IN REVIEW

INNERGEX RENEWABLE ENERGY INC.'S ANNUAL REVIEW

INNERGEX

2014 ISSUE

25 YEARS SUSTAINABLE by NATURE

FORWARD-LOOKING INFORMATION

To inform readers of the Company's future prospects, this document contains forward-looking information within the meaning of applicable securities laws ("Forward-Looking Information"). Forward-Looking Information can generally be identified by the use of words such as "approximately", "may", "will", "could", "believes", "expects", "intends", "should", "plans", "potential", "project", "anticipates", "estimates", "scheduled" or "forecasts", or other comparable terminology that states that certain events will or will not occur. It represents the projections and expectations of the Company relating to future events or results, as of the date of this document. FUTURE-ORIENTED FINANCIAL INFORMATION: Forward-Looking Information includes future-oriented financial information or financial outlook within the meaning of securities laws, such as expected production, projected revenues, projected Adjusted EBITDA, estimated project financing or project costs, as well as projected Free Cash Flows and Payout Ratio, to inform readers of the potential financial impact of expected results, of the expected commissioning of development projects, of recently announced acquisitions, of its ability to sustain current dividends and dividend increases and its ability to fund its growth. Such information may not be appropriate for other purposes. ASSUMPTIONS: The Forward-Looking Information is based on certain key assumptions made by the Company, including those concerning hydrology, wind regimes and solar irradiation, performance of operating facilities, financial market conditions, and the Company's success in developing new facilities. RISKS AND UNCERTAINTIES: Forward-Looking Information involves risks and uncertainties that may cause the 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 Company's Annual Information Form in the "Risk Factors" section 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 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; health, safety and environmental risks; uncertainty surrounding the development of new facilities; obtainment of permits; variability of installation performance and related penalties; 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; the ability to secure new power purchase agreements or to renew existing ones; changes in governmental support to increase electricity to be generated from renewable sources by independent power producers; 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; changes in general economic conditions; regulatory and political risks; the ability to secure appropriate land; reliance on power purchase agreements; availability and reliability of transmission systems; increases in water rental cost or changes to regulations applicable to water use; assessment of water, wind and sun resources and associated electricity production; dam failure; natural disasters and force majeure; foreign exchange fluctuations; sufficiency of insurance coverage limits and exclusions; a credit rating that may not reflect actual performance of the Corporation or a lowering (downgrade) of the credit rating; potential undisclosed liabilities associated with acquisitions; integration of the facilities and projects acquired and to be acquired; failure to realize the anticipated benefits of acquisitions; reliance on shared transmission and interconnection infrastructure; and the fact that revenues from the Miller Creek facility will vary based on the spot price of electricity. Although the Company believes that the expectations and assumptions on which Forward-Looking Information is based are reasonable under current circumstances, readers are cautioned not to rely unduly on this Forward- Looking Information since no assurance can be given that it will prove to be correct. The Forward-Looking Information contained herein is made as at February 24, 2015, and the Company 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 legislation. The principal assumptions, risks and uncertainties concerning specific Forward-Looking Information contained in this document are more fully outlined on page 34 of this document.

NON-IFRS MEASURES DISCLAIMER

Some measures referred to in this document are not recognized measures under IFRS, and therefore may not be comparable to those presented by other issuers. Innergex believes that these indicators are important, as they provide management and readers with additional information about the Company'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. Adjusted EBITDA, Free Cash Flow and Payout Ratio are not measures recognized by IFRS and have no standardized meaning prescribed by IFRS. References in this document to "Adjusted EBITDA" are to revenues less operating expenses, general and administrative expenses and prospective project expenses. References to "Free Cash Flow" are to cash flows from operations 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 cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to other facilities owned by the Corporation over the course of their power purchase agreement, 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) and realized losses or gains on derivative financial instruments used to hedge the interest rate on project-level debt. References to "Payout Ratio" are to dividends declared on common shares divided by Free Cash Flow. Investors are cautioned that Adjusted EBITDA should not be construed as an alternative to net earnings and Free Cash Flow should not be construed as an alternative to cash flows from operating activities, as determined in accordance with IFRS.

25 YEARS SUSTAINABLE by NATURE

MARCH 24, 2014

INNERGEX AND ITS PARTNER, THE THREE MI'GMAQ FIRST NATIONS OF QUEBEC, SIGN A 20-YEAR POWER PURCHASE AGREEMENT FOR A 150 MW WIND PROJECT IN THE GASPÉ PENINSULA.

