines Operating Facilities and Development Projects as at May 10, 2022.

	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	2	324	38	226	32	—	—
United States	8	1	714	332	662	332	—	—
Subtotal	32	3	1,946	370	1,602	364	—	—
SOLAR								
Canada	1	—	27	—	27	—	—	—
United States	4	5	467	280	466	280	—	320 [5]
Chile	3	—	153	—	138	—	150 [4]	—
Subtotal	8	5	647	280	631	280	150	320
STORAGE								
France	—	1	—	—	—	—	—	9 [6]
Chile	—	2	—	—	—	—	—	425 [7]
Subtotal	—	3	—	—	—	—	—	434
Total	80	14	3,852	770	3,152	733	150	754

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 (30 MW/120 MWh (4 hours)), Paeahu (15 MW/60 MWh (4 hours)), Kahana (20 MW/80 MWh (4 hours)) and Barbers Point (15 MW/60 MWh (4 hours)) solar projects.
6. Tonnerre standalone battery storage project (9 MW/9 MWh (1 hour)).
7. Salvador battery storage capacity of 50 MW/250 MWh (5 hours) and San Andrés battery storage capacity of 35MW/175 MWh (5 hours).

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-month period ended March 31, 2022, and reflects all material events up to May 10, 2022, the date on which this MD&A was approved by the Corporation's Board of Directors.

The MD&A should be read in conjunction with the unaudited condensed interim consolidated financial statements and the accompanying notes for the three-month period ended March 31, 2022.

The unaudited condensed interim consolidated financial statements attached to this MD&A and the accompanying notes for the three-month period ended March 31, 2022, along with the 2021 comparative figures, have been prepared in accordance with International Financial Reporting Standards ("IFRS"). However, some measures referred to in this MD&A are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

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

To inform readers of the Corporation's future prospects, this MD&A contains forward-looking information within the meaning of applicable securities laws ("Forward-Looking Information"). Please refer to the "Forward-Looking Information" section for more information.

Additional information relating to Innergex, including its Annual Information Form, can be found on the Canadian Securities Administrators' System for Electronic Document Analysis and Retrieval ("SEDAR") at sedar.com or on the Corporation's website at innergex.com. Information contained in or otherwise accessible through our website does not form part of this MD&A and is not incorporated into the MD&A by reference.

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1- HIGHLIGHTS

	Three months ended March 31			
	2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized[3]
OPERATING RESULTS				
Production (MWh)	2,304,600	1,785,947	—	1,785,947
Revenues	188,723	189,651	(54,967)	134,684
Operating, general, administrative and prospective projects expenses	58,197	46,532	—	46,532
Adjusted EBITDA[1]	130,526	143,119	(54,967)	88,152
Adjusted EBITDA Margin[1]	69.2 %	75.5 %	(10.0)%	65.5 %
Net (Loss) Earnings	(34,930)	(217,872)	64,219	(153,653)
Adjusted Net Loss[1]	(2,336)	(27,540)	—	(27,540)
PROPORTIONATE				
Production Proportionate (MWh)[1]	2,358,027	2,049,621	—	2,049,621
Revenues Proportionate[1]	216,116	261,735	(95,273)	166,462
Adjusted EBITDA Proportionate[1]	154,911	208,891	(95,273)	113,618
Adjusted EBITDA Proportionate Margin[1]	71.7 %	79.8 %	(11.5)%	68.3 %
COMMON SHARES				
Dividends declared on Common Shares	36,733	31,445	—	31,445
Dividends declared on Series A Preferred Shares	689	689	—	689
Dividends declared on Series C Preferred Shares	719	719	—	719
Weighted Average Number of Common Shares (in 000s)	196,690	174,111	—	174,111

	Trailing twelve months ended March 31			
	2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized[3]
CASH FLOW AND PAYOUT RATIO				
Cash Flow From Operating Activities[2]	290,386	276,045	(16,801)	259,244
Free Cash Flow[1,2]	129,448	73,762	15,789	89,551
Payout Ratio[1,2]	106 %	170 %	(30)%	140 %
Adjusted Payout Ratio[1,2]	89 %	116 %	— %	116 %

	As at	
FINANCIAL POSITION	March 31, 2022	December 31, 2021
Total Assets	7,353,348	7,396,068
Total Liabilities	5,818,939	6,035,388
Equity Attributable to Owners	1,274,534	1,093,112
Non-Controlling Interests	259,875	267,568

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 period ended March 31, 2021, the operating results, the Cash Flow From Operating Activities, Free Cash Flow and Payout Ratio are normalized to exclude the impacts of the February 2021 Texas Events. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

1- HIGHLIGHTS | First Quarter 2022 – Operating Performance

For the three-month period ended March 31, 2022, **Revenues**, were up 40% to $188.7 million compared with the same period last year, for which Revenues were normalized to exclude the February 2021 Texas Events. The **hydroelectric** power generation segment recorded an increase in revenues mainly attributable to the acquisition of Curtis Palmer completed on October 25, 2021, and of the remaining 50% interest in Energía Llaima on July 9, 2021, for which results are now included in Innergex's consolidated revenues. The increase is also explained by the BC Hydro Curtailment Payment combined with higher production from the facilities in British Columbia. The increase in revenues in the **wind** power generation segment is attributable to the Quebec facilities resulting mainly from higher production and the commissioning of the Griffin Trail facility on July 26, 2021. The increase was partly offset by lower average selling prices at the Foard City facility. The increase in revenues from the **solar** power generation segment was mostly due to the commissioning of the Amazon Solar Farm Ohio - Hillcrest ("Hillcrest") facility, the San Andrés Acquisition completed on January 28, 2022, and the contribution of the Pampa Elvira facility following the acquisition of the remaining 50% interest in Energía Llaima on July 9, 2021. Revenues Proportionate[1] were up 30% at $216.1 million compared with the same period last year, for which Revenues were normalized to exclude the February 2021 Texas Events.

For the three-month period ended March 31, 2022, **Operating, general, administrative and prospective projects expenses** were up 25% to $58.2 million compared with the same period last year. The **hydroelectric** power generation segment recorded an increase in expenses due to higher maintenance costs at some facilities in British Columbia and to the acquisition of Curtis Palmer and the acquisition of facilities in Chile in 2021. In the **wind** power generation segment, these expenses were stable. The increase in the **solar** power generation segment is explained by higher operating expenses stemming from the commissioning of the Hillcrest facility and the acquisition of facilities in Chile in 2021 and 2022.

As a result of the above explanations and in combination with higher corporate General and administrative expenses to support the business, the Adjusted EBITDA[1] was 48% higher at $130.5 million for the three-month period ended March 31, 2022, compared with the same period last year for which the Adjusted EBITDA[1] was normalized to exclude the February 2021 Texas Events. The Adjusted EBITDA Proportionate[1] reached $154.9 million, a 36% increase compared with the same period last year, for which the Adjusted EBITDA Proportionate[1] was normalized to exclude the February 2021 Texas Events.

Innergex recorded a **net loss** of $34.9 million ($0.18 loss per share - basic and diluted) for the quarter ended March 31, 2022, compared with a **net loss** of $217.9 million ($1.24 loss per share - basic and diluted) for the corresponding period in 2021. This was mainly due to the February 2021 Texas Events, resulting in a net unfavourable impact of $64.2 million, the recognition of $112.6 million in impairment charges and a mark-to-market loss on the Flat Top and Shannon joint ventures in 2021. The decrease in net loss is also explained by a $71.5 million favourable movement in the realized portion of changes in fair value of financial instruments mainly stemming from the net unfavourable impact of the February 2021 Texas Events and an $8.2 million increase in other net 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 of 2021.

These items were partly offset by a $37.5 million decrease in income tax recovery, mainly related to the impacts of the February 2021 Texas Events, an unfavourable $24.3 million unrealized change in the fair value of financial instruments, a $21.3 million increase in depreciation and amortization and a $6.8 million increase in finance costs, mainly attributable to the Energía Llaima and Curtis Palmer acquisitions and the Griffin Trail and Hillcrest commissioning in 2021.

[1] These measures 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.

1- HIGHLIGHTS | First Quarter 2022 – Capital and Resources

The decrease in total assets results largely from the depreciation and amortization, from the strengthening of the Canadian dollar and from an upward shift in interest rate curves, which contributed to the decrease of the asset retirement obligation included in property, plant and equipment. This was partly offset by an increase in property, plant and equipment following the San Andrés Acquisition and the start of the Hale Kuawehi construction activities.

The decrease in total liabilities results largely from the decrease in long-term loans and borrowings, including the current portion thereof, explained by a $112.1 million net repayment of the revolving credit facility, mainly stemming from the February 2022 public offering and private placement, partly offset by the San Andrés Acquisition. In addition, the decrease is also explained by a strengthening of the Canadian dollar and an upward shift in interest rate curves, which contributed to the decrease of the asset retirement obligation and of derivative financial instruments' fair value.

The increase in equity attributable to owners results largely from the shares issued related to the public offering in February 2022 and the concurrent Hydro-Québec private placement, and the total comprehensive income, partly offset by the dividends declared on common and preferred shares.

The increase in cash flows from operating activities before changes in non-cash operating working capital items for the three months ended March 31, 2022, is mainly due to the contribution from the acquisitions, the Hillcrest and Griffin Trail commissioning, and the BC Hydro Curtailment Payment. For the trailing twelve months ended March 31, 2022, Free Cash Flow[1] was favourably impacted by the above, partly offset by an increase in debt principal repayments stemming from the Energía Llaima Acquisition and the beginning of debt repayments for Upper Lillooet/Boulder Creek project loan, and an increase in Free Cash Flow[1] attributed to non-controlling interests, stemming mainly from the Curtis Palmer Acquisition and the full-year impact of the Mountain Air Acquisition realized in 2020.

1- HIGHLIGHTS | First Quarter 2022 – Growth Initiatives

On January, 28, 2022, Innergex completed the acquisition of the 50.6 MW San Andrés solar farm in Chile.The facility, commissioned in 2014, is located in the Atacama Desert in northern Chile. San Andrés was acquired for a total consideration of US$26.8 million ($34.1 million). The facility is expected to produce a gross long-term average of approximately 118.9 GWh per year.

On February 3, 2022, Innergex entered into an agreement to acquire 100% of the ordinary shares of Aela Generación S.A. and Aela Energía SpA (together “Aela”), a 332 MW portfolio of three newly built operating wind assets in Chile, for a purchase price of US$685.5 million ($870.6 million) (the “Aela Acquisition”), including the assumption of US$385.5 million ($489.6 million) of existing debt, subject to customary closing adjustments. The acquisition is expected to close in Q2 2022.

On February 10, 2022, Innergex entered into foreign exchange forward contracts with an aggregate notional amount of US$100.0 million ($124.9 million) to manage its exposure to exchange rate fluctuations related to the purchase price. In addition, in order to manage its exposure to the risk of increasing interest rates on a portion of the expected refinancing of the Aela Acquisition and the existing Chilean projects, Innergex entered into forward start interest rate swaps on between February 17 and March 1, 2022, with an aggregate notional amount of US$331.2 million ($413.9 million). Furthermore, to mitigate the interest rate risk related to the Alterra term loan, Innergex entered into interest rate swaps between February 24 and February 28, 2022, respectively, with an aggregate notional amount of $145.0 million.

The **Salvador Battery Storage project** with a 50 MW/250 MWh (5 hours) capacity and the **San Andrés Battery Storage project** with a 35 MW/175 MWh (5 hours) capacity were promoted to the development stage with an expected Commercial Operation Date ("COD") in 2023.

The **Prospective Projects'** pipeline will allow several opportunities in the years to come, with 11 projects currently at an advanced stage, for a total 508 MW of installed capacity.

During the quarter, some project in construction and development in the United States faced challenges related mainly to supply chain issues as well as the recent decision by the U.S. Department of Commerce to initiate anticircumvention inquiries into the import of solar panels from Asian countries, which impacted projects' schedule. In 2019, the Corporation secured 125 MW of solar panels qualifying approximately 650 MW of future solar projects eligible for the tax investment credit program ("ITC"), that could be used for some current and future development projects. For more information, please refer to the "Construction Activities" and "Development Activities" sections of this MD&A.

[1] These measures 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.

1- HIGHLIGHTS | Subsequent Events

On April 29, 2022, to take advantage of the currently favourable energy pricing environment in France, Innergex entered into three power purchase agreements for its Antoigné, Porcien and Vallottes wind facilities (the “New PPAs”), which are to take effect on August 1, 2022, concurrently with the termination of the current power purchase agreements. In addition, the New PPAs effectively increase the contracted period of the facilities to December 31, 2025.

On May 10, 2022, the Corporation amended its existing revolving term credit facility, extending the term from 2023 to 2027 and increasing the borrowing limit to $950.0 million.

On May 10, 2022, Innergex announced that it has awarded Mitsubishi Power an order for two utility-scale battery energy storage systems (“BESS”). These projects will be colocated with solar energy and enable peak shifting by storing excess solar energy during the day and dispatching at night. Innergex’s 68 MW Salvador solar photovoltaic facility will add 50 MW/250 MWh (5 hours) of energy storage, and its 50.6 MW San Andrés solar photovoltaic facility will add 35 MW/175 MWh (5 hours) of energy storage.

