INNERGEX

Renewable Energy.
Sustainable Development.

QUARTERLY REPORT 2020

for the period ended
September 30, 2020

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

For 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 generating power from renewable sources will lead the way to a better world. Innergex operates in Canada, the United States, France and Chile. The Corporation's shares are listed on the Toronto Stock Exchange under the symbols INE, INE.PR.A and INE.PR.C and its convertible debentures are listed under the symbols INE.DB.B and INE.DB.C.

MANAGEMENT'S DISCUSSION AND ANALYSIS

This Management's Discussion and Analysis ("MD&A") is a discussion of the operating results, cash flows and financial position of Innergex Renewable Energy Inc. ("Innergex" or the "Corporation") for the three- and nine-month periods ended September 30, 2020, and reflects all material events up to November 10, 2020, the date on which this MD&A was approved by the Corporation's Board of Directors.

The MD&A should be read in conjunction with the unaudited condensed interim consolidated financial statements and the accompanying notes for the three- and nine-month periods ended September 30, 2020.

The unaudited condensed interim consolidated financial statements attached to this MD&A and the accompanying notes for the three- and nine-month periods ended September 30, 2020, along with the 2019 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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HIGHLIGHTS

- Four projects now under construction since the Griffin Trail construction activities officially started in September 2020.
- The Payout Ratio for the trailing twelve-month period ended September 30, 2020 amounted to 124% of Free Cash Flow; when normalizing for non-recurring items, the Payout Ratio would have been 100%.
- Production was 93% of the long-term average ("LTA") in Q3 2020. Excluding the impact of the BC Hydro curtailment, production would have reached 96% of the LTA.
- Revenues increased 14% to $162.7 million in Q3 2020.
- Adjusted EBITDA increased 1% to $108.5 million in Q3 2020, corresponding to an Adjusted EBITDA Margin of 66.7%.
- Adjusted EBITDA Proportionate increased 6% to $151.4 million in Q3 2020, corresponding to an Adjusted EBITDA Proportionate Margin of 70.9%.
- On July 15, 2020, Innergex completed the acquisition of six wind farms in Idaho, United States totalling 138 MW.
- On September 17, 2020, Innergex signed two long-term power purchase agreements for solar and battery energy storage projects in Hawaii.

	Three months ended September 30[1]		Nine months ended September 30[1]	
	2020	2019	2020	2019
OPERATING RESULTS				
Production (MWh)	2,021,559	1,665,362	5,886,949	4,715,820
Revenues	162,651	142,814	445,280	413,926
Adjusted EBITDA[2]	108,524	107,351	304,279	305,842
Adjusted EBITDA Margin[2]	66.7 %	75.2 %	68.3 %	73.9 %
Net Earnings (Loss) From Continuing Operations	7,492	9,896	(41,005)	(4,977)
Net Earnings (Loss)	7,492	9,703	(41,005)	16,194
Adjusted Net Earnings (Loss) From Continuing Operations[2]	13,376	13,585	9,319	(443)
PROPORTIONATE				
Production Proportionate (MWh)[2]	2,471,149	2,149,151	7,016,780	5,875,960
Revenues Proportionate[2]	213,736	186,904	570,111	511,520
Adjusted EBITDA Proportionate[2]	151,433	142,884	407,398	376,999
Adjusted EBITDA Proportionate Margin [2]	70.9 %	76.4 %	71.5 %	73.7 %
COMMON SHARES				
Dividends declared on common shares	31,409	23,917	94,118	70,650
Weighted Average Number of Common Shares (in 000s)	173,858	133,400	169,048	133,229
	Trailing twelve months ended September 30		2020	2019
CASH FLOW AND PAYOUT RATIO				
Cash Flow From Operating Activities [3]			229,152	213,585
Free Cash Flow[2,3]			95,612	100,455
Payout Ratio[2,3]			124 %	93 %
Adjusted Payout Ratio[2,3]			102 %	77 %
		As at	September 30	December 31
			2020	2019
FINANCIAL POSITION				
Total Assets			7,148,134	6,372,104
Total Liabilities			6,031,459	5,756,778
Non-Controlling Interests			69,238	10,942
Equity Attributable to Owners			1,047,437	604,384

1. Results from continuing operations unless otherwise indicated.
2. These measures are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Production Proportionate is a key performance indicator 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.
3. For more information on the calculation and explanation, please refer to the "Free Cash Flow and Payout Ratio" section.

UPDATE ON COVID-19

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

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

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

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

Power Production an Essential Service

Power production activities have continued in all segments, as they have been deemed essential services in every region where the Corporation operates. Only BC Hydro sent curtailment notices for some hydro facilities; the Corporation disputes these notices, as described below. 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.

The Corporation has 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 as a joint venture), Upper Lillooet River, Northwest Stave River, and Boulder Creek facilities, 2.0 MW/h for the Tretheway Creek facility and 4.0 MW/h for the Big Silver Creek facility.

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

Innergex disputes that the current pandemic and related governmental measures in any way prevent BC Hydro from fulfilling its obligations to accept and purchase energy under the EPAs or enable it to invoke “force majeure” provisions under the EPAs to suspend these obligations. Innergex acknowledges that BC Hydro retains “turn-down” rights under the EPAs, which enable it to require Innergex to turn down or shut off its facilities in certain circumstances, including in order to avoid a safety or stability risk. Where BC Hydro exercises this right, it is required under the EPAs to compensate Innergex for energy that would have been produced at the facilities in the absence of the curtailment. Innergex complied with BC Hydro’s curtailment request, but did so under protest and seeks to enforce its rights under the EPAs on the basis described above.

COVID-19 Financial Impact

For the three- and nine-month periods ended September 30, 2020, actual eligible energy revenue that would have been produced at the facilities in the absence of the curtailments requested by BC Hydro mentioned above amounted to $3.0 million ($3.6 million on a Revenues Proportionate[1] basis) and $13.0 million ($14.8 million on a Revenues Proportionate[1] basis), respectively.

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

Direct costs related to COVID-19 measures implemented by Innergex and potential savings from reduced travel have been immaterial.

Health and Safety of our Employees and Visitors
In March 2020, Innergex implemented numerous measures to protect employees, suppliers and business partners from COVID-19.

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

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

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

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

Impacts of COVID-19 on our Construction Activities

Hillcrest Solar Project (Ohio)
The construction of Hillcrest is progressing well. Contingency plans and measures in place were deployed to address the cases of COVID-19 that have occurred on site. Unless a decree is issued to halt construction, Hillcrest should continue to progress with commissioning planned in Q1 2021.

Innavik Hydro Project (Quebec)
Construction activities resumed in July 2020. COVID-19 protocols limit our ability to hire local workers. They also create delays for workers from other regions who must get their test results before travelling to Inukjuak.

Yonne II Wind Project (France)
Construction activities on-site began in July 2020. As of today, installation work is still progressing and commercial operation remains scheduled for Q1 2021. This timeline may be revisited following the recent announcement of lockdown by the French Government on October 28, 2020, which could cause delays in construction activities due mainly to border closures.

Griffin Trail Wind Project (Texas)
The construction of Griffin Trail is progressing well. There have been no COVID-19 cases on the site and contingency plans and measures are in place to address any problems that may arise due to the current pandemic. Commercial operation is scheduled for Q3 2021.

Support to Surrounding Communities
To support communities surrounding our facilities and projects in all segments, the Corporation launched the "Time for Solidarity" campaign in March 2020.

The Corporation distributed $255,000 in total to local charities such as food banks, women's shelters and relief organizations to alleviate the effects of the COVID-19 crisis. Employees were also invited to make personal donations to these charities and proudly raised $37,225. Such relief organizations included United Way, Ressort Gaspésie-Iles-de-la-Madeleine, BC First Nations Health Authority, BC Society of Transition Houses, Women in Need, BCAAFC - British Columbia Association of Aboriginal Friendship Centres, Moisson Montréal and Regroupement des centres d’amitié autochtones du Québec in Canada, the Wichita Falls Feeding America Food Bank, United Way and Hope Emergency Services in the United States, Restos du Coeur in France, and Red de Alimentos and Banco de Alimentos Biobío Solidario in Chile.

OVERVIEW

The Corporation is a developer, acquirer, owner and operator of renewable power-generating and energy storage facilities with a focus on hydroelectric, wind and solar power that benefit from simple, proven technologies.

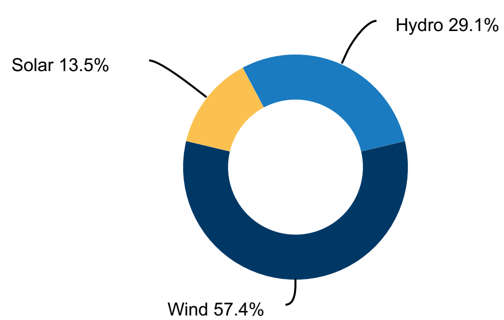
Discontinued Operations
On May 23, 2019, the Corporation announced completion of the sale of its wholly owned subsidiary Magma Energy Sweden A.B. ("Magma Sweden"), which owns an equity interest of approximately 53.9% in HS Orka hf ("HS Orka"), owner of two geothermal facilities in operation, one hydro project in development and prospective projects in Iceland. The Geothermal Power Generation Segment is now accounted for as discontinued operations. For more information, please refer to the "Discontinued Operations" section of this MD&A. The figures presented in this MD&A are for the continuing operations unless otherwise indicated.

Segments

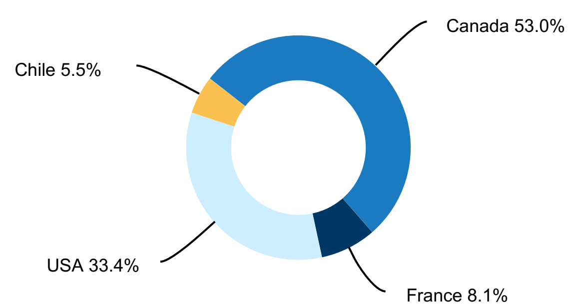
As at September 30, 2020, the Corporation has three operating segments and four geographic segments.

Operating Segments	Geographic Segments
Hydroelectric Power Generation	Canada
Wind Power Generation	France
Solar Power Generation	United States
	Chile

Net Installed Capacity by Operating Segment



Net Installed Capacity by Geographic Segment



Portfolio of Assets

As at the date of this MD&A, the Corporation owns interests in three groups of projects at various stages: the Operating Facilities, the Development Projects and the Prospective Projects.

Operating Facilities

The Corporation owns and operates 75 facilities in commercial operation (the "Operating Facilities"). Commissioned between 1992 and November 2019, the facilities have a weighted average age of approximately 7.7 years.

They mostly sell the generated power under long-term power purchase agreements, power hedge contracts[1] and short- and long-term industrial contracts (each, a "PPA") to rated public utilities or other creditworthy counterparties or on the open market. The PPAs have a weighted average remaining life of 14.4 years (based on gross long-term average production).

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

[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).

	Number of Operating Facilities[1]	Installed Capacity (MW)		Storage Capacity (MWh)
		Gross[2]	Net[3]	
HYDRO				
Canada	33	1,019	713	—
United States	1	10	10	—
Chile	3	152	74	—
Subtotal	37	1,181	797	—
WIND				
Canada	8	908	714	—
France	15	317	221	—
United States	9	892	640	—
Subtotal	32	2,117	1,575	—
SOLAR				
Canada	1	27	27	—
United States	3	267	266	—
Chile	2	102	77	150 [4]
Subtotal	6	396	370	150
Total	75	3,694	2,742	150

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.

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

Development Projects

The Corporation now holds interests in ten projects under development. Four Development Projects are currently under construction. These projects are scheduled to begin commercial operation between 2021 and 2023 (the "Development Projects"). For more information on the Development Projects, please refer to the "Third Quarter Update" section.

	Number of Development Projects	Installed Capacity (MW)		Storage Capacity (MWh)
		Gross[1]	Net[2]	
HYDRO				
Canada	1	8	4	—
Chile	1	109	41	—
Subtotal	2	117	45	—
WIND				
France	1	7	5	—
United States	1	225	225	—
Subtotal	2	232	230	—
SOLAR				
United States	5	280	280	320 [3]
STORAGE				
France	1	—	—	9 [4]
Total	10	629	555	329

1. Gross installed capacity is the total capacity of all Development Projects of Innergex, including non-wholly owned subsidiaries and joint ventures and associates.
2. Net installed capacity is the proportional share of the total capacity attributable to Innergex based on its ownership interest in each facility.
3. Battery storage capacity related to Hale Kuawehi (120 MWh), Paeahu (60 MWh), Kahana (80 MWh) and Barbers Point (60 MWh) solar projects.
4. Standalone battery storage project.

Prospective Projects

The Corporation also 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 Proposal or a Standing Offer Program (collectively the "Prospective Projects"). The list of Prospective Projects is revised annually to add or remove projects, according to their advancement potential.

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

	Prospective Projects Gross Projected Capacity (MW)[1]			
	Hydro	Wind	Solar	Total
Canada	730	4,343	320	5,393
United States	—	300	634	934
France	—	296	—	296
Chile	207	9	32	248
Total	937	4,948	986	6,871

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

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

Tax Equity Investment

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

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

Innergex recognizes the TEI contributions as long-term loans and borrowings, at an amount representing the proceeds received from the tax equity investor 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 tax equity investor derived from the power generated during the period and recognized in other net income as incurred
Investment Tax Credits ("ITC")	Allocation of ITCs to the tax equity investor stemming from the construction activities and recognized as a reduction in the cost of the assets to which they relate
Taxable income (loss), including tax attributes such as accelerated tax depreciation	Allocation of taxable income and other tax attributes to the tax equity investor recognized in other net income as incurred
Pay-go contributions	Additional cash contributions made by the tax equity investor when the annual production exceeds the contractually determined threshold and recognized as an increase in the tax equity financing
Cash distributions	Cash allocation to the tax equity investor

Production Tax Credit Program (“PTC”)

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

	Commercial Operation Date	Expected TEI Flip Point[1]	TEI Investment (M$)	Expected Annual PTC Generation[3] (M$)	Expected Annual Pay-go Contribution[4] (M$)	TEI Allocation of Taxable Income (Loss) and PTCs (Pre-Flip Point)	TEI Allocation of Cash Distributions (Pre-Flip Point)
Shannon[1,2]	2015	2028	274.2	23.7	—	24.80 %	64.10 %
Flat Top[1,2]	2018	2028	267.2	29.1	—	99.00 %	21.97 %
Foard City[1,2,4]	2019	2029	372.7	43.5	4.6	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 tax equity investor or a change to the Flip Point. Figures provided are for the year ending December 31, 2020.
2. TEIs in U.S. projects generally require certain sponsor guarantees as a condition for their investment. To support the tax equity investments at Shannon, Flat Top and Foard City, Alterra, a subsidiary of Innergex, executed a guarantee indemnifying the tax equity investors against certain breaches of project-level representations, warranties and covenants. The Corporation believes these indemnifications cover matters that are substantially within its control, and are very unlikely to occur.
3. Based on the gross estimated LTA and the current credit of US$25/MWh generated for the period from COD to Flip Point, translated into Canadian dollars at 1.3339. PTCs generation will vary depending on actual production.
4. Average annual Pay-go Contributions estimate is based on PTCs generated on gross estimated LTA for each year from COD to Flip Point, translated into Canadian dollars at 1.3339. Pay-go Contributions will be earned on actual production in excess of a specified annual threshold, subject to a contractual cumulative maximum.

Investment Tax Credit Program (“ITC”)

Current United States tax law allows wind and solar facilities to receive a one-time federal tax credit, calculated on the basis of the facility's capital cost. Projects that began construction through 2019 are eligible for 30% ITC. This credit steps down to 26% for facilities that began construction in 2020, 22% in 2021 and 10% thereafter.

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

	Commercial Operation Date	Expected TEI Flip Point	TEI Investment (M$)	TEI Allocation of Taxable Income (Loss) and ITC (Pre-Flip Point)	TEI Preferred Allocation of Cash (Pre-Flip Point)
Phoebe[1,2,3]	2019	2026	244.3	67.00 %	10.62% 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 tax equity investors against certain breaches of project-level representations, warranties and covenants. The Corporation believes these indemnifications cover matters that are substantially within its control, and are very unlikely to occur.
2. Phoebe's cash distribution amounts to the TEI are fixed and defined within the TEI partnership agreement. All amounts of distributable cash in excess of this defined threshold are distributed at the rate of 10.62% and 89.38% to the TEI and Innergex respectively.
3. TEI Allocation of Taxable Income (Loss) and ITC are 99% until February 15, 2020, down to 67% from February 15, 2020, to December 31, 2024, and then back to 99.0% until TEI Flip Point.

Basis Hedge

In order to protect the project's returns in the event of a change in the expected price dynamics between the ERCOT South Hub and the Phoebe Node, and in light of the existing transmission congestion prevailing in Texas, broadening the basis differential risk at numerous locations, on August 2, 2019, the Corporation entered into a 2-year basis hedge, effective from November 1, 2019, to December 31, 2021.

Under the basis hedge, Innergex swaps the ERCOT South Hub and the Phoebe Node prices at a contractual hourly quantity of 100 MW per hour, for 16 hours daily. As supported by the studies carried out by Innergex's external consultants prior to the transaction being executed, the basis hedge was designed to protect against the basis risk associated with the power hedge during the daily generation period, while the exposure outside of such generation period was expected to be limited.

However, contrary to the initial expectation, the project has been exposed to large unfavourable basis differentials outside of generation hours, which contributed to a cumulated realized loss of $31.2 million to date. The basis hedge is accounted for at fair value, with subsequent changes being recognized in the consolidated statements of earnings (loss), as change in fair value of financial instruments. Such changes incorporated a realized loss of $0.6 million for the three-month period ended September 30, 2020 (nil for the comparable period of 2019), and a realized loss of $19.5 million for the nine-month period ended September 30, 2020 (nil for the comparable period of 2019), recorded in the project's tracking account[1].

[1] Renewable energy projects selling energy under a power/basis hedge structure are exposed to mismatch risks mainly driven by: (1) the risk of a shortfall in the actual energy produced in comparison to the contractual hourly quantity under the hedges; and (2) a price differential risk between hub, node, and fixed contractual prices per MW of contracted energy. To cover such temporary unfavourable mismatches, the counterparty provides the project with a tracking account; a working capital loan that is repaid with subsequent favourable mismatches.

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

KEY PERFORMANCE INDICATORS

The Corporation measures its performance using key performance indicators ("KPIs").

Production KPIs

When evaluating its operating results, a key performance indicator for the Corporation is to compare actual electricity generation with a long-term average ("LTA"), which is determined to allow long-term forecasting of the expected power generation of each facility.

- Production in comparison with LTA in megawatt/hours ("MWh") and gigawatt/hours ("GWh")
- Production and Production Proportionate

Financial KPIs

- Revenues and Revenues Proportionate
- Adjusted EBITDA, Adjusted EBITDA Margin, Adjusted EBITDA Proportionate and Adjusted EBITDA Proportionate Margin
- Adjusted Net Earnings (Loss)
- Free Cash Flow
- Payout Ratio

The Corporation believes that these indicators are important, as they provide management and the reader with additional information about the Corporation's production and cash-generating capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. The indicators also facilitate the comparison of results over different periods.

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

BUSINESS STRATEGY

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

Innergex is guided by its philosophy that balances investing in people, caring for the 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.

Produce Renewable Energy

The Corporation is committed to producing energy from sustainable renewable sources exclusively and to providing energy storage capacity, by balancing economic, social and environmental considerations. By harnessing the power of the sun's rays, the natural flow of water and the motion of the air, we work with nature to generate clean energy for a brighter future.

Optimize Operations

Innergex owns interests in 37 hydroelectric facilities drawing on 31 watersheds, 32 wind farms and 6 solar farms. The expertise and innovation developed by our skilled team in various energies and different locations can be leveraged and shared among the Corporation to maximize returns from our high-quality assets.

Maintain Diversification of Energy Sources

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 year could have an impact on the Corporation's revenues and hence on its profitability.

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

	Consolidated LTA and Quarterly Seasonality[1]									
In GWh and %	Q1		Q2		Q3		Q4		Total	
HYDRO	370	12 %	1,065	36 %	1,002	33 %	581	19 %	3,018	35 %
WIND	1,364	29 %	1,112	23 %	916	20 %	1,292	28 %	4,684	54 %
SOLAR	213	22 %	276	29 %	270	28 %	200	21 %	959	11 %
Total	1,947	22 %	2,453	29 %	2,188	25 %	2,073	24 %	8,661	100 %

1. The consolidated long-term average production is the annualized LTA for the facilities in operation as of November 10, 2020. 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 Performance Indicators" section.

Grow Responsibly

The transition to a carbon-neutral economy will be led by the renewable energy sector. Innergex stands well-positioned to continue its strategic growth by further developing, acquiring, owning and operating high-quality renewable energy projects and energy storage facilities and will continue to champion the advancement of renewable energy solutions.

Nurturing relationships to develop long-term partnerships that support fruitful renewable energy projects is at the core of our business strategy and values. Our projects flourish with the support of our financial, corporate, Indigenous and municipal partners. Our values of following our passion, getting involved, driving opportunities, leading with integrity, achieving together, acting safely and generating prosperity are all ingredients of our success.

Acquisitions are another important component of the Corporation's business strategy. Gaining a foothold in new markets increases our reach, diversity and opportunities for growth. Similarly, increasing our presence in established locations allows us to consolidate our position as a renewable energy leader, such as in the Canadian market. Our focus will remain on generating energy solely from renewable sources and we will continue to explore new technologies that could bring further opportunities in electricity production and beyond, such as energy storage.

Deliver Exceptional Results

Innergex recognizes that what we have accomplished and what is yet to come would not be possible without our highly skilled team of employees who share our mission, vision, values and key principles.

Their collective knowledge, talent, abilities, experience and sound judgment have always been key to our long-term success. Our management team has a proven track record of delivering projects on-time and on-budget.

Furthermore, we have nurtured a pool of specialized partners we can rely on to provide services outside our realm of expertise when necessary, from engineering firms to environmental monitoring professionals.

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

THIRD QUARTER UPDATE

Corporate Development

Acquisition of six wind farms in Idaho, United States

- On July 15, 2020, the Corporation completed the acquisition of all Class B shares of a portfolio of six operating wind farms in Elmore County, Idaho in the United States (the "Mountain Air Acquisition") for a purchase price of US$56.8 million ($77.3 million).
- The six 23 MW wind farms, Cold Springs, Desert Meadow, Hammett Hill, Mainline, Ryegrass and Two Ponds, have a total installed capacity of 138 MW and were fully commissioned in December 2012. The wind turbines are currently under a full scope Service Maintenance Agreement, and all wind farms have power purchase agreements with Idaho Power Company, a power utility rated BBB by Standard & Poor's, for 100% of their capacity over a remaining period of approximately 12 years.
- The Mountain Air Acquisition is expected to produce a gross estimated long-term average of 331 GWh per year and a US$21.1 million ($28.1 million) projected adjusted EBITDA for 2021.
- The Class B shares should provide Innergex with additional cash immediately available for distribution representing 62.25% of the project free cash flow. Following cash distributions to the tax equity investor, the distributions receivable by Innergex would be approximately US$6.1 million ($8.1 million). The Class A shares will remain the property of the tax equity investor.
- The existing long-term non-recourse project-level financing amortized over the next 12 years remains in place and was assumed by the Corporation, as part of the acquisition, at a fair value of US$126.5 million ($172.3 million).