IN REVIEW

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IN REVIEW can also be read online at **www.innergex.com**

ANNUAL REVIEW 2014 ISSUE

JUNE 20, 2014

INNERGEX AND ITS PARTNER, THE DESJARDINS GROUP PENSION PLAN, COMPLETE THE ACQUISITION OF THE 30.5 MW SM-1 RUN-OF-RIVER HYDROELECTRIC FACILITY LOCATED IN QUEBEC.

INVESTING IN THE FUTURE

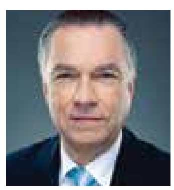
Each year, Innergex funds thousands of dollars in scholarships to support young people in their personal development.

24

SUSTAINABLE DEVELOPMENT MEANS TAKING RESPONSIBILITY

Health, safety and environmental management.

26



RENEWED BOLDNESS

Jean La Couture, Chairman of the Board, speaks about Innergex's 25 years of existence, its renewed drive, and how the Board of Directors is evolving in response.

28

AUGUST 12, 2014

INNERGEX AND THE IN-SHUCK-CH NATION SIGN A PARTNERSHIP AGREEMENT TO DEVELOP SIX RUN-OF-RIVER HYDROELECTRIC PROJECTS IN BRITISH COLUMBIA, TOTALLING 150 MW.

SEPTEMBER 30, 2014

INNERGEX CLOSES A $92.9 MILLION FINANCING FOR THE TRETHEWAY CREEK RUN-OF-RIVER HYDROELECTRIC PROJECT.

OCTOBER 16, 2014

INNERGEX ANNOUNCES THAT THE MESGI'G UGJU'S'N (MU) WIND PROJECT OBTAINED ITS GOVERNMENT DECREE. THE CORPORATION AND ITS PARTNER ALSO ANNOUNCE THE RECENT SIGNING OF THE TURBINE SUPPLY CONTRACT WITH SENVION SE.

DASHBOARD

- Financial and operational highlights
- Report card

AND MORE

30

RENEWABLE. SUSTAINABLE. FOR 25 YEARS.

Innergex is a leading Canadian independent renewable power producer. Active since 1990, the Company develops, owns, and operates run-of-river hydroelectric facilities, wind farms, and solar photovoltaic farms and carries out operations in Quebec, Ontario and British Columbia and in Idaho, USA. In 2014, the Company produced 2,962 GWh of electricity, generating revenues of $242 million. As of February 2015, the Company had 33 operating facilities with a total net installed capacity of 687 MW, and five projects under development with a total net installed capacity of 208 MW for which power purchase agreements have been secured. Innergex also has several prospective projects with an aggregate net capacity totalling more than 3,190 MW. Its shares are listed on the Toronto Stock Exchange under the symbol "INE".

07_1990
Start of the Company's activities, presided by Gilles Lefrançois. Its mission is to develop, build, own and operate hydroelectric facilities in Canada.

11_1994
Commissioning of the Saint-Paulin hydroelectric facility in Quebec.

05_1996
Commissioning of the Portneuf 1-2-3 hydroelectric facilities in Quebec.

03_1999
Commissioning of the Chaudière hydroelectric facility in Quebec.

12_1999
Commissioning of the Batawa hydroelectric facility in Ontario.

INNERGEX CURRENTLY HAS A PORTFOLIO OF 26 RUN-OF-RIVER HYDROELECTRIC FACILITIES, INCLUDING 13 IN BRITISH COLUMBIA, NINE IN QUEBEC, THREE IN ONTARIO, AND ONE IN THE UNITED STATES, WITH A TOTAL GROSS INSTALLED CAPACITY OF 547 MW. HYDRO REMAINS INNERGEX'S PRIMARY SOURCE OF RENEWABLE ENERGY, REPRESENTING MORE THAN 75% OF THE ELECTRICITY IT GENERATED IN 2014. THE COMPANY REMAINS VERY ACTIVE IN THIS SECTOR. IN 2014, IT COMPLETED THE ACQUISITION OF THE 30.5 MW SM-1 FACILITY IN QUEBEC. THE COMPANY ALSO HAS FOUR HYDROELECTRIC PROJECTS UNDER DEVELOPMENT WITH POWER PURCHASE AGREEMENTS IN BRITISH COLUMBIA, ALL OF WHICH SHOULD BE IN OPERATION BY THE END OF 2016.