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	35 %
WIND	1,579	29 %	1,342	24 %	1,083	20 %	1,507	27 %	5,511	51 %
SOLAR	330	21 %	443	29 %	449	29 %	316	21 %	1,538	14 %
Total	2,448	22 %	3,042	28 %	2,751	26 %	2,648	24 %	10,889	100 %

1. The consolidated long-term average production is the annualized LTA for the facilities in operation as of May 10, 2022. The LTA is presented in accordance with revenue recognition accounting rules under IFRS and excludes production from facilities that are accounted for using the equity method. Production in comparison to the LTA is a key performance indicator for the Corporation. For more information, please refer to the “Key Figures” section.

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

2- OVERVIEW OF OPERATIONS | Operating Facilities

Energy segment	Location	Three months ended March 31, 2022		Three months ended March 31, 2021		Three months Production % change
		Production (MWh)	Production as a % of LTA	Production (MWh)	Production as a % of LTA	
HYDRO	Quebec	129,667	104 %	142,140	114 %	(9)%
	Ontario	23,680	97 %	22,928	94 %	3 %
	British Columbia	171,175	80 %	143,613	67 %	19 %
	United States[3]	99,932	99 %	4,379	55 %	2,182 %
	Chile[4]	50,469	66 %	—	— %	— %
	Subtotal	**474,923**	**88 %**	**313,060**	**85 %**	**52 %**
WIND	Quebec	704,246	102 %	638,178	92 %	10 %
	France	207,857	90 %	207,210	91 %	— %
	United States	650,958	100 %	450,800	102 %	44 %
	Subtotal	**1,563,061**	**99 %**	**1,296,188**	**95 %**	**21 %**
SOLAR	Ontario	6,030	87 %	5,921	85 %	2 %
	United States	183,401	82 %	122,296	80 %	50 %
	Chile[4,5]	77,185	89 %	48,482	92 %	59 %
	Subtotal	**266,616**	**84 %**	**176,699**	**83 %**	**51 %**
TOTAL PRODUCTION[1]		**2,304,600**	**95 %**	**1,785,947**	**92 %**	**29 %**
Innergex's share of production of joint venture and associates		53,427	111 %	263,674	92 %	(80)%
PRODUCTION PROPORTIONATE[1,2]		**2,358,027**	**95 %**	**2,049,621**	**92 %**	**15 %**

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, until their sale on December 28, 2021, and March 4, 2022, respectively.
3. The Curtis Palmer Acquisition was completed on October 25, 2021.
4. 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.
5. The San Andrés Acquisition was completed on January 28, 2022.

Production for the three-month period ended March 31, 2022, was 95% of LTA. The result is mostly explained by lower production at the facilities in British Columbia, the unfavourable impact of the intermittent curtailment required by the distribution network in Texas at the Phoebe facility, below-average water flows in Chile combined with below-average wind regimes in France and at the Foard City facility in Texas. These items were partly offset by above-average wind regimes at the Griffin Trail facility in Texas and at the Quebec facilities. Excluding Phoebe economic curtailment, production for the United States solar segment would have reached 100% of LTA. Innergex's share of production of joint ventures and associates was 111% of LTA, translating into a Production Proportionate at 95% of LTA.

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

2- OVERVIEW OF OPERATIONS | Construction Activities

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

Name (Location)	Type	Ownership %	Gross installed capacity (MW)	Gross estimated LTA[1] (GWh)	PPA term (years)	Expected COD
Hale Kuawehi (Hawaii, U.S.)	Solar	100	30.0 [2]	87.4 [3]	25	— [6]
Innavik (QC, Canada)	Hydro	50	7.5	54.7	40	2023
Tonnerre (France)	Storage	100	Note [4]	—	— [5]	2022

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. Solar project with a battery storage capacity of 30 MW/120 MWh (4 hours).
3. PPA is a fixed lump sum capacity payment for the availability of dispatchable energy.
4. Standalone battery storage capacity of 9 MW/9 MWh (1 hour).
5. The project has been awarded a 7-year Contract for Difference offering a fixed-price contract for capacity certificate.
6. Project schedule under revision.

Updated status for the following projects:

Hale Kuawehi:

- The construction loan has been secured and the first draw has been completed.
- Construction activities were temporarily halted on April 25, 2022, due to a combined effect of a Force majeure notice received from the battery supplier regarding supply chain issues and the recent decision by the U.S. Department of Commerce to initiate an anticircumvention investigation into the import of solar panels from Asian countries, which has the potential to result in retroactive tariffs on silicon PV modules.
- The PPA offtaker has been notified of the Force Majeure condition and the requirement for amendments to the PPA.
- Project schedule is under revision.

Innavik:

- Powerhouse concrete work is completed.
- Powerhouse superstructure is completed at 95%; the envelope will be completed in Q2 2022.
- Transmission line permit has been received and construction should start in Q2 2022.
- Conversion of the Office municipal d'habitation Kativik (OMHK) residences has started and is progressing as per schedule. Work was halted during winter and will resume in Q2 2022.
- Some delays have been encountered due partly to the pandemic situation.
- Project COD postponed to Q1 2023.

Tonnerre:

- Commissioning and testing works are ongoing.
- Commissioning is expected to be achieved by Q2 2022.

(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 732.2 MW. The table below outlines their status as at the date of this MD&A.

Name (Location)	Type	Gross installed capacity (MW)	PPA term (years)	Expected COD
Frontera (Chile)	Hydro	109.0	— [1]	— [6]
Rucacura (Chile)	Hydro	3.0	— [1]	2025
Lazenay (France)	Wind	9.0	— [1]	2023
Auxy Bois Régnier (France)	Wind	29.4	20	2024
Boswell Springs (Wyoming, U.S.)	Wind	331.8	30 [2]	2024
Paeahu (Hawaii, U.S.)	Solar	15.0 [3]	25	— [6]
Kahana (Hawaii, U.S.)	Solar	20.0 [3]	25	— [6]
Barbers Point (Hawaii, U.S.)	Solar	15.0 [3]	25	— [6]
Palomino (Ohio, U.S.)	Solar	200.0	15	2025
Salvador Battery Storage (Chile)	Storage	— [4]	—	2023
San Andrés Battery Storage (Chile)	Storage	— [5]	—	2023

1. Power to be sold on the open market or through PPAs yet to be signed.
2. The project 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.
3. Solar project with a battery storage capacity of 15 MW/60 MWh (4 hours) for Paeahu, 20 MW/80 MWh (4 hours) for Kahana and 15 MW/60 MWh (4 hours) for Barbers Point.
4. Battery storage capacity of 50 MW / 250 MWh (5 hours).
5. Battery storage capacity of 35 MW/175 MWh (5 hours).
6. Project schedule under revision.

Frontera
- Construction contract and permitting are progressing slowly, awaiting decisions on financial items.
- Project schedule is under revision.

Rucacura
- Due to supply chain issues, the electromechanical components delivery has been delayed. COD is still expected in 2025.

Auxy Bois Régnier
- 20-year PPA with EDF-OA obtained on February 23, 2022.
- Interconnection request was made.
- Environmental approval given, but recourse procedures against it were initiated.

Boswell Springs
- PPA negotiations are underway and are expected to be completed in Q2 2022.
- Procurement of turbines has been secured.
- EPC contractor selection process is in progress.
- Permitting is nearing completion.

Paeahu
- The project has been delayed by an unfavourable decision at the circuit court regarding the county special use permit due to local opposition. The project commenced a new proceeding with the Maui County Planning Commission on the required permit in April 2022.
- PPA was approved by the Public Utilities Commission ("PUC") on October 5, 2020. The project received a favourable decision at the Hawaii Supreme Court on March 2, 2022, upholding the PUC approval of the PPA.
- Project plans to use the maximum 148 days extension allowed in the PPA to reach COD. .
- Overhead Line Approval process remains under temporary suspension; the review may be reinstated by end of Q2 2022 as the Hawaii Supreme Court ruled in favour of the PPA.
- Project schedule is under revision and partial re-design may be required due to a Force majeure notice received from the battery supplier regarding supply chain issues and the recent decision by the U.S.

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Department of Commerce to initiate anticircumvention inquiries into the import of solar panels from Asian countries, which has the potential to result in retroactive tariffs on silicon PV modules. The PPA offtaker was notified of the Force Majeure condition and tariff impacts which will require amendments to the PPA.

Kahana

- PPA was approved by the Hawaii PUC on January 5, 2022.
- Overhead Line approval process is underway and expected to be concluded per the indicated PUC schedule.
- Discretionary permit applications were filed at the end of March 2022.
- Project schedule is under revision due to a Force majeure notice received from the battery supplier regarding supply chain issues and the recent decision by the U.S. Department of Commerce to initiate anticircumvention inquiries into the import of solar panels from Asian countries, which has the potential to result in retroactive tariffs on silicon PV modules. The PPA offtaker was notified of the Force Majeure condition and tariff impacts, which may require amendments to the PPA

Barbers Point

- Final Environmental Assessment and Findings of No Significant Impact was published on January 8, 2022. Discretionary permitting applications in preparation.
- PPA was approved by the Hawaii PUC on March 24, 2022.
- Project schedule is under revision due to a Force majeure notice received from the battery supplier regarding supply chain issues and to the recent decision by the U.S. Department of Commerce to initiate anticircumvention inquiries into the import of solar panels from Asian countries, which has the potential to result in retroactive tariffs on silicon PV modules. The PPA offtaker has been notified that the project would not proceed without further PPA amendments.

Palomino

- State permitting application was accepted and public hearings to begin in Q2 2022.
- Interconnection studies review progressed to final stage.

Salvador Battery Storage

- The contract for the supply of the Battery Energy Storage Systems has been signed.
- The Environmental Qualification Resolution was approved on April 13, 2022.

San Andrés Battery Storage

- The contract for the supply of the Battery Energy Storage Systems has been signed.

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 (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 their development maturity leading to obtaining a final notice to proceed to construction phase combined with a success probability factor that the project will reach COD. 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** development maturity combined with a **LOW** success probability factor; or a **MID**-stage development maturity combined with a **LOW** success probability factor.
Mid Stage	The prospective projects in this category have a **MID**-stage development maturity combined with a **MEDIUM** success probability factor; or a **HIGH**-stage development maturity combined with a **MEDIUM** success probability factor.
Advanced Stage	The prospective projects in this category have a **HIGH** development maturity combined with a **HIGH** success probability factor; or a **MID**-stage development 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	15	—	—	—	—	500	15
Solar	280	5	—	—	—	—	280	5
Wind	1,963	12	1,600	4	—	—	3,563	16
Subtotal	2,743	32	1,600	4	—	—	4,343	36
UNITED STATES								
Solar	639	7	609	3	120	1	1,368	11
Wind	—	—	400	1	—	—	400	1
Green hydrogen[2]	5	1	—	—	—	—	5	1
Subtotal	644	8	1,009	4	120	1	1,773	13
FRANCE								
Solar	—	—	—	—	85	1	85	1
Wind	61	4	44	2	149	8	254	14
Subtotal	61	4	44	2	234	9	339	15
CHILE								
Hydro	29	2	—	—	154	1	183	3
Solar	32	1	—	—	—	—	32	1
Wind	9	1	—	—	—	—	9	1
Subtotal	70	4	—	—	154	1	224	5
Total	3,518	48	2,653	10	508	11	6,679	69

1. Only Gross Installed Capacity is disclosed for Prospective Projects as the net capacity is not yet defined at this stage.
2. In this table, the electrolyser was attributed to the United States until additional progress is achieved. The production is estimated at 800,000 kg per year, which corresponds to approximately 5 MW based on current assumptions.

Compared to Q4 2021, the Salvador battery storage project in Chile moved from the advanced stage to the development activities. In Canada, new projects were added to Mid-Stage to respond to the future request for proposals announced by the Quebec government. Other changes were made following the annual reassessment of all the prospective projects pipeline.