Development Activities

(as at the date of this MD&A)

	Location	Gross installed capacity (MW)	Expected COD	Gross estimated LTA[1] (GWh)	PPA term (years)
HYDRO (Chile)					
Frontera	Biobío	109.0	—	464.0	— [2]
SOLAR (United States)					
Hale Kuawehi	Hawaii	30.0 [3]	2022	87.4 [5]	25
Paeahu	Hawaii	15.0 [3]	2023	41.2 [5]	25
Kahana	Hawaii	20.0 [3]	2023	74.6 [5]	25
Barbers Point	Hawaii	15.0 [3]	2023	37.0 [5]	25
STORAGE (France)					
Tonnerre	France	— [4]	2021	—	— [6]

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

Frontera

- The financing process, the construction contract and permitting are progressing slowly due to the COVID-19 pandemic.
- Project schedule is under revision.

Hale Kuawehi

- The Public Utilities Commission ("PUC") approved the PPA.
- Environmental and technical studies are completed.
- 30% design engineering is completed.
- Engineering, procurement and construction ("EPC") request for proposals is underway. Selection to be made in Q4 2020.
- Permitting applications are underway.

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

Paeahu

- The PUC has approved the PPA.
- Environmental and technical studies are completed.
- 30% design engineering is completed.
- EPC request for proposals is underway. Selection to be made in Q4 2020.
- The Special Use Permit application will be filed in Q4 2020.
- Expected COD postponed to 2023.

Kahana

The Kahana solar project is a 20 MW_{AC} facility with 80 MWh of battery storage located on the island of Maui. The project has signed a 25-year power purchase agreement with the Maui Electric Company that provides a fixed price. The agreement is subject to approval by the PUC of Hawaii. Sales will start upon the facility reaching commercial operation, which is expected in 2023.

- Environmental studies are ongoing as are other permitting-related activities.

Barbers Point

The Barbers Point solar project is a 15 MW_{AC} facility with 60 MWh of battery storage located on the island of Oahu. The project has signed a 25-year power purchase agreement with the Hawaiian Electric Company that provides a fixed price. The agreement is subject to approval by the PUC of Hawaii. Sales will start upon the facility reaching commercial operation, which is expected in 2023.

- Environmental studies are ongoing as are other permitting-related activities.

Tonnerre

- The preferred battery provider has been selected and exclusive negotiations are in progress.

Construction Activities

(as at the date of this MD&A)

	Ownership %	Gross installed capacity (MW)	Expected COD	Gross estimated LTA[1] (GWh)	PPA term (years)	Total project cost	Expected first 5-year average	
						Estimated[1] ($M)	Revenues[1] ($M)	Adjusted EBITDA[1,2] ($M)
SOLAR (United States)								
Hillcrest	100.0	200.0	2021	413.3	15	385.5 [3]	22.7 [3]	13.6 [4]
HYDRO (Quebec)								
Innavik	50.0	7.5	2022	54.7	40	127.8 [4]	10.8 [4]	8.6 [4]
WIND (France)								
Yonne II	69.6	6.9	2021	11.0	20	16.9 [5]	1.6 [5]	1.2 [5]
WIND (United States)								
Griffin Trail	100.0	225.6	2021	799.0	— [6]	379.1 [7]	20.9	9.2
Total		440.0		1,278.0		909.3	56.0	32.6

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. Adjusted EBITDA is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.
3. Total Estimated Project Cost at US$289.0 million, Expected Revenues at US$17.0 million and Expected Adjusted EBITDA at US$10.2 million translated at a rate of 1.3339.
4. Corresponding to 100% of this facility.
5. Total Estimated Project Cost at €10.8 million, Expected Revenues at €1.0 million and Expected Adjusted EBITDA at €0.8 million translated at a rate of 1.5631.
6. Power to be sold on the open market.
7. Total Estimated Project Cost at US$284.2 million, Expected Revenues at US$15.7 million and Expected Adjusted EBITDA at US$6.9 million translated at a rate of 1.3339.

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

Hillcrest

- All major work activities are well underway and the project is approximately 65% complete.
- All major equipment has been received on-site.
- Pile driving, tracker installation and module installation are ongoing with multiple crews on each activity and over 650 total personnel on site.
- Installation of AC and DC cabling is well underway and is expected to be completed in November 2020.
- Construction of the substation is complete and the transmission line and substation have been energized.
- Feeder 1 completion occurred in late October, and first synchronization is scheduled mid-November.
- Total estimated construction costs increased by US$9.5 million ($12.7 million).
- The tax equity investor made an initial investment of US$22.4 million ($29.8 million), representing 20% of its total investment amount on October 29, 2020.
- Full commercial operation is scheduled for Q1 2021.

Innavik

- Contractor mobilization on-site was completed and workers' camp capacity increased from 30 to 120.
- Eight maritime transports were achieved to deliver all necessary equipment to site.
- Powerhouse access road, powerhouse and tailrace excavation have started and are progressing well.
- Aggregate from the excavation was used to prepare the laydown area where the concrete batch plant will be installed in Q4 2020.
- Upgrade of the existing North shore road is 50% completed.
- Total estimated construction costs increased by $2.8 million.
- Construction and long-term credit agreement of $92.8 million entered into on November 4, 2020.
- Commercial operation is scheduled for Q4 2022.

Yonne II

- Craning pads, storage area, access roads and all three foundations are now completed.
- All concrete tower sections have been delivered to site and erection works have begun.
- Remaining turbine components (blades, nacelles, hubs, steel tower sections) will be delivered and installed in Q4 2020.
- Commercial operation is scheduled for late Q1 2021.

Griffin Trail

- A Turbine Supply Agreement was executed with a turbine manufacturer in June for supply of 80 2.8MW turbines with deliveries starting in January 2021.
- A construction agreement was executed in early November with an EPC contractor for a balance of plant construction including installation of the turbines.
- Work on-site commenced in September, including construction of the roads, turbine foundations and the operations and maintenance building.
- Procurement of long-lead items has commenced and deliveries to the site started in October.
- Construction of the interconnection point is underway by a local transmission provider.
- Financing and tax equity investment process are progressing well.
- Commercial operation is scheduled for Q3 2021.
- Griffin Trail is planned to be a ‘merchant facility’, and will sell the energy from the project on the spot market in ERCOT.

OPERATING RESULTS

Electricity Production

The Corporation's operating results for the three-month period ended September 30, 2020, are compared with the operating results for the same period in 2019.

	Three months ended September 30					
	2020			2019		
Energy Segment	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA
HYDRO						
Quebec	181,050	180,224	100 %	142,039	180,225	79 %
Ontario	6,904	8,233	84 %	2,269	8,233	28 %
British Columbia	663,946	796,474	83 %	714,892	796,474	90 %
United States	16,531	16,694	99 %	15,694	16,694	94 %
Subtotal	868,431	1,001,625	87 %	874,894	1,001,626	87 %
WIND						
Quebec	485,791	447,857	108 %	460,212	422,148	109 %
France	101,934	140,544	73 %	127,718	140,544	91 %
United States[2,3]	314,987	317,132	99 %	43,331	43,331	100 %
Subtotal	902,712	905,533	100 %	631,261	606,023	104 %
SOLAR						
Ontario	12,804	12,197	105 %	14,202	12,283	116 %
United States[4]	196,393	219,388	90 %	145,005	145,161	100 %
Chile[5]	41,219	38,863	106 %	—	—	— %
Subtotal	250,416	270,448	93 %	159,207	157,444	101 %
Total	2,021,559	2,177,606	93 %	1,665,362	1,765,093	94 %

1. Some facilities are treated as joint ventures and associates and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for consistency, their electricity production figures have been excluded from the production table.
2. Foard City was commissioned on September 27, 2019.
3. Production and LTA for the period from July 15, 2020, to September 30, 2020, following the Mountain Air Acquisition.
4. Phoebe was commissioned on November 19, 2019.
5. Production and LTA for the period from July 1, 2020, to September 30, 2020, following the Salvador Acquisition on May 14, 2020.

Overall, the **hydroelectric** facilities produced 87% of their LTA mainly due to:

- the curtailment imposed by BC Hydro from May 22, 2020, to July 20, 2020, for five facilities; and
- below-average water flows at some British Columbia facilities.

Overall, the **wind** farms produced 100% of their LTA mainly due to:

- above-average wind regimes in Quebec.

This item was partly offset by:

- the curtailment due to environmental monitoring results at some facilities in France combined with the temporary shutdown of production at two facilities.

Overall, the **solar** farms produced 93% of their LTA mostly due to:

- below-average solar irradiation in the United States combined with outages and a curtailment required by the distribution network in Texas at the Phoebe facility.

Production for the three-month period ended September 30, 2020, was 2,021,559 MWh compared with 1,665,362 MWh for the same period last year. The 21% increase is due mainly to:

- the contribution of the Foard City wind farm and Phoebe solar facility commissioned on September 27, 2019, and November 19, 2019, respectively;
- the contribution of the Salvador Acquisition and Mountain Air Acquisition completed on May 14, 2020, and July 15, 2020, respectively;
- higher production from the Quebec hydro facilities; and
- higher production at some British Columbia hydro facilities not affected by the curtailment.

These items were partly offset by:

- the curtailment imposed by BC Hydro for five hydro facilities.

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

The Corporation's operating results for the nine-month period ended September 30, 2020, are compared with the operating results for the same period in 2019.

	Nine months ended September 30, 2020					
	2020			2019		
Energy Segment	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA
HYDRO						
Quebec	501,598	518,444	97 %	501,854	518,444	97 %
Ontario	45,914	53,332	86 %	45,771	53,332	86 %
British Columbia	1,503,565	1,822,904	82 %	1,638,644	1,822,904	90 %
United States	39,386	41,577	95 %	35,490	41,577	85 %
Subtotal	2,090,463	2,436,257	86 %	2,221,759	2,436,257	91 %
WIND						
Quebec	1,693,988	1,649,467	103 %	1,778,425	1,640,563	108 %
France	503,002	525,374	96 %	482,678	525,374	92 %
United States[2,3]	993,938	1,025,655	97 %	43,331	43,331	100 %
Subtotal	3,190,928	3,200,496	100 %	2,304,434	2,209,268	104 %
SOLAR						
Ontario	33,311	31,260	107 %	34,209	31,480	109 %
United States[4]	515,422	601,541	86 %	155,418	158,080	98 %
Chile[5]	56,825	54,782	104 %	—	—	— %
Subtotal	605,558	687,583	88 %	189,627	189,560	100 %
Total	5,886,949	6,324,336	93 %	4,715,820	4,835,085	98 %
GEOTHERMAL[6]						
Iceland	—	—	— %	545,424	505,395	108 %

1. Some facilities are treated as joint ventures and associates and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for consistency, their electricity production figures have been excluded from the production table.
2. Foard City was commissioned on September 27, 2019.
3. Production and LTA for the period from July 15, 2020, to September 30, 2020, following the Mountain Air Acquisition.
4. Phoebe was commissioned on November 19, 2019.
5. Production and LTA for the period from May 14, 2020, to September 30, 2020, following the Salvador Acquisition.
6. Production and LTA were nil for the period in 2020 as opposed to production and LTA for the period from January 1, 2019, to May 23, 2019.

Overall, the **hydroelectric** facilities produced 86% of their LTA mostly due to:

- the curtailment imposed by BC Hydro for five facilities combined with below-average water flows at the British Columbia facilities.

Overall, the **wind** farms produced 100% of their LTA mainly due to:

- the temporary production shutdown at two facilities and the curtailment due to environmental monitoring results at some facilities, partly offset by above-average wind regime in France; and
- below-average wind regimes in the United States.

These items were offset by:

- above-average wind regime at the Quebec facilities.

Overall, the **solar** farms produced 88% of their LTA mostly due to:

- below-average solar irradiation in the United States combined with a curtailment required by the distribution network in Texas and outages at the Phoebe facility.

Production for the nine-month period ended September 30, 2020, was 5,886,949 MWh compared with 4,715,820 MWh for the same period last year. The 25% increase is due mainly to:

- the contribution of the Foard City wind farm and the Phoebe solar facility commissioned on September 27, 2019, and November 19, 2019, respectively; and
- the contribution of the Salvador Acquisition and Mountain Air Acquisition completed on May 14, 2020, and July 15, 2020, respectively.

These items were partly offset by:

- the curtailment imposed by BC Hydro for five facilities partly offset by higher production from almost all other British Columbia hydro facilities; and
- lower production at the Quebec wind facilities.

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

Production Proportionate[1]

(in MWh)	Three months ended September 30			Nine months ended September 30		
	2020	2019	Change	2020	2019	Change
Production	2,021,559	1,665,362	356,197	5,886,949	4,715,820	1,171,129
Innergex's share of Production of joint ventures and associates:						
Hydro	267,937	286,416	(18,479)	453,660	492,507	(38,847)
Wind	178,434	194,143	(15,709)	666,886	657,835	9,051
Solar	3,219	3,230	(11)	9,285	9,798	(513)
	449,590	483,789	(34,199)	1,129,831	1,160,140	(30,309)
Production Proportionate	2,471,149	2,149,151	321,998	7,016,780	5,875,960	1,140,820

1. Production Proportionate is a "Key performance indicator" for the Corporation, which cannot be reconciled with an IFRS measure and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section of this MD&A for more information.

For the three-month period ended on September 30, 2020, compared with the same period last year

Production Proportionate of the joint ventures' and associates' **hydroelectric facilities** was 267,937 MWh (97% of their LTA) in the third quarter of 2020, compared with 286,416 MWh (102% of their LTA) for the same quarter last year, a 6% decrease due mainly to:

- the curtailment imposed by BC Hydro at the Jimmie Creek facility; and
- lower contribution from the facilities in Chile due to below-average water flows.

Production Proportionate of the joint ventures' and associates' **wind farms** was 178,434 MWh (95% of their LTA) in the third quarter of 2020 compared with 194,143 MWh (104% of their LTA) for the same period last year, an 8% decrease due mostly to:

- lower contribution from the Shannon and Flat Top facilities in Texas.

This item was partly offset by:

- higher contribution from the Dokie facility in British Columbia.

For the nine-month period ended on September 30, 2020, compared with the same period last year

Production Proportionate of the joint ventures' and associates' **hydroelectric facilities** was 453,660 MWh (91% of their LTA) in the nine-month period of 2020, compared with 492,507 MWh (100% of their LTA) for the same period last year, an 8% decrease due mainly to:

- the curtailment imposed by BC Hydro at the Jimmie Creek facility; and
- lower contribution from the facilities in Chile due to below-average water flows.

These items were partly offset by:

- higher contribution from the Toba Montrose facility due to above-average water flows.

Production Proportionate of the joint ventures' and associates' **wind farms** was 666,886 MWh (99% of their LTA) in the nine-month period of 2020 compared with 657,835 MWh (98% of their LTA) for the same period last year, a 1% increase due mostly to:

- higher contribution from the Dokie facility in British Columbia.

This item was partly offset by:

- lower contribution from the Shannon and Flat Top facilities in Texas.

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

Financial Results

	Three months ended September 30[1]				Nine months ended September 30[1]			
	2020	2019	Change		2020	2019	Change	
Revenues	162,651	142,814	19,837	14 %	445,280	413,926	31,354	8 %
Operating expenses	37,040	24,403	12,637	52 %	94,932	72,147	22,785	32 %
General and administrative expenses	12,388	7,731	4,657	60 %	32,969	25,272	7,697	30 %
Prospective project expenses	4,699	3,329	1,370	41 %	13,100	10,665	2,435	23 %
Adjusted EBITDA[2]	108,524	107,351	1,173	1 %	304,279	305,842	(1,563)	(1)%
Adjusted EBITDA margin[2]	66.7 %	75.2 %			68.3 %	73.9 %		
Finance costs	60,122	59,474	648	1 %	175,700	170,704	4,996	3 %
Other net income	(16,725)	(3,917)	(12,808)	327 %	(58,250)	(2,639)	(55,611)	2,107 %
Depreciation and amortization	59,368	48,343	11,025	23 %	170,061	141,558	28,503	20 %
Share of (earnings) losses of joint ventures and associates[3]	(11,382)	(16,225)	4,843	(30)%	21,398	(9,193)	30,591	(333)%
Change in fair value of financial instruments	(1,859)	6,031	(7,890)	(131)%	24,835	9,225	15,610	169 %
Income tax expense	11,508	3,749	7,759	207 %	11,540	1,164	10,376	891 %
Net earnings (loss) from continuing operations	7,492	9,896	(2,404)	(24)%	(41,005)	(4,977)	(36,028)	724 %
Net (loss) earnings from discontinued operations	—	(193)	193	(100)%	—	21,171	(21,171)	(100)%
Net earnings (loss)	7,492	9,703	(2,211)	(23)%	(41,005)	16,194	(57,199)	(353)%
Net earnings (loss) attributable to:								
Owners of the parent	11,740	14,085	(2,345)	(17)%	(44,548)	18,117	(62,665)	(346)%
Non-controlling interests	(4,248)	(4,382)	134	(3)%	3,543	(1,923)	5,466	(284)%
	7,492	9,703	(2,211)	(23)%	(41,005)	16,194	(57,199)	(353)%
Basic and diluted net earnings (loss) per share from continuing operations attributable to owners ($)	0.06	0.10			(0.29)	(0.04)		
Basic and diluted net earnings (loss) per share attributable to owners ($)	0.06	0.09			(0.29)	0.10		

1. Results from continuing operations unless otherwise indicated.
2. 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.
3. 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.

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

Revenues

Up 14% to $162.7 million for the three-month period ended September 30, 2020
Up 8% to 445.3 million for the nine-month period ended September 30, 2020

	Three months ended September 30			Nine months ended September 30		
Energy Segment	2020	2019	Change	2020	2019	Change
Hydro	76,170	74,440	1,730	169,157	178,969	(9,812)
Wind	67,726	54,778	12,948	235,325	211,797	23,528
Solar	18,755	13,596	5,159	40,798	23,160	17,638
Revenues	162,651	142,814	19,837	445,280	413,926	31,354

For the three-month period ended on September 30, 2020, compared with the same period last year

The increase in revenues from the **hydroelectric** power generation segment is mainly due to:

- higher production at some Quebec facilities.

This item was partly offset by:

- lower revenues from the facilities in British Columbia due to a combination of BC Hydro curtailment and lower average selling prices.

The increase in revenues from the **wind** power generation segment is mainly due to:

- the Mountain Air Acquisition in Idaho on July 15, 2020;
- the commissioning of the Foard City wind farm in Texas on September 27, 2019; and
- higher revenues at the Quebec facilities due to higher production.

These items were partly offset by:

- lower revenues from the wind farms in France due to lower production.

The increase in revenues from the **solar** power generation segment is mainly due to:

- the commissioning of the Phoebe solar facility in Texas on November 19, 2019; and
- the Salvador Acquisition in Chile on May 14, 2020.

These items were partly offset by:

- lower revenues at the Ontario facility due to lower production.

For the nine-month period period ended on September 30, 2020, compared with the same period last year

The decrease in revenues from the **hydroelectric** power generation segment is mainly due to:

- lower revenues in British Columbia attributable to a net unfavourable impact of lower production from five facilities due to the curtailment imposed by BC Hydro over higher average selling prices; and
- lower average selling prices at some Quebec facilities.

The increase in revenues from the **wind** power generation segment is mainly due to:

- the commissioning of the Foard City wind farm in Texas on September 27, 2019;
- the Mountain Air Acquisition in Idaho on July 15, 2020; and
- higher revenues from the wind farms in France due to higher production.

These items were partly offset by:

- lower revenues at the Quebec facilities due to lower production.

The increase in revenues from the **solar** power generation segment is mainly due to:

- the commissioning of the Phoebe solar facility in Texas on November 19, 2019; and
- the Salvador Acquisition in Chile on May 14, 2020.

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

Revenues Proportionate[1]

	Three months ended September 30			Nine months ended September 30		
	2020	2019	Change	2020	2019	Change
Revenues	162,651	142,814	19,837	445,280	413,926	31,354
Innergex's share of Revenues of joint ventures and associates:						
Hydro	30,521	32,203	(1,682)	49,982	53,896	(3,914)
Wind	6,917	4,324	2,593	22,597	21,503	1,094
Solar	403	475	(72)	1,420	1,507	(87)
	37,841	37,002	839	73,999	76,906	(2,907)
PTCs and Innergex's share of PTCs generated:	13,244	7,088	6,156	50,832	20,688	30,144
Revenues Proportionate	213,736	186,904	26,832	570,111	511,520	58,591

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

For the three-month period ended on September 30, 2020, compared with the same period last year

Joint ventures' and associates' **hydroelectric facilities** contributed $30.5 million to Revenues Proportionate in the third quarter of 2020, compared with a contribution of $32.2 million for the same quarter last year, a 5% decrease due mostly to:

- lower production at the Jimmie Creek facility due to the curtailment imposed by BC Hydro over higher average selling prices; and
- lower revenues from the facilities in Chile mostly due to lower production.

These items were partly offset by:

- higher revenues from the Toba Montrose facility in British Columbia due to higher average selling prices.

Joint ventures' and associates' **wind farms** contributed $6.9 million to Revenues Proportionate in the third quarter of 2020, compared with $4.3 million for the same quarter last year, a 60% increase mainly due to:

- higher contribution from the Shannon and Flat Top wind farms in Texas due to favourable net prices.
- higher revenues at the Dokie facility attributable to higher production.

The proportional PTCs generated by the **wind farms** contributed $13.2 million in the third quarter of 2020, compared with a $7.1 million contribution in the same quarter last year. The increase is due to:

- PTCs generated by the Foard City wind farm following its commissioning on September 27, 2019.

For the nine-month period ended on September 30, 2020, compared with the same period last year

Joint ventures' and associates' **hydroelectric facilities** contributed $50.0 million to Revenues Proportionate in the nine-month period of 2020, compared with a contribution of $53.9 million for the same period last year, a 7% decrease due mostly to:

- lower revenues from the facilities in Chile mostly due to lower production combined with lower average selling prices; and
- lower production at the Jimmie Creek facility due to the curtailment imposed by BC Hydro over higher average selling prices.

These items were partly offset by:

- higher revenues from the Toba Montrose facility in British Columbia due to the combined impact of higher production and higher average selling prices.

Joint ventures' and associates' **wind farms** contributed $22.6 million to Revenues Proportionate in the nine-month period of 2020, compared with $21.5 million for the same period last year, a 5% increase mainly due to:

- higher revenues from the Dokie facility attributable to a net favourable impact of higher production over lower average selling prices.
- higher contribution from the Shannon and Flat Top wind farms in Texas due to the net impact of favourable net prices over lower production.

The proportional PTCs generated by the **wind farms** contributed $50.8 million in the nine-month period of 2020, compared with a $20.7 million contribution in the same period last year. The increase is due to:

- PTCs generated by the Foard City wind farm following its commissioning on September 27, 2019.

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

Adjusted EBITDA[1]

Up 1% to $108.5 million for the three-month period ended September 30, 2020
Down 1% to $304.3 million for the nine-month period ended September 30, 2020

	Three months ended September 30			Nine months ended September 30		
Energy Segment	2020	2019	Change	2020	2019	Change
Hydro	61,847	62,778	(931)	130,368	140,897	(10,529)
Wind	48,431	41,589	6,842	185,287	175,237	10,050
Solar	14,034	13,187	847	31,079	22,238	8,841
	124,312	117,554	6,758	346,734	338,372	8,362
Other items	(15,788)	(10,203)	(5,585)	(42,455)	(32,530)	(9,925)
Adjusted EBITDA	108,524	107,351	1,173	304,279	305,842	(1,563)

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.