INSTALLATION OF AN OBERMEYER SPILLWAY GATE DURING CONSTRUCTION OF THE UPPER STAVE RIVER POWER STATION IN BRITISH COLUMBIA.

12_2000

Acquisition of the Montmagny hydroelectric facility in Quebec.

06_2003

Innergex Power Income Fund completes an initial public offering of $146M.

01_2004

Commissioning of the Rutherford Creek hydroelectric facility in British Columbia.

04_2004

Acquisition of the Windsor hydroelectric facility in Quebec.

Innergex completes a $12.3M private placement of common shares.

05_2004

Founding of Cartier Wind Energy, a joint venture between Innergex and TransCanada to develop wind energy projects in the Gaspé Peninsula in Quebec.

4

In 1994, Innergex commissioned its first run-of-river hydro station: St-Paulin. This power station in Quebec harnesses the waterflows of the Rivière-du-Loup river, with its 1,372-km² catchment area. The site of the St-Paulin station is famous in the area for its remarkably beautiful waterfall. Innergex has made a number of improvements that upgrade the site's recreational potential and public access.

INNERGEX CURRENTLY HAS A PORTFOLIO OF SIX WIND FARMS OPERATING IN QUEBEC, WITH A TOTAL GROSS INSTALLED CAPACITY OF 614 MW. IN 2014, A 20-YEAR POWER PURCHASE AGREEMENT WAS SIGNED FOR MESGI'G UGJU'S'N (MU), A 150-MW WIND ENERGY PROJECT LOCATED IN THE GASPÉ PENINSULA, QUEBEC. THE SIGNING OF THIS CONTRACT UNDER A 50-50 PARTNERSHIP WITH THE THREE MI'GMAQ FIRST NATIONS OF QUEBEC – GESGAPEGIAG, GESPEG AND LISTUGUJ – REPRESENTED AN IMPORTANT MILESTONE FOR THIS PROJECT. ITS COMMERCIAL OPERATION IS EXPECTED TO BEGIN IN 2016.

10_2004
Cartier Wind Energy is awarded almost 75% of Hydro-Québec's first call for tenders for 1,000 MW of wind-generated electricity.

12_2004
Acquisition of the Horseshoe Bend hydroelectric facility in Idaho, USA.

12_2005
Commissioning of the Glen Miller hydroelectric facility in Ontario.

04_2006
Innergex opens an office in Vancouver.

11_2006
Commissioning of the Baie-des-Sables wind farm in Quebec by Cartier Wind Energy.

2004

THE ROTORS ON THE WIND TURBINES ERECTED AT VIGER-DENONVILLE, QUEBEC, ARE 92.5 METERS IN DIAMETER.

10_2007

Michel Letellier is named President and Chief Executive Officer of Innergex Renewable Energy Inc.

11_2007

Commissioning of the L'Anse-à-Valleau wind farm in Quebec by Cartier Wind Energy.

12_2007

Innergex completes an initial public offering of $115M for Innergex Renewable Energy Inc.

11_2008

Commissioning of the Carleton wind farm in Quebec by Cartier Wind Energy.

Commissioning of the Umbata Falls hydroelectric facility in Ontario.

11_2009

Commissioning of the Ashlu Creek hydroelectric facility in British Columbia.

In 2004, Innergex made an impressive move into the wind power sector when it won the lion's share of Hydro-Québec's first call for tenders for 1,000 MW of wind-generated power. Cartier Wind Energy, a joint venture between Innergex and TransCanada, was awarded 739.5 MW. This recognition has allowed the Company to develop and operate several sites on the Gaspé Peninsula over the years. Baie-des-Sables, the first project resulting from the call for tenders, was commissioned in 2006 and has been acknowledged as a model for social acceptability – one of Innergex's defining principles.