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

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS

	Three months ended March 31					
	2022	2021	February 2021 Texas Events (9 days)[3]	2021 Normalized[3]	Change	
Revenues	188,723	189,651	(54,967)	134,684	54,039	40 %
Operating expenses	40,038	30,993	—	30,993	9,045	29 %
General and administrative expenses	14,139	9,750	—	9,750	4,389	45 %
Prospective projects expenses	4,020	5,789	—	5,789	(1,769)	(31)%
Adjusted EBITDA[1]	130,526	143,119	(54,967)	88,152	42,374	48 %
Adjusted EBITDA margin[1]	69.2 %	75.5 %	(10.0)%	65.5 %		
Finance costs	66,401	59,600	—	59,600	6,801	11 %
Other net income	(20,129)	(11,904)	—	(11,904)	(8,225)	69 %
Depreciation and amortization	80,231	58,885	—	58,885	21,346	36 %
Share of losses (earnings) of joint ventures and associates:[2]						
Share of losses (earnings), before impairment charges	2,208	95,375	(64,197)	31,178	(28,970)	(93)%
Share of impairment charges	—	112,609	—	112,609	(112,609)	(100)%
Change in fair value of financial instruments	40,515	87,709	(72,060)	15,649	24,866	159 %
Income tax (recovery) expense	(3,770)	(41,283)	17,071	(24,212)	20,442	(84)%
Net (loss) earnings	(34,930)	(217,872)	64,219	(153,653)	118,723	(77)%
Net loss attributable to:						
Owners of the parent	(34,402)	(214,161)	64,219	(149,942)	115,540	(77)%
Non-controlling interests	(528)	(3,711)	—	(3,711)	3,183	(86)%
	(34,930)	(217,872)	64,219	(153,653)	118,723	(77)%
Basic and diluted net loss per share attributable to owners ($)	(0.18)	(1.24)	0.37	(0.87)		

1. Adjusted EBITDA and Adjusted EBITDA Margin are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
2. Some facilities are treated as joint ventures and associates and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues.
3. For the three months ended March 31, 2021, the Financial Performance and Operating Results are normalized to exclude the impacts of the February 2021 Texas Events. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

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

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Hydroelectric Segment

	Three months ended March 31		
Hydroelectric Segment	2022	2021	Change
Production (MWh)	474,923	313,060	52 %
LTA (MWh)	538,432	369,682	46 %
Revenues (in $M)	65,911	26,570	148 %
Operating, general and administrative expenses	19,281	12,080	60 %
Adjusted EBITDA (in $M)[1]	46,630	14,490	222 %
Adjusted EBITDA Margin[1]	70.7 %	54.5 %	
PROPORTIONATE[1]			
Production Proportionate (MWh)	489,568	351,152	39 %
Revenues Proportionate (in $M)	69,142	30,909	124 %
Adjusted EBITDA Proportionate (in $M)	47,771	15,997	199 %
Adjusted EBITDA Margin Proportionate	69.1 %	51.8 %	

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

For the three-month period ended March 31, 2022, the increase of 148% in Revenues in the hydroelectric segment compared with the same period last year is mainly explained by the acquisition of Curtis Palmer completed on October 25, 2021, and of the remaining 50% interest in Energía Llaima on July 9, 2021, for which results are now included in Innergex's consolidated revenues. The increase is also explained by the BC Hydro Curtailment Payment combined with higher production at the facilities in British Columbia. The increase of 60% in Operating, general and administrative expenses is explained by higher maintenance costs at some facilities in British Columbia following the flooding that occured at the end of 2021, higher expenses following the acquisition of Curtis Palmer and from the Chilean facilities following the acquisition of the remaining 50% interest in Energía Llaima. As a result, the Adjusted EBITDA[1] increased by 222% to $46.6 million. The Adjusted EBITDA Margin[1] was up from 54.5% to 70.7%, mainly explained by the BC Hydro Curtailment Payment.

For the three-month period ended March 31, 2022, the increase in Revenues Proportionate[1] was partly offset by the joint ventures' and associates' hydroelectric facilities' Revenues, which decreased compared to the same period last year explained by a lower contribution from the Chilean facilities since their results are now included in the Corporation's consolidated results, following the acquisition of the remaining 50% interest in Energía Llaima, partly offset by the BC Hydro Curtailment Payment at the Jimmie Creek facility. The proportionate impact of joint ventures' and associates' on operating, general and administrative expenses decreased mainly at the Chilean facilities for the reason previously stated. As a result, the Adjusted EBITDA Proportionate[1] increased by 199% to $47.8 million.

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

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Wind Segment

	Three months ended March 31				
Wind Segment	2022	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized[2]	Change
Production (MWh)	1,563,061	1,296,188	—	1,296,188	21 %
LTA (MWh)	1,578,983	1,364,691	—	1,364,691	16 %
Revenues (in $M)	105,897	116,013	(16,801)	99,212	7 %
Operating, general and administrative expenses	16,421	16,390	—	16,390	— %
Adjusted EBITDA (in $M)[1]	89,476	99,623	(16,801)	82,822	8 %
Adjusted EBITDA Margin[1]	84.5 %	85.9 %	(2.4)%	83.5 %	
PROPORTIONATE[1]					
Production Proportionate (MWh)	1,601,843	1,518,873	—	1,518,873	5 %
Revenues Proportionate (in $M)	130,059	183,254	(57,107)	126,147	3 %
Adjusted EBITDA Proportionate (in $M)	112,720	163,590	(57,107)	106,483	6 %
Adjusted EBITDA Margin Proportionate	86.7 %	89.3 %	(4.9)%	84.4 %	

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

For the three-month period ended March 31, 2022, Revenues increased by 7% in the wind power generation segment compared with the same period last year for which Revenues were normalized to exclude the February 2021 Texas Events. The increase is due to the facilities in Quebec mainly explained by higher production and the commissioning of the Griffin Trail facility on July 26, 2021. The increase was partly offset by lower average selling prices at the Foard City facility. The Operating, general and administrative expenses are stable due to higher operating expenses following the commissioning of the Griffin Trail facility, mainly offset by lower variable expenses following lower revenues at the Foard City facility. As a result, the Adjusted EBITDA[1] increased by 8% to $89.5 million, compared with the same period last year for which the Adjusted EBITDA[1] was normalized to exclude the February 2021 Texas Events. The Adjusted EBITDA Margin[1] was up from 83.5% to 84.5%, on a normalized basis, explained by higher revenues at the Quebec facilities.

For the three-month period ended March 31, 2022, the increase in Revenues Proportionate[1] was partly offset by the joint ventures' and associates' wind farms' Revenues which decreased compared with the same period last year for which Revenues were normalized to exclude the February 2021 Texas Events. The decrease is explained by the Flat Top and Shannon facilities for which results have been excluded from April 1, 2021 onwards, following the February 2021 Texas Events, until their effective disposal on December 28, 2021 and March 4, 2022, respectively. The proportionate impact of joint ventures' and associates' on operating, general and administrative expenses decreased for the same reason stated above.

The Production Tax Credits ("PTCs") generated by the wind farms increase, in the three-month period ended March 31, 2022, is explained by the PTCs earned at the Griffin Trail facility following its commissioning on July 26, 2021. The increase is partly offset by lower PTCs earned at the Flat Top and Shannon facilities for which results have been excluded from April 1, 2021, onward, following the February 2021 Texas Events, until their effective disposal on December 28, 2021, and March 4, 2022, respectively. As a result, the Adjusted EBITDA Proportionate[1] increased by 6% to $112.7 million.

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

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Solar Segment

	Three months ended March 31				
Solar Segment	2022	2021	February 2021 Texas Events (9 days)[2]	2021 Normalized[2]	Change
Production (MWh)	266,616	176,699	—	176,699	51 %
LTA (MWh)	316,715	212,520	—	212,520	49 %
Revenues (in $M)	16,915	47,068	(38,166)	8,902	90 %
Operating, general and administrative expenses	5,605	2,993	—	2,993	87 %
Adjusted EBITDA (In $M)[1]	11,310	44,075	(38,166)	5,909	91 %
Adjusted EBITDA Margin[1]	66.9 %	93.6 %	(27.2)%	66.4 %	
PROPORTIONATE[1]					
Production Proportionate (MWh)	266,616	179,596	—	179,596	48 %
Revenues Proportionate (In $M)	16,915	47,572	(38,166)	9,406	80 %
Adjusted EBITDA Proportionate (In $M)	11,310	44,373	(38,166)	6,207	82 %
Adjusted EBITDA Margin Proportionate	66.9 %	93.3 %	(27.3)%	66.0 %	

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

For the three-month period ended March 31, 2022, Revenues increased 90% in the solar power generation segment compared with the same period last year, for which Revenues were normalized to exclude the February 2021 Texas Events. The increase is mainly attributable to the commissioning of the Hillcrest facility, the San Andrés Acquisition completed on January 28, 2022, and to the contribution of the Pampa Elvira facility following the acquisition of the remaining 50% interest in Energía Llaima on July 9, 2021. The increase of 87% in Operating, general and administrative expenses is explained by higher operating expenses following the commissioning of the Hillcrest facility and the acquisition of the San Andrés and Pampa Elvira facilities. As a result, the Adjusted EBITDA[1] increased by 91% to $11.3 million, compared with the same period last year, for which the Adjusted EBITDA was normalized to exclude the February 2021 Texas Events. The Adjusted EBITDA Margin[1] was up from 66.4% to 66.9%, on a normalized basis, mainly explained by the San Andrés Acquisition, for which margins are higher and partly offset by the Hillcrest commissioning, for which margins are lower.

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

3- FINANCIAL PERFORMANCE AND OPERATING RESULTS | Consolidated Margin

Innergex believes these indicators are important, as they provide management and the reader with additional information about Innergex's operating performance. For more information, please refer to the Non-IFRS Measures section of this MD&A.

For the three-month period ended on March 31, 2022, on a consolidated basis, the Adjusted EBITDA[1] was up 48% from $88.2 million to $130.5 million, compared with the same period last year, for which the Adjusted EBITDA was normalized to exclude the February 2021 Texas Events. The increase stems mainly from the increase in the cumulative segmented Adjusted EBITDA[1] as explained in the previous sections and is partly offset by higher general and administrative expenses to support the business.

The Adjusted EBITDA Margin[1,2], on a normalized basis to exclude the February 2021 Texas Events, was up from 65.5% to 69.2%. This increase is mainly explained by the BC Hydro Curtailment Payment.

For the three-month period ended on March 31, 2022, the Adjusted EBITDA Proportionate Margin[1], on a normalized basis to exclude the February 2021 Texas Events, was up from 68.3% to 71.7%. This increase is explained by higher Adjusted EBITDA margin[1,2].

[1] These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
[2] The Adjusted EBITDA Margin is a measure of Adjusted EBITDA as a percentage of revenues.

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

Net loss of $34.9 million ($0.18 net loss per share - basic and diluted) for the three-month period ended March 31, 2022, compared with a net loss of $217.9 million ($1.24 net loss per share - basic and diluted) for the corresponding period in 2021.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously explained, the $182.9 million decrease in net loss mainly stems from:

- a $205.8 million decrease in the share of loss of joint ventures and associates, mainly related to:
    - the recognition of $112.6 million in impairment charges through the Corporation's share of loss of the Flat Top and Shannon joint venture facilities in 2021;
    - the February 2021 Texas Events, resulting in a net unfavourable impact of $64.2 million on the Flat Top and Shannon joint venture facilities in 2021 (refer to the "February 2021 Texas Events" section of this MD&A for more information);
    - the recognition of a $26.9 million mark-to-market loss through the Corporation's share of loss of the Flat Top and Shannon joint venture facilities in 2021, compared to nil in 2022;
- a $71.5 million favourable movement in the realized portion of changes in fair value of financial instruments mainly stemming from the net unfavourable impact of the February 2021 Texas Events; and
- an $8.2 million increase in other net 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 of 2021.

These items were partly offset by:
- a $37.5 million decrease in recovery of income tax, mainly related to the impacts of the February 2021 Texas Events, and the Flat Top and Shannon impairment charges in 2021.
- an unfavourable $24.3 million unrealized change in the fair value of financial instruments, mainly related to the increase in merchant power curves for the Phoebe power hedge and an unfavourable $21.1 million movement in the unrealized portion of the change in fair value on the Phoebe basis hedge following its maturity in 2021, partly offset by a favourable change in foreign exchange forward curves and interest rate curves, compared with the same period in 2021.
- a $21.3 million increase in depreciation and amortization, mainly attributable to the Energía Llaima and Curtis Palmer acquisitions and the Griffin Trail and Hillcrest commissioning in 2021; and
- a $6.8 million increase in finance costs mainly related to the Griffin Trail and Hillcrest facilities, the Energía Llaima Acquisition, and an increase in inflation compensation interests on the Harrison Hydro real return bonds.

3- FINANCIAL PERFORMANCE ON OPERATING RESULTS | Adjusted Net Loss

The Adjusted Net Loss[1] seeks to provide a measure that eliminates the earnings impacts of certain derivative financial instruments and non-recurring events, which do not represent the Corporation's operating performance. Adjusted Net Loss[1] is not a recognized measure under IFRS, has no standardized meaning prescribed by IFRS and therefore may not be comparable with measures presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.

References to "Adjusted Net Loss[1]" 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, items that are outside of the normal course of the Corporation's cash generating operations 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 Loss[1] (Please refer to the "Non-IFRS Measures" for a reconciliation to the Consolidated Statements of Earnings (Loss):

	Three months ended March 31	
	2022	2021
Revenues	188,723	134,684
Expenses:		
Operating expenses	40,038	30,993
General and administrative expenses	14,139	9,750
Prospective project expenses	4,020	5,789
Adjusted EBITDA[1]	130,526	88,152
Finance costs	66,401	59,600
Other net income	(19,642)	(11,589)
Depreciation and amortization	80,231	58,885
Share of losses of joint ventures and associates	2,630	5,384
Realized gains on power hedges	(270)	(3,654)
Income tax (recovery) expense	3,512	7,066
Adjusted Net Loss [1]	(2,336)	(27,540)

1. Adjusted Net Loss and Adjusted EBITDA 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.

Adjusted Net Loss[1] of $2.3 million for the three-month period ended March 31, 2022, compared with an Adjusted Net Loss[1] of $27.5 million for the corresponding period in 2021.

In addition to the hydroelectric, wind and solar segments' respective operating performance previously explained, the $25.2 million decrease in Adjusted Net Loss[1] mainly stems from:

- an $8.1 million increase in other income mainly related to the PTCs and tax attributes allocated to the tax equity investors at the Griffin Trail wind facility recognized primarily in the year of the commissioning.

These items were partly offset by:

- a $21.3 million increase in depreciation and amortization**,** mainly attributable to the Energía Llaima and Curtis Palmer acquisitions and the Griffin Trail and Hillcrest commissioning in 2021; and
- a $6.8 million increase in finance costs mainly related to the Griffin Trail and Hillcrest facilities, and the Energía Llaima Acquisition.