For the three-month period ended on September 30, 2020, compared with the same period last year

The decrease in Adjusted EBITDA in the **hydroelectric** power generation segment is mainly due to:

- lower contribution from the facilities in British Columbia due to the combined impact of lower revenues and higher operational expenses.

This item was partly offset by:

- higher contribution from the Quebec facilities explained by a net favourable impact of higher revenues over higher operational expenses.

The increase in Adjusted EBITDA in the **wind** power generation segment is mainly due to:

- the Mountain Air Acquisition in Idaho on July 15, 2020;
- higher contribution from the Quebec facilities explained by higher revenues; and
- the commissioning of the Foard City wind farm in Texas on September 27, 2019.

These items were partly offset by:

- lower contribution from the wind facilities in France due to lower revenues and higher operational expenses.

The increase in Adjusted EBITDA in the **solar** power generation segment is mainly due to:

- the commissioning of the Phoebe solar facility on November 19, 2019

The Adjusted EBITDA was also impacted by higher general and administrative expenses.

For the nine-month period ended on September 30, 2020, compared with the same period last year

The decrease in Adjusted EBITDA in the **hydroelectric** power generation segment is mainly due to:

- lower contribution from the facilities in British Columbia mostly attributable to lower revenues; and
- lower contribution from the Quebec facilities explained by lower revenues and higher operational expenses.

The increase in Adjusted EBITDA in the **wind** power generation segment is due mainly to:

- the Mountain Air Acquisition in Idaho on July 15, 2020;
- the commissioning of the Foard City wind facility on September 27, 2019; and
- higher contribution from the wind facilities in France due to a net favourable impact of higher revenues over lower operational expenses.

These items were partly offset by:

- lower contribution from the Quebec facilities mostly attributable to a net unfavourable impact of lower revenues over lower operational expenses.

The increase in Adjusted EBITDA in the **solar** power generation segment is mainly due to:

- the commissioning of the Phoebe solar facility on November 19, 2019.

The Adjusted EBITDA was also impacted by higher general and administrative expenses to support the Corporation's growth.

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

Adjusted EBITDA Margin[1]

Down from 75.2% to 66.7% for the three-month period ended on September 30, 2020
Down from 73.9% to 68.3% for the nine-month period ended on September 30, 2020

The decrease for the three-month period is mainly explained by:

- lower contribution from the hydro facilities due to the increased relative weight of the solar and wind segments, which intrinsically exhibit lower margins, following the recent acquisitions and commissioning activities;
- higher operational expenses from the hydro facilities; and
- higher general and administrative expenses.

The decrease for the nine-month period is mainly explained by:

- lower contribution from the hydro facilities due to the increased relative weight of the solar and wind segments, which intrinsically exhibit lower margins, following the recent acquisitions and commissioning activities; and
- higher general and administrative expenses.

1. Adjusted EBITDA Margin 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.

Adjusted EBITDA Proportionate[2]

	Three months ended September 30			Nine months ended September 30		
	2020	2019	Change	2020	2019	Change
Adjusted EBITDA	108,524	107,351	1,173	304,279	305,842	(1,563)
Innergex's share of Adjusted EBITDA of joint ventures and associates:						
Hydro	26,402	28,176	(1,774)	39,472	40,639	(1,167)
Wind	2,989	(122)	3,111	11,979	9,165	2,814
Solar	274	391	(117)	836	665	171
	29,665	28,445	1,220	52,287	50,469	1,818
PTCs and Innergex's share of PTCs generated:	13,244	7,088	6,156	50,832	20,688	30,144
Adjusted EBITDA Proportionate	151,433	142,884	8,549	407,398	376,999	30,399

2. Adjusted EBITDA 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.

For the three-month period ended onSeptember 30, 2020, compared with the same period last year

The joint ventures' and associates' **hydroelectric facilities** contributed $26.4 million to the Adjusted EBITDA Proportionate in the third quarter of 2020, compared with $28.2 million for the same quarter last year, a 6% decrease mainly due to:

- lower contribution from the facilities in Chile due to lower revenues and higher operational costs;
- lower contribution from the Jimmie Creek facility due to lower revenues.

These items were partly offset by:

- higher contribution from the Toba Montrose facility due to higher revenues.

The joint ventures' and associates' **wind farms** contributed $3.0 million to the Adjusted EBITDA Proportionate for the third quarter of 2020, compared with a negative $0.1 million contribution in the same quarter last year mainly due to:

- higher contribution from the Shannon and Flat Top facilities due to higher revenues and lower operational expenses;
- higher contribution from the Dokie facility due to higher revenues.

The proportional PTCs generated by the **wind farms** contributed $13.2 million in the third quarter of 2020, compared with a $7.1 million contribution in the same quarter last year. The increase is due to:

- PTCs generated by the Foard City wind farm following its commissioning on September 27, 2019.

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

For the nine-month period ended on September 30, 2020, compared with the same period last year

The joint ventures' and associates' **hydroelectric facilities** contributed $39.5 million to the Adjusted EBITDA Proportionate in the nine-month period of 2020, compared with $40.6 million for the same period last year, a 3% decrease mainly due to:

- lower contribution from the Jimmie Creek facility due to lower revenues.
- lower contribution from the facilities in Chile due to a net unfavourable impact of lower revenues over lower operational costs.

These items were partly offset by:

- higher contribution from the Toba Montrose facility due to higher revenues.

The joint ventures' and associates' **wind farms** contributed $12.0 million to the Adjusted EBITDA Proportionate for the nine-month period of 2020, compared with a $9.2 million contribution in the same period last year, a 31% increase mainly due to:

- higher contribution from the Flat Top and Shannon facilities due to lower operational expenses and higher revenues; and
- higher contribution from the Dokie facility due to higher revenues.

The proportional PTCs generated by the **wind farms** contributed $50.8 million in the nine-month period of 2020, compared with a $20.7 million contribution in the same period last year. The increase is due to:

- PTCs generated by the Foard City wind farm following its commissioning on September 27, 2019.

Adjusted EBITDA Proportionate Margin[1]

Down from 76.4% to 70.9% for the three-month period ended on September 30, 2020
Down from 73.7% to 71.5% for the nine-month period ended on September 30, 2020

The decrease for the three-month period is mainly explained by:

- lower adjusted EBITDA margin.

This item was partly offset by:

- higher margin in the wind segment due to the Foard City facility's PTCs, which directly improve the margin combined with higher margin at the Shannon and Flat Top facilities.

The decrease for the nine-month period is mainly explained by:

- lower adjusted EBITDA margin.

This item was partly offset by:

- higher margin in the wind segment mostly due to the Foard City facility's PTCs, which directly improve the margin.

1. Adjusted EBITDA Proportionate Margin 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.

Finance Costs

Up 1% to $60.1 million for the three-month period ended September 30, 2020
Up 3% to $175.7 million for the nine-month period ended September 30, 2020

The increase for the three-month period is mainly due to:

- interest expenses related to the Phoebe and Foard City project loans and lease liabilities following the commissionning in late 2019, and interest on tax equity financing entered into concurrently in the fourth quarter of 2019;
- interest expenses relating to the long-term loans assumed in the Mountain Air Acquisition.

These items were partly offset by:

- interest income on the preferred shares owned in the Innavik joint venture; and
- lower interest on the corporate credit facilities that was partially repaid during the first quarter of 2020.

The increase for the nine-month period is mainly due to:

- interest expenses related to the Phoebe and Foard City project loans and lease liabilities following the commissionning in late 2019, and interest on tax equity financing entered into concurrently in the fourth quarter of 2019;
- interest expenses relating to the long-term loans assumed in the Mountain Air Aquisition.

These items were partly offset by:

- lower inflation compensation interest on the Harrison Hydro real return bonds owing to periods of negative inflation during the second quarter of 2020, compared with the same periods last year;
- interest income on the preferred shares owned in the Innavik joint venture; and
- lower interest on the corporate credit facility that was partially repaid during the first quarter of 2020.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 4.48% as at September 30, 2020 (4.48% as at December 31, 2019).

Other Net Income

Income of $16.7 million for the three-month period ended September 30, 2020
Income of $58.3 million for the nine-month period ended September 30, 2020

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Tax attributes allocated to tax equity investors	(4,303)	—	(15,733)	—
Production tax credits	(8,229)	—	(31,281)	—
Realized gain on contingent considerations	—	—	(945)	—
Restructuring costs	707	1,822	1,157	1,822
Transaction costs related to business combinations	527	199	868	211
Realized gain on foreign exchange	(689)	(2,723)	(4,878)	(2,939)
Others, net	(4,738)	(3,215)	(7,438)	(1,733)
	(16,725)	(3,917)	(58,250)	(2,639)

The increase for the three-month period is mainly due to:

- PTCs generated by the Foard City wind project, following its commissioning in late 2019, and applied as principal payment against the tax equity financing;
- tax attributes allocated to the tax equity investors and applied as principal payment against the tax equity financing related to the in most part to the Phoebe solar project commissioned in late 2019, which is subject to accelerated tax depreciation.

The increase for the nine-month period is mainly due to:

- PTCs generated by the Foard City wind project, following its commissioning in late 2019, and applied as principal payment against the tax equity financing;
- tax attributes allocated to the tax equity investors and applied as principal payment against the tax equity financing related to the in most part to the Phoebe solar project commissioned in late 2019, which is subject to accelerated tax depreciation.
- a compensation for business interruptions that occurred during 2020 related to the curtailment due to environmental monitoring results at some facilities in France, combined with the temporary shutdown of production at two French facilities; and
- an increase in the foreign exchange gain on the revaluation of net U.S. dollar-denominated monetary assets in conjunction with a weakening of the Canadian dollar against the U.S. dollar.

Depreciation and Amortization

Up 23% to $59.4 million for the three-month period ended September 30, 2020
Up 20% to $170.1 million for the nine-month period ended September 30, 2020

The increases for the three- and nine-month periods are mainly due to:

- the depreciation expense on the Foard City and Phoebe facilities following their commissioning in late 2019.
- the depreciation expense on the Salvador facility in Chile following its acquisition on May 14, 2020.
- the depreciation expense on the Mountain Air facilities in Idaho following their acquisition on July 15, 2020.

Share of (earnings) loss of joint ventures and associates

Share of earnings of $11.4 million for the three-month period ended September 30, 2020, compared with $16.2 million for the corresponding period in 2019
Share of loss of $21.4 million for the nine-month period ended September 30, 2020, compared with share of earnings of $9.2 million for the corresponding period in 2019

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

The earnings decrease for the three-month period is mainly due to:

- ◦ an unfavourable change in the fair value of $1.2 million for the Shannon and $1.5 million for the Flat Top power hedges, which are not designated as cash flow hedges, with changes in the fair value of the derivatives therefore being recognized directly as an element of the investees' net loss.

These items were partly offset by:

- ◦ a favouable change in the fair value of $ 0.2 million for the Innavik bond forward contracts, entered into in February 2020, which are not designated as cash flow hedges, with changes in the fair value of the derivatives therefore being recognized directly as an element of the investee's net loss; and
- ◦ a favourable change in Innergex's share of Adjusted EBITDA of joint ventures and associates of $1.2 million.

The loss for the nine-month period is mainly due to:

- ◦ an unfavourable change in the fair value of $7.7 million for the Shannon and $18.7 million for the Flat Top power hedges, which are not designated as cash flow hedges, with changes in the fair value of the derivatives therefore being recognized directly as an element of the investees' net loss.
- ◦ an unfavourable change in the fair value of $2.2 million for the Innavik bond forward contracts entered into in February 2020, which are not designated as cash flow hedges, with changes in the fair value of the derivatives therefore being recognized directly as an element of the investee's net loss.

These items were partly offset by:

- ◦ a favourable change in Innergex's share of Adjusted EBITDA of joint ventures and associates of $1.8 million.

Change in Fair Value of Financial Instruments

Gain related to a change in fair value of financial instruments of $1.9 million for the three-month period ended September 30, 2020, compared with a loss of $6.0 million for the corresponding period in 2019

Loss related to a change in fair value of financial instruments of $24.8 million for the nine-month period ended September 30, 2020, compared with a loss of $9.2 million for the corresponding period in 2019

(Gain) Loss	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Unrealized portion of change in fair value of financial instruments	(23)	6,031	12,796	9,225
Realized portion of change in fair value of financial instruments:				
Realized gain on the power hedges	(2,447)	—	(7,414)	—
Realized loss on Phoebe basis hedge	611	—	19,453	—
Change in fair value of financial instruments recognized in condensed consolidated statements of earnings (loss)	(1,859)	6,031	24,835	9,225

Derivatives are used by the Corporation to manage its exposure to interest rate risk on its existing and upcoming debt financing, to manage its exposure to foreign exchange risk, thereby protecting the economic value of its facilities, and to manage its exposure to electricity price risk for projects that deliver electricity at variable prices per MWh.

The gain related to the change in fair value of financial instruments for the three-month period ended September 30, 2020, is mainly due to:

- a net realized gain on derivative financial instruments stemming from:
    - ▪ net favourable settlements under the Phoebe and Salvador power hedges.

    This item was partially offset by:
    - ▪ net unfavourable settlements under the Phoebe basis hedge.
- a net unrealized gain on derivative financial instruments stemming from:
    - ▪ a favourable impact related to the change in the fair value of the Phoebe power hedge;
    - ▪ a favourable impact related to the change in the fair value of the Phoebe basis hedge; and
    - ▪ an unrealized gain on the conversion of intragroup loans.

    These items were partially offset by:
        - ▪ an unfavourable impact related to the change in the fair value of the Corporation's portfolio of foreign exchange forward contracts; and
        - ▪ an unfavourable movement in the fair value of the Salvador power hedge.

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

The loss related to the change in fair value of financial instruments for the nine-month period ended September 30, 2020, is mainly due to:

- a net realized loss on derivative financial instruments stemming from:
  - net unfavourable settlements under the Phoebe basis hedge.

  This item was partially offset by:
  - net favourable settlements under the Phoebe and Salvador power hedges.
- a net unrealized loss on derivative financial instruments stemming from:
  - an unfavourable impact related to the change in the fair value of the Phoebe power hedge;
  - an unfavourable impact related to the change in fair value of the Corporation's portfolio of foreign exchange forwards contracts.

  These items were partially offset by:
    - a favourable impact related to the change in fair value of the Phoebe basis hedge; and
    - an unrealized gain on the conversion of intragroup loans.

Income Tax Expense

Income tax expense of $11.5 million for the three-month period ended September 30, 2020, compared with an Income tax expense of $3.7 million for the same period in 2019

Income tax amount $11.5 million for the nine-month period ended September 30, 2020, compared with an income tax expense of $1.2 million for the same period in 2019

For the three- and nine-month periods ended September 30, 2020, the Corporation recorded an income tax expense of $11.5 million explained mainly by change in deferred tax position allocated to the Tax equity investors in the Phoebe solar project and to a lesser extent the Flat Top and Shannon projects.

Net earnings (loss) from continuing operations

Net earnings of $7.5 million ($0.06 earnings per share - basic and diluted) for the three-month period ended September 30, 2020, compared with net earnings from continuing operations of $9.9 million ($0.10 earnings per share - basic and diluted) for the same period in 2019

Net loss of $41.0 million ($0.29 loss per share - basic and diluted) for the nine-month period ended September 30, 2020, compared with a net loss from continuing operations of $5.0 million ($0.04 loss per share - basic and diluted) for the same period in 2019

For the three-month period, the $2.4 million decrease in net earnings can be explained by:

- an $11.0 million increase in depreciation and amortization mainly related to the Foard City and Phoebe facilities commissioned in late 2019, and the Salvador and Mountain Air Acquisitions in 2020;
- a $7.8 million increase in income tax expense, mainly related to tax attributes being allocated to Tax equity investors.
- a $4.8 million decrease in the share of earnings of joint ventures and associates, mainly due to the change in fair value of the Shannon and Flat Top power hedges, and the Innavik bond forward contracts, which are not designated as cash flow hedges, and thus recognized directly as an element of the investees' net loss;

These items were partly offset by:

- a $12.8 million increase in other income mainly related to PTCs generated by the Foard City wind project, and tax attributes allocated to the tax equity investors at the Phoebe solar project; and
- a $7.9 million gain related to the change in fair value of financial instruments, largely related to the unrealized gains on the Phoebe power and basis hedges, and to the realized gain on the Salvador power hedge.

For the nine-month period, the $36.0 million increase in net loss can be explained by:

- a $30.6 million increase in the share of loss of joint ventures and associates, mainly due to the change in fair value of the Shannon and Flat Top power hedges, and the Innavik bond forward contracts, which are not designated as cash flow hedges, and thus recognized directly as an element of the investees' net loss;
- a $28.5 million increase in depreciation and amortization mainly related to the Foard City and Phoebe facilities commissioned in late 2019, and the Salvador and Mountain Air Acquisitions in 2020;
- a $15.6 million loss related to the change in fair value of financial instruments, largely related to:
  - a $12.0 million increase in realized loss, largely driven by a $19.5 million loss on the Phoebe basis hedge which materialized mainly during the first quarter of 2020, partly offset by realized gains on the Phoebe and Salvador power hedges; and
  - a $3.6 million increase in unrealized loss, stemming mainly from a net unfavourable change in unrealized loss on the Phoebe power and basis hedges and an unfavourable change in unrealized loss on the Corporation's portfolio of foreign exchange forward contracts, partly offset by a favourable change in the currency translation of intragroup loans;
- a $10.4 million increase in income tax expense, mainly related to tax attributes being allocated to tax equity investors, partly reduced by a taxable gain from the introduction of a tax equity investor in the Phoebe solar project.

- a $5.0 million increase in finance costs, related mainly to the commissioning of Foard City and Phoebe in late 2019 and to the Mountain Air Acquisition in 2020, partly offset by interest savings made on the corporate revolving facilities following the Hydro-Québec Private Placement, a lower inflation compensation interest on the Harrison Hydro real return bonds, and interest income earned on the Innavik preferred shares.

These items were partly offset by:

- a $55.6 million increase in other net income, mainly related to PTCs generated by the Foard City wind project and tax attributes allocated to the tax equity investors at the Phoebe solar facilities.

Adjusted Net Earnings (Loss) from Continuing Operations

Adjusted Net Earnings from Continuing Operations of $13.4 million for the three-month period ended September 30, 2020, compared with $13.6 million in 2019.

Adjusted Net Earnings from Continuing Operations of $9.3 million for the nine-month period ended September 30, 2020, compared with an Adjusted Net Loss from Continuing Operations of $0.4 million in 2019

When evaluating its operating results, a key performance indicator for the Corporation is Adjusted Net Earnings (Loss) from Continuing Operations. Adjusted Net Earnings (Loss) from Continuing Operations 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.

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. As such, the following items are excluded from the Adjusted Net Earnings (Loss):

- The unrealized portion of the change in fair value of the derivatives that are not subject to hedge accounting, as is the case for the Corporation's power hedges and basis hedge, as well as for its equity accounted investments' power hedges;
- The amount of hedge ineffectiveness in the changes in fair value of the Corporation's derivatives that are subject to hedge accounting.

In addition, due to their limited occurrence (over the remaining contractual period of 15 months), realized losses on the Phoebe basis hedge are deemed not to represent the long-term cash-generating capacity of Innergex, and are thus excluded from the Adjusted Net Earnings (Loss) from Continuing Operations.

Impact on net earnings (loss) of financial instruments	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Net earnings (loss) from continuing operations	7,492	9,896	(41,005)	(4,977)
Add (Subtract):				
Unrealized portion of the change in fair value of financial instruments	(23)	6,031	12,796	9,225
Realized portion of the change in fair value of the Phoebe basis hedge	611	—	19,453	—
Realized loss on foreign exchange forward contracts	(755)	(1,973)	(1,580)	(2,421)
Income tax expense (recovery of) related to above items	1,201	84	(4,000)	(690)
Share of unrealized portion of the change in fair value of financial instruments of joint ventures and associates, net of related income tax	4,850	(453)	23,655	(1,580)
Adjusted Net Earnings (Loss) from continuing operations	13,376	13,585	9,319	(443)

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

Non-controlling Interests

Attribution of losses of $4.2 million to non-controlling interests for the three-month period ended September 30, 2020, compared with $4.4 million for the corresponding period in 2019

Attribution of earnings of $3.5 million to non-controlling interests for the nine-month period ended September 30, 2020, compared with a loss of $1.9 million for the corresponding period in 2019

The attribution of loss to non-controlling interests remained relatively stable for the three-month period ended September 30, 2020, compared with the same period last year.

The earnings attributed to non-controlling interests for the nine-month period ended September 30, 2020, are mainly due to:

- a lower allocation of loss to the non-controlling interests on Innergex Europe, largely due to a net unrealized gain on derivative financial instruments and to an increase in revenues compared with the same period last year; and
- a lower allocation of loss to the non-controlling interests, mostly explained by lower inflation compensation interest on the Harrison Hydro real return bonds owing to periods of negative inflation during the second quarter of 2020, compared with the same period last year.

GEOGRAPHIC SEGMENTS

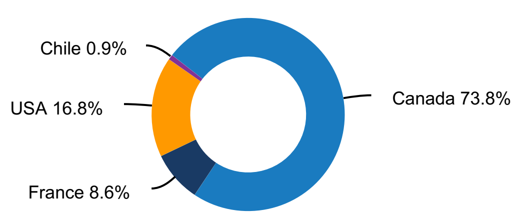
As at September 30, 2020, and excluding its investments in joint ventures and associates, which are accounted for using the equity method, the Corporation had interests in the following operating facilities: 29 hydroelectric facilities, six wind farms and one solar farm in Canada, 15 wind farms in France, one hydroelectric facility, seven wind farms and three solar farms in the United States and one solar farm in Chile. The Corporation operates in four principal geographical areas, which are detailed below.

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Revenues				
Canada	120,038	116,993	320,958	338,137
France	13,938	16,274	67,063	63,413
United States	27,274	9,547	54,738	12,376
Chile	1,401	—	2,521	—
	162,651	142,814	445,280	413,926

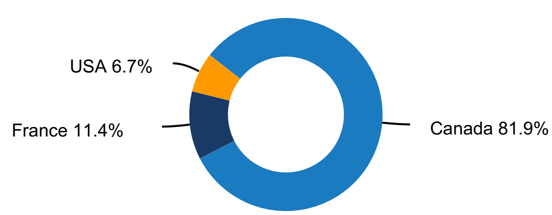
	As at	
	September 30, 2020	December 31, 2019
Non-current assets, excluding derivative financial instruments and deferred tax assets [1]		
Canada	3,558,240	3,629,942
France	929,489	891,764
United States	1,900,629	1,293,983
Chile	208,003	142,268
	6,596,361	5,957,957

1. Includes the investments in joint ventures and associates.

Q3 2020 Revenues by Country



Q3 2019 Revenues by Country



Canada

Revenues up 3% to $120.0 million for the three-month period ended September 30, 2020
Revenues down 5% to $321.0 million for the nine-month period ended September 30, 2020

Non-current assets, excluding derivative financial instruments and deferred tax assets, down 2% to $3,558.2 million at September 30, 2020, compared with December 31, 2019

The increase in Canadian revenues for the three-month period is attributable mainly to:

- higher revenues from the Quebec wind facilities due to higher production; and
- higher revenues from the Quebec hydro facilities due to higher production.