INNERGEX BEGAN COMMERCIAL OPERATION OF ITS FIRST SOLAR FARM IN MAY 2012. THIS REPRESENTED YET ANOTHER IMPORTANT MILESTONE FOR THE COMPANY, AS THIS NEW SOURCE OF ENERGY PROVIDES ADDITIONAL DIVERSIFICATION AND GROWTH OPPORTUNITIES. STARDALE IS A 33.2 MW_{DC} SOLAR FARM LOCATED IN EAST HAWKESBURY, ONTARIO. WITH MORE THAN 144,000 SOLAR PANELS, IT PROVIDES ENOUGH ELECTRICITY TO POWER MORE THAN 3,200 ONTARIO HOUSEHOLDS EACH YEAR. TO DATE, STARDALE'S PERFORMANCE HAS EXCEEDED EXPECTATIONS. INNERGEX BELIEVES THAT SOLAR TECHNOLOGY IS PROVEN, SIMPLE, AND RELIABLE AND LOOKS FORWARD TO EXPANDING ITS PRESENCE IN THIS SECTOR.

01_2010

Commissioning of the Fitzsimmons Creek hydroelectric facility in British Columbia.

03_2010

Strategic combination by way of reverse takeover of Innergex Renewable Energy Inc. by Innergex Power Income Fund.

Innergex completes an $80.5M offering of convertible subordinated debentures.

09_2010

Innergex completes an $85M offering of Class A preferred shares.

04_2011

Acquisition of Cloudworks Energy Inc., an independent power producer headquartered in Vancouver, British Columbia.

Innergex completes a $39.3M private placement of common shares.

Innergex completes a $166M public offering of common shares.

Acquisition of Stardale, first solar project in Ontario.

11_2011

Commissioning of the Montagne Sèche wind farm in Quebec by Cartier Wind Energy.

Commissioning of phase I of the Gros-Morne wind farm in Quebec by Cartier Wind Energy.

In 2012, Innergex commissioned the Stardale solar farm in Ontario, simultaneously entering the solar power sector and further diversifying its operations. Recent technological advances have made solar power increasingly competitive at the global level. The Company plans to continue its expansion in the solar power sector, where growth is booming.

THE STARDALE SOLAR FARM IN ONTARIO COMPRISES OVER 144,000 POLYCRYSTALLINE MODULES. THEY ARE SET AT AN OPTIMUM TILT OF 30°.

05_2012
Commissioning of the Stardale solar farm in Ontario.

07_2012
Innergex completes a $123.7M private placement of common shares.

10_2012
Acquisition of the Brown Lake and Miller Creek hydroelectric facilities in British Columbia.

11_2012
Commissioning of phase II of the Gros-Morne wind farm in Quebec by Cartier Wind Energy.