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

Attribution of loss of $0.5 million to non-controlling interests for the three-month period ended March 31, 2022, compared with an attribution of loss of $3.7 million for the corresponding period in 2021

The $3.2 million decrease in loss attributed to non-controlling interests for the three-month period ended March 31, 2022, is mainly due to:

- the earnings allocated to the non-controlling interests in Innergex HQI USA following the Curtis Palmer Acquisition in the fourth quarter of 2021;
- a favourable unrealized change in the fair value of derivative financial instruments in Innergex Europe; and
- a contractual increase in the percentage of allocation to the non-controlling interests of Mesgi'g Ugju's'n.

These items were partly offset by:

- 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.

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

4- CAPITAL AND LIQUIDITY | Capital Structure

The Corporation's capital structure consists of the following components, as shown below:

	As at March 31, 2022	As at December 31, 2021
Equity[1]		
Common shares[2]	4,056,950	3,580,388
Preferred shares[3]	107,934	109,080
Non-controlling interests	259,875	267,568
	4,424,759	3,957,036
Long-term loans and borrowings[1]		
Corporate revolving credit facility	286,624	398,758
Other corporate debt	295,000	295,000
Project-level debt	3,503,901	3,562,380
Tax Equity financing	438,346	455,967
Convertible debentures	280,842	280,258
Deferred financing costs	(67,509)	(67,928)
	4,737,204	4,924,435
	9,161,963	8,881,471

1.Common and preferred shares are presented at their fair value as at March 31, 2022, and December 31, 2021, while non-controlling interests and long-term loans and borrowings are presented at their respective book value.
2.Consists of the number of common shares outstanding as at March 31, 2022, and December 31, 2021, multiplied by the prevailing share price of $19.88 (2021 - $18.60) at the close of markets.
3.Consists of the number of preferred shares outstanding as at March 31, 2022, and December 31, 2021, multiplied by the prevailing share price of $17.01 and $25.05 (2021 - $17.20 and $25.30), 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 a net favourable change in the share price, and by the shares issued related to the February 2022 public offering and the concurrent Hydro-Québec private placement (refer to the "Information on Capital Stock" section of this MD&A for more information). The preferred shares structure remained consistent compared to December 31, 2021. The fair value was therefore impacted by a net unfavourable change in the preferred shares prices. The decrease in non-controlling interests stems mainly from a distribution allocated to the non-controlling interests during the quarter. The decrease in long-term loans and borrowings is mainly due to the decrease in tax equity financing from PTCs and tax attributes allocated to the TEIs, the repayment of a portion of the corporate revolving credit facility mainly stemming from the public offering and private placement, and scheduled principal repayments on project loans, partly offset by the San Andrés Acquisition purchase, which was financed using the corporate revolving credit facility.

The effective all-in interest rate on the Corporation's long-term loans and borrowings was 4.77% as at March 31, 2022 (4.62% as at December 31, 2021).

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

Credit Agreements – Material Financial and Non-Financial Conditions

As at March 31, 2022, 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 Duqueco hydro project was in breach of the change of control covenant under 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$105.0 million ($131.1 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. On April 25, 2022, a waiver was obtained from the project lenders.

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. The TEIs are allocated a portion of the renewable energy facilites' taxable income (losses), PTCs/ITCs 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.

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 TEIs are obligated to make a cash contribution (“Pay-go Contribution”) to the Corporation. The Pay-go arrangement results in a lower initial investment by the TEI and provides them with some protection from potential underperformance of the asset.

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

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

Production Tax Credit Program ("PTC")

Current United States tax law allows wind energy projects to receive tax credits that are earned for each MWh of generation during the first 10 years of the projects' operation. As at March 31, 2022, the credit amounts to US$27/MWh generated, and subject to annual CPI inflation. Projects that commenced construction[1] before 2017 are eligible for 100% of the credit, decreasing annually by tranches of 20%, to 60% of the credit for projects that commenced construction[1] between January 1 and December 31, 2021. There is no PTC credit for projects that commence construction[1] on or after January 1, 2022. Both Foard City and Griffin Trail were eligible for the full credit.

	Commercial Operation Date	Expected TEI Flip Point[5]	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	44.0	4.6	99.00 %	5.00 %
Griffin Trail[1,2]	2021	2031	210.6	28.1	5.0	99.00 %	5.00 %

1. Before the Flip Point, TEI cash distributions are based on a quarterly test measurement of cumulative generation for the project since commercial operations date. Lower production could result in a higher cash allocation to the TEI or a change to the Flip Point. Figures provided are for 2022.
2. TEIs in U.S. projects generally require certain sponsor guarantees as a condition for their investment. To support the tax equity investments at Foard City and Griffin Trail, 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$27/MWh generated for the period from COD to Flip Point, translated into Canadian dollars at 1.2496. PTCs generation will vary depending on actual production. PTCs are subject to annual CPI inflation.
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 1.2496. Pay-go Contributions will be earned on actual production in excess of a specified annual threshold, subject to a contractual cumulative maximum.
5. Represents the expected TEI Flip Point as estimated at the date of final funding from the TEI. Actual Flip Point may differ, subject to the facilities' respective operating performance.

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 commenced construction[1] before 2021 are eligible for 30% ITC. This credit decreases to 26% for facilities that commence construction[1] in 2021 and 2022, 22% in 2023 and 10% thereafter. Both Phoebe and Hillcrest were eligible for a 30% ITC.

	Commercial Operation Date	Expected TEI Flip Point[7]	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	2026	244.3	67.00 %	10.62% in excess of priority distribution
Hillcrest [1,4,5,6,7]	2021	2028	142.2	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. Phoebe 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$90.4 million ($112.9 million) was received upon commissioning of the project on November 2021.
5. Hillcrest allocation of taxable income (loss) and ITCs is 99.00% to the TEI. From January 1, 2027, allocation of taxable income (loss) to the TEI will be 5.00%
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. Represents the expected TEI Flip Point as estimated at the date of final funding from the TEI. Actual Flip Point may differ, subject to the facilities' respective operating performance.

[1] Specifically, to be eligible for the credit, the regulations stipulate that, for construction to be deemed to have commenced, a project must have either invested 5% of the total cost of the project or started "physical work of a significant nature", and prove that work is continuing on the project.

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

4- CAPITAL AND LIQUIDITY | Financial Position

As at	March 31, 2022	December 31, 2021
ASSETS		
Current assets		
Cash and cash equivalents	201,537	166,266
Restricted cash	51,092	61,659
Investment tax credits recoverable	1,183	1,200
Other current assets	171,929	159,552
Total current assets	425,741	388,677
Non-current assets		
Property, plant and equipment	5,458,219	5,513,392
Intangible assets	998,122	1,043,994
Investments in joint ventures and associates	130,555	133,398
Goodwill	59,772	60,858
Other non-current assets	280,939	255,749
Total non-current assets	6,927,607	7,007,391
Total assets	7,353,348	7,396,068
LIABILITIES		
Current liabilities	718,242	733,527
Non-current liabilities		
Long-term loans and borrowings	4,245,500	4,411,239
Other non-current liabilities	855,197	890,622
Total non-current liabilities	5,100,697	5,301,861
Total liabilities	5,818,939	6,035,388
SHAREHOLDERS' EQUITY		
Equity attributable to owners	1,274,534	1,093,112
Non-controlling interests	259,875	267,568
Total shareholders’ equity	1,534,409	1,360,680
	7,353,348	7,396,068

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

Working Capital Items

As at March 31, 2022, working capital[1] was negative at $292.5 million, from negative $344.9 million in 2021, mainly explained by:

- Current assets amounted to $425.7 million as at March 31, 2022, an increase of $37.1 million compared with December 31, 2021, mainly due to a $35.3 million increase in cash and cash equivalent (see the "Cash Flow" section of this MD&A for more information).

- Current liabilities amounted to $718.2 million as at March 31, 2022, a decrease of $15.3 million compared with December 31, 2021, mainly due to a $21.9 million decrease in the current portion of long-term loans and borrowings, which primarily relates to the resolution of breaches under the Phoebe, Beaumont and Vallottes project loans, partly offset by the classification of the subordinated unsecured term loan as current, following the upcoming maturity on February 6, 2023.

- 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[1] to be sufficient to meet its needs, considering that a total amount of $131.1 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 March 31, 2022, the Corporation had $700.0 million in revolving term credit facility and had drawn $286.6 million as cash advances, while $51.9 million had been used to issue letters of credit, leaving $361.5 million available.

Non-Current Assets

Non-current assets amounted to $6,927.6 million as at March 31, 2022, a decrease of $79.8 million compared with December 31, 2021. The decrease is mainly due to depreciation and amortization of $80.2 million, to the strengthening of the Canadian dollar and to an upward shift in interest rate curves, which contributed to the decrease of the asset retirement obligation included in property, plant and equipement.

These items were partly offset by an increase in property, plant and equipment of $38.7 million following the San Andrés Acquisition. The construction activities also contributed to an increase in property, plant and equipment by an aggregate amount of $37.9 million, net of the ITC recoverable recognized against the project construction costs of Hale Kuawehi. Derivative financial instruments also favourably impacted non-current assets (please refer to the "Financial Position – Derivative Financial Instruments and Risk Management" subsection below for more information).

Non-Current Liabilities

Non-current liabilities amounted to $5,100.7 million as at March 31, 2022, a decrease of $201.2 million compared with December 31, 2021. The decrease is mainly due to a $165.7 million decrease in the non-current portion of long-term loans and borrowings, explained by a $112.1 million net repayment of the revolving credit facility, mainly stemming from the February 2022 public offering and private placement, partly offset by the San Andrés Acquisition. The reclassification of the subordinated unsecured term loan as current following its upcoming maturity on February 6, 2023, and the scheduled principal repayments also contributed in decreasing the non-current portion of long-term loans and borrowings. In addition, the decrease is also explained by a strengthening of the Canadian dollar and an upward shift in interest rate curves, which contributed to the decrease of the asset retirement obligation and of derivative financial instruments' fair values (please refer to the "Financial Position – Derivative Financial Instruments and Risk Management" subsection below for more information).

These items were partly offset by the classification of a project loan as non-current following the resolution of breaches under the Phoebe, Beaumont and Vallottes credit agreements (see the "Capital Structure" section of this MD&A for more information).

[1] Working capital represents the excess or deficiency of current assets over current liabilities.

Shareholders' Equity

As at March 31, 2022, Shareholders' equity increased by $173.7 million compared with December 31, 2021, mainly attributable to the shares issued related to the public offering in February 2022 and the concurrent Hydro-Québec private placement (please refer to the "Information on Capital Stock" section of this MD&A for more information), and the total comprehensive income of $19.8 million, partly offset by the dividends declared on common and preferred shares totalling $38.1 million, and $6.2 million in distributions to non-controlling interests.

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 asset of $6.2 million as at March 31, 2022, from a net liability of $59.4 million as at December 31, 2021. 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 the foreign exchange forward contracts, favourably impacted by a general downward shift in the Euro-Cad forward curve. These items were partly offset by the unfavourable change in the Phoebe power hedge, following an increase in the merchant price curves.

Contingencies

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 cited 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 was allegedly unable to accept or purchase energy under the EPAs. The notices to Innergex followed public statements by BC Hydro regarding measures it was taking to address the reduced electricity demand during the COVID-19 pandemic and related challenges to the safe operation of its hydroelectric system.

Innergex disputed that the pandemic and related governmental measures in any way prevented BC Hydro from fulfilling its obligations to accept and purchase energy under the EPAs or enabled 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 complied with BC Hydro's curtailment request, but did so under protest, seeking 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 amounted to $12.5 million ($14.2 million on a Revenues Proportionate[2] basis). The dispute was settled in the first quarter of 2022 to Innergex's satisfaction.

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

[2] 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.

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 Limited Partnerships have filed their response to petition on April 14, 2020. The hearing took place in Victoria in the last week of September 2020. A decision was rendered on February 9, 2021, by the Supreme Court of British Columbia, which concluded that the Environmental Appeal Board's decision was reasonable, and dismissed the Comptroller of Water Rights' petition accordingly. The Comptroller of Water Rights subsequently appealed the decision of the Supreme Court of British Columbia; the appeal was unanimously dismissed by the British Columbia Court of Appeal on January 7, 2022. The Corporation recognized the amount of $3.2 million in the consolidated statements of earnings (loss) during the year ended December 31, 2019. A total amount of $3.4 million, including interest, was received by the Corporation during the first quarter of 2022.

Off-Balance-Sheet Arrangements

As at March 31, 2022, the Corporation had issued letters of credit totalling $213.7 million, including $51.9 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 $80.6 million in corporate guarantees used mainly to guarantee certain activities of prospective projects. The corporate guarantees 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 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 March 31			
	2022	2021	February 2021 Texas Events (9 days)[1]	2021 Normalized[1]
OPERATING ACTIVITIES				
Cash flows from operating activities	84,858	59,970	(16,801)	43,169
FINANCING ACTIVITIES				
Cash flows from financing activities	3,918	45,185	—	45,185
INVESTING ACTIVITIES				
Cash flows used in investing activities	(50,270)	(81,884)	—	(81,884)
Effects of exchange rate changes on cash and cash equivalents	(3,235)	(3,346)	—	(3,346)
Net change in cash and cash equivalents	35,271	19,925	(16,801)	3,124
Cash and cash equivalents, beginning of period	166,266	161,465	—	161,465
Cash and cash equivalents, end of period	201,537	181,390	(16,801)	164,589

1.Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

Cash Flows from Operating Activities

For the three-month period ended March 31, 2022, cash flows from operating activities totalled $84.9 million, compared with $60.0 million in the same period last year. The increase relates primarily to the contribution from the Energía Llaima, Licán, Curtis Palmer and San Andrés acquisitions, the Hillcrest and Griffin Trail commissioning, and the BC Hydro Curtailment Payment. These items were partly offset by the February 2021 Texas Events, which contributed to a $16.8 million increase in cash flows from operating activities in the comparative period, as the Phoebe solar facility's $33.9 million net payable related to the February 2021 Texas Events remained unpaid until July 19, 2021.