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

These items were partly offset by:

- lower revenues from the facilities in British Columbia due to a combination of BC Hydro curtailment and lower average selling prices; and
- lower revenues at the solar facility in Ontario due to lower production.

The decrease in Canadian revenues for the nine-month period is attributable mainly to:

- lower revenues in British Columbia due to a net unfavourable impact of lower production over higher average selling prices;
- lower revenues from the Quebec wind facilities due to lower production; and
- lower production and lower average selling prices at some Quebec hydro facilities.

The decrease in non-current assets, excluding derivative financial instruments and deferred income tax assets in Canada, is attributable mainly to:

- depreciation of property, plant and equipment, and amortization of intangible assets.

This item was partly offset by:

- increase in preferred shares received in exchange for cash contributions made to Innavik Hydro LP toward the construction of the joint venture hydro project.

France

Revenues down 14% to $13.9 million for the three-month period ended September 30, 2020
Revenues up 6% to $67.1 million for the nine-month period ended September 30, 2020

Non-current assets, excluding derivative financial instruments and deferred tax assets, up 4% to $929.5 million at September 30, 2020, compared with December 31, 2019

The decrease in revenues in France for the three-month period is attributable mainly to:

- lower revenues from the wind farms due to lower production.

The increase in revenues in France for the nine-month period is attributable mainly to:

- higher revenues from the wind farms due to higher production.

The increase in non-current assets, excluding derivative financial instruments and deferred income tax assets in France, is attributable mainly to:

- the weakening of the Canadian Dollar against the Euro.

This item was partly offset by:

- depreciation of property, plant and equipment, and amortization of intangible assets.

United States

Revenues up to $27.3 million for the three-month period ended September 30, 2020
Revenues up to $54.7 million for the nine-month period ended September 30, 2020

Non-current assets, excluding derivative financial instruments and deferred tax assets, up 47% to $1,900.6 million at September 30, 2020, compared with December 31, 2019

The increase in US revenues for the three-month period is attributable mainly to:

- the Mountain Air Acquisition on July 15, 2020;
- the contribution of the Foard City wind facility commissioned on September 27, 2019; and
- the contribution of the Phoebe solar facility commissioned on November 19, 2019.

The increase in US revenues for the nine-month period is attributable mainly to:

- the contribution of the Foard City wind facility commissioned on September 27, 2019;
- the contribution of the Phoebe solar facility commissioned on November 19, 2019; and
- the Mountain Air Acquisition on July 15, 2020.

The increase in non-current assets, excluding derivative financial instruments and deferred income tax assets in the United States, is attributable mainly to:

- property, plant and equipment additions related to the construction of the Hillcrest solar and Griffin Trail wind projects;
- non-current assets additions related to the Mountain Air Acquisition on July 15, 2020; and
- the weakening of the Canadian Dollar against the US Dollar.

These items were partly offset by:

- depreciation of property, plant and equipment, and amortization of intangible assets;
- decrease in investments in joint ventures and associates due to unfavourable changes in fair value of the Shannon and Flat Top power hedges.

Chile

Revenues up to $1.4 million for the three-month period ended September 30, 2020
Revenues up to $2.5 million for the nine-month period ended September 30, 2020

Non-current assets, excluding derivative financial instruments and deferred tax assets, up 46% to $208.0 million at September 30, 2020, compared with December 31, 2019

The increase in revenues in Chile for the three-month period and for the nine-month period is attributable mainly to:

- the Salvador Acquisition on May 14, 2020.

For the period ended September 30, 2020, the increase in non-current assets is attributable to:

- the Salvador Acquisition on May 14, 2020; and
- a foreign exchange gain in the Energía Llaima investment recorded as a other comprehensive income.

The Corporation's investment in Energía Llaima in Chile is accounted for using the equity method; therefore its revenues are not consolidated and the Corporation's investment value is initially recognized in the consolidated statement of financial position at cost and adjusted thereafter to recognize the Corporation's share of the earnings (loss) and other comprehensive income (loss) of the joint venture.

DISCONTINUED OPERATIONS FINANCIAL RESULTS

	Three months ended September 30, 2020			Three months ended September 30, 2019		
	Innergex[1]	HS Orka[2]	Total	Innergex[1]	HS Orka[2]	Total
Production	2,021,559	—	2,021,559	1,665,362	—	1,665,362
Revenues	162,651	—	162,651	142,814	—	142,814
Adjusted EBITDA[3]	108,524	—	108,524	107,351	—	107,351
Net earnings (loss)	7,492	—	7,492	9,896	(193)	9,703

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

	Nine months ended September 30, 2020			Nine months ended September 30, 2019		
	Innergex[1]	HS Orka[2]	Total	Innergex[1]	HS Orka[2]	Total
Production	5,886,949	—	5,886,949	4,715,820	545,424	5,261,244
Revenues	445,280	—	445,280	413,926	40,006	453,932
Adjusted EBITDA[3]	304,279	—	304,279	305,842	13,291	319,133
Net (loss) earnings	(41,005)	—	(41,005)	(4,977)	21,171	16,194

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

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

SHARE CAPITAL STRUCTURE

Information on Capital Stock

Number of Common Shares Outstanding

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Weighted average number of common shares (in 000s)	173,858	133,400	169,048	133,229
Weighted average number of common shares (in 000s)				
Effect of share options	78	175	—	—
Effect of shares held in trust related to the Performance Share Plan	557	301	—	—
Effect of convertible debentures	—	—	—	—
	174,493	133,876	169,048	133,229
Instruments that are excluded from the dilutive elements (in 000s):				
Effect of share options	—	—	507	738
Effect of shares in trust related to the Performance Share Plan	—	—	557	301
Effect of convertible debentures	13,777	16,576	13,777	16,576
	13,777	16,576	14,841	17,615

The Corporation's Equity Securities

	As at		
	November 9, 2020	September 30, 2020	September 30, 2019
Number of common shares	174,575,061	174,495,317	136,667,170
Number of 4.75% convertible debentures	149,400	150,000	150,000
Number of 4.65% convertible debentures	125,000	125,000	125,000
Number of 4.25% convertible debentures	—	—	54,257
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 share options outstanding	252,400	266,143	737,977

As at the closing of the market on November 9, 2020, and since September 30, 2020, the increase in the number of common shares of the Corporation is attributable mainly to the conversion of $1.3 million of the outstanding 4.75% Convertible Debentures into 66,500 common shares, as well as the issuance of 8,825 common shares related to the Corporation's Dividend Reinvestment Plan ("DRIP"). In addition, the increase was also attributable to the issuance of 4,419 common shares following the cashless exercise of 13,743 options.

As at September 30, 2020, the increase in the number of common shares since September 30, 2019, was attributable mainly to the issuance of 34,636,823 common shares to Hydro-Québec under a private placement of common shares of Innergex as well as the conversion of a portion of the 4.25% Convertible Debentures into 2,727,265 common shares. In addition, the increase was also attributable to the issuance of 181,839 common shares following the cashless exercise of 521,056 options and 282,220 common shares related to the DRIP.

Dividends

The Corporation's dividend policy is determined by its Board of Directors and is based on the Corporation's operating results, cash flows, financial condition, debt covenants, long-term growth prospects, solvency test imposed under corporate law for the declaration of dividends and other relevant factors.

The following dividends were declared by the Corporation:

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Dividends declared on common shares[1]	31,409	23,917	94,118	70,650
Dividends declared on common shares ($/share)	0.180	0.175	0.540	0.525
Dividends declared on Series A Preferred Shares	767	767	2,300	2,300
Dividends declared on Series A Preferred Shares ($/share)	0.2255	0.2255	0.6765	0.6765
Dividends declared on Series C Preferred Shares	719	719	2,157	2,157
Dividends declared on Series C Preferred Shares ($/share)	0.3594	0.3594	1.0781	1.0781

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

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

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
11/10/2020	12/31/2020	1/15/2021	0.1800	0.2255	0.359375

Normal Course Issuer Bid

On May 21, 2020, the Corporation received the approval from the Toronto Stock Exchange ("TSX") to proceed with a normal course issuer bid on its common shares (the "New Bid"). Under the New Bid, the Corporation could purchase for cancellation up to 2,000,000 of its common shares, representing approximately 1.15% of the 174,234,629 issued and outstanding common shares of the Corporation as at May 21, 2020. The Corporation could also purchase for cancellation up to 68,000 of its Series A Preferred Shares, representing approximately 2% of the 3,400,000 issued and outstanding shares of the Corporation as at May 21, 2020. And finally, the Corporation could purchase for cancellation up to 40,000 of its Series C Preferred Shares, representing approximately 2% of the 2,000,000 issued and outstanding shares of the Corporation as at May 21, 2020. The New Bid commenced on May 24, 2020 and will terminate on May 23, 2021. No common or preferred shares have been purchased and cancelled as at September 30, 2020.

Contributed surplus from reduction of capital account on common shares

A special resolution to approve the reduction of the legal stated capital account maintained in respect of the common shares of the Corporation, without any payment or distribution to the shareholders was adopted on May 12, 2020. This resulted in a decrease of the shareholders' capital account of $754,355 and an equivalent increase of the contributed surplus.

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

FINANCIAL POSITION

As at	September 30, 2020	December 31, 2019
ASSETS		
Current assets		
Cash and cash equivalents	156,360	156,224
Restricted cash	39,509	39,451
Investment tax credit recoverable	92,861	—
Other current assets	153,464	109,957
Total current assets	442,194	305,632
Non-current assets		
Property, plant and equipment	4,983,481	4,620,025
Intangible assets	945,036	682,227
Investments in joint ventures and associates	475,495	511,899
Goodwill	76,608	60,666
Other non-current assets	225,320	191,655
Total non-current assets	6,705,940	6,066,472
Total assets	7,148,134	6,372,104
LIABILITIES		
Current liabilities	701,757	641,353
Non-current liabilities		
Long-term loans and borrowings	4,331,199	4,281,586
Other non-current liabilities	998,503	833,839
Total non-current liabilities	5,329,702	5,115,425
Total liabilities	6,031,459	5,756,778
SHAREHOLDERS' EQUITY		
Equity attributable to owners	1,047,437	604,384
Non-controlling interests	69,238	10,942
Total shareholders' equity	1,116,675	615,326
	7,148,134	6,372,104

Working Capital Items

Current assets

Current assets amounted to $442.2 million as at September 30, 2020, compared with $305.6 million as at December 31, 2019, an increase of $136.6 million due mainly to:

- a $92.9 million increase in investment tax credits recoverable relating to the Hillcrest construction activities;
- a $20.7 million increase in trade accounts receivable related to seasonality; and
- a $20.2 million increase in current assets stemming from the Salvador and Mountain Air Acquisitions.

These increases were partly offset by:

- a net $11.5 million decrease in advances receivable from the Innavik hydro project related to $29.6 million in preferred shares received in exchange for cash contributions made in 2019 and 2020 to Innavik Hydro LP toward the construction of the joint venture hydro project.

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

Current liabilities
Current liabilities amounted to $701.8 million as at September 30, 2020, compared with $641.4 million as at December 31, 2019, an increase of $60.4 million due mainly to:

- a $39.0 million increase in derivative financial instruments following a general decrease in interest rate curves over the first nine months of 2020;
- a $4.7 million decrease in current portion of long-term loans and borrowings and other liabilities mainly relating to Phoebe tax equity financing, partially offset by the current portion of the long-term loans assumed in the Mountain Air Acquisition;
- a $23.3 million increase in accounts payable and other payables attributable mainly from an increase in interest payable due to seasonality in the payments of certain debt instruments, as well as an increase in the dividends payable, largely related to the additional shares outstanding on September 30, 2020, compared with December 31, 2019;
- a $15.1 million increase in current liabilities stemming from the Salvador and Mountain Air Acquisitions; and
- a strengthening of the US dollar and Euro against the Canadian dollar.

Working capital was negative at $259.6 million, as at September 30, 2020, with a working capital ratio of 0.63:1.00 (December 31, 2019 - working capital was negative at $335.7 million, with a working capital ratio of 0.48:1.00), an improvement of $76.2 million due to the items explained above.

The Corporation considers its current level of working capital to be sufficient to meet its needs. As at September 30, 2020, the Corporation had $700.0 million in revolving term credit facilities and had drawn $253.0 million as cash advances, while $59.8 million had been used to issue letters of credit, leaving $387.2 million available. In addition, a default in the Mesgi'g Ugju's'n credit agreement, due to the bankruptcy of a supplier considered a major project participant under the agreement, caused the total project loan balance of $235.3 million to be classified within current liabilities since December 31, 2019.

Non-current assets
Non-current assets amounted to $6,705.9 million as at September 30, 2020, compared with $6,066.5 million as at December 31, 2019, an increase of $639.5 million mainly due to:

- a $363.5 million increase in property, plant and equipment due to:
    - an increase of $242.0 million stemming from a $338.1 million investment in the construction activities related to the Hillcrest solar project, net of a $96.2 million investment tax credit;
    - an increase of $84.8 million stemming from the construction activities related to the Griffin Trail wind project;
    - an increase of $85.4 million stemming from the Salvador and Mountain Air Acquisitions;
    - a strengthening of the US dollar and Euro against the Canadian dollar.

    These items were partially offset by depreciation expense.
- a $262.8 million increase in intangible assets, primarily related to $286.8 million from the Salvador and Mountain Air Acquisitions, partially offset by amortization expense.
- a $29.6 million increase in other long-term assets related to preferred shares received in exchange for cash contributions made to Innavik Hydro LP toward the construction of the joint venture hydro project; and
- a $57.1 million increase in non-current assets, excluding the property, plant and equipment and intangibles discussed above, stemming from the Salvador and Mountain Air Acquisitions.

These increases were partly offset by:

- a $36.4 million decrease in investments in joint ventures and associates; and
- a $36.6 million decrease in derivative financial instruments.

Non-current liabilities
Non-current liabilities amounted to $5,329.7 million as at September 30, 2020, compared with $5,115.4 million as at December 31, 2019, an increase of $214.3 million mainly due to:

- a $49.6 million increase in long-term loans and borrowings mainly due to:
    - $180.2 million draws made on the Hillcrest project construction loan and tax equity bridge loan;
    - $166.0 million long-term loan facilities assumed in the Mountain Air Acquisition; and
    - a strengthening of the US dollar and Euro against the Canadian dollar.

    These items were partially offset by:
    - a repayment of $238.0 million of the corporate credit facilities from the $661.0 million Hydro-Québec Private Placement proceeds, net of draws made toward the Hillcrest construction, business acquisitions and other cash requirements for operating activities; and
    - scheduled principal repayments on long-term debt.

This item was partly offset by:
- a $58.7 million increase in derivative financial instruments due to a general downward shift of interest rate curves, partly offset by a favourable variation in the longer-term foreign exchange forward rates;
- a $71.0 million increase in lease obligations relating to the Hillcrest and Griffin Trail projects under construction; and
- a $43.3 million increase in non-current liabilities, excluding long-term loans and borrowings, stemming from the Salvador and Mountain Air Acquisitions.

As at September 30, 2020, the Corporation and its subsidiaries have met all material financial and non-financial conditions, unless indicated below, related to their credit agreements, trust indentures and PPAs. Were they not met, certain financial and non-financial covenants included in the credit agreements, trust indentures and PPAs entered into by various subsidiaries of the Corporation could limit the capacity of these subsidiaries to transfer funds to the Corporation. These restrictions could have a negative impact on the Corporation's ability to meet its obligations. As at December 31, 2019, and September 30, 2020, the Mesgi'g Ugju's'n project was in default of its credit agreement. A breach was triggered by the bankruptcy of a supplier considered a major project participant under the credit agreement. A waiver was obtained and subsequently extended until December 31, 2020. A plan was put in place to ensure the continuity of the operations of the project. Ongoing dialogue and reporting are provided to the project lenders until this situation is resolved. If the waiver is not renewed, the lenders would have the right to request repayment. As a result, the $235.3 million loan was reallocated to the current portion of long-term debt. As at September 30, 2020, and as at December 31, 2019, the project was in compliance with financial covenants.

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.

		Current Notional		Fair Value After Credit Adjustment	
As at September 30, 2020	Currency	Currency of origin	CAD	Currency of origin	CAD
Interest rate swaps	CAD	1,140,852	1,140,852	(131,816)	(131,816)
Interest rate swaps	USD	178,650	238,301	(29,806)	(40,023)
Interest rate swaps	EURO	141,014	220,419	(13,957)	(21,816)
Foreign exchange forward contracts	CAD	469,007	469,007	(30,408)	(30,408)
Power and basis hedges	USD	N/A	N/A	25,002	33,350
				(180,985)	(190,713)

Shareholders' Equity

Shareholders' equity amounted to $1,116.7 million as at September 30, 2020, compared with $615.3 million as at December 31, 2019, an increase of $501.3 million mainly due to:
- the Private Placement by Hydro-Québec of $661.0 million in Innergex common shares at a price of $19.08 per share for a total of 34.6 million shares; and
- a $63.2 million increase in non-controlling interests stemming from the Mountain Air acquisition.

These items were partly offset by:
- dividends declared on common and preferred shares totaling $98.6 million during the period, compared with $75.1 million for the same period last year.

Contingencies

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 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 as a joint venture), Upper Lillooet River, Northwest Stave River, and Boulder Creek facilities, 2.0 MW/h for the Tretheway Creek facility and 4.0 MW/h for the Big Silver Creek facility.

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

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

Innergex disputes that the pandemic and related governmental measures in any way prevent BC Hydro from fulfilling its obligations to accept and purchase energy under the EPAs or enable it to invoke “force majeure” provisions under the EPAs to suspend these obligations. Innergex acknowledges that BC Hydro retains “turn-down” rights under the EPAs, which enable it to require Innergex to turn down or shut off its facilities in certain circumstances, including in order to avoid a safety or stability risk. Where BC Hydro exercises this right, it is required under the EPAs to compensate Innergex for energy that would have been produced at the facilities in the absence of the curtailment. Innergex has complied with BC Hydro’s curtailment request, but has done so under protest and seeks to enforce its rights under the EPAs on the basis described above. For the three- and nine-month periods ended September 30, 2020, actual eligible energy revenue that would have been produced at the facilities in the absence of the curtailment amounted to $3.0 million ($3.6 million on a Revenues Proportionate[1] basis) and $13.0 million ($14.8 million on a Revenues Proportionate[1] basis), respectively.

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

Off-Balance-Sheet Arrangements

As at September 30, 2020, the Corporation had issued letters of credit totaling $175.0 million, including $96.2 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 $109.0 million in corporate guaranties used mainly to guarantee certain activities of prospective projects. The corporate guaranties were also used to support the long-term currency hedging instruments of its operations in France, and the performance of the Brown Lake and Miller Creek hydroelectric facilities.

Tax equity investors in U.S. projects generally require sponsor guaranties as a condition to their investment. To support the tax equity investments at Shannon, Kokomo, Spartan, Flat Top, Phoebe, Foard City and Hillcrest, Alterra, 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 to the lenders related to debt-service payments, which will become effective only in the unlikely event that the Phoebe tax equity investors call upon their corresponding guarantee.

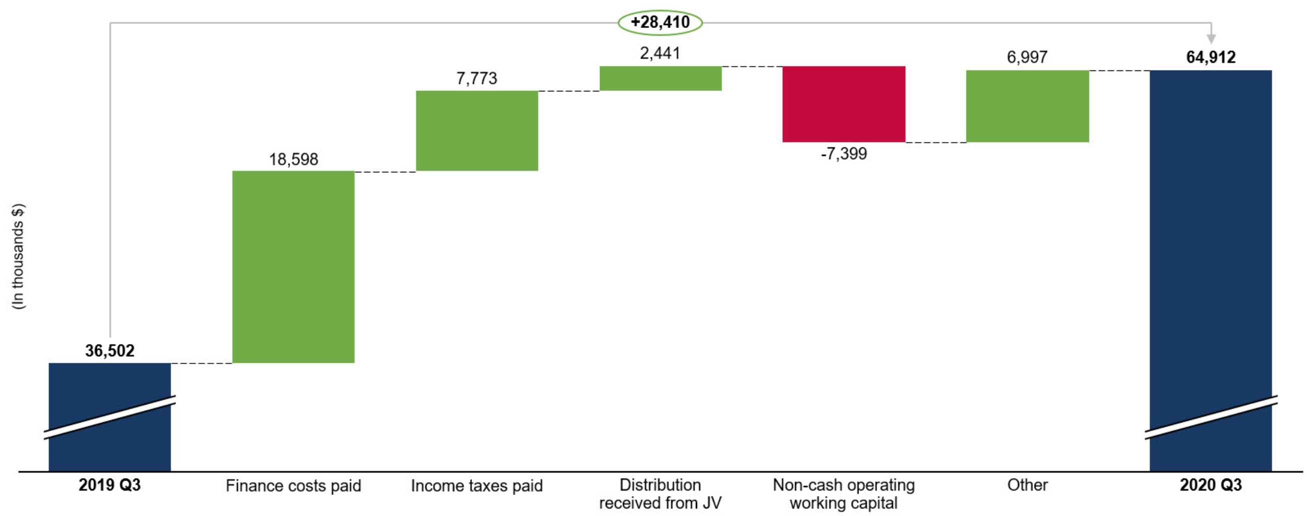
LIQUIDITY AND CAPITAL RESOURCES

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
OPERATING ACTIVITIES				
Cash flows from operating activities from continuing operations before changes in non-cash operating working capital items	81,214	45,405	183,264	163,163
Changes in non-cash operating working capital items	(16,302)	(8,903)	(25,848)	(7,956)
Cash flows from operating activities from continuing operations	64,912	36,502	157,416	155,207
Cash flows from operating activities from discontinued operations	—	—	—	13,122
	64,912	36,502	157,416	168,329
FINANCING ACTIVITIES				
Cash flows from financing activities from continuing operations	118,382	223,019	394,497	292,346
Cash flows from financing activities from discontinued operations	—	—	—	20,059
	118,382	223,019	394,497	312,405
INVESTING ACTIVITIES				
Cash flows from investing activities from continuing operations	(252,890)	(201,682)	(555,805)	(380,666)
Cash flows from investing activities from discontinued operations	—	—	—	(31,957)
	(252,890)	(201,682)	(555,805)	(412,623)
Effects of exchange rate changes on cash and cash equivalents	(3,022)	(826)	4,028	(2,062)
Net change in cash and cash equivalents	(72,618)	57,013	136	66,049
Cash and cash equivalents, beginning of period	228,978	88,622	156,224	79,586
Cash and cash equivalents, end of period	156,360	145,635	156,360	145,635

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

Cash Flows from Operating Activities from Continuing Operations

Up $28.4 million to $64.9 million for the three-month period ended September 30, 2020
Up $2.2 million to $157.4 million for the nine-month period ended September 30, 2020



For the three-month period ended on September 30, 2020, compared with the same period last year

The increase in cash flows from operating activities from continuing operations is primarily attributable to:

- an $18.6 million decrease in finance costs paid, mainly stemming from the timing of certain project loan payments in the comparative quarter and a decrease in the corporate revolving facilities interest expense;
- a $7.8 million decrease in income taxes paid largely related to a payment made in 2019 toward a taxable gain following an intercompany transaction related to the introduction of a tax equity investor in the Phoebe solar project; and
- a $2.4 million increase in distributions received from joint ventures and associates, mainly related to the Toba Montrose hydro project and the Dokie wind project.