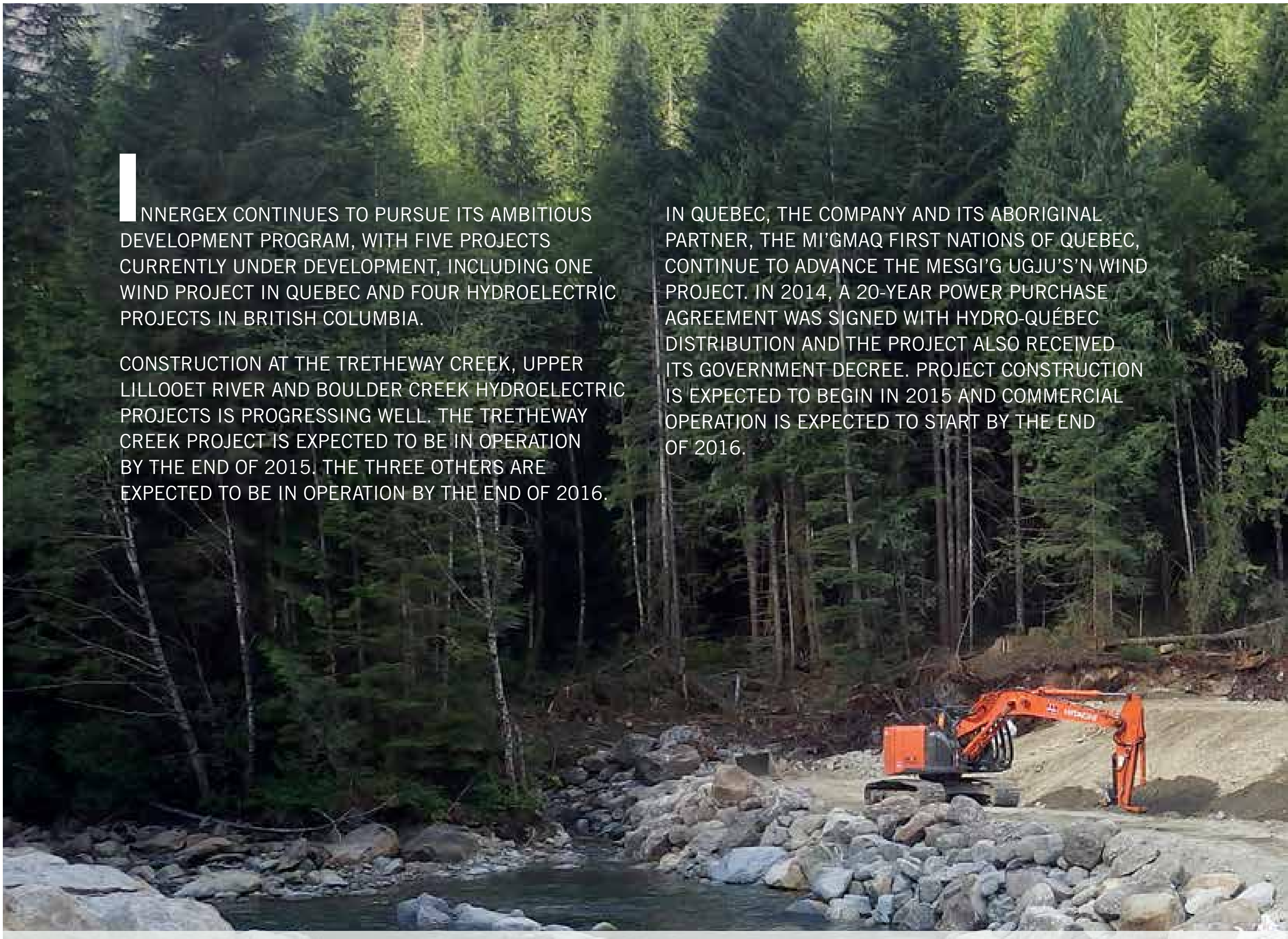
12_2012
Innergex completes a $50M offering of Class C preferred shares.

2012

INNERGEX CONTINUES TO PURSUE ITS AMBITIOUS DEVELOPMENT PROGRAM, WITH FIVE PROJECTS CURRENTLY UNDER DEVELOPMENT, INCLUDING ONE WIND PROJECT IN QUEBEC AND FOUR HYDROELECTRIC PROJECTS IN BRITISH COLUMBIA.

CONSTRUCTION AT THE TRETHEWAY CREEK, UPPER LILLOOET RIVER AND BOULDER CREEK HYDROELECTRIC PROJECTS IS PROGRESSING WELL. THE TRETHEWAY CREEK PROJECT IS EXPECTED TO BE IN OPERATION BY THE END OF 2015. THE THREE OTHERS ARE EXPECTED TO BE IN OPERATION BY THE END OF 2016.

IN QUEBEC, THE COMPANY AND ITS ABORIGINAL PARTNER, THE MI'GMAQ FIRST NATIONS OF QUEBEC, CONTINUE TO ADVANCE THE MESGI'G UGJU'S'N WIND PROJECT. IN 2014, A 20-YEAR POWER PURCHASE AGREEMENT WAS SIGNED WITH HYDRO-QUÉBEC DISTRIBUTION AND THE PROJECT ALSO RECEIVED ITS GOVERNMENT DECREE. PROJECT CONSTRUCTION IS EXPECTED TO BEGIN IN 2015 AND COMMERCIAL OPERATION IS EXPECTED TO START BY THE END OF 2016.



07_2013

Acquisition of the Magpie hydroelectric facility in Quebec.

10_2013

Start of construction for the Tretheway Creek hydroelectric facility.

11_2013

Commissioning of the Viger-Denonville wind farm in Quebec.

12_2013

Innergex is added to the S&P/TSX Composite Index.

Commissioning of the Northwest Stave River hydroelectric facility in British Columbia.

01_2014

Commissioning of the Kwoiek Creek hydroelectric facility in British Columbia.

In 2013, Innergex started construction for the Tretheway Creek run-of-river hydroelectric facility. Located about 50 km north of Harrison Hot Springs, B.C., this run-of-river facility, scheduled for commissioning in 2015, will have a total installed capacity of 21.2 MW and an estimated annual production of 81.0 GWh.