Cash Flows from Financing Activities

For the three-month period ended March 31, 2022, cash flows from financing activities totalled $3.9 million, compared with $45.2 million in the same period last year. The decrease stems mainly from the net $147.4 million repayment of long-term loans and borrowings in 2022, mainly explained by the repayment of the revolving credit facility following the public offering and private placement, partly offset by the San Andrés Acquisition and the additions to property, plant and equipment. This compares with net draws of $84.0 million in 2021, mainly related to the construction of the Griffin Trail and Hillcrest facilities. The decrease was partly offset by the issuance of common shares as part of the public offering and the concurrent private placement to Hydro-Québec in February 2022 for a total amount of $202.2 million.

Cash Flows Used in Investing Activities

For the three-month period ended March 31, 2022, cash flows used in investing activities totalled $50.3 million, compared with $81.9 million in the same period last year. The decrease is mainly due to a decrease in additions to property, plant and equipment, partly offset by the consideration paid toward the San Andrés Acquisition in 2022.

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

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

Free Cash Flow and Payout Ratio calculation[1]	Trailing twelve months ended March 31			
	2022	2021	February 2021 Texas Events (9 days)[4]	2021 Normalized[4]
Cash flows from operating activities[5]	290,386	276,045	(16,801)	259,244
Add (Subtract) the following items:				
Changes in non-cash operating working capital items	47,411	(34,821)	33,894	(927)
Maintenance capital expenditures, net of proceeds from disposals	(7,719)	(3,531)	—	(3,531)
Scheduled debt principal payments	(163,323)	(151,609)	—	(151,609)
Free Cash Flow attributed to non-controlling interests[2]	(34,297)	(15,701)	—	(15,701)
Dividends declared on Preferred shares	(5,632)	(5,865)	—	(5,865)
Add (subtract) the following specific items[3]*:*				
Realized loss on contingent considerations	—	3,568	—	3,568
Realized (gain) loss on termination of interest rate swaps	(377)	2,885	—	2,885
Transaction costs related to realized acquisitions	6,744	1,664	—	1,664
Realized (gain) loss on the Phoebe basis hedge	(3,745)	1,127	(1,304)	(177)
Free Cash Flow[4]	129,448	73,762	15,789	89,551
Dividends declared on common shares	137,517	125,649	—	125,649
Payout Ratio[4]	106 %	170 %	(30)%	140 %
Adjust for the following items:				
Prospective projects expenses	25,598			18,858
Adjusted Free Cash Flow	155,046			108,409
Adjusted Payout Ratio	89 %			116 %

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. These items are excluded from the Free Cash Flow and Payout Ratio calculations as they are deemed not representative of the Corporation's long-term cash-generating capacity, and include items such as gains and losses on the Phoebe basis hedge due to their limited occurrence (maturity attained on December 31, 2021), realized gains and losses on contingent considerations related to past business acquisitions, transaction costs related to realized acquisitions, realized losses or gains on refinancing of certain borrowings or derivative financial instruments used to hedge the interest rate on certain borrowings or the exchange rate on equipment purchases, and tax payments related to fiscal strategies for the purpose of improving the long-term cash generating capacity of Innergex.
4. For the trailing twelve months ended March 31, 2021, the Free Cash Flow and Payout Ratio are normalized to exclude the impacts of the February 2021 Texas Events. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.
5. Cash flows from operating activities for the trailing twelve months ended March 31, 2022 include the one-time BC Hydro Curtailment Payment received during the first quarter of 2022.

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

Free Cash Flow

For the trailing twelve months ended March 31, 2022, the Corporation generated Free Cash Flow[1] of $129.4 million, compared with $73.8 million for the corresponding period last year (Normalized Free Cash Flow[1,2] of $89.6 million, when excluding the impacts from the February 2021 Texas Events - refer to the "February 2021 Texas Events" section of this MD&A for more information).

Free Cash Flow[1] increased $39.9 million compared with Normalized Free Cash Flow[1,2] in the comparative period, mainly due to:

- the contribution to cash flows from operating activities before changes in non-cash operating working capital items from the Energía Llaima, Licán, Curtis Palmer and San Andrés acquisitions, the Hillcrest and Griffin Trail commissioning, and the full year impact of the Mountain Air and Salvador acquisitions realized in 2020; and
- an increase in revenues from the the BC Hydro Curtailment Payment.

These items were partly offset by:

- an increase in debt principal payments stemming from the Energía Llaima Acquisition in the third quarter of 2021 and the beginning of debt principal repayment for the Upper Lillooet/Boulder Creek project loan;
- an increase in Free Cash Flow attributed to non-controlling interests, stemming mainly from the Curtis Palmer Acquisition and the full year impact of the Mountain Air Acquisition realized in 2020; 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.

Payout Ratio

For the trailing twelve months ended March 31, 2022, the dividends on common shares declared by the Corporation amounted to 106% of Free Cash Flow[1], compared with 170% for the corresponding period last year. Excluding the impacts from the February 2021 Texas Events (please refer to the "February 2021 Texas Events" section of this MD&A for more information), the dividends on common shares declared by the Corporation amounted to 140% of Normalized Free Cash Flow[1,2].

1 Free Cash Flow 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.

2 Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "February 2021 Texas Events" section for more information.

4- CAPITAL AND LIQUIDITY | Information on Capital Stock

The Corporation’s Equity Securities

	As at		
	May 9, 2022	March 31, 2022	December 31, 2021
Number of common shares	204,103,658	204,071,907	192,493,999
Number of 4.75% convertible debentures	148,023	148,023	148,023
Number of 4.65% convertible debentures	142,056	142,056	142,056
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	316,922	316,922	265,570

As at the closing of the market on May 9, 2022, and since March 31, 2022, the increase in the number of common shares of the Corporation is attributable mainly to the issuance of 31,751 common shares related to the Corporation's Dividend Reinvestment Plan ("DRIP").

As at March 31, 2022, the increase in the number of common shares since March 31, 2021, was mainly due to the following:

- the issuance of 9,718,650 common shares as part of the public offering closed on February 22, 2022. Concurrently with the closing of the offering, the Corporation issued 2,100,000 common shares to Hydro-Québec to maintain its ownership;
- the issuance of 12,939 common shares related to the DRIP.

These items were partly offset by:

- the 253,681 common shares purchased and cancelled by the Corporation under the Normal Course Issuer Bid renewed on May 24, 2021, (the "New Bid"), at an average price of $18.08 per share for a total cash consideration of $10.2 million.

(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 March 31	
	2022	2021
Dividends declared on common shares[1]	36,733	31,445
Dividends declared on common shares ($/share)	0.180	0.180
Dividends declared on Series A Preferred Shares	689	689
Dividends declared on Series A Preferred Shares ($/share)	0.202750	0.202750
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 offerings, Hydro-Québec private placements, and to the issuance of common shares under the DRIP, partly offset by common shares purchased and cancelled under the NCIB.

The following dividends will be paid by the Corporation on July 15, 2022:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
May 10, 2022	June 30, 2022	July 15, 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. Revenues Proportionate, Adjusted EBITDA, Adjusted EBITDA Margin, Adjusted EBITDA Proportionate, Adjusted EBITDA Margin Proportionate, Adjusted Net 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.

Revenues Proportionate, Adjusted EBITDA and corresponding Margin and Proportionate measures

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 "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. Adjusted EBITDA is used by investors to evaluate the operating performance and cash generating operations, and to derive financial forecasts and valuations. Revenues Proportionate and Adjusted EBITDA Proportionate measures are used by investors to evaluate the contribution of the joint-ventures and associates to the Corporation’s operating performance and cash generating operations, and the contribution of such for financial forecasts and valuations purposes. In addition, Revenues Proportionate and Adjusted EBITDA Proportionate measures help investors seize the relative importance of PTCs generated by the operations, and evaluate their contribution to the Corporation’s operating performance, as PTCs form an important part of certain wind projects’ economics in the United States. Adjusted EBITDA Margin and Adjusted EBITDA Margin Proportionate are used by investors to understand the relative weight of certain jurisdictions, which are subject to various competitive and energy pricing environments, to the Corporation’s and its reportable segments’ operating performance. Readers are cautioned that Revenues Proportionate, should not be construed as an alternative to Revenues, as determined in accordance with IFRS. Readers are also cautioned that Adjusted EBITDA, 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.

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

	Three months ended March 31, 2022				Three months ended March 31, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	188,723	8,346	19,047	216,116	189,651	54,661	17,423	261,735
Net loss	(34,930)	—	—	(34,930)	(217,872)	—	—	(217,872)
Income tax (recovery) expense	(3,770)	—	—	(3,770)	(41,283)	773	—	(40,510)
Finance costs	66,401	4,424	—	70,825	59,600	9,095	—	68,695
Depreciation and amortization	80,231	4,195	—	84,426	58,885	8,955	—	67,840
Impairment of long-term assets	—	—	—	—	—	112,609	—	112,609
EBITDA	107,932	8,619	—	116,551	(140,670)	131,432	—	(9,238)
Other net income, before PTCs	(1,082)	(175)	—	(1,257)	(515)	1,601	—	1,086
Production tax credits ("PTCs")	(19,047)	—	19,047	—	(11,389)	(6,034)	17,423	—
Share of losses of joint ventures and associates	2,208	(2,208)	—	—	207,984	(207,984)	—	—
Change in fair value of financial instruments	40,515	(898)	—	39,617	87,709	129,334	—	217,043
Adjusted EBITDA	130,526	5,338	19,047	154,911	143,119	48,349	17,423	208,891
Adjusted EBITDA Margin	69.2 %	64.0 %		71.7 %	75.5 %	88.5 %		79.8 %

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

Adjusted Net Loss

References to "Adjusted Net Loss" are to net earnings or losses of the Corporation, to which the following elements are added (subtracted): unrealized portion of the change in fair value of derivative 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, items that are outside of the normal course of the Corporation's cash generating operations such as the February 2021 Texas Events, the net income tax expense (recovery) related to these items, and the share of loss (earnings) of joint ventures and associates related to the above items, net of related income tax.

The Adjusted Net Loss seeks to provide a measure that eliminates the earnings impacts of certain derivative financial instruments and other items that are outside of the normal course of the Corporation's cash generating operations, 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. Adjusted Net Loss is used by investors to evaluate and compare Innergex's profitability before the impacts of unrealized portion of the change in fair value of derivative financial instruments and other items that are outside of the normal course of the Corporation's cash generating operations. Readers are cautioned that Adjusted Net Loss should not be construed as an alternative to net earnings, as determined in accordance with IFRS. Please refer to the "Operating Results" section for reconciliation of the Adjusted Net Loss.

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

	Three months ended March 31	
	2022	2021
Net loss	(34,930)	(217,872)
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	(660)	20,437
Unrealized portion of the change in fair value of financial instruments	40,785	16,523
Realized loss on termination of interest rate swaps	—	2,885
Realized loss on the Phoebe basis hedge	—	1,199
Realized gain on foreign exchange forward contracts	(487)	(315)
Income tax recovery related to above items	(7,044)	(42,992)
Adjusted Net loss	(2,336)	(27,540)

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

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

	Three months ended March 31					
	2022			2021		
	IFRS	Adj.	Non-IFRS	IFRS	Adj.	Non-IFRS
Revenues	188,723	—	188,723	189,651	(54,967)	134,684
Operating expenses	40,038	—	40,038	30,993	—	30,993
General and administrative expenses	14,139	—	14,139	9,750	—	9,750
Prospective projects expenses	4,020	—	4,020	5,789	—	5,789
Adjusted EBITDA	130,526	—	130,526	143,119	(54,967)	88,152
Finance costs	66,401	—	66,401	59,600	—	59,600
Other net income	(20,129)	487	(19,642)	(11,904)	315	(11,589)
Depreciation and amortization	80,231	—	80,231	58,885	—	58,885
Share of losses (earnings) of joint ventures and associates	2,208	422	2,630	207,984	(202,600)	5,384
Change in fair value of financial instruments	40,515	(40,785)	(270)	87,709	(91,363)	(3,654)
Income tax (recovery) expense	(3,770)	7,282	3,512	(41,283)	48,349	7,066
Net (loss) earnings	(34,930)	32,594	(2,336)	(217,872)	190,332	(27,540)

(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, realized gains and losses on contingent considerations related to past business acquisitions, transaction costs related to realized acquisitions, realized losses or gains on refinancing of certain borrowings or derivative financial instruments used to hedge the interest rate on certain borrowings or the exchange rate on equipment purchases, and tax payments related to fiscal strategies for the purpose of improving the long-term cash generating capacity of Innergex.