These items were partly offset by:

- a $7.4 million unfavourable change in non-cash operating working capital items, due mainly to:
  - an $18.2 million unfavourable variation in non-cash operating working capital changes from accounts receivable, partly offset by an $11.3 million favourable variation in non-cash operating working capital changes from accounts payable and other payables.

For the nine-month period ended on September 30, 2020, compared with the same period last year

The increase in cash flows from operating activities from continuing operations is primarily attributable to:

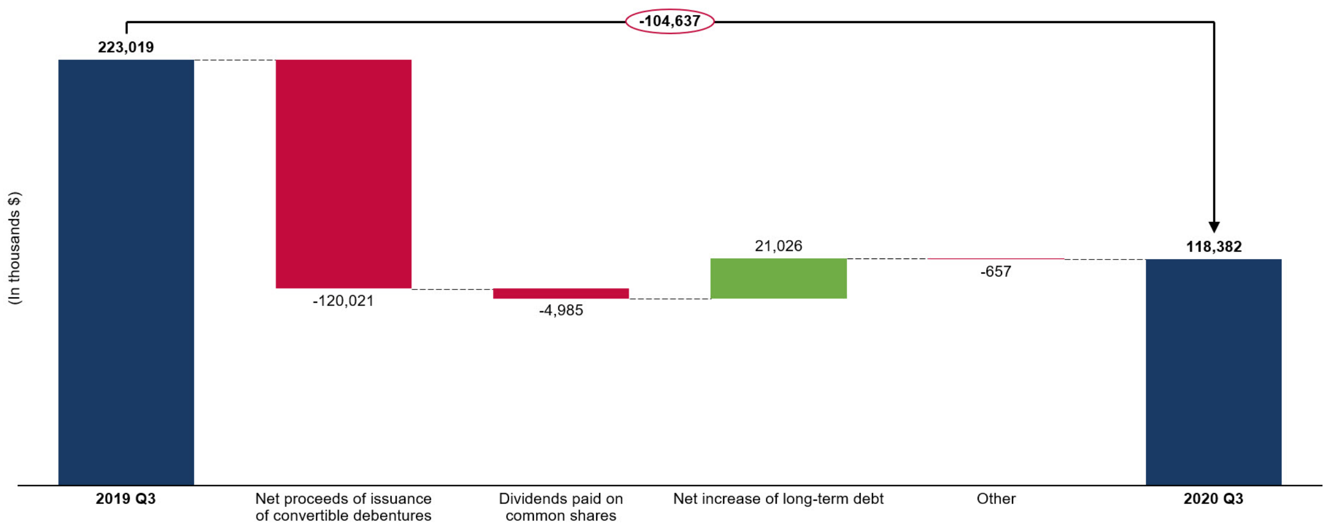
- a $14.8 million decrease in finance costs paid, mainly stemming from a decrease in the corporate revolving facilities interest expense concurrent with the Hydro-Québec Private Placement;
- an $8.6 million decrease in income taxes paid largely related to a payment made in 2019 toward a taxable gain following an intercompany transaction related to the introduction of a tax equity investor in the Phoebe solar project;
- a $3.7 million increase in distributions received from joint ventures and associates, mainly related to the Toba Montrose hydro project and the Dokie and Flat Top wind projects.

These items were partly offset by:

- a $17.9 million unfavourable change in non-cash operating working capital items, due mainly to:
  - a $12.5 million unfavourable variation in accounts receivable, and a $6.0 million unfavourable variation in prepaid and other;
- a $12.0 million realized loss on derivative financial instruments (nil in 2019) mainly attributable to a $19.5 million realized loss on the Phoebe basis hedge due to unfavourable basis differentials outside of generation hours during the first quarter of 2020, partly offset by a $7.4 million realized gain on the Phoebe and Salvador power hedges.

Cash Flows from Financing Activities from Continuing Operations

Down $104.6 million to $118.4 million for the three-month period ended September 30, 2020
Up $102.2 million to $394.5 million for the nine-month period ended September 30, 2020



For the three-month period ended on September 30, 2020, compared with the same period last year

The decrease in cash inflows from financing activities from continuing operations stems mainly from:

- a $120.0 million decrease in financing cash flows stemming from the issuance of convertible debentures during the third quarter of 2019, while no such issuance occurred during 2020; and
- a $5.0 million increase in dividends paid on common shares, mainly due to the 34,636,823 shares issued to Hydro-Québec on February 6, 2020.

These items were partly offset by:

- a $21.0 million net increase of long-term debt mainly due to:
  - draws made toward the Hillcrest and Griffin Trail construction, partly offset by scheduled principal repayments on long-term debt.

For the nine-month period ended on September 30, 2020, compared with the same period last year

The increase in cash flows from financing activities from continuing operations stems mainly from:

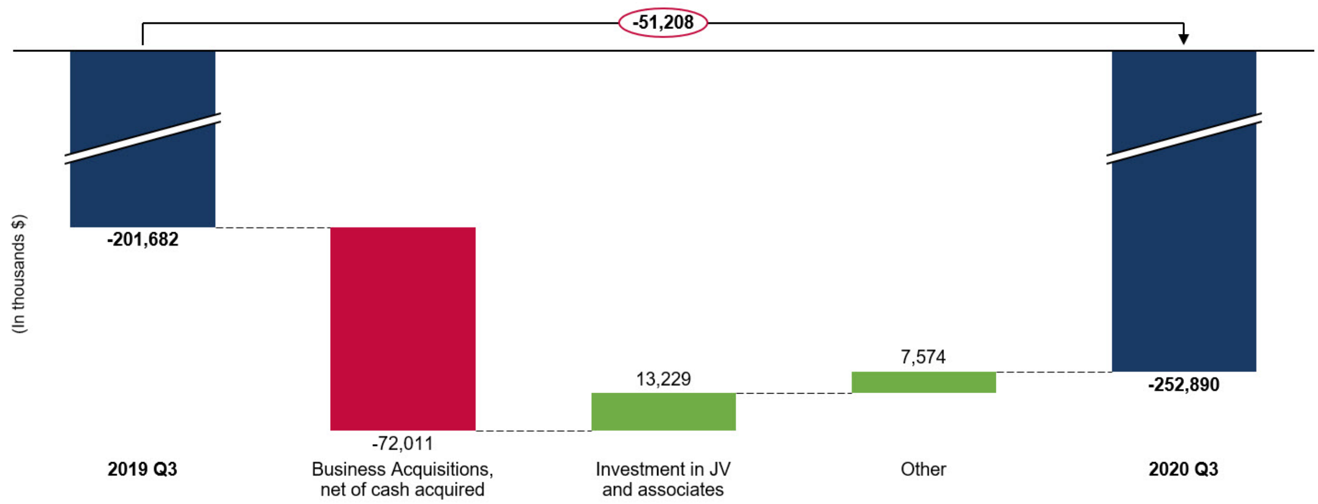
- a $658.4 million net cash inflow from the Hydro-Québec Private Placement.

This item was partly offset by:

- a $421.9 million net repayment of long-term debt mainly due to:
  - repayments made to the corporate credit facilities concurrent with the Hydro-Québec Private Placement, partly offset by draws made toward the construction of Hillcrest and Griffin Trail, and the Salvador and Mountain Air acquisitions; and
  - scheduled principal repayments on long-term loans and borrowings;
- a $120.0 million decrease in financing cash flows stemming from the issuance of convertible debentures during 2019, while no such issuance occurred during 2020; and
- a $14.1 million increase in dividends paid on common shares, mainly due to the 34,636,823 shares issued to Hydro-Québec on February 6, 2020.

Cash Flows from Investing Activities from Continuing Operations

Outflow up $51.2 million to $252.9 million for the three-month period ended September 30, 2020
Outflow up $175.1 million to $555.8 million for the nine-month period ended September 30, 2020



For the three-month period ended on September 30, 2020, compared with the same period last year

The increase in cash outflows from investing activities from continuing operations is mainly related to:

- a $72.0 million cash contribution, net of cash acquired, made toward the Mountain Air Acquisition;

partly offset by:

- a $13.2 million increase in investing cash flows mainly due to the payment, during 2019, of the remaining investment commitment into Energía Llaima.

For the nine-month period ended on September 30, 2020, compared with the same period last year

The increase in cash outflows from investing activities from continuing operations is mainly related to:

- a decrease in proceeds received from a business disposal, from $383.7 million in 2019, related to the sale of HS Orka to Jarðvarmi slhf, to nil in 2020;
- a $161.8 million cash contribution, net of cash acquired, made toward the Salvador and Mountain Air Acquisitions;
- a $20.3 million increase in project development costs additions, which mainly relates to the Griffin Trail wind project; and
- a $16.7 million increase in other long-term assets related to preferred shares received in exchange for cash contributions made to Innavik Hydro LP toward the construction of the joint venture hydro project;

These items were partly offset by:

- a $351.4 million decrease in additions to property, plant and equipment, from $703.6 million in 2019, related primarily to the construction of the Phoebe solar and Foard City wind projects, to $352.3 million in 2020, mostly related to the construction of the Hillcrest solar project and, more recently, of the Griffin Trail wind project;
- a $45.8 million favourable change in restricted cash balances, from a $38.8 million increase in restricted cash in 2019, mainly related to the initial tax equity funding in Phoebe during the second quarter of 2019, to a $7.0 million decrease in restricted cash in 2020.
- a $13.8 million increase in investing cash flows mainly due to the payment, during 2019, of the remaining investment commitment in Energía Llaima.

FREE CASH FLOW AND PAYOUT RATIO

Free Cash Flow and Payout Ratio calculation[1]	Trailing twelve months ended September 30	
	2020	2019
Cash flows from operating activities	229,152	213,585
Add (Subtract) the following items:		
Changes in non-cash operating working capital items	(4,510)	6,956
Maintenance capital expenditures, net of proceeds from disposals	(3,428)	(10,282)
Scheduled debt principal payments	(144,261)	(112,604)
Free Cash Flow attributed to non-controlling interests[2]	(11,617)	(18,601)
Dividends declared on Preferred shares	(5,942)	(5,942)
Add (subtract) the following non-recurring elements:		
Transaction costs related to realized acquisitions	923	1,593
Realized loss on termination of interest rate swaps	4,145	6,914
Realized loss on the Phoebe basis hedge[3]	31,150	—
Income tax paid on realized intercompany gain	—	10,594
Recovery of maintenance capital expenditures and prospective project expenses on sale of HS Orka, net of attribution to non-controlling interests[4]	—	8,242
Free Cash Flow	95,612	100,455
Dividends declared on common shares	118,514	93,258
Payout Ratio	124 %	93 %
Adjust for the following items:		
Prospective projects expenses	15,340	16,945
Adjusted Free Cash Flow	110,952	117,400
Dividends declared on common shares - DRIP adjusted	113,084	90,856
Adjusted Payout Ratio	102 %	77 %

1. Free Cash Flow, Adjusted Free Cash Flow, Payout Ratio and Adjusted Payout Ratio are not recognized measures under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to the "Non-IFRS Measures" section for more information.
2. The portion of Free Cash Flow attributed to non-controlling interests is subtracted, regardless of whether an actual distribution to non-controlling interests is made, in order to reflect the fact that such distributions may not occur in the period they are generated.
3. Due to their limited occurrence (over the remaining contractual period of 15 months), gains and losses on the Phoebe basis hedge are deemed not to represent the long-term cash-generating capacity of Innergex.
4. The sale of HS Orka has allowed for the recovery of maintenance capital expenditures and prospective project expenses incurred thereon since the acquisition of the project in February 2018, totaling $5.7 million and $9.6 million, respectively. An amount of $7.1 million was deducted from the total recovery as it pertains to non-controlling interests.

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

Payout Ratio[1]

For the trailing twelve months ended September 30, 2020, the dividends on common shares declared by the Corporation amounted to 124% of Free Cash Flow, compared with 93% for the corresponding period last year.

The following table summarizes elements to add or subtract to derive a normalized Free Cash Flow and Payout Ratio:

	Trailing twelve months ended September 30, 2020		
(in millions of Canadian dollars)	Free Cash Flow	Dividends	Payout Ratio
Free Cash Flow and Payout Ratio	96	119	124 %
Add (subtract) the following items:			
BC Hydro curtailment	15	—	
Decrease in corporate revolving facilities interest payment	(11)	—	
Hydro-Québec additional dividend	—	(19)	
Free Cash Flow and Payout Ratio - Normalized	100	100	100 %

The Corporation considers the $95.6 million Free Cash Flow not to represent the current cash-generating capacity.

The above table normalizes the Free Cash Flow and Payout Ratio for the following items:

- an unfavourable impact on the Adjusted EBITDA Proportionate stemming from the BC Hydro imposed curtailment during 2020; and
- an increase in quarterly dividends mainly related to the issuance of 34,636,823 common shares following the Hydro-Québec Private Placement, while a large portion of the funds have yet to be invested in cash-generating projects, or have been used toward recent acquisitions whose contributions to the Corporation's Free Cash Flow have not yet fully materialized.

These items were partly offset by:

- a decrease in the corporate revolving facilities interest expense concurrent with the Hydro-Québec Private Placement.

1 The Payout Ratio is a measure of the Corporation's ability to sustain current dividends and dividend increases as well as its ability to fund its growth. The Payout Ratio level reflects the Corporation's decision to invest yearly in advancing the development of its Prospective Projects, for which investments must be expensed as incurred. The Corporation considers such investments essential to its long-term growth and success, as it believes that the greenfield development of renewable energy projects offers the greatest potential internal rates of return and represents the most efficient use of management's expertise and value-added skills.

Free Cash Flow

For the trailing twelve months ended September 30, 2020, the Corporation generated Free Cash Flow of $95.6 million, compared with $100.5 million for the corresponding period last year.

The unfavourable variance in Free Cash Flow is due mainly to:

- an increase in scheduled debt principal repayments due to the commencement of the repayment period on certain project financing which were not in full effect in the comparative period;
- an unfavourable impact to Adjusted EBITDA Proportionate stemming from the BC Hydro-imposed curtailment during 2020;
- a decrease in Free Cash Flow attributable to discontinued operations, including the recovery of maintenance capital expenditures, following the sale of HS Orka in the second quarter of 2019;
- lower generation mostly due to unfavourable weather conditions.

These items were partly offset by:

- timing of certain project loan interest payments which resulted in the Corporation having made five quarterly payments during the comparative period;
- the Free Cash Flow contribution of recently acquired and commissioned projects; and
- lower interest payment on the corporate revolving facilities concurrent with the Hydro-Québec Private Placement.

QUARTERLY FINANCIAL INFORMATION

(in millions of dollars, unless otherwise stated)	Three months ended Sept 30, 2020	June 30, 2020	March. 31, 2020	Dec. 31, 2019
Production (MWh)	2,021,559	2,185,793	1,679,598	1,793,803
Revenues	162.7	150.5	132.1	143.1
Adjusted EBITDA[1]	108.5	105.3	90.4	103.3
Net earnings (loss)	7.5	(1.6)	(46.9)	(47.4)
Net earnings (loss) from continuing operations attributable to owners of the parent	11.7	(2.5)	(53.7)	(46.8)
Net earnings (loss) from continuing operations attributable to owners of the parent ($ per share – basic and diluted)	0.06	(0.02)	(0.35)	(0.35)
Net earnings (loss) attributable to owners of the parent	11.7	(2.5)	(53.7)	(46.2)
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.06	(0.02)	(0.35)	(0.35)
Dividends declared on common shares	31.4	31.4	31.3	24.4
Dividends declared on common shares, $ per share	0.180	0.180	0.180	0.175

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

(in millions of dollars, unless otherwise stated)	Three months ended Sept 30, 2019	June 30, 2019	March. 31, 2019	Dec. 31, 2018
Production (MWh)	1,665,362	1,741,953	1,308,505	1,396,066
Revenues	142.8	144.7	126.4	138.3
Adjusted EBITDA[1]	107.4	105.2	93.2	103.3
Net earnings (loss)	9.7	7.3	(0.9)	14.2
Net earnings (loss) from continuing operations attributable to owners of the parent	14.3	(7.8)	(7.4)	15.9
Net earnings (loss) from continuing operations attributable to owners of the parent ($ per share – basic and diluted)	0.10	(0.07)	(0.07)	0.12
Net earnings (loss) attributable to owners of the parent	14.1	10.8	(6.7)	13.7
Net earnings (loss) attributable to owners of the parent ($ per share – basic and diluted)	0.09	0.07	(0.06)	0.10
Dividends declared on common shares	23.9	23.4	23.4	22.6
Dividends declared on common shares, $ per share	0.175	0.175	0.175	0.170

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.

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 the Corporation's production and cash generation capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. These indicators also facilitate the comparison of results over different periods. Innergex's share of Revenues of joint ventures and associates, Revenues Proportionate, Adjusted EBITDA, Adjusted EBITDA Margin, Adjusted EBITDA Proportionate, Adjusted EBITDA Proportionate Margin, Innergex's share of Adjusted EBITDA of joint ventures and associates, Adjusted Net Earnings (Loss) from Continuing Operations, 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

References in this document to "Innergex's share of Revenues of joint ventures and associates" are to Innergex's equity interest in the joint ventures and associates' Revenues. Readers are cautioned that Innergex's share of Revenues of joint ventures and associates should not be construed as an alternative to Revenues, as determined in accordance with IFRS.

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

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Revenues	162,651	142,814	445,280	413,926
Innergex's share of Revenues of joint ventures and associates:				
Toba Montrose (40%)	17,590	17,197	26,730	25,170
Shannon (50%)	1,482	1,013	4,711	5,558
Flat Top (51%)	1,976	582	6,470	6,305
Dokie (25.5%)	2,268	1,712	7,302	5,465
Jimmie Creek (50.99%)	6,384	7,677	7,607	9,974
Umbata Falls (49%)	541	490	2,861	2,773
Viger-Denonville (50%)	1,191	1,017	4,114	4,175
Duqueco (50%)[1]	5,616	6,370	11,535	14,499
Guayacán (50%)[1]	390	469	1,249	1,480
Pampa Elvira (50%)[1]	403	475	1,420	1,507
	37,841	37,002	73,999	76,906
PTCs and Innergex's share of PTCs generated:				
Foard City	8,229	1,423	31,281	1,423
Shannon (50%)	2,054	2,355	8,486	8,324
Flat Top (51%)	2,961	3,310	11,065	10,941
	13,244	7,088	50,832	20,688
Revenues Proportionate	213,736	186,904	570,111	511,520

1. Innergex owns a 50% interest in Energía Llaima, which owns the Guayacán (69.47% interest) and the Pampa Elvira (55% interest) facilities and Duqueco, which includes the Mampil (100% interest) and Peuchén (100% interest) facilities.

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

Adjusted EBITDA and Adjusted EBITDA Margin

References in this document to “Adjusted EBITDA” are to net earnings (loss) from continuing operations, to which are added (deducted) income tax expense (recovery), finance costs, depreciation and amortization, other net income, share of (earnings) loss of joint ventures and associates and change in fair value of financial instruments. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Readers are cautioned that Adjusted EBITDA should not be construed as an alternative to net earnings, as determined in accordance with IFRS.

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

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Net earnings (loss) from continuing operations	7,492	9,896	(41,005)	(4,977)
Income tax expense	11,508	3,749	11,540	1,164
Finance costs	60,122	59,474	175,700	170,704
Depreciation and amortization	59,368	48,343	170,061	141,558
EBITDA	138,490	121,462	316,296	308,449
Other net income	(16,725)	(3,917)	(58,250)	(2,639)
Share of (earnings) loss of joint ventures and associates	(11,382)	(16,225)	21,398	(9,193)
Change in fair value of financial instruments	(1,859)	6,031	24,835	9,225
Adjusted EBITDA	108,524	107,351	304,279	305,842
Adjusted EBITDA margin	66.7 %	75.2 %	68.3 %	73.9 %

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

Adjusted EBITDA Proportionate and Adjusted EBITDA Proportionate Margin

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

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

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

During the year ended December 31, 2019, upon commissioning of the Foard City wind project, the Adjusted EBITDA Proportionate measure was changed to reflect PTC generation from the Corporation's wind facilities and from its joint ventures' and associates' wind facilities. PTCs represent an important factor to a U.S. wind project's financial performance and have been a major driver to determining their economic feasibility. PTCs are currently used, for the most part, as an element of the principal repayment of the Corporation's tax equity financing.

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Adjusted EBITDA	108,524	107,351	304,279	305,842
Innergex's share of Adjusted EBITDA of joint ventures and associates:				
Toba Montrose (40%)	15,341	15,030	21,585	20,046
Shannon (50%)	(56)	(872)	546	1,237
Flat Top (51%)	412	(1,213)	2,304	711
Dokie (25.5%)	1,603	1,095	5,659	3,799
Jimmie Creek (50.99%)	6,023	6,908	6,398	8,278
Umbata Falls (49%)	311	315	2,254	2,178
Viger-Denonville (50%)	1,030	868	3,470	3,418
Duqueco (50%)[1]	4,543	5,454	8,499	9,115
Guayacán (50%)[1]	184	469	736	1,022
Pampa Elvira (50%)[1]	274	391	836	665
	29,665	28,445	52,287	50,469
PTCs and Innergex's share of PTCs generated:				
Foard City	8,229	1,423	31,281	1,423
Shannon (50%)	2,054	2,355	8,486	8,324
Flat Top (51%)	2,961	3,310	11,065	10,941
	13,244	7,088	50,832	20,688
Adjusted EBITDA Proportionate	151,433	142,884	407,398	376,999
Adjusted EBITDA Proportionate Margin	70.9 %	76.4 %	71.5 %	73.7 %

1. Innergex owns a 50% interest in Energía Llaima, which owns the Guayacán (69.47% interest) and the Pampa Elvira (55% interest) facilities, and Duqueco, which includes the Mampil (100% interest) and Peuchén (100% interest) facilities.

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

Adjusted Net Earnings (Loss) from Continuing Operations

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

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, preferred share dividends declared and the portion of Free Cash Flow attributed to non-controlling interests, plus or minus other elements that are not representative of the Corporation's long-term cash-generating capacity, such as transaction costs related to realized acquisitions (which are financed at the time of the acquisition), realized losses or gains on derivative financial instruments used to hedge the interest rate on project-level debt or the exchange rate on equipment purchases. Innergex believes that presentation of this measure enhances the understanding of the Corporation's cash generation capabilities, its ability to sustain current dividends and dividend increases and its ability to fund its growth. Readers are cautioned that Free Cash Flow should not be construed as an alternative to cash flows from operating activities, as determined in accordance with IFRS. Please refer to the "Free Cash Flow and Payout Ratio" section for the reconciliation of Free Cash Flow.

References to "Adjusted Free Cash Flow" are to Free Cash Flow excluding prospective project expenses and non-recurring items.

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

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

Production KPIs

Production Proportionate

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

References in this document to "Production Proportionate" are to Production plus Innergex's share of Production of the joint ventures and associates. Innergex believes that the presentation of this measure enhances the understanding of the Corporation's operating performance. Please refer to the "Operating Results" section of this MD&A for more information.