CONSTRUCTION OF THE DAM-SPILLWAY AND DIVERSION CHANNEL AT THE TRETHEWAY CREEK POWER STATION IN BRITISH COLUMBIA WAS COMPLETED IN THE SUMMER OF 2014.

06_2014

Acquisition of the SM-1 hydroelectric facility in Quebec.

2013

A MESSAGE FROM MICHEL LETELLIER

MEETING THE CHALLENGE OF GROWTH

MICHEL LETELLIER, PRESIDENT AND CHIEF EXECUTIVE OFFICER, LAUNCHES THE NEXT CHAPTER IN THE COMPANY'S STORY.

Michel Letellier has been President and Chief Executive Officer of Innergex since 2007.
He joined Innergex in 1997 and has been active in the renewable energy sector since 1990.

Innergex is recognized today as a leader in developing, building, operating, maintaining, and financing renewable energy projects. Each new achievement over the years – first in run-of-river hydro, then in wind, and in solar – has served to build the Company's reputation as a Canadian pioneer in the renewable energy industry.

This year, Innergex celebrates its 25th anniversary – an important milestone in the evolution of any organization.

Together, we have worked hard to build a company that we are very proud of. We have demonstrated an iron discipline in implementing a business model that is respectful, prudent, and sustainable, and in building a diversified portfolio of 38 high-quality and long-lasting assets. By the end of 2016, we will complete an ambitious development program that will have taken us from one end of Canada to the other.

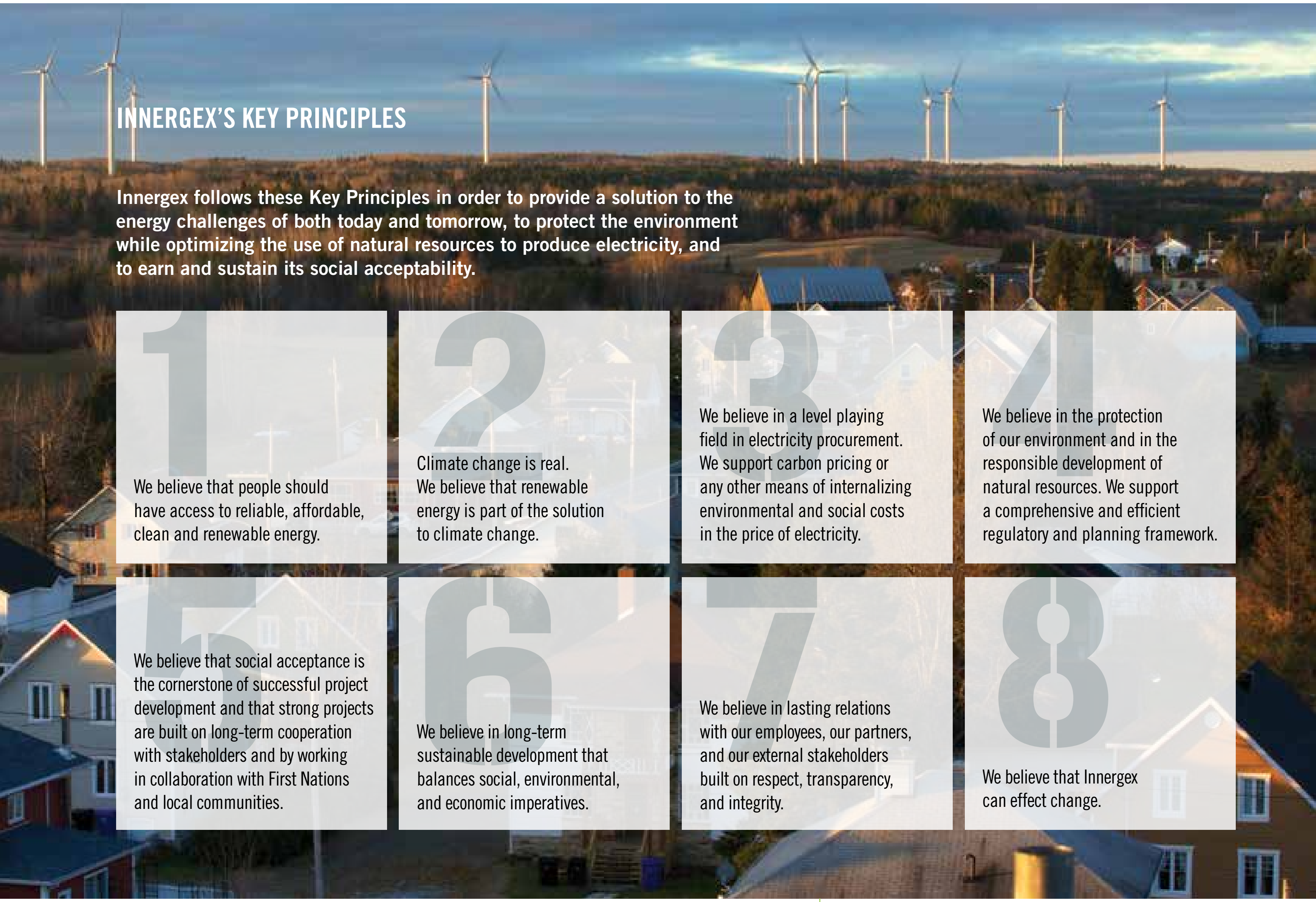
Today, Innergex enjoys an enviable critical mass and reputation. These will help us to meet an important challenge: replenishing our sources of long-term growth. It is up to us to define our future. We therefore recently conducted a strategic planning exercise in order to lay the groundwork for the next chapter of our story.