The Payout Ratio is a measure of the Corporation's ability to sustain current dividends as well as its ability to fund its growth from its cash generating operations, in the normal course of business. 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. Free Cash Flow is used by investors in this regard. 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. Adjusted Free Cash Flow is used by investors to evaluate the Corporation's cash generation capabilities and its ability to sustain current dividends, before the impacts of the Corporation's decision to invest yearly in its growth through investing in the development of its Prospective Projects.

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. Payout Ratio is used by investors in this regard.

References to "Adjusted Payout Ratio" are to dividends declared on common shares divided by Adjusted Free Cash Flow. Adjusted Payout Ratio is used by investors to evaluate the Corporation's ability to sustain current dividends, before the impacts of the Corporation's decision to invest yearly in its growth through investing in the development of its Prospective Projects.

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

	As at	
	March 31, 2022	December 31, 2021
Non-current assets, excluding derivative financial instruments and deferred tax assets[1]		
Canada	3,328,145	3,390,029
United States	2,258,391	2,301,353
France	753,440	801,752
Chile	463,191	423,856
	6,803,167	6,916,990

1. Includes the investments in joint ventures and associates.

6- ADDITIONAL CONSOLIDATED INFORMATION | Geographic Segments – Revenues

	Three months ended March 31	
	2022	2021
Revenues		
Canada	105,007	83,150
United States	43,313	76,033
France	27,396	28,368
Chile	13,007	2,100
	188,723	189,651

(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 March 31, 2022	Dec 31, 2021	Sept 30, 2021	June 30, 2021	March 31, 2021	Dec 31, 2020	Sept 30, 2020	June 30, 2020
Production (MWh)	2,304,600	2,583,157	2,290,086	2,396,027	1,785,947	2,186,961	2,021,559	2,185,793
Revenues	188.7	202.4	184.6	170.6	189.7	167.9	162.7	150.5
Operating, general and administrative and prospective projects expenses	58.2	65.1	62.1	47.9	46.6	50.1	54.2	45.2
Adjusted EBITDA[1]	130.5	137.3	122.5	122.7	143.1	117.8	108.5	105.3
Net (loss) earnings	(34.9)	5.7	(23.5)	50.2	(217.9)	11.9	7.5	(1.6)
Net (loss) earnings attributable to owners of the parent	(34.4)	(2.3)	(16.4)	41.1	(214.2)	11.9	11.7	(2.5)
Net (loss) earnings attributable to owners of the parent ($ per share – basic and diluted)	(0.18)	(0.02)	(0.10)	0.23	(1.24)	0.06	0.06	(0.02)
Dividends declared on common shares	36.7	34.6	34.7	31.4	31.4	31.4	31.4	31.4
Dividends declared on common shares, $ per share	0.180	0.180	0.180	0.180	0.180	0.180	0.180	0.180

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

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. 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 facility is subject to power hedges. In addition, prior to their sale on December 28, 2021 and March 4, 2022, respectively, the Flat Top and Shannon facilities were also subject to power hedges. For facilities subject to power hedges, the power that is generated by the facility is delivered to the grid at the project's node (point of delivery) at the prevailing merchant prices. Production delivered at the node at merchant prices is recognized by Innergex as revenue. Under the power hedges, the hourly contracted energy is virtually purchased at the point of withdrawal on the grid ("hub"), subject to the prevailing merchant prices, and exchanged for the contractual fixed price per MWh. Settlements under the power hedges are recognized as change in fair value of financial instruments.

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

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

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.

(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:

	Three months ended March 31, 2021				
	Hydro	Wind	Solar	Unallocated	Total
Revenues	26,570	116,013	47,068	—	189,651
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Revenues[2]	26,570	99,212	8,902	—	134,684
Revenues Proportionate[1]	30,909	183,254	47,572	—	261,735
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Revenues Proportionate[1,2]	30,909	126,147	9,406	—	166,462
Adjusted EBITDA[1]	14,490	99,623	44,075	(15,069)	143,119
Impacts from the February 2021 Texas Events	—	(16,801)	(38,166)	—	(54,967)
Normalized Adjusted EBITDA[1,2]	14,490	82,822	5,909	(15,069)	88,152
Adjusted EBITDA Proportionate[1]	15,997	163,590	44,373	(15,069)	208,891
Impacts from the February 2021 Texas Events	—	(57,107)	(38,166)	—	(95,273)
Normalized Adjusted EBITDA Proportionate[1,2]	15,997	106,483	6,207	(15,069)	113,618

1. These measures 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. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers.

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 year ended December 31, 2021, the February 2021 Texas Events, whose cash impacts are detailed above, have impacted the Free Cash Flow[1] and Payout Ratio[1] as follows:

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

1. Free Cash Flow and Payout ratio measures 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. Normalized measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers.

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

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

(2) In the Free Cash Flow[1] and Payout Ratio[1] calculation, Innergex reverses the impacts of the Phoebe basis hedge due to its limited occurrence, 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.

1. Free Cash Flow and Payout ratio measures 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.

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[2] in this region. While the other key assumptions remained largely consistent as compared to December 31, 2020, the 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%.

2. 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

- During the year ended December 31, 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

- The carrying amount of the Flat Top and Shannon investments was decreased to nil following the aggregate $112.6 million non-cash impairment charges on these facilities as at March 31, 2021.
- During the period ended June 30, 2021, the underlying assets and liabilities of the Flat Top and Shannon investments were classified as disposal groups held for sale.
- 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.
- On December 28, 2021, the Corporation completed the sale of its 51% interest in Flat Top for a nominal amount.
- On March 4, 2022, the Corporation completed the sale of its 50% interest in Shannon for a nominal amount.
- The impact of the sale of the Flat Top and Shannon facilities on the Corporation's Free Cash Flow[1], based on the facilities' respective 2020 contribution, represents a loss of approximately $4.2 million annually.
- The sale of the Flat Top and Shannon facilities 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 had funded through an equity contribution in the facilities.

1. Free Cash Flow and Payout ratio measures 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.

7- ACCOUNTING POLICIES AND DISCLOSURE CONTROLS | Significant Accounting Policies

New Accounting Standards and Interpretations Adopted During the Year

On January 1, 2022, the Corporation adopted the following new standards and interpretations:

Amendments to IAS 16, Property, Plant and Equipment - Proceeds before Intended Use

On May 14, 2020, the IASB issued *Property, Plant and Equipment — Proceeds before Intended Use* (Amendments to IAS 16). The amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. The amendments are effective for annual reporting periods commencing on or after January 1, 2022. The Corporation adopted the amendments on January 1, 2022, with no impact to the unaudited 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 beginning on January 1, 2022, and ended on March 31, 2022, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

The President and Chief Executive Officer and the Chief Financial Officer have also limited the scope of the Corporation's design of DC&P and ICFR to exclude the controls, policies and procedures of the Curtis/Palmer Hydroelectric Company LP and Energía Llaima SpA (collectively "entities excluded from the Corporation's control policies and procedures"). The evaluation of the design and the operating effectiveness of the DC&P and ICFR for these entities will be completed in the 12 months following their dates of acquisition. A summary of the financial information about the entities excluded is presented in the "Entities Excluded from The Corporation's Control Policies and Procedures" section of this MD&A.

7- ACCOUNTING POLICIES AND DISCLOSURE CONTROLS | Entities excluded from the Corporation's control, policies and procedures

As stated in the "Disclosure Controls and Procedures" section of this MD&A, the scope of the Corporation's design of DC&P and ICFR exclude the controls, policies and procedures of the Curtis/Palmer Hydroelectric Company LP and Energía Llaima SpA. The following tables present a summary of the entities excluded from the Corporation's control policies and procedures:

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

	For the period ended March 31, 2022[1]
Revenues	28,108
Net earnings	2,654
Other comprehensive loss	(3,040)
Total comprehensive loss	(386)

1. Includes the combined results of San Andrés for a 62-day period ended March 31, 2022, respectively.

Summary Statement of Financial Position

	As at March 31, 2022
Current assets	127,849
Non-current assets	813,054
	940,903
Current liabilities	180,543
Non-current liabilities	106,454
Equity	653,906
	940,903

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

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 growth targets, 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 targeted production, the estimated targeted revenues, targeted Revenues Proportionate, targeted Adjusted EBITDA and targeted Adjusted EBITDA Proportionate, targeted Free Cash Flow, targeted 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 and of the Corporation's ability to sustain current dividends and to fund its growth. Such information may not be appropriate for other purposes.

Assumptions: Forward-Looking Information is based on certain key assumptions made by the Corporation, including, without restriction, those concerning hydrology, wind regimes and solar irradiation; performance of operating facilities, acquisitions and commissioned projects; project performance; availability of capital resources and timely performance by third parties of contractual obligations; favourable market conditions for share issuance to support growth financing; favourable economic and financial market conditions; the Corporation’s success in developing and constructing new facilities; successful renewal of PPAs; sufficient human resources to deliver service and execute the capital plan; no significant event occurring outside the ordinary course of business such as a natural disaster, pandemic or other calamity; continued maintenance of information technology infrastructure and no material breach of cybersecurity. Please refer to Section 5 - Outlook of this MD&A for details regarding the assumptions used with respect to the 2022 growth targets and outlook for the 2020-2025 Strategic Plan.

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: performance of major counterparties; equipment supply; delays and cost overruns in the design and construction of projects; health, safety and environmental risks; equipment failure or unexpected operations and maintenance activity; variability of installation performance and related penalties; increase in water rental cost or changes to regulations applicable to water use; availability and reliability of transmission systems; assessment of water, wind and solar resources and associated electricity production; global climate change; variability in hydrology, wind regimes and solar irradiation; preparedness to facing natural disasters and force majeure; pandemics, epidemics or other public health emergencies; cybersecurity; reliance on shared transmission and interconnection infrastructure; inability of the Corporation to execute its strategy for building shareholder value; inability to raise additional capital and the state of the capital market; inability to secure new PPAs or renew any PPA; reliance on various forms of PPAs; volatility of supply and demand in the energy market; fluctuations affecting prospective power prices; uncertainties surrounding development of new facilities; obtainment of permits; inability to realize the anticipated benefits of completed and future acquisitions; integration of the completed and future acquisitions; changes in governmental support to increase electricity to be generated from renewable sources by independent power producers; regulatory and political risks; risks related to U.S. production and investment tax credits, changes in U.S. corporate tax rates and availability of tax equity financing; exposure to many different forms of taxation in various jurisdictions; social acceptance of renewable energy projects; relationships with stakeholders; inability to secure appropriate land; foreign market growth and development risks; liquidity risks related to derivative financial instruments; interest rate fluctuations and refinancing; financial leverage and restrictive covenants governing current and future indebtedness; changes in general economic conditions; foreign exchange fluctuations; possibility that the Corporation may not declare or pay a dividend; insufficiency of insurance coverage; ability to attract new talent or to retain officers or key employees; litigation; credit rating may not reflect actual performance of the Corporation or a lowering (downgrade) of the credit rating; revenues from certain facilities will vary based on the market (or spot) price of electricity; host country economic, social and political conditions; adverse claims to property title; reliance on intellectual property and confidential agreements to protect the Corporation's rights and confidential information; and 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.

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

	Notes	Three months ended March 31 2022	2021
Revenues		188,723	189,651
Expenses			
Operating		40,038	30,993
General and administrative		14,139	9,750
Prospective projects		4,020	5,789
Earnings before the following:		130,526	143,119
Depreciation	9	55,134	44,297
Amortization		25,097	14,588
Earnings before the following:		50,295	84,234
Finance costs	4	66,401	59,600
Other net income	5	(20,129)	(11,904)
Share of losses of joint ventures and associates:			
Share of losses, before impairment charges		2,208	95,375
Share of impairment charges		—	112,609
Change in fair value of financial instruments	7 b)	40,515	87,709
Loss before income tax		(38,700)	(259,155)
Recovery of income tax		(3,770)	(41,283)
Net loss		(34,930)	(217,872)
Net loss attributable to:			
Owners of the parent		(34,402)	(214,161)
Non-controlling interests		(528)	(3,711)
		(34,930)	(217,872)
Loss per share attributable to owners:			
Basic net loss per share ($)	8	(0.18)	(1.24)
Diluted net loss per share ($)	8	(0.18)	(1.24)

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

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

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Notes	Three months ended March 31 2022	2021
Net loss		(34,930)	(217,872)
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:			
Foreign currency translation differences for foreign operations		(22,667)	(16,668)
Change in fair value of financial instruments designated as net investment hedges	7	(225)	1,682
Change in fair value of financial instruments designated as cash flow hedges	7	97,802	74,339
Change in fair value of financial instruments of joint ventures and associates designated as cash flow hedges		5,295	5,176
Related deferred income tax		(25,463)	(19,109)
Other comprehensive income		54,742	45,420
Total comprehensive income (loss)		19,812	(172,452)
Total comprehensive income (loss) attributable to:			
Owners of the parent		21,341	(169,539)
Non-controlling interests		(1,529)	(2,913)
		19,812	(172,452)