	Three months ended September 30					
	2020			2019		
(in MWh)	Production (MWh)	LTA (MWh)	Production as a % of LTA	Production (MWh)	LTA (MWh)	Production as a % of LTA
Production	2,021,559	2,177,606	93 %	1,665,362	1,765,093	94 %
Innergex's share of Production of joint ventures and associates:						
Toba Montrose (40%)	155,851	154,145	101 %	152,144	154,145	99 %
Shannon (50%)	61,220	70,004	87 %	72,155	70,004	103 %
Flat Top (51%)	89,726	91,725	98 %	101,347	91,725	110 %
Dokie (25.5%)	19,639	17,231	114 %	13,912	17,231	81 %
Jimmie Creek (50.99%)	46,035	54,373	85 %	61,723	54,373	114 %
Umbata Falls (49%)	7,347	10,443	70 %	6,486	10,444	62 %
Viger-Denonville (50%)	7,849	8,175	96 %	6,729	8,175	82 %
Duqueco (50%)[1]	53,485	52,743	101 %	61,864	57,079	108 %
Guayacán (50%)[1]	5,219	4,333	120 %	4,199	4,406	95 %
Pampa Elvira (50%)[1]	3,219	3,780	85 %	3,230	3,665	88 %
	449,590	466,952	96 %	483,789	471,247	103 %
Production Proportionate	2,471,149	2,644,558	93 %	2,149,151	2,236,340	96 %

1. Innergex owns a 50% interest in Energía Llaima, which owns the Guayacán (69.47% interest) and Pampa Elvira (55% interest) facilities, and Duqueco, which includes the Mampil (100% interest) and Peuchén (100% interest) facilities.

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

(in MWh)	Nine months ended September 30					
	2020			2019		
	Production (MWh)	LTA (MWh)	Production as a % of LTA	Production (MWh)	LTA (MWh)	Production as a % of LTA
Production	5,886,949	6,324,336	93 %	4,715,820	4,835,085	98 %
Innergex's share of Production of joint ventures and associates:						
Toba Montrose (40%)	256,449	254,227	101 %	243,782	254,227	96 %
Shannon (50%)	248,728	264,208	94 %	252,936	264,208	96 %
Flat Top (51%)	328,042	327,715	100 %	332,474	327,715	101 %
Dokie (25.5%)	63,005	54,447	116 %	44,799	54,447	82 %
Jimmie Creek (50.99%)	55,059	78,051	71 %	87,944	78,051	113 %
Umbata Falls (49%)	38,052	37,271	102 %	36,635	37,271	98 %
Viger-Denonville (50%)	27,111	26,050	104 %	27,626	26,050	106 %
Duqueco (50%)[1]	89,763	110,451	81 %	109,161	108,445	101 %
Guayacán (50%)[1]	14,337	17,310	83 %	14,985	16,158	93 %
Pampa Elvira (50%)[1]	9,285	11,050	84 %	9,798	10,713	91 %
	1,129,831	1,180,780	96 %	1,160,140	1,177,285	99 %
Production Proportionate	7,016,780	7,505,116	93 %	5,875,960	6,012,370	98 %

1. Innergex owns a 50% interest in Energía Llaima, which owns the Guayacán (69.47% interest) and Pampa Elvira (55% interest) facilities, and Duqueco, which includes the Mampil (100% interest) and Peuchén (100% interest) facilities.

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

FORWARD-LOOKING INFORMATION

To inform readers of the Corporation's future prospects, this MD&A contains forward-looking information within the meaning of applicable securities laws (“Forward-Looking Information”), including the Corporation's power production, prospective projects, successful development, construction and financing (including tax equity funding) of the projects under construction and the advanced-stage prospective projects, sources and impact of funding, project acquisitions, execution of non-recourse project-level financing (including the timing and amount thereof), and strategic, operational and financial benefits and accretion expected to result from such acquisitions, business strategy, future development and growth prospects (including expected growth opportunities under the Strategic Alliance with Hydro-Québec), business integration, governance, business outlook, objectives, plans and strategic priorities, and other statements that are not historical facts. Forward-Looking Information can generally be identified by the use of words such as “approximately”, “may”, “will”, "could", “believes", “expects", “intends”, "should", "would", “plans”, “potential”, "project", “anticipates”, “estimates”, “scheduled” or “forecasts”, or other comparable terms that state that certain events will or will not occur. It represents the projections and expectations of the Corporation relating to future events or results as of the date of this MD&A.

Future-oriented financial information: Forward-Looking Information includes future-oriented financial information or financial outlook within the meaning of securities laws, including information regarding the Corporation's expected production, the estimated project costs, projected revenues, projected Adjusted EBITDA and projected Adjusted EBITDA Proportionate, Projected Free Cash Flow 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, project performance, economic, financial and financial market conditions, the Corporation’s success in developing and constructing new facilities, expectations and assumptions concerning availability of capital resources and timely performance by third parties of contractual obligations and receipt of regulatory approvals.

Risks and Uncertainties: Forward-Looking Information involves risks and uncertainties that may cause actual results or performance to be materially different from those expressed, implied or presented by the Forward-Looking Information. These are referred to in the "Risks and Uncertainties" section of the Annual Report and include, without limitation: the ability of the Corporation to execute its strategy for building shareholder value; its ability to raise additional capital and the state of the capital markets; liquidity risks related to derivative financial instruments; variability in hydrology, wind regimes and solar irradiation; delays and cost overruns in the design and construction of projects; the ability to secure new power purchase agreements or renew any power purchase agreement; fluctuations affecting prospective power prices; health, safety and environmental risks; uncertainties surrounding the development of new facilities; obtainment of permits; equipment failure or unexpected operations and maintenance activity; interest rate fluctuations and refinancing risk; financial leverage and restrictive covenants governing current and future indebtedness; the possibility that the Corporation may not declare or pay a dividend; failure to realize the anticipated benefits of 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; variability of installation performance and related penalties; the ability to attract new talent or to retain officers or key employees; litigation; performance of major counterparties; social acceptance of renewable energy projects; relationships with stakeholders; equipment supply; exposure to many different forms of taxation in various jurisdictions; changes in general economic conditions; regulatory and political risks; ability to secure appropriate land; reliance on PPAs; availability and reliability of transmission systems (including due to reliance on third parties); foreign market growth and development risks; foreign exchange fluctuations; increases in water rental cost or changes to regulations applicable to water use; assessment of water, wind and solar resources and associated electricity production; global climate change; natural disasters and force majeure; cybersecurity; sufficiency of insurance coverage; a credit rating that may not reflect actual performance of the Corporation or a lowering (downgrade) of the credit rating; reliance on shared transmission and interconnection infrastructure; the fact that revenues from certain facilities will vary based on the market (or spot) price of electricity; risks related to U.S. production and investment tax credits; changes in U.S. corporate tax rates and availability of tax equity financing; host country economic, social and political conditions; risk inherent to rockslides, avalanches, tornadoes, hurricanes or other occurrences outside the Corporation’s control; adverse claims to property title; unknown liabilities; reliance on intellectual property and confidential agreements to protect our rights and confidential information; and reputational risks arising from misconduct of representatives of the Corporation.

To combat the spread of the COVID-19, authorities in all regions where we operate 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 essential service in every region where we operate. Only BC Hydro sent curtailment notices for some hydro facilities that the Corporation disputes. Our renewable power production is sold mainly through PPAs to solid counterparts. 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 and financial position. The issuance of permits and authorizations, negotiations and finalizations of agreements with regard to development and acquisition projects, construction activities and procurement of equipment could be adversely impacted by the COVID-19 restrictive measures.

Although the Corporation believes that the expectations and assumptions on which Forward-Looking Information is based are reasonable under the current circumstances, readers are cautioned not to rely unduly on this Forward-Looking Information, as no assurance can be given that it will prove to be correct. Forward-Looking Information contained herein is provided as at the date of this MD&A, and the Corporation does not undertake any obligation to update or revise any Forward-Looking Information, whether as a result of events or circumstances occurring after the date hereof, unless so required by law.

Forward-Looking Information in this MD&A

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

	Principal Risks and Uncertainties
Expected production For each facility, the Corporation determines a long-term average annual level of electricity production ("LTA") over the expected life of the facility, based on engineers' studies that take into consideration a number of important factors: for hydroelectricity, the historically observed flows of the river, the operating head, the technology employed and the reserved aesthetic and ecological flows; for wind energy, the historical wind and meteorological conditions and turbine technology; and for solar energy, the historical solar irradiation conditions, panel technology and expected solar panel degradation. Other factors considered include, without limitation, site topography, installed capacity, energy losses, operational features and maintenance. Although production will fluctuate from year to year, over an extended period it should approach the estimated LTA. On a consolidated basis, the Corporation estimates its LTA by adding together the expected LTAs of all the Operating Facilities that it consolidates. This consolidation excludes, however, the facilities that are accounted for using the equity method.	Improper assessment of water, wind and solar resources and associated electricity production Variability in hydrology, wind regimes and solar irradiation resources Equipment supply risk, including failure or unexpected operations and maintenance activity Natural disasters and force majeure Regulatory and political risks affecting production Health, safety and environmental risks affecting production Variability of installation performance and related penalties Availability and reliability of transmission systems Litigation
Projected revenues For each facility, expected annual revenues are estimated by multiplying the LTA by a price for electricity stipulated in the PPA secured with a public utility or other creditworthy counterparty. In most cases, these PPAs stipulate a base price for electricity produced and, in some cases, a price adjustment depending on the month, day and hour of its delivery. This excludes facilities that receive revenues based on the market (or spot) price for electricity, including the Foard City, Shannon and Flat Top wind farms, the Phoebe solar farm and the Miller Creek hydroelectric facility, which receives a price based on a formula using the Platts Mid-C pricing indices; and the Horseshoe Bend hydroelectric facility, for which 85% of the price is fixed and 15% is adjusted annually as determined by the Idaho Public Utility Commission. In most cases, PPAs also contain an annual inflation adjustment based on a portion of the Consumer Price Index. On a consolidated basis, the Corporation estimates annual revenues by adding together the projected revenues of the Operating Facilities that it consolidates. The consolidation excludes, however, the facilities that are accounted for using the equity method.	See principal assumptions, risks and uncertainties identified under "Expected Production" Reliance on PPAs Revenues from certain facilities will vary based on the market (or spot) price of electricity Fluctuations affecting prospective power prices Changes in general economic conditions Ability to secure new PPAs or renew any PPA

Projected Adjusted EBITDA For each facility, the Corporation estimates annual operating earnings by adding (deducting) to net earnings (loss) income tax expense (recovery), finance costs, depreciation and amortization, other net income, share of (earnings) loss of joint ventures and associates and change in fair value of financial instruments.	See principal assumptions, risks and uncertainties identified under “Expected Production” and "Projected Revenues" Unexpected maintenance expenditures
Projected Adjusted EBITDA Proportionate On a consolidated basis, the Corporation estimates annual Adjusted EBITDA Proportionate by adding to the projected Adjusted EBITDA Innergex's share of Adjusted EBITDA of the operating joint ventures and associates, other revenues related to PTCs, and Innergex's share of the other net income of the operating joint ventures and associates related to PTCs.	See principal assumptions, risks and uncertainties identified under “Expected Production”, "Projected Revenues" and "Projected Adjusted EBITDA"
Intention to pay dividend quarterly The Corporation estimates the annual dividend it intends to distribute based on the Corporation's operating results, cash flows, financial conditions, debt covenants, long-term growth prospects, solvency test imposed under corporate law for declaration of dividends and other relevant factors.	See principal assumptions, risks and uncertainties identified under “Expected Production”, “Projected Revenues” and "Projected Adjusted EBITDA". Possibility that the Corporation may not declare or pay a dividend
Estimated project costs, expected obtainment of permits, start of construction, work conducted and start of commercial operation for Development Projects or Prospective Projects For each Development Project and Prospective Project, the Corporation may provide (where available) an estimate of potential installed capacity, estimated storage capacity, estimated project costs, project financing terms and each project’s development and construction schedule, based on its extensive experience as a developer, in addition to information directly related to incremental internal costs, site acquisition costs and financing costs, which are eventually adjusted for the projected costs and construction schedule provided by the engineering, procurement and construction (“EPC”) contractor retained for the project. The Corporation provides indications based on assumptions regarding its current strategic positioning and competitive outlook, as well as scheduling and construction progress, for its Development Projects and its Prospective Projects, which the Corporation evaluates based on its experience as a developer.	Uncertainties surrounding development of new facilities Performance of major counterparties, such as suppliers or contractors Delays and cost overruns in the design and construction of projects Ability to secure appropriate land Obtainment of permits Health, safety and environmental risks Ability to secure new PPAs or renew any PPA Higher-than-expected inflation Equipment supply Interest rate fluctuations and financing risk Risks related to U.S. PTCs and ITCs, changes in U.S. corporate tax rates and availability of tax equity financing Regulatory and political risks Natural disaster and force majeure Relationships with stakeholders Foreign market growth and development risks Outcome of insurance claims Social acceptance of renewable energy projects Ability of the Corporation to execute its strategy of building shareholder value Failure to realize the anticipated benefits of completed and future acquisitions Changes in governmental support to increase electricity to be generated from renewable sources by independent power producers COVID-19 restrictive measures

	Principal Risks and Uncertainties
Intention to respond to requests for proposals The Corporation provides indications of its intention to submit proposals in response to requests for proposals (“Request for Proposals” or “RFP”) based on the state of readiness of some of its Prospective Projects and their compatibility with the announced terms of these RFPs.	Regulatory and political risks Ability of the Corporation to execute its strategy for building shareholder value Ability to secure new PPAs Changes in governmental support to increase electricity to be generated from renewable sources by independent power producers Social acceptance of renewable energy projects Relationships with stakeholders
Qualification for PTCs and ITC and expected tax equity investment Flip Point For certain Development Projects in the United States, the Corporation has conducted on- and off-site activities expected to qualify its Development Projects for PTCs or ITC at the full rate and to obtain tax equity financing on such a basis. To assess the potential qualification of a project, the Corporation takes into account the construction work performed and the timing of such work. The expected Tax Equity Flip Point for tax equity investment is determined according to the LTAs and revenues of each such project and is subject in addition to the related risks mentioned above.	Risks related to U.S. PTCs and ITC, changes in U.S. corporate tax rates and availability of tax equity financing Regulatory and political risks Delays and cost overruns in the design and construction of projects Obtainment of permits

CHANGE IN ACCOUNTING POLICIES

New Accounting Standards and Interpretations Adopted During the Year

On January 1, 2020, the Corporation adopted the following new standards and interpretations:

Amendments to materiality definition

On October 31, 2018, the IASB issued Definition of Material (Amendments to IAS 1 *Presentation of Financial Statements* and IAS 8 *Accounting Policies, Changes in Accounting Estimates and Errors*) to clarify the definition of ‘material’ and to align the definition used in the Conceptual Framework and the standards themselves. The amendments are effective for annual reporting periods beginning on or after January 1, 2020.

Amendments to References to the Conceptual Framework

Together with the revised Conceptual Framework published in March 2018, the IASB also issued Amendments to References to the Conceptual Framework in IFRS Standards. The amendments are effective for annual periods beginning on or after January 1, 2020.

Amendments to IFRS 3 *Business Combinations*

On October 22, 2018, the IASB issued Definition of a Business (Amendments to IFRS 3) aimed at resolving the difficulties that arise when an entity determines whether it has acquired a business or a group of assets. The amendments are effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2020.

New accounting standards and interpretations issued but not yet adopted

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

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

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 application of this standard is not expected to have a material impact for the Corporation.

Interest Rate Benchmark Reform — Phase 2 (Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16)

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

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

The amendments are effective for annual periods beginning on or after January 1, 2021. Early adoption is permitted. The impact for the Corporation is being assessed by management.

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

In accordance with Regulation 52-109 respecting Certification of Disclosure in Issuers' Annual and Interim Filings, the President and Chief Executive Officer and the Chief Financial Officer of the Corporation have certified that they have designed, or caused it to be designed under their supervision:

- Disclosure controls and procedures (“DC&P”) to provide reasonable assurance that: (i) material information relating to the Corporation is made known to the President and Chief Executive Officer and the Chief Financial Officer by others, particularly during the period in which the interim filings are being prepared; and (ii) the information required to be disclosed by the Corporation in its annual filings, interim filings and other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time periods specified in securities legislation.
- Internal control over financial reporting (“ICFR”) to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with IFRS.

During the period beginning on July 1, 2020 and ended on September 30, 2020, there was no change in the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

SUBSEQUENT EVENTS

Tax equity investor's cash contribution made to the Hillcrest solar project
On October 29, 2020, Hillcrest Solar Partners received US$22.4 million ($29.8 million) from the tax equity investor in return for its Class A membership interest. Such an amount represents 20% of the tax equity investor’s total investment amount. On the same date, the Class B member (Hillcrest Equity Holdings, under the Corporation’s control) made its contribution to Hillcrest Solar Partners in return for its Class B membership interest. The interest in the Class A shares is accounted for as a debt instrument by the Corporation.

Closing of the financing of the Innavik hydroelectric project
On November 4, 2020, Innavik Hydro Limited Partnership entered into a $92.8 million construction and long-term credit agreement for the Innavik hydroelectric project. On the same day, the bond forward has been unwound, resulting in a realized net loss of $1.7 million. The construction term loan bears interest at 3.95%. Following completion of construction, the remaining balance of the aforementioned loan will be converted into a long-term loan bearing the same fixed interest rate and maturing in 2062.

CONDENSED CONSOLIDATED STATEMENTS OF EARNINGS (LOSS)

	Notes	Three months ended September 30 2020	Three months ended September 30 2019	Nine months ended September 30 2020	Nine months ended September 30 2019
Revenues		162,651	142,814	445,280	413,926
Expenses					
Operating		37,040	24,403	94,932	72,147
General and administrative		12,388	7,731	32,969	25,272
Prospective projects		4,699	3,329	13,100	10,665
Earnings before the following:		108,524	107,351	304,279	305,842
Depreciation	10	45,226	38,230	134,748	110,964
Amortization		14,142	10,113	35,313	30,594
Earnings before the following:		49,156	59,008	134,218	164,284
Finance costs	5	60,122	59,474	175,700	170,704
Other net income	6	(16,725)	(3,917)	(58,250)	(2,639)
Share of (earnings) loss of joint ventures and associates		(11,382)	(16,225)	21,398	(9,193)
Change in fair value of financial instruments	8 b)	(1,859)	6,031	24,835	9,225
Earnings (loss) before income tax		19,000	13,645	(29,465)	(3,813)
Income tax expense		11,508	3,749	11,540	1,164
Net earnings (loss) from continuing operations		7,492	9,896	(41,005)	(4,977)
Net (loss) earnings from discontinued operations	4	—	(193)	—	21,171
Net earnings (loss)		7,492	9,703	(41,005)	16,194
Net earnings (loss) attributable to:					
Owners of the parent		11,740	14,085	(44,548)	18,117
Non-controlling interests		(4,248)	(4,382)	3,543	(1,923)
		7,492	9,703	(41,005)	16,194
Earnings (loss) per share from continuing operations attributable to owners:					
Basic net earnings (loss) per share ($)	9	0.06	0.10	(0.29)	(0.04)
Diluted net earnings (loss) per share ($)	9	0.06	0.10	(0.29)	(0.04)
Earnings (loss) per share attributable to owners:					
Basic net earnings (loss) per share ($)	9	0.06	0.09	(0.29)	0.10
Diluted net earnings (loss) per share ($)	9	0.06	0.09	(0.29)	0.10

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

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

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

	Notes	Three months ended September 30 2020	Three months ended September 30 2019	Nine months ended September 30 2020	Nine months ended September 30 2019
Net earnings (loss)		7,492	9,703	(41,005)	16,194
Items of comprehensive income (loss) that will be subsequently reclassified to earnings:					
Foreign currency translation differences for foreign operations		(21,589)	3,424	16,378	(11,359)
Change in fair value of financial instruments designated as net investment hedges	8	587	771	1,834	4,337
Change in fair value of financial instruments designated as cash flow hedges	8	4,589	(12,899)	(111,237)	(15,647)
Change in fair value of financial instruments of joint ventures and associates designated as cash flow hedges		598	3,308	(5,788)	7,571
Related deferred income tax		(1,241)	3,138	27,863	4,486
Other comprehensive loss from continuing operations		(17,056)	(2,258)	(70,950)	(10,612)
Other comprehensive income from discontinued operations	4	—	—	—	3,928
Other comprehensive loss		(17,056)	(2,258)	(70,950)	(6,684)
Total comprehensive (loss) income		(9,564)	7,445	(111,955)	9,510
Total comprehensive (loss) income attributable to:					
Owners of the parent		(5,804)	13,249	(115,881)	37,352
Non-controlling interests		(3,760)	(5,804)	3,926	(27,842)
		(9,564)	7,445	(111,955)	9,510

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

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

CONDENSED CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

As at	Notes	September 30, 2020	December 31, 2019
ASSETS			
Current assets			
Cash and cash equivalents		156,360	156,224
Restricted cash		39,509	39,451
Accounts receivable		115,864	92,265
Derivative financial instruments	8	11,235	5,419
Investment tax credits recoverable	10	92,861	—
Prepaid and other		26,365	12,273
Total current assets		442,194	305,632
Non-current assets			
Property, plant and equipment	10	4,983,481	4,620,025
Intangible assets		945,036	682,227
Project development costs		8,671	11,135
Investments in joint ventures and associates		475,495	511,899
Derivative financial instruments	8	77,452	78,251
Deferred tax assets		32,127	30,264
Goodwill		76,608	60,666
Other long-term assets		107,070	72,005
Total non-current assets		6,705,940	6,066,472
Total assets		7,148,134	6,372,104
LIABILITIES			
Current liabilities			
Accounts payable and other payables		199,422	176,157
Derivative financial instruments	8	92,956	51,093
Current portion of long-term loans and borrowings and other liabilities		409,379	414,103
Total current liabilities		701,757	641,353
Non-current liabilities			
Derivative financial instruments	8	186,444	112,625
Long-term loans and borrowings		4,331,199	4,281,586
Other liabilities		388,676	292,421
Deferred tax liabilities		423,383	428,793
Total non-current liabilities		5,329,702	5,115,425
Total liabilities		6,031,459	5,756,778
SHAREHOLDERS' EQUITY			
Equity attributable to owners		1,047,437	604,384
Non-controlling interests		69,238	10,942
Total shareholders’ equity		1,116,675	615,326
Total liabilities and shareholders’ equity		7,148,134	6,372,104

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

For the nine-month period ended September 30, 2020	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, 2020	97,215	1,268,311	131,069	2,869	(879,849)	(15,231)	604,384	10,942	615,326
Net (loss) earnings	—	—	—	—	(44,548)	—	(44,548)	3,543	(41,005)
Other comprehensive (loss) income	—	—	—	—	—	(71,333)	(71,333)	383	(70,950)
Total comprehensive (loss) income	—	—	—	—	(44,548)	(71,333)	(115,881)	3,926	(111,955)
Common shares issued on February 6, 2020: private placement	660,870	—	—	—	—	—	660,870	—	660,870
Issuance fees (net of $672 of deferred income tax)	(1,842)	—	—	—	—	—	(1,842)	—	(1,842)
Business acquisition (Note 3)	—	—	—	—	—	—	—	63,169	63,169
Common shares issued through dividend reinvestment plan	5,247	—	—	—	—	—	5,247	—	5,247
Reduction of capital on common shares (Note 12b)	(754,355)	754,355	—	—	—	—	—	—	—
Share-based payments	—	58	—	—	—	—	58	—	58
Common share options exercised	363	(2,226)	—	—	—	—	(1,863)	—	(1,863)
Shares vested - Performance Share Plan	1,046	—	—	—	—	—	1,046	—	1,046
Shares purchased - Performance Share Plan	(6,008)	—	—	—	—	—	(6,008)	—	(6,008)
Dividends declared on common shares	—	—	—	—	(94,118)	—	(94,118)	—	(94,118)
Dividends declared on preferred shares	—	—	—	—	(4,456)	—	(4,456)	—	(4,456)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(8,799)	(8,799)
Balance September 30, 2020	2,536	2,020,498	131,069	2,869	(1,022,971)	(86,564)	1,047,437	69,238	1,116,675