Coming out of this strategic planning exercise, we unequivocally reaffirm our commitment to produce renewable energy exclusively. Furthermore, the course we originally set remains just as relevant today – if not more so – and we reiterate our mission to increase our production of renewable energy by developing and operating high-quality facilities while respecting the environment and balancing the best interests of the host communities, our partners and our investors.

Innergex has always intuitively strived to achieve this balance, and we've come to acknowledge that our success is deeply rooted in the principles of sustainable development. The decision to produce our first sustainable development report this year is entirely in keeping with our 25th anniversary celebration and our strategic planning.

Of course, we will redouble our efforts to consolidate our leadership position in the renewable energy industry in Canada. In addition, 2015 will mark a significant turning point as the Company transposes its business model to target international markets. There are a number of markets where conditions are ripe for the Company to leverage its project development and financing know-how, its capacity to create fruitful and lasting partnerships, and its ability to make value-added acquisitions. Wherever possible, we will also leverage our specific expertise in hydroelectricity, which for us represents both a competitive advantage and a key differentiator.

Strengthened by the success of our first 25 years, we view the future with confidence and enthusiasm. On behalf of Innergex's management team and employees, I wish to thank our clients, shareholders, lenders, suppliers, and partners for their trust and their contribution to our success, and I invite them to continue on the journey with us.



INNERGEX'S KEY PRINCIPLES

Innergex follows these Key Principles in order to provide a solution to the energy challenges of both today and tomorrow, to protect the environment while optimizing the use of natural resources to produce electricity, and to earn and sustain its social acceptability.

1. We believe that people should have access to reliable, affordable, clean and renewable energy.
2. Climate change is real. We believe that renewable energy is part of the solution to climate change.
3. We believe in a level playing field in electricity procurement. We support carbon pricing or any other means of internalizing environmental and social costs in the price of electricity.
4. We believe in the protection of our environment and in the responsible development of natural resources. We support a comprehensive and efficient regulatory and planning framework.
5. We believe that social acceptance is the cornerstone of successful project development and that strong projects are built on long-term cooperation with stakeholders and by working in collaboration with First Nations and local communities.
6. We believe in long-term sustainable development that balances social, environmental, and economic imperatives.
7. We believe in lasting relations with our employees, our partners, and our external stakeholders built on respect, transparency, and integrity.
8. We believe that Innergex can effect change.

The Viger-Denonville wind farm in Quebec was built in partnership with the Rivière-du-Loup RCM.

Innergex's vision is to provide sustainable energy for a greener future.

In 2014, Innergex produced 2,962 GWh of electricity, generating virtually no CO_2 emissions. If it had been produced using coal, this amount of electricity would have generated approximately 2.8 million tonnes of CO_2 emissions. If it had been produced using natural gas, this amount of electricity would have generated approximately 1.6 million tonnes of CO_2 emissions.

The last 25 years have unfolded under the sign of stability and continuity. Few companies do this well for this long. Doing so requires developing a winning formula: our growth has been driven by our people. They are the ones who generate ideas, movement, and progress, and they are the ones responsible for our success.

Jean Perron, Chief Financial Officer