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

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	Notes	March 31, 2022	December 31, 2021
ASSETS			
Current assets			
Cash and cash equivalents		201,537	166,266
Restricted cash		51,092	61,659
Accounts receivable		114,131	117,906
Derivative financial instruments	7	27,308	17,024
Investment tax credits recoverable	9	1,183	1,200
Prepaid and other		30,490	24,622
Total current assets		425,741	388,677
Non-current assets			
Property, plant and equipment	9	5,458,219	5,513,392
Intangible assets		998,122	1,043,994
Project development costs		55,891	70,829
Investments in joint ventures and associates	6	130,555	133,398
Derivative financial instruments	7	75,362	39,917
Deferred tax assets		49,078	50,484
Goodwill		59,772	60,858
Other long-term assets		100,608	94,519
Total non-current assets		6,927,607	7,007,391
Total assets		7,353,348	7,396,068
LIABILITIES			
Current liabilities			
Accounts payable and other payables		177,481	174,364
Derivative financial instruments	7	44,804	41,315
Current portion of long-term loans and borrowings and other liabilities		495,957	517,848
Total current liabilities		718,242	733,527
Non-current liabilities			
Derivative financial instruments	7	51,688	75,064
Long-term loans and borrowings		4,245,500	4,411,239
Other liabilities		384,319	414,343
Deferred tax liabilities		419,190	401,215
Total non-current liabilities		5,100,697	5,301,861
Total liabilities		5,818,939	6,035,388
SHAREHOLDERS' EQUITY			
Equity attributable to owners		1,274,534	1,093,112
Non-controlling interests		259,875	267,568
Total shareholders' equity		1,534,409	1,360,680
Total liabilities and shareholders' equity		7,353,348	7,396,068

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the three-month period ended March 31, 2022	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, 2022	360,936	2,022,540	131,069	2,819	(1,373,628)	(50,624)	1,093,112	267,568	1,360,680
Net loss	—	—	—	—	(34,402)	—	(34,402)	(528)	(34,930)
Other comprehensive income (loss)	—	—	—	—	—	55,743	55,743	(1,001)	54,742
Total comprehensive (loss) income	—	—	—	—	(34,402)	55,743	21,341	(1,529)	19,812
Common shares issued on public offering (Note 11)	172,506	—	—	—	—	—	172,506	—	172,506
Issuance fees (net of $2,021 of deferred income tax)	(5,547)	—	—	—	—	—	(5,547)	—	(5,547)
Common shares issued on private placement (Note 11)	37,275	—	—	—	—	—	37,275	—	37,275
Issuance fees (net of $11 of deferred income tax)	(33)	—	—	—	—	—	(33)	—	(33)
Common shares issued through dividend reinvestment plan	223	—	—	—	—	—	223	—	223
Buyback of common shares	(4,417)	—	—	—	—	—	(4,417)	—	(4,417)
Share-based payments and Performance Share Plan	—	887	—	—	—	—	887	—	887
Shares vested - Performance Share Plan	2,114	(4,883)	—	—	—	—	(2,769)	—	(2,769)
Shares purchased - Performance Share Plan	—	97	—	—	—	—	97	—	97
Dividends declared on common shares (Note 11)	—	—	—	—	(36,733)	—	(36,733)	—	(36,733)
Dividends declared on preferred shares (Note 11)	—	—	—	—	(1,408)	—	(1,408)	—	(1,408)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(6,164)	(6,164)
Balance March 31, 2022	563,057	2,018,641	131,069	2,819	(1,446,171)	5,119	1,274,534	259,875	1,534,409

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the three-month period ended March 31, 2021	Equity attributable to owners								
	Common 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, 2021	4,185	2,026,415	131,069	2,843	(1,043,962)	(111,696)	1,008,854	62,078	1,070,932
Net loss	—	—	—	—	(214,161)	—	(214,161)	(3,711)	(217,872)
Other comprehensive income	—	—	—	—	—	44,622	44,622	798	45,420
Total comprehensive (loss) income	—	—	—	—	(214,161)	44,622	(169,539)	(2,913)	(172,452)
Common shares issued through dividend reinvestment plan	154	—	—	—	—	—	154	—	154
Share-based payments and Performance Share Plan	—	478	—	—	—	—	478	—	478
Convertible debentures converted into common shares and redemption	2,330	—	—	(24)	—	—	2,306	—	2,306
Shares vested - Performance Share Plan	3,174	(6,250)	—	—	—	—	(3,076)	—	(3,076)
Dividends declared on common shares (Note 11)	—	—	—	—	(31,445)	—	(31,445)	—	(31,445)
Dividends declared on preferred shares (Note 11)	—	—	—	—	(1,408)	—	(1,408)	—	(1,408)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(891)	(891)
Balance March 31, 2021	9,843	2,020,643	131,069	2,819	(1,290,976)	(67,074)	806,324	58,274	864,598

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

		Three months ended March 31	
		2022	2021
OPERATING ACTIVITIES	Notes		
Net loss		(34,930)	(217,872)
Items not affecting cash:			
Depreciation and amortization		80,231	58,885
Share of losses of joint ventures and associates		2,208	207,984
Unrealized portion of change in fair value of financial instruments	7	40,785	16,523
Production tax credits and tax attributes allocated to tax equity investors	5	(19,403)	(11,196)
Other		693	992
Finance costs	4	66,401	59,600
Finance costs paid	12	(43,582)	(38,622)
Distributions received from joint ventures and associates		5,912	6,414
Recovery of income tax		(3,770)	(41,283)
Income tax paid		(2,801)	33
Effect of exchange rate fluctuations		281	(278)
		92,025	41,180
Changes in non-cash operating working capital items	12 a)	(7,167)	18,790
		84,858	59,970
FINANCING ACTIVITIES			
Dividends paid on common and preferred shares		(35,833)	(32,756)
Distributions to non-controlling interests		(6,164)	(891)
Increase in long-term debt, net of deferred financing costs	12 c)	115,813	271,898
Repayment of long-term debt	12 c)	(263,261)	(187,880)
Payment of other liabilities		(1,717)	(2,110)
Net proceeds from issuance of common shares		202,169	—
Payment for buyback of common shares		(4,417)	—
Purchase of common shares under the Performance Share Plan		97	—
Payment of payroll withholding on exercise of stock options and Performance Share Plan		(2,769)	(3,076)
		3,918	45,185
INVESTING ACTIVITIES			
Business acquisitions, net of cash acquired	3	(30,666)	—
Change in restricted cash		10,045	622
Additions to property, plant and equipment, net		(19,044)	(76,331)
Additions to intangible assets		(22)	—
Additions to project development costs		(12,415)	(7,027)
Investments in joint ventures and associates		—	(65)
Change in other long-term assets		1,832	917
		(50,270)	(81,884)
Effects of exchange rate changes on cash and cash equivalents		(3,235)	(3,346)
Net change in cash and cash equivalents		35,271	19,925
Cash and cash equivalents, beginning of period		166,266	161,465
Cash and cash equivalents, end of period		**201,537**	**181,390**

Additional information is presented in Note 12.

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

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

DESCRIPTION OF BUSINESS

Innergex Renewable Energy Inc. (“Innergex” or the “Corporation”) was incorporated under the *Canada Business Corporation Act* on October 25, 2002, and its shares and convertible debentures are listed on the Toronto Stock Exchange. The Corporation is a developer, acquirer, owner and operator of renewable power-generating and energy storage facilities, essentially focused on the hydroelectric, wind and solar power sectors. The Corporation's head office is located at 1225 St-Charles Street West, 10th floor, Longueuil, QC, J4K 0B9, Canada.

These unaudited condensed interim consolidated financial statements were approved by the Board of Directors on May 10, 2022.

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, 2022, the Corporation adopted the following new standards and interpretations which did not have an impact on these unaudited condensed interim consolidated financial statements:

Amendments to IAS 16, Property, Plant and Equipment - Proceeds before Intended Use

On May 14, 2020, the IASB issued *Property, Plant and Equipment — Proceeds before Intended Use* (Amendments to IAS 16). The amendments prohibit deducting from the cost of an item of property, plant and equipment any proceeds from selling items produced while bringing that asset to the location and condition necessary for it to be capable of operating in the manner intended by management. Instead, an entity recognizes the proceeds from selling such items, and the cost of producing those items, in profit or loss. The amendments are effective for annual reporting periods commencing on or after January 1, 2022. The Corporation adopted the amendments on January 1, 2022, with no impact to the unaudited condensed interim consolidated financial statements.

3. BUSINESS ACQUISITIONS

a. Acquisition of San Andrés SpA

Innergex acquired on January, 28, 2022 the 50.6 MW San Andrés solar farm in Chile ("San Andrés"). The facility, commissioned in 2014, is located in the Atacama Desert in northern Chile. San Andrés was acquired for a total consideration of US$26,815 ($34,088).The facility is expected to produce a gross long-term average of approximately 118.9 GWh per year.

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	2,692	3,422
Accounts receivable	499	634
Prepaid and other	526	669
Property, plant and equipment	30,449	38,707
Accounts payable and other payables	(727)	(925)
Other liabilities	(4,003)	(5,088)
Deferred tax liability	(2,621)	(3,331)
Net assets acquired	26,815	34,088

The acquisition gave rise to transaction costs of $2,140 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 $1,740 and $508, respectively for the 62-day period ended March 31, 2022. Had the acquisition taken place on January 1, 2022, revenues and net earnings included in the consolidated statements of earnings (loss) for the period from January 1, 2021 to March 31, 2022 would have been $501 higher and $449 lower, respectively.

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

4. FINANCE COSTS

	Three months ended March 31	
	2022	2021
Interest expense on long-term corporate and project loans	45,956	43,050
Interest expense on tax equity financing	7,213	5,686
Interest expense on convertible debentures	3,390	3,395
Inflation compensation interest	2,687	1,384
Amortization of financing fees	3,049	2,001
Accretion expenses on other liabilities	1,656	1,255
Interest on lease liabilities	1,475	1,015
Accretion of long-term loans and borrowings	112	158
Other	863	1,656
	66,401	59,600

5. OTHER NET INCOME

	Three months ended March 31	
	2022	2021
Production tax credits income	(19,047)	(11,389)
Tax attributes allocated to tax equity investors income	(356)	193
Transaction costs related to business acquisitions	2,181	—
Loss on repayment of loans	—	1,125
Professional and other fees - February 2021 Texas Events	—	311
Realized loss on contingent considerations	—	547
Other income, net	(2,907)	(2,691)
	(20,129)	(11,904)

6. INVESTMENTS IN JOINT VENTURES AND ASSOCIATES

Disposition of Shannon

On March 4, 2022, the Corporation completed the sale of its 50% interest in Shannon for a nominal amount.

(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 :

Financial assets (liabilities)	Foreign exchange forwards (Level 2)	Interests hedging derivatives (Level 2)	Power hedges (Level 3)	Currency translation of intragroup loans[1]	Total
As at January 1, 2022	2,485	(78,482)	16,559	—	(59,438)
Unrealized portion of change in fair value recognized in earnings (loss) [2]	5,548	8,954	(47,208)	(8,079)	(40,785)
Change in fair value recognized in other comprehensive income (loss)	(225)	98,498	(696)	—	97,577
Amortization of accumulated other comprehensive income recognized in revenue	—	—	696	—	696
Net foreign exchange differences	—	(530)	579	8,079	8,128
As at March 31, 2022	7,808	28,440	(30,070)	—	6,178

1. Loss 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 income (loss), therefore not eliminating the loss recognized in earnings (loss).
2. Refer to Note 7 b) for a reconciliation to the change in fair value recognized in earnings (loss).

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

Recognized in the consolidated statements of earnings (loss):

	Three months ended March 31	
	2022	2021
Unrealized portion of change in fair value of financial instruments	40,785	16,523
Realized portion of financial instruments:		
Realized (gain) loss on the power hedges	(270)	67,102
Realized loss on the interest rate swaps	—	2,885
Realized loss on Phoebe basis hedge	—	1,199
Change in fair value of financial instruments	40,515	87,709

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

8. EARNINGS (LOSS) PER SHARE

Basic	Three months ended March 31 2022	2021
Net loss attributable to owners of the parent	(34,402)	(214,161)
Dividends declared on preferred shares	(1,408)	(1,408)
Net loss attributable to common shareholders	(35,810)	(215,569)
Weighted average number of common shares	196,689,642	174,110,971
Basic net loss per share ($)	(0.18)	(1.24)

Diluted	Three months ended March 31 2022	2021
Net loss attributable to common shareholders	(35,810)	(215,569)
Diluted weighted average number of common shares	196,689,642	174,110,971
Diluted net loss per share ($)	(0.18)	(1.24)

	Three months ended March 31 2022	2021
Instruments that are excluded from the dilutive elements:		
Stock options	316,922	262,784
Shares held in trust related to the Performance Share Plan	413,660	425,576
Convertible debentures	13,604,473	13,604,473
	14,335,055	14,292,833

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

9. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facilities	Facilities under construction	Other	Total
Cost							
As at January 1, 2022	185,100	2,594,780	2,891,964	819,621	72,877	45,064	6,609,406
Additions [1]	8,331	333	188	292	21,353	1,302	31,799
Investment tax credits [2]	—	—	—	—	(8,535)	—	(8,535)
Business acquisitions (Note 3)	—	—	—	38,703	—	4	38,707
Transfer from project development costs	—	—	—	—	25,034	—	25,034
Reclassification	—	—	(1,362)	—	—	1,362	—
Dispositions	—	—	(181)	—	—	(34)	(215)
Other changes	(1,442)	—	(25,745)	(5,431)	—	—	(32,618)
Net foreign exchange differences	(2,926)	(7,332)	(39,829)	(10,257)	(1,515)	(273)	(62,132)
As at March 31, 2022	189,063	2,587,781	2,825,035	842,928	109,214	47,425	6,601,446
Accumulated depreciation							
As at January 1, 2022	(16,801)	(391,093)	(549,980)	(115,531)	—	(22,609)	(1,096,014)
Depreciation [3]	(1,568)	(13,132)	(30,536)	(8,351)	—	(1,589)	(55,176)
Dispositions	—	—	181	—	—	34	215
Net foreign exchange differences	285	190	6,302	937	—	34	7,748
As at March 31, 2022	(18,084)	(404,035)	(574,033)	(122,945)	—	(24,130)	(1,143,227)
Carrying amounts as at March 31, 2022	170,979	2,183,746	2,251,002	719,983	109,214	23,295	5,458,219

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 $646 of capitalized financing costs incurred prior to commissioning.
2. The Corporation accrued for US$6,712 ($8,535) in investment tax credits recoverable in relation to the construction of the Hale Kuawehi solar project, which were recognized as a reduction in the cost of property, plant and equipment. As at March 31, 2022, the balance of investments tax credits recoverable, on the Hillcrest and the Hale Kuawehi projects, amounts to US$947 ($1,183).
3. An amount of $42 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)

10. LONG-TERM LOANS AND BORROWINGS

As at March 31, 2022, the Corporation and its subsidiaries have met all material financial and non-financial conditions related to their credit agreements, except for the following:

- the Duqueco hydro project was in breach of the change of control covenant under 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$104,951 ($131,147) portion of the loan that would otherwise be classified as long-term was reclassified to the current portion of long-term loans and borrowings. On April 25, 2022, a waiver was obtained from the project lenders.