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

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

CONDENSED CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

	Equity attributable to owners								
For the nine-month period ended September 30, 2019	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, 2019	6,546	1,272,604	131,069	3,976	(748,890)	(35,513)	629,792	329,769	959,561
Net earnings (loss)	—	—	—	—	18,117	—	18,117	(1,923)	16,194
Other comprehensive income (loss)	—	—	—	—	—	19,235	19,235	(25,919)	(6,684)
Reclassification of defined benefit plan actuarial losses	—	—	—	—	(378)	378	—	—	—
Total comprehensive income (loss)	—	—	—	—	17,739	19,613	37,352	(27,842)	9,510
Common shares issued through dividend reinvestment plan	2,219	—	—	—	—	—	2,219	—	2,219
Share-based payments	—	49	—	—	—	—	49	—	49
Common share options exercised	1,323	(4,357)	—	—	—	—	(3,034)	—	(3,034)
Common shares issued through the conversion of convertible debentures	46,599	—	—	(856)	—	—	45,743	—	45,743
Convertible debentures issued (Net of $243 of deferred income taxes)	—	—	—	670	—	—	670	—	670
Shares vested - Performance Share Plan	1,057	—	—	—	—	—	1,057	—	1,057
Shares purchased - Performance Share Plan	(2,385)	—	—	—	—	—	(2,385)		(2,385)
Buyback of non-controlling interests	—	—	—	—	—	—	—	(218)	(218)
Disposition of non-controlling interests	—	—	—	—	—	—	—	(260,846)	(260,846)
Dividends declared on common shares	—	—	—	—	(70,650)	—	(70,650)	—	(70,650)
Dividends declared on preferred shares	—	—	—	—	(4,456)	—	(4,456)	—	(4,456)
Distributions to non-controlling interests	—	—	—	—	—	—	—	(13,233)	(13,233)
Balance September 30, 2019	55,359	1,268,296	131,069	3,790	(806,257)	(15,900)	636,357	27,630	663,987

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

	Notes	Three months ended September 30 2020	Three months ended September 30 2019	Nine months ended September 30 2020	Nine months ended September 30 2019
OPERATING ACTIVITIES					
Net earnings (loss)		7,492	9,703	(41,005)	16,194
Net earnings (loss) from discontinued operations		—	193	—	(21,171)
Net earnings (loss) from continuing operations		7,492	9,896	(41,005)	(4,977)
Items not affecting cash:					
Depreciation and amortization		59,368	48,343	170,061	141,558
Share of (earnings) loss of joint ventures and associates		(11,382)	(16,225)	21,398	(9,193)
Unrealized portion of change in fair value of financial instruments	8	(23)	6,031	12,796	9,225
Production tax credits and tax attributes allocated to tax equity investors		(12,532)	—	(47,014)	—
Other		(2,777)	1,156	(2,565)	1,076
Finance costs expense		60,122	59,474	175,700	170,704
Finance costs paid	13 b)	(37,755)	(56,352)	(127,306)	(142,133)
Distributions received from joint ventures and associates		11,249	8,808	19,394	15,728
Income tax expense		11,508	3,749	11,540	1,164
Income tax paid		(4,745)	(12,518)	(7,407)	(15,995)
Effect of exchange rate fluctuations		689	(6,957)	(2,328)	(3,994)
		81,214	45,405	183,264	163,163
Changes in non-cash operating working capital items	13 a)	(16,302)	(8,903)	(25,848)	(7,956)
Cash flows from operating activities from continuing operations		64,912	36,502	157,416	155,207
Cash flows from operating activities from discontinued operations		—	—	—	13,122
		64,912	36,502	157,416	168,329
FINANCING ACTIVITIES					
Dividends paid on common and preferred shares		(29,663)	(24,678)	(85,673)	(71,578)
Distributions to non-controlling interests		(3,177)	(2,706)	(8,799)	(9,956)
Increase of long-term debt, net of deferred financing costs	13 c)	195,194	476,148	500,871	1,159,480
Repayment of long-term debt	13 c)	(42,121)	(344,101)	(661,142)	(897,867)
Payment of lease liabilities		(1,145)	679	(1,700)	(2,335)
Net proceeds from issuance of convertible debentures		—	120,021	—	120,021
Net proceeds from issuance of common shares		(150)	—	658,356	—
Purchase of common shares under the Performance Share Plan		—	(2,385)	(6,008)	(2,385)
Payment of payroll withholding on exercise of share options		(556)	41	(1,408)	(3,034)
Cash flows from financing activities from continuing operations		118,382	223,019	394,497	292,346
Cash flows from financing activities from discontinued operations		—	—	—	20,059
		118,382	223,019	394,497	312,405
INVESTING ACTIVITIES					
Business acquisition, net of cash acquired	3	(72,011)	—	(161,792)	—
Proceeds from sale of business, net of transaction costs ($6,634) and cash disposed ($13,877)	4	—	(193)	—	383,696
Change in restricted cash		66	197	6,971	(38,825)
Net funds invested in the reserve accounts		(757)	(233)	(5,934)	(2,357)
Additions to property, plant and equipment		(181,027)	(184,304)	(352,259)	(703,645)
Additions to project development costs		(2,031)	(2,966)	(25,667)	(5,410)
Investments in joint ventures and associates		—	(13,229)	—	(13,753)
Additions to other long-term assets		2,870	(362)	(17,124)	(388)
Proceeds from disposal of property, plant and equipment		—	(592)	—	16
Cash flows used in investing activities from continuing operations		(252,890)	(201,682)	(555,805)	(380,666)
Cash flows used in investing activities from discontinued operations		—	—	—	(31,957)
		(252,890)	(201,682)	(555,805)	(412,623)
Effects of exchange rate changes on cash and cash equivalents		(3,022)	(826)	4,028	(2,062)
Net change in cash and cash equivalents		(72,618)	57,013	136	66,049
Cash and cash equivalents, beginning of period		228,978	88,622	156,224	79,586
Cash and cash equivalents, end of period		156,360	145,635	156,360	145,635

Additional information is presented in Note 13.

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

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

DESCRIPTION OF BUSINESS

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

These unaudited condensed interim consolidated financial statements were approved by the Board of Directors on November 10, 2020.

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 and assets and liabilities acquired in business combinations that are measured at fair value. 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

Change in accounting policies

On January 1, 2020, the Corporation adopted the following new standards and interpretation which did not have a significant impact on these unaudited condensed interim consolidated financial statements:

Amendments to materiality definition

On October 31, 2018, the IASB issued Definition of Material (Amendments to IAS 1, *Presentation of Financial Statements* and IAS 8, *Accounting Policies, Changes in Accounting Estimates and Errors*) to clarify the definition of 'material' and to align the definition used in the Conceptual Framework and the standards themselves. The amendments are effective for annual reporting periods beginning on or after January 1, 2020.

Amendments to References to the Conceptual Framework

Together with the revised Conceptual Framework published in March 2018, the IASB also issued Amendments to References to the Conceptual Framework in IFRS Standards. The amendments are effective for annual periods beginning on or after January 1, 2020.

Amendments to IFRS 3, *Business Combinations*

On October 22, 2018, the IASB issued Definition of a Business (Amendments to IFRS 3, *Business Combinations*) aimed at resolving the difficulties that arise when an entity determines whether it has acquired a business or a group of assets. The amendments are effective for business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after January 1, 2020.

New accounting standards and interpretations issued but not yet adopted

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 application of this standard is not expected to have a material impact for the Corporation.

Interest Rate Benchmark Reform — Phase 2 (Amendments to IFRS 9, IAS 39, IFRS 7, IFRS 4 and IFRS 16)

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

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

The amendments are effective for annual periods beginning on or after January 1, 2021. Early adoption is permitted. The impact for the Corporation is being assessed by management.

3. BUSINESS ACQUISITIONS

Acquisition of Mountain Air Alternatives LLC

On July 15, 2020, the Corporation acquired all the outstanding class B shares of Mountain Air Alternatives LLC ('Mountain Air") which owns a portfolio of six operating wind farms in Elmore County, Idaho, in the United States. Mountain Air class B shares were acquired for a total cash consideration of US$56,751 ($77,272), financed entirely from the Corporation's revolving credit facilities. The Mountain Air acquisition added an additional gross installed capacity of 138 MW to the Corporation's portfolio.

The acquisition gave rise to transaction costs of $768 which were expensed as incurred in other net income in the condensed consolidated statements of earnings (loss).

The investment was accounted for as a business combination and the results have been included in the condensed consolidated statements of earnings (loss) since the date of the acquisition. The revenues and net earnings included in the condensed consolidated statements of earnings (loss) are $5,664 and $57, respectively for the 77-day period ended September 30, 2020. Had the acquisition taken place on January 1, 2020, revenues and net earnings for the period from January 1, 2020 to September 30, 2020 would have been $19,656 and $2,942 higher, respectively.

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

	Preliminary acquisition accounting	
	US$	CA$
Cash and cash equivalents	3,864	5,261
Restricted cash	4,544	6,187
Accounts receivable	1,482	2,018
Prepaid and other	188	256
Property, plant and equipment	17,867	24,328
Intangible assets	207,201	282,125
Goodwill	10,378	14,131
Accounts payable and other payables	(2,075)	(2,825)
Derivative financial instruments	(1,520)	(2,070)
Long-term loans and borrowings	(126,507)	(172,252)
Other liabilities	(1,900)	(2,587)
Deferred tax liabilities	(10,378)	(14,131)
Non-controlling interests	(46,393)	(63,169)
Net assets acquired	56,751	77,272

The non-controlling interests are held by the original tax equity partner, which is entitled, as the project was acquired after the flip date, to 37.75% of the cash distributions. The fair value of the non-controlling interest in Mountain Air Alternatives LLC, an unlisted company, was estimated by applying an income approach.

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

Acquisition of PV Salvador SPA

On May 14, 2020, the Corporation acquired all the outstanding shares of PV Salvador SpA ("Salvador"), a solar photovoltaic farm in Chile, including 11-year demand-based power hedge agreements covering a total electricity generation of 54.6 GWh/year. Salvador was acquired for a total cash consideration of US$66,051 ($92,953), financed entirely from the Corporation's revolving credit facilities. The Salvador acquisition added an additional gross installed capacity of 68 MW to the Corporation's portfolio.

The acquisition gave rise to transaction costs of $100 which were expensed as incurred in other net income in the condensed consolidated statements of earnings (loss).

The investment was accounted for as a business combination and the results have been included in the condensed consolidated statements of earnings (loss) since the date of the acquisition. The revenues and net earnings included in the condensed consolidated statements of earnings (loss) are $2,521 and $90, respectively for the 139-day period ended September 30, 2020. Had the acquisition taken place on January 1, 2020, revenues and net earnings for the period from January 1, 2020 to September 30, 2020 would have been $5,422 and $253 higher, respectively.

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

	Preliminary acquisition accounting	
	US$	CA$
Cash and cash equivalents	2,254	3,172
Accounts receivable	2,527	3,555
Prepaid and other	1,253	1,764
Property, plant and equipment	43,361	61,022
Intangible assets	3,323	4,676
Derivative financial instruments	18,694	26,308
Deferred tax assets	5,048	7,104
Accounts payable and other payables	(2,279)	(3,207)
Other liabilities	(3,082)	(4,337)
Deferred tax liabilities	(5,048)	(7,104)
Net assets acquired	66,051	92,953

In the financial statements for the quarterly period ended June 30, 2020, a $7,104 amount was recognized for goodwill. More information has been obtained about the specifics of the tax position during the quarter. As an adjustment to the initial acquisition accounting, such an amount is now recognized as deferred tax assets.

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

4. DISCONTINUED OPERATIONS

On May 23, 2019, the Corporation sold its wholly-owned subsidiary Magma Energy Sweden A.B., which owned an equity interest of approximately 53.9% in HS Orka hf ("HS Orka"), to Jarðvarmi slhf. The closing adjustments to the sale were finalized in July 2019.

The following table summarizes the net earnings from discontinued operations:

	Three months ended September 30	Nine months ended September 30
	2019	2019
Revenues	—	40,006
Expenses	—	39,677
Share of earnings of joint ventures and associates	—	(3,718)
Earnings before income tax	—	4,047
Recovery of income tax	—	(40)
Net earnings from discontinued operations before the following	—	4,087
Loss (gain) on sale of the subsidiary	193	(17,084)
Net (loss) earnings from discontinued operations	(193)	21,171
Other comprehensive income from discontinued operations	—	3,928
Total comprehensive (loss) income from discontinued operations	(193)	25,099
Net (loss) earnings from discontinued operations attributable to:		
Owners of the parent	(193)	19,038
Non-controlling interests	—	2,133
	(193)	21,171
Total comprehensive (loss) income from discontinued operations attributable to:		
Owners of the parent	(193)	42,188
Non-controlling interests	—	(17,089)
	(193)	25,099
Net (loss) earnings per share from discontinued operations		
Basic net (loss) earnings per share ($)	(0.01)	0.14
Diluted net (loss) earnings per share ($)	(0.01)	0.14

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

5. FINANCE COSTS

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Interest expense on long-term corporate and project loans	42,873	46,763	129,399	138,801
Interest expense on convertible debentures	3,488	2,850	10,362	8,533
Interest expense on tax equity investors financing	6,118	—	19,106	—
Interest on lease liabilities	1,054	500	3,319	1,512
Interest income on preferred shares	(1,252)	—	(4,214)	—
Inflation compensation interest	3,007	2,059	1,212	6,005
Amortization of financing fees	2,339	3,290	7,120	7,611
Accretion of long-term loans and borrowings	733	1,218	2,082	1,852
Accretion expenses on other liabilities	1,413	1,478	3,892	3,227
Other	349	1,316	3,422	3,163
	60,122	59,474	175,700	170,704

6. OTHER NET INCOME

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Tax attributes allocated to tax equity investors	(4,303)	—	(15,733)	—
Production tax credits	(8,229)	—	(31,281)	—
Realized gain on contingent considerations	—	—	(945)	—
Restructuring costs	707	1,822	1,157	1,822
Transaction costs related to business combinations	527	199	868	211
Realized gain on foreign exchange	(689)	(2,723)	(4,878)	(2,939)
Others, net	(4,738)	(3,215)	(7,438)	(1,733)
	(16,725)	(3,917)	(58,250)	(2,639)

Tax attributes allocated to tax equity investors

In tax equity structures, a portion of the tax attributes generated by a renewable project, such as taxable income (loss), including accelerated tax depreciation under the U.S. Modified Accelerated Cost Recovery System ("MACRS"), are allocated to the tax equity investors and applied against the related tax equity financing as principal repayment. During the three and nine months ended September 30, 2020, tax attributes allocated to the tax equity investors and applied as principal payment against the tax equity financing totalled $4,303 and $15,733, respectively, and relate to the Foard City wind and the Phoebe solar projects commissioned in 2019, which were subject to accelerated tax depreciation under the MACRS.

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

Production tax credits ("PTCs")

Certain projects are eligible to receive U.S. renewable tax incentives such as PTCs, which are earned as production occurs. In tax equity structures, the portion of these tax attributes which is allocated to the tax equity investors is applied against the related tax equity financing as principal repayment. During the three and nine months ended September 30, 2020, PTCs earned and applied as principal payment against the tax equity financing totalled $8,229 and $31,281, respectively, and relate to the Foard City wind project commissioned during 2019.

7. INVESTMENTS IN JOINT VENTURES AND ASSOCIATES

Innavik

The Innavik hydroelectric project is currently in the process of securing financing for the forthcoming construction. In order to mitigate the risk of interest rate fluctuations during the negotiation process, therefore affecting the cost of future financing and the project's expected rate of return, Innavik entered, between February 20, 2020 and March 6, 2020, into 7 bond forward contracts, for a total notional of $58,000 Government of Canada 2.75%, December 1, 2048 bonds. The bonds forwards matured on August 20, 2020 and were rolled over into a single bond forward maturing on November 20, 2020, for the same total notional amount. The bond forward contract is a financial derivative and is measured at fair value, with changes recognized in the net earnings of the joint venture.

8. DERIVATIVE FINANCIAL INSTRUMENTS

a. Financial position

The following table shows a reconciliation from the opening balances to the closing balances for the derivative financial instruments (refer to Note 14 for financial risk management and fair value disclosures):

Financial assets (liabilities)	Foreign exchange forwards (Level 2)	Interests hedging derivatives (Level 2)	Power and basis hedges (Level 3)	Currency translation of intragroup loans[1]	Total
As at January 1, 2020	(24,269)	(83,536)	27,757	—	(80,048)
Derivatives acquired on business acquisition (Note 3)	—	(2,070)	26,308	—	24,238
Change in fair value recognized in consolidated statements of earnings (loss) - unrealized portion [2]	(7,973)	1,335	(20,048)	13,890	(12,796)
Change in fair value recognized in other comprehensive income (loss)	1,834	(108,320)	(2,917)	—	(109,403)
Amortization of other accumulated comprehensive income recognized in revenue	—	—	2,796	—	2,796
Net foreign exchange differences	—	(1,064)	(546)	(13,890)	(15,500)
As at September 30, 2020	(30,408)	(193,655)	33,350	—	(190,713)

1. A gain of $13,890 results from the revaluation, into Canadian dollars, of foreign currency-denominated intragroup loans. On consolidation, although the intragroup loans are eliminated from the condensed consolidated statement of financial position, the foreign subsidiaries' financial positions, including their loan balances towards the Corporation, are converted into Canadian dollars, with currency translation differences being recorded within other comprehensive (loss) income, therefore not eliminating the gain recognized on the condensed consolidated statements of earnings (loss).
2. Refer to Note 8b for a reconciliation to the change in fair value recognized in the condensed consolidated statements of earnings (loss).

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

Reported in the condensed consolidated statements of financial position:

As at	September 30, 2020	December 31, 2019
Current assets	11,235	5,419
Non-current assets	77,452	78,251
Current liabilities	(92,956)	(51,093)
Non-current liabilities	(186,444)	(112,625)
	(190,713)	(80,048)

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

Recognized in the consolidated statements of earnings (loss):

(Gain) loss	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Unrealized portion of change in fair value of financial instruments	(23)	6,031	12,796	9,225
Realized portion of change in fair value of financial instruments:				
Realized gain on the power hedges	(2,447)	—	(7,414)	—
Realized loss on Phoebe basis hedge	611	—	19,453	—
Change in fair value of financial instruments recognized in condensed consolidated statements of earnings (loss)	(1,859)	6,031	24,835	9,225

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

9. EARNINGS (LOSS) PER SHARE

Basic	Three months ended September 30 2020	Three months ended September 30 2019 Continuing operations [1]	Nine months ended September 30 2020	Nine months ended September 30 2019 Continuing operations [1]
Net earnings (loss) attributable to owners of the parent	11,740	14,278	(44,548)	(921)
Dividends declared on preferred shares	(1,485)	(1,485)	(4,456)	(4,456)
Net earnings (loss) available to common shareholders	10,255	12,793	(49,004)	(5,377)
Weighted average number of common shares (in 000s)	173,858	133,400	169,048	133,229
Basic net earnings (loss) per share ($)	0.06	0.10	(0.29)	(0.04)

Diluted	Three months ended September 30 2020	Three months ended September 30 2019 Continuing operations [1]	Nine months ended September 30 2020	Nine months ended September 30 2019 Continuing operations [1]
Net earnings (loss) available to common shareholders	10,255	12,793	(49,004)	(5,377)
Diluted weighted average number of common shares (in 000s)	174,493	133,876	169,048	133,229
Diluted net earnings (loss) per share ($)	0.06	0.10	(0.29)	(0.04)

[1] Net earnings (loss) from discontinued operations attributable to owners of the parent for the three and nine months ended September 30, 2019 was $(193) and $19,038, or $(0.01) and $0.14 per share, respectively. Total net earnings available to common shareholders for the three and nine months ended September 30, 2019 was $12,600 and $13,661, or $0.09 and $0.10 per share, respectively.

Reconciliation of the denominators	Three months ended September 30 2020	Three months ended September 30 2019 Continuing Operations	Nine months ended September 30 2020	Nine months ended September 30 2019 Continuing Operations
Weighted average number of common shares (in 000s)	173,858	133,400	169,048	133,229
Effect of share options	78	175	—	—
Effect of shares held in trust related to the Performance Share Plan	557	301	—	—
Diluted weighted average number of common shares (in 000s)	174,493	133,876	169,048	133,229

Instruments that are excluded from the dilutive elements (in 000s):	Three months ended September 30 2020	Three months ended September 30 2019	Nine months ended September 30 2020	Nine months ended September 30 2019
Share options	—	—	507	738
Shares in trust related to the Performance Share Plan	—	—	557	301
Convertible debentures	13,777	16,576	13,777	16,576
	13,777	16,576	14,841	17,615

10. PROPERTY, PLANT AND EQUIPMENT

	Lands	Hydroelectric facilities	Wind farm facilities	Solar facilities	Facilities under construction	Other	Total
Cost							
As at January 1, 2020	120,809	2,091,034	2,514,434	466,078	102,952	32,462	5,327,769
Additions [1]	71,021	311	1,927	1,473	339,337	695	414,764
Investment tax credits [2]	—	—	—	—	(96,156)	—	(96,156)
Business acquisitions (Note 3)	660	—	24,328	60,362	—	—	85,350
Transfer from projects under development	—	—	—	—	28,110	—	28,110
Dispositions	—	—	(325)	—	—	—	(325)
Other changes	(14,447)	(7)	12,345	1,705	—	916	512
Net foreign exchange differences	3,417	259	64,531	5,836	(73)	166	74,136
As at September 30, 2020	181,460	2,091,597	2,617,240	535,454	374,170	34,239	5,834,160
Accumulated depreciation							
As at January 1, 2020	(4,672)	(310,000)	(328,004)	(50,593)	—	(14,475)	(707,744)
Depreciation [3]	(4,229)	(28,568)	(85,209)	(14,798)	—	(2,800)	(135,604)
Dispositions	—	—	152	—	—	—	152
Net foreign exchange differences	(124)	(219)	(6,920)	(152)	—	(68)	(7,483)
As at September 30, 2020	(9,025)	(338,787)	(419,981)	(65,543)	—	(17,343)	(850,679)
Carrying amount as at September 30, 2020 [4]	172,435	1,752,810	2,197,259	469,911	374,170	16,896	4,983,481

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 $5,984 of capitalized financing costs incurred prior to commissioning.
2. During the nine-month period ended September 30, 2020, the Corporation accrued for US$69,616 ($96,156) in investment tax credits recoverable in relation to the construction of the Hillcrest solar project, which were recognized as a reduction in the cost of the Hillcrest property, plant and equipment. As at September 30, 2020, the balance of investment tax credit recoverable amounts to US$69,616 ($92,861).
3. An amount of $856 of the depreciation expense for the land leases is capitalized as a construction cost in facilities under construction.
4. Included in property, plant and equipment are right-of-use assets with a carrying amount of $176,030 ($168,653, $106 and $7,271 included in Lands, Hydroelectric facilities and Other, respectively) pursuant to lease agreements.