The Corporation reclassified the subordinated unsecured term loan as current, following the upcoming maturity on February 6, 2023.

a. Financing of the Hale Kuawehi project

On March 16, 2022, the Corporation entered into a financing agreement for the construction of the Hale Kuawehi solar and battery storage project in Hawaii consisting of a US$54,543,000 construction loan bearing interest at 1-month SOFR + 1.375% maturing in 2023, and a US$61,630,000 tax equity bridge loan bearing interest at 1-month SOFR + 0.75% maturing in 2023.

11. SHAREHOLDERS' CAPITAL

Common Shares

Issuance of common shares

As part of the public offering that closed on February 22, 2022, the Corporation issued 9,718,650 common shares at a price per share of $17.75 for cash proceeds of $172,506. Concurrently with the closing of the public offering, Hydro-Québec subscribed 2,100,000 common shares in the share capital of the Corporation for cash proceeds of $37,275.

Buyback of common shares and preferred shares

During the three months ended March 31, 2022, 253,681 common shares have been purchased and cancelled under the normal course issuer bid to terminate on May 23, 2022, at an average price of $17.40 per share.

Equity-based compensation

a) Stock option plan

Granted

During the three months ended March 31, 2022, 51,352 options were granted. The options granted vest in four equal tranches until February 25, 2026 and must be exercised before February 25, 2029 at an exercise price of $17.50 per share.

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:

Risk-free interest rate	1.78 %
Expected annual dividend per common share	$ 0.72
Expected life of options	6
Expected volatility	26.77 %

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

A compensation expense of $23 was recorded during the three months ended March 31, 2022 with respect to the stock option plan.

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

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

Performance Share Plan

During the three months ended March 31, 2022, 269,482 performance share rights vested.

In addition, 251,650 share rights were granted during the three months ended March 31, 2022. The performance share rights vest on December 31, 2024.

Deferred Share Unit Plan

During the three months ended March 31, 2022, 16,881 units were granted.

A compensation expense of $1,376 was recorded during the three months ended March 31, 2022 with respect to the PSP and DSU plans.

Dividends

a) Dividend Declared

The following dividends were declared by the Corporation:

	Three months ended March 31			
	2022		2021	
	($/share)	Total	($/share)	Total
Dividends declared on common shares	0.180	36,733	0.180	31,445
Dividends declared on Series A preferred shares	0.202750	689	0.202750	689
Dividends declared on Series C preferred shares	0.359375	719	0.359375	719

Dividend Declared subsequent to period end and not recognized at the end of the reporting period.

The following dividends will be paid by the Corporation on July 15, 2022:

Date of announcement	Record date	Payment date	Dividend per common share	Dividend per Series A Preferred Share	Dividend per Series C Preferred Share
May 10, 2022	June 30, 2022	July 15, 2022	$ 0.180	$ 0.202750	$ 0.359375

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

12. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a) Changes in non-cash operating working capital items

	Three months ended March 31	
	2022	2021
Accounts receivable	3,208	(1,992)
Prepaids and other	(5,539)	(3,366)
Accounts payable and other payables	(4,836)	24,148
	(7,167)	18,790

b) Additional information

	Three months ended March 31	
	2022	2021
Finance costs paid relative to operating activities before interest on leases	(39,049)	(37,893)
Interest on leases paid relative to operating activities	(4,533)	(729)
Capitalized interest relative to investing activities	(205)	(1,029)
Capitalized interest on leases relative to investing activities	—	(578)
Total finance costs paid	(43,787)	(40,229)
Non-cash transactions:		
Change in unpaid property, plant and equipment	2,066	28,466
Investment tax credits	8,535	4,473
Change in other long-term assets	84	14
Change in unpaid project development costs	(1,418)	1,061
Remeasurement of other liabilities	(40,536)	(21,577)
Initial measurement of other liabilities	8,331	(370)
Common shares issued through the conversion of convertible debentures	—	2,306
Common shares issued through equity based compensation	2,114	3,174
Common shares issued through dividend reinvestment plan	223	154

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

c) Changes in liabilities arising from financing activities

	Three months ended March 31	
	2022	2021
Changes in long-term loans and borrowings		
Long-term debt at beginning of period	4,924,435	4,813,881
Increase in long-term debt	119,604	271,898
Repayment of long-term debt	(263,261)	(187,880)
Payment of deferred financing costs	(3,791)	—
Tax attributes	(356)	193
Production tax credits	(19,047)	(11,389)
Other non-cash finance costs	13,018	11,536
Convertible debentures converted into common shares	—	(2,306)
Accretion of convertible debentures	583	708
Net foreign exchange differences	(33,981)	(42,988)
Long-term loans and borrowings at end of period	4,737,204	4,853,653

13. 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 which reflects the relevant benchmark interbank rate used by market participants for this purpose when pricing interest rate swaps. The fair value estimate is subject to a credit risk adjustment that reflects the credit risk of the Corporation and of the counterparty.

Foreign exchange forwards

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

Power hedges

The fair values of the power and basis hedges are calculated using a discounted cash flow model. The fair value calculation of power and basis hedges gives rise to measurement uncertainty as the power price curves are constructed using various methodologies and assumptions, which consider certain unobservable inputs. As at March 31, 2022, 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$22.78 to US$106.81 per MWh between April 1, 2022 and June 30, 2031.

With respect to the Salvador power hedges, Polpaico node future power prices are expected to be in a range of US $4.09 to US$73.21 per MWh between April 1, 2022 and December 31, 2030.

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

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

Phoebe power hedge: The fair value of the power hedge is derived from forward power prices that are not based on observable market data for the entirety of the contracted period. The power ERCOT South Hub forward price curves are constructed using various assumptions available as of the valuation date depending on a combination of observable exchange prices and over-the-counter broker quotes obtained through June 2031.

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.

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$307,563 ($384,331) as at March 31, 2022.

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

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

a. Market risk

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

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

14. 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.

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 cited 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 was allegedly unable to accept or purchase energy under the EPAs. The notices to Innergex followed public statements by BC Hydro regarding measures it was taking to address the reduced electricity demand during the COVID-19 pandemic and related challenges to the safe operation of its hydroelectric system.

Innergex disputed that the pandemic and related governmental measures in any way prevented BC Hydro from fulfilling its obligations to accept and purchase energy under the EPAs or enabled 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, seeking 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 amounted to $12,456 ($14,183 on a Revenues Proportionate[1] basis), respectively. The dispute was settled in the first quarter of 2022 to Innergex's satisfaction.

[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 16, Segment Information, for more information.

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 Limited Partnerships have filed their response to petition on April 14, 2020. The hearing took place in Victoria in the last week of September 2020. A decision was rendered on February 9, 2021 by the Supreme Court of British Columbia, which concluded that the Environmental Appeal Board's decision was reasonable, and dismissed the Comptroller of Water Rights' petition accordingly. The Comptroller of Water Rights subsequently appealed the decision of the Supreme Court of British Columbia, which was unanimously dismissed by the British Columbia Court of Appeal on January 7, 2022. The Corporation recognized the amount of $3,181 in the consolidated statements of earnings (loss) during the year ended December 31, 2019. A total amount of $3,385, including interests, was received by the Corporation during the first quarter of 2022.

15. 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, 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 finalization 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.

16. 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.

Three months ended March 31, 2022				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	65,911	105,897	16,915	188,723
Innergex's share of revenues of joint ventures and associates	3,231	5,115	—	8,346
PTCs and Innergex's share of PTCs generated	—	19,047	—	19,047
Segment Revenues Proportionate	69,142	130,059	16,915	216,116
Segment Adjusted EBITDA	46,630	89,476	11,310	147,416
Innergex's share of Adjusted EBITDA of joint ventures and associates	1,141	4,197	—	5,338
PTCs and Innergex's share of PTCs generated	—	19,047	—	19,047
Segment Adjusted EBITDA Proportionate	47,771	112,720	11,310	171,801
Segment Adjusted EBITDA Margin	70.7 %	84.5 %	66.9 %	78.1 %

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

Three months ended March 31, 2022	Hydroelectric	Wind	Solar	Segment totals [1]
Property, plant and equipment acquired through business acquisitions	—	—	38,707	38,707
Acquisition of property, plant and equipment	341	188	292	821

1. Segment totals include only operating projects.

Three months ended March 31, 2021				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	26,570	116,013	47,068	189,651
Innergex's share of revenues of joint ventures and associates	4,339	49,818	504	54,661
PTCs and Innergex's share of PTCs generated	—	17,423	—	17,423
Segment Revenues Proportionate	30,909	183,254	47,572	261,735
Segment Adjusted EBITDA	14,490	99,623	44,075	158,188
Innergex's share of Adjusted EBITDA of joint ventures and associates	1,507	46,544	298	48,349
PTCs and Innergex's share of PTCs generated	—	17,423	—	17,423
Segment Adjusted EBITDA Proportionate	15,997	163,590	44,373	223,960
Segment Adjusted EBITDA Margin	54.5 %	85.9 %	93.6 %	83.4 %

Three months ended March 31, 2021	Hydroelectric	Wind	Solar	Segment totals [1]
Transfer of assets upon commissioning	—	14,351	—	14,351
Acquisition of property, plant and equipment	194	1,028	—	1,222

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 March 31, 2022				Three months ended March 31, 2021			
	Consolidation	Share of joint ventures	PTCs	Proportionate	Consolidation	Share of joint ventures	PTCs	Proportionate
Revenues	188,723	8,346	19,047	216,116	189,651	54,661	17,423	261,735
Net loss	(34,930)	—	—	(34,930)	(217,872)	—	—	(217,872)
Recovery of income tax	(3,770)	—	—	(3,770)	(41,283)	773	—	(40,510)
Finance costs	66,401	4,424	—	70,825	59,600	9,095	—	68,695
Depreciation and amortization	80,231	4,195	—	84,426	58,885	8,955	—	67,840
Impairment of long-term assets	—	—	—	—	—	112,609	—	112,609
EBITDA	107,932	8,619	—	116,551	(140,670)	131,432	—	(9,238)
Other net income, before PTCs	(1,082)	(175)	—	(1,257)	(515)	1,601	—	1,086
Production tax credits ("PTCs")	(19,047)	—	19,047	—	(11,389)	(6,034)	17,423	—
Share of losses of joint ventures and associates	2,208	(2,208)	—	—	207,984	(207,984)	—	—
Change in fair value of financial instruments	40,515	(898)	—	39,617	87,709	129,334	—	217,043
Adjusted EBITDA	130,526	5,338	19,047	154,911	143,119	48,349	17,423	208,891
Unallocated expenses:								
General and administrative	12,870	—	—	12,870	9,280	—	—	9,280
Prospective projects	4,020	—	—	4,020	5,789	—	—	5,789
Segment Adjusted EBITDA	147,416	5,338	19,047	171,801	158,188	48,349	17,423	223,960
Segment Adjusted EBITDA Margin	78.1 %	64.0 %		79.5 %	83.4 %	88.5 %		85.6 %

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

Geographic segments

As at March 31, 2022, 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 4 hydroelectric facilities and 3 solar farm in Chile. The Corporation operates in four principal geographical areas, which are detailed below:

	Three months ended March 31	
	2022	2021
Revenues		
Canada	105,007	83,150
United States	43,313	76,033
France	27,396	28,368
Chile	13,007	2,100
	188,723	189,651

As at	March 31, 2022	December 31, 2021
Non-current assets, excluding derivative financial instruments and deferred tax assets [1]		
Canada	3,328,145	3,390,029
United States	2,258,391	2,301,353
France	753,440	801,752
Chile	463,191	423,856
	6,803,167	6,916,990

1. Includes the investments in joint ventures and associates

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

17. SUBSEQUENT EVENTS

On May 10, 2022, the Corporation amended its existing revolving term credit facility, extending the term from 2023 to 2027 and increasing the borrowing limit to $950,000.

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 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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