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

11. LONG-TERM LOANS AND BORROWINGS

As at September 30, 2020, the Corporation and its subsidiaries have met all material financial and non-financial conditions related to their credit agreements, except for the following:

- the Mesgi'g Ugju's'n project was in default of its credit agreement as at September 30, 2020 and as at December 31, 2019. A breach was triggered by the bankruptcy of a supplier considered a major project participant under the credit agreement. A waiver has been obtained and was subsequently extended until December 31, 2020. A plan was put in place to ensure the continuity of the operations of the project. Ongoing dialogue and reporting are provided to the project lenders until this situation is resolved. If the waiver is not renewed, the lenders would have the right to request repayment. As a result, the $235.3 million loan was reallocated to the current portion of long-term debt. As at September 30, 2020 and as at December 31, 2019 the project was in compliance with financial covenants.

a. Corporate Indebtedness

Revolving Term Credit Facility

In February 2020, the Corporation completely reimbursed the revolving term credit facility from the proceeds of the private placement of Hydro-Québec in common shares of the Corporation (see Note 12a). Following the repayment, additional draws of $252,996 were made to support the Corporation's business acquisitions, construction and operating activities. The outstanding balance as at September 30, 2020 is $252,996 (December 31, 2019 - $490,996).

b. Closing of the financing of the Hillcrest Solar Project

On May 7, 2020, the Corporation entered into a construction and long-term credit agreement for the Hillcrest solar project.

The credit agreement comprises two facilities:

- a US$82,033 ($115,864) construction term loan bearing interest at LIBOR +1.75% maturing in 2027. As at September 30, 2020, an amount of US$82,033 ($109,424) has been drawn. Following the commencement of commercial operations, the construction facility will be converted into a 7-year term loan bearing interest at LIBOR +2.25% for the first four years and at LIBOR +0.125% thereafter until maturity. All of the variable interest rate exposure has been fixed through an interest rate swap which becomes effective on December 31 2020, resulting in a fixed interest rate of 0.945%; and
- a US$109,800 ($155,082) tax equity bridge loan bearing interest at LIBOR +1.75% maturing in 2027. As at September 30, 2020, an amount of US$50,026 ($66,730) has been drawn. Following the commencement of commercial operations, the tax equity bridge loan will be repaid with the proceeds from the tax equity investor’s contribution.

c. Closing of the financing of the Yonne II Project

On May 26, 2020, the Corporation's subsidiary Éoles-Yonne S.A.S. entered into an amendment to its credit agreement for the financing of the Yonne II wind farm project, an extension of the Yonne wind farm. The Yonne II project loan, for a total loan commitment of €12,767 ($19,347), comprises :

- a €5,425 loan bearing a fixed interest rate of 1.45%, repayable in quarterly installments beginning in December 2021 and maturing in March 2039;
- a €5,425 loan bearing a fixed interest rate of 1.65%, repayable in quarterly installments beginning in December 2021 and maturing in March 2039;
- a €1,600 short term revolving credit facility to finance the value added taxes during the construction phase; and
- additional credit and guarantees on the original credit agreement of €317.

The outstanding balance as at September 30, 2020 is €4,104 ($6,414).

d. Acquisition of Mountain Air

As part of the acquisition of Mountain Air, the Corporation assumed the related loan facilities for a total fair value of US$126,507 ($172,252), which are comprised of:

- US$94,011 ($128,005) senior secured notes (the "Notes") bearing interest at an annual rate of 6.00% and maturing on June 30, 2032. The Notes are collateralized by the Mountain Air wind farm facilities. The Notes were accounted for at their fair market value of US$109,407 ($148,969) for an effective interest rate of 3.80%; and
- a US$17,100 ($23,283) term loan bearing interest at LIBOR + 3.00% and maturing on November 30, 2029. The loan was accounted for at its book value which was considered representative of the fair value of the remaining debt.

The outstanding balance as at September 30, 2020 is US$127,994 ($170,731).

12. SHAREHOLDERS' CAPITAL

a. Strategic Alliance and private placement with Hydro-Québec

On February 6, 2020, Hydro-Québec invested $660,870 through a private placement in common shares of the Corporation at a price of $19.08 per share, representing a total of 34,636,823 shares (19.9% of the then-issued and outstanding common shares on a non-diluted basis).

b. Contributed surplus from reduction of capital account on common shares

A special resolution to approve the reduction of the legal stated capital account maintained in respect of the common shares of the Corporation, without any payment or distribution to the shareholders was adopted on May 12, 2020. This resulted in a decrease of the shareholders' capital account of $754,355 and an equivalent increase of the contributed surplus.

c. Buyback of common shares and preferred shares

On May 21, 2020, the Corporation received the approval from the Toronto Stock Exchange ("TSX") to proceed with a normal course issuer bid on its common shares (the "New Bid"). Under the New Bid, the Corporation could purchase for cancellation up to 2,000,000 of its common shares, representing approximately 1.15% of the 174,234,629 issued and outstanding common shares of the Corporation as at May 21, 2020. The Corporation could also purchase for cancellation up to 68,000 of its Series A Preferred Shares, representing approximately 2% of the 3,400,000 issued and outstanding shares of the Corporation as at May 21, 2020. And finally, the Corporation could purchase for cancellation up to 40,000 of its Series C Preferred Shares, representing approximately 2% of the 2,000,000 issued and outstanding shares of the Corporation as at May 21, 2020.The New Bid commenced on May 24, 2020 and will terminate on May 23, 2021. No common or preferred shares have been purchased and cancelled as at September 30, 2020.

d. Equity-based compensation

Share option plan

During the three and nine months ended September 30, 2020, a total of nil and 51,895 options were granted. The options granted under the share options plan vest over a period of four years following the grant date. Options must be exercised before March 2, 2027 at an exercise price of $20.52.

During the three and nine months ended September 30, 2020, 241,855 and 521,056 options were exercised, respectively, resulting in 87,905 and 181,839 shares issued, respectively. The difference between the options exercised and the shares issued is the result of a cashless exercise by the holders, and the payroll withholding assumed by the Corporation, as authorized by the share option plan and the Board of Directors. In addition, during the nine months ended September 30, 2020, 2,673 options expired.

e. Dividend Declared on common shares

The following dividends were declared on common shares by the Corporation:

	Three months ended September 30	
	2020	2019
Dividends declared on common shares ($/share)	0.180	0.175

For the nine months ended September 30, 2020, the Corporation declared a dividend of $94,118 (2019 - $70,650).

Dividend declared on common shares not recognized at the end of the reporting period

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

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
11/10/2020	12/31/2020	1/15/2021	0.1800	0.2255	0.359375

13. ADDITIONAL INFORMATION TO THE CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Accounts receivable	(29,992)	(11,760)	(26,107)	(13,566)
Prepaid and others	(6,033)	(5,536)	(12,048)	(6,062)
Accounts payable and other payables	19,723	8,393	12,307	11,672
	(16,302)	(8,903)	(25,848)	(7,956)

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

b. Additional information

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Finance costs paid relative to operating activities before interest on leases	(37,261)	(56,120)	(125,778)	(141,435)
Interest on leases paid relative to operating activities	(494)	(232)	(1,528)	(698)
Capitalized interest relative to investing activities	(3,272)	(8,223)	(4,780)	(14,082)
Capitalized interest on leases relative to investing activities	(521)	(656)	(1,052)	(1,949)
Total finance costs paid	(41,548)	(65,231)	(133,138)	(158,164)
Non-cash transactions:				
Change in unpaid property, plant and equipment	(19,111)	(75,031)	(13,773)	44,968
Investment tax credits	19,403	—	96,156	—
Unpaid long term assets	11,521	—	11,521	—
Change in unpaid project development costs	266	329	266	(382)
Unpaid investment in joint venture and associates	—	(13,753)	—	(13,753)
Remeasurement of other liabilities	3,207	12,130	6,061	38,002
Initial measurement of other liabilities	22,494	—	75,270	—
Common shares issued through the conversion of convertible debentures	—	45,743	—	45,743
Common shares issued through share options exercised	568	142	818	1,323
Shares vested in Performance Share Plan	—	—	1,046	1,057
Common shares issued through dividend reinvestment plan	2,552	180	5,247	2,219
Unpaid closing adjustments related to the sale of HS Orka	—	—	—	3,327

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

c. Changes in liabilities arising from financing activities

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Changes in long-term debt				
Long-term debt at beginning of period	4,133,473	4,470,596	4,412,842	4,470,252
Reclassified as held for sale	—	—	—	(96,515)
Increase of long-term debt	195,194	476,148	510,127	1,174,117
Repayment of long-term debt	(42,121)	(344,101)	(661,142)	(897,867)
Payment of deferred financing costs	—	—	(9,256)	(14,637)
Business acquisitions (Note 3)	172,252	—	172,252	—
Tax attributes	(4,303)	—	(15,733)	—
Production tax credits	(8,229)	—	(31,281)	—
Other non-cash finance costs	11,794	15,403	28,093	33,407
Net foreign exchange differences	(5,500)	(11,705)	46,658	(62,416)
Long-term debt at end of period	4,452,560	4,606,341	4,452,560	4,606,341
Changes in convertible debentures				
Convertible debentures at beginning of period	280,057	240,038	278,827	238,648
Issuance of convertible debentures	—	125,000	—	125,000
Transaction costs	—	(5,750)	—	(5,750)
Convertible debentures converted into common shares	—	(45,743)	—	(45,743)
Amount classified as equity	—	(913)	—	(913)
Accretion of convertible debentures	662	1,299	1,892	2,689
Convertible debentures at end of period	280,719	313,931	280,719	313,931

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

14. FINANCIAL RISK MANAGEMENT AND FAIR VALUE DISCLOSURES

Fair value disclosures

Interest rate swaps

The fair value is calculated as the present value of the expected cash flows. Expected 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 or of the counterparty.

Foreign exchange forwards

The fair value is calculated as the present value of the expected 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 and basis hedges

The fair value calculation of power and basis hedges gives rise to measurement uncertainty as the power price curves are constructed using various methodologies and assumptions, which consider certain unobservable inputs. As at September 30, 2020, the forward power prices used in the calculation of fair value were as follows:

With respect to the Phoebe power hedge, ERCOT[1] South Hub forward power prices are expected to be in a range of US$17.82 to US$94.09 per MWh between October 1, 2020 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 $16.65 to US$106.68 per MWh between October 1, 2020 and June 30, 2031.

With respect to the Phoebe basis hedge, ERCOT South Hub forward power prices are expected to be in a range of US$24.01 to US$94.09 per MWh between October 1, 2020 and December 31, 2021, while Phoebe node forward power prices are derived using a historical spread against the ERCOT South Hub of US$30.51 per MWh.

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

Phoebe power hedge: The fair value of the power hedge is derived from forward power prices that are not based on observable market data for the entirety of the contracted period. The power ERCOT South Hub forward price curves are constructed using various assumptions depending on the following observable market data available as of the valuation date: (1) observable monthly market prices through December 2024 for the ERCOT South Hub, as obtained from the Intercontinental Exchange ("ICE") open interest data; (2) quoted prices obtained from ICE through August 2030; (3) for the ten remaining months until June 2031, a heat rate based on the calendar year forward electricity price and the NYMEX[2] Natural Gas Calendar Strip resulting in calendar year average power prices, adjusted for seasonality based on calendar year 2021.

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.

Phoebe basis hedge: The fair value of the basis hedge is derived from observable forward power prices at the ERCOT South Hub for the duration of the contract period and a Phoebe node forward price curve constructed using various assumptions depending on the following observable market data available as of the valuation date: (1) forward power prices at the ERCOT South Hub for the duration of the contract period; (2) historical spread between the ERCOT South Hub and the Phoebe node prices from July 2019 onwards (“Observable Period”); and (3) historical spread prior to July 2019 between the ERCOT South Hub and a proxy to the Phoebe node, adjusted for the average price differential between the Phoebe node and its proxy during the Observable Period.

[1] Electricity Reliability Council of Texas.
[2] New York Mercantile Exchange.

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 condensed consolidated statements of earnings (loss), as unrealized portion of the change in fair value of financial instruments.

Sensitivities

Phoebe power hedge: A reasonably possible change of plus (minus) 10% at the reporting date in the ERCOT South forward prices would have caused an increase (a decrease) in the power hedge floating leg expected outflows and thus a shift in the Phoebe power hedge fair value and the net loss by minus (plus) $26,857. This analysis assumes that all other variables remain constant.

Salvador power hedges: A reasonably possible change of plus (minus) 10% at the reporting date in the Polpaico node forward prices would have caused an increase (a decrease) in the energy swaps floating leg expected outflows and thus a shift in the Salvador energy swaps aggregate fair values and the net loss by minus $1,582 (plus $1,272). This analysis assumes that all other variables remain constant.

Phoebe basis hedge: A reasonably possible change of plus (minus) 10% at the reporting date in the spread between the Phoebe node prices and the ERCOT South Hub would have resulted in larger (smaller) outflows and thus a shift in the basis hedge fair value and the net loss by minus (plus) $2,966. This analysis assumes that all other variables remain constant.

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.

Market risk

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

Power price risk is the risk that future cash flows or fair value of a financial instrument will fluctuate because of changes in market prices of electricity.

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.

15. COVID-19

To combat the spread of the COVID-19, authorities in all regions where we operate have put in place restrictive measures for businesses. However, with the exception of the curtailment notices received from BC Hydro, as described in Note 16, *Contingencies*, these measures have not impacted the Corporation in a material way to date as electricity production has been deemed an essential service in every region where we operate. 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 and financial position. The issuance of permits and authorizations, negotiations and finalizations of agreements with regards to development and acquisition projects, construction activities and procurement of equipment could be adversely impacted by the COVID-19 restrictive measures.

Construction activities at our Hillcrest solar project continued without interruption while construction activities for the Innavik hydro project have, after a slight delay, started on July 7, 2020. Constructions of the Yonne II and the Griffin Trail wind projects have commenced during the third quarter of 2020. Construction of the Griffin Trail project is not expected to be further delayed. Following the recent announcement of lockdown by the French Government, the Yonne II project could experience delays in the construction activities due mainly to border closures.

16. CONTINGENCIES

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

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 as a joint venture), Upper Lillooet River, Northwest Stave River, and Boulder Creek facilities, 2.0 MW/h for the Tretheway Creek facility and 4.0 MW/h for the Big Silver Creek facility.

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

Innergex disputes that the current pandemic and related governmental measures in any way prevent BC Hydro from fulfilling its obligations to accept and purchase energy under the EPAs or enable it to invoke "force majeure" provisions under the EPAs to suspend these obligations. Innergex acknowledges that BC Hydro retains "turn-down" rights under the EPAs, which enable it to require Innergex to turn down or shut off its facilities in certain circumstances, including in order to avoid a safety or stability risk. Where BC Hydro exercises this right, it is required under the EPAs to compensate Innergex for energy that would have been produced at the facilities in the absence of the curtailment. Innergex has complied with BC Hydro's curtailment request, but has done so under protest and seeks to enforce its rights under the EPAs on the basis described above. For the three- and nine-month periods ended September 30, 2020, actual eligible energy revenue that would have been produced at the facilities in the absence of the curtailment amounted to $3,015 ($3,599 on a Revenues Proportionate[1] basis) and $13,031 ($14,758 on a Revenues Proportionate[1] basis), respectively.

1. Revenues Proportionate is not a recognized measure under IFRS and therefore may not be comparable to those presented by other issuers. Please refer to Note 17, Segment Information, for more information.

17. SEGMENT INFORMATION

Operating segments

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

"Revenues Proportionate" are Revenues plus Innergex's share of Revenues of the operating joint ventures and associates, other incomes related to PTCs, and Innergex's share of the operating joint ventures and associates' other incomes related to PTCs. "Adjusted EBITDA" represents net earnings (loss) before income tax expense, finance costs, depreciation and amortization, adjusted to exclude other net (income) expenses, share of (earnings) loss of joint ventures and associates, and change in fair value of financial instruments. "Adjusted EBITDA Proportionate" represents Adjusted EBITDA plus the Corporation's share of Adjusted EBITDA of the operating joint ventures and associates, other incomes related to PTCs, and Innergex's share of the operating joint ventures and associates' other incomes related to PTCs. 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 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 September 30, 2020				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	76,170	67,726	18,755	162,651
Innergex's share of revenues of joint ventures and associates	30,521	6,917	403	37,841
PTCs and Innergex's share of PTCs generated	—	13,244	—	13,244
Segment Revenues Proportionate	106,691	87,887	19,158	213,736
Segment Adjusted EBITDA	61,847	48,431	14,034	124,312
Innergex's share of Adjusted EBITDA of joint ventures and associates	26,402	2,989	274	29,665
PTCs and Innergex's share of PTCs generated	—	13,244	—	13,244
Segment Adjusted EBITDA Proportionate	88,249	64,664	14,308	167,221
Segment Adjusted EBITDA Margin	81 %	72 %	75 %	76 %

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

As at September 30, 2020	Hydroelectric	Wind	Solar	Segment totals [1]
Investments in joint ventures and associates	184,003	220,462	16,031	420,496
Property, plant and equipment acquired through business acquisitions (Note 3)	—	24,328	61,022	85,350
Acquisition of property, plant and equipment during the period	311	1,927	1,473	3,711

1. Segment totals include only operating projects.

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

Three months ended September 30, 2019				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	74,440	54,778	13,596	142,814
Innergex's share of revenues of joint ventures and associates	32,203	4,324	475	37,002
PTCs and Innergex's share of PTCs generated	—	7,088	—	7,088
Segment Revenues Proportionate	106,643	66,190	14,071	186,904
Segment Adjusted EBITDA	62,778	41,589	13,187	117,554
Innergex's share of Adjusted EBITDA of joint ventures and associates	28,176	(122)	391	28,445
PTCs and Innergex's share of PTCs generated	—	7,088	—	7,088
Segment Adjusted EBITDA Proportionate	90,954	48,555	13,578	153,087
Segment Adjusted EBITDA Margin	84 %	76 %	97 %	82 %

Nine months ended September 30, 2019				
Operating segments	Hydroelectric	Wind	Solar	Segment results
Segment revenues	178,969	211,797	23,160	413,926
Innergex's share of revenues of joint ventures and associates	53,895	21,503	1,506	76,904
PTCs and Innergex's share of PTCs generated	—	20,688	—	20,688
Segment Revenues Proportionate	232,864	253,988	24,666	511,518
Segment Adjusted EBITDA	140,897	175,237	22,238	338,372
Innergex's share of Adjusted EBITDA of joint ventures and associates	40,639	9,165	665	50,469
PTCs and Innergex's share of PTCs generated	—	20,688	—	20,688
Segment Adjusted EBITDA Proportionate	181,536	205,090	22,903	409,529
Segment Adjusted EBITDA Margin	79 %	83 %	96 %	82 %

As at September 30, 2019	Hydroelectric	Wind	Solar	Segment totals [1]
Acquisition of property, plant and equipment during the period	604	2,734	174	3,512

1. Segment totals include only operating projects.

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

Segment Adjusted EBITDA is reconciled to the most comparable IFRS measure, namely, net earnings (loss) from continuing operations, in the following table:

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Segment Adjusted EBITDA	124,312	117,554	346,734	338,372
Unallocated expenses:				
General and administrative	11,089	6,874	29,355	21,865
Prospective projects	4,699	3,329	13,100	10,665
Adjusted EBITDA	108,524	107,351	304,279	305,842
Other net income	(16,725)	(3,917)	(58,250)	(2,639)
Share of (earnings) loss of joint ventures and associates	(11,382)	(16,225)	21,398	(9,193)
Change in fair value of financial instruments	(1,859)	6,031	24,835	9,225
EBITDA	138,490	121,462	316,296	308,449
Finance costs	60,122	59,474	175,700	170,704
Depreciation and amortization	59,368	48,343	170,061	141,558
Income tax expense	11,508	3,749	11,540	1,164
Net earnings (loss) from continuing operations	7,492	9,896	(41,005)	(4,977)

Geographic segments

As at September 30, 2020, excluding its investments in joint ventures and associates which are accounted for as equity method, the Corporation had interests in the following operating assets: 29 hydroelectric facilities, six wind farms and one solar farm in Canada, 15 wind farms in France, and one hydroelectric facility, seven wind farm and three solar farms in the United States, and one solar farm in Chile. The Corporation operates in four principal geographical areas, which are detailed below:

	Three months ended September 30		Nine months ended September 30	
	2020	2019	2020	2019
Revenues				
Canada	120,038	116,993	320,958	338,137
France	13,938	16,274	67,063	63,413
United States	27,274	9,547	54,738	12,376
Chile	1,401	—	2,521	—
	162,651	142,814	445,280	413,926

As at	September 30, 2020	December 31, 2019
Non-current assets, excluding derivatives financial instruments and deferred tax assets [1]		
Canada	3,558,240	3,629,942
France	929,489	891,764
United States	1,900,629	1,293,983
Chile	208,003	142,268
	6,596,361	5,957,957

1. Includes the investments in joint ventures and associates

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

18. SUBSEQUENT EVENTS

Tax equity investor's cash contribution made to the Hillcrest solar project

On October 29, 2020, Hillcrest Solar Partners received US$22,374 ($29,809) from the tax equity investor in return for its Class A membership interest. Such an amount represents 20% of the tax equity investor’s total investment amount. On the same date, the Class B member (Hillcrest Equity Holdings, under the Corporation’s control) made its contribution to Hillcrest Solar Partners in return for its Class B membership interest. The interest in the Class A shares is accounted for as a debt instrument by the Corporation.

Closing of the financing of the Innavik hydroelectric project

On November 4, 2020, Innavik Hydro Limited Partnership entered into a $92,840 construction and long-term credit agreement for the Innavik hydroelectric project. On the same day, the bond forward has been unwound, resulting in a realized net loss of $1,685. The construction term loan bears interest at 3.95 %. Following completion of construction, the remaining balance of the aforementioned loan will be converted into a long-term loan bearing the same fixed interest rate and maturing in 2062.

19. COMPARATIVE FIGURES

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

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

SHAREHOLDER INFORMATION

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Transfer Agent and Registrar

For information concerning share certificates, dividend payments, a change of address, or electronic delivery of shareholder documents, please contact:	***Computershare Investor Services Inc.*** 1500 Robert-Bourassa Blvd, suite 700 Montreal QC H3A 3S8 Tel. 1 800 564.6253 514 982.7555 service@computershare.com

Common Shares - TSX: INE

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

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

Convertible Debentures - TSX: INE.DB.B

Convertible Debentures - TSX: INE.DB.C

Credit Rating by Standard & Poor's

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

Dividend Reinvestment Plan (DRIP)

Innergex Renewable Energy Inc. offers a Dividend Reinvestment Plan (DRIP) for its shareholders of common shares. This plan enables eligible holders of common shares to acquire additional common shares of the Corporation by reinvesting all or part of their cash dividends. For more information about the Corporation's DRIP, please visit our website at innergex.com or contact the DRIP administrator: Computershare Trust 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.

Ce document est disponible en français.
Pour la version numérique, visitez innergex.com
Pour la version papier, écrivez-nous à info@innergex.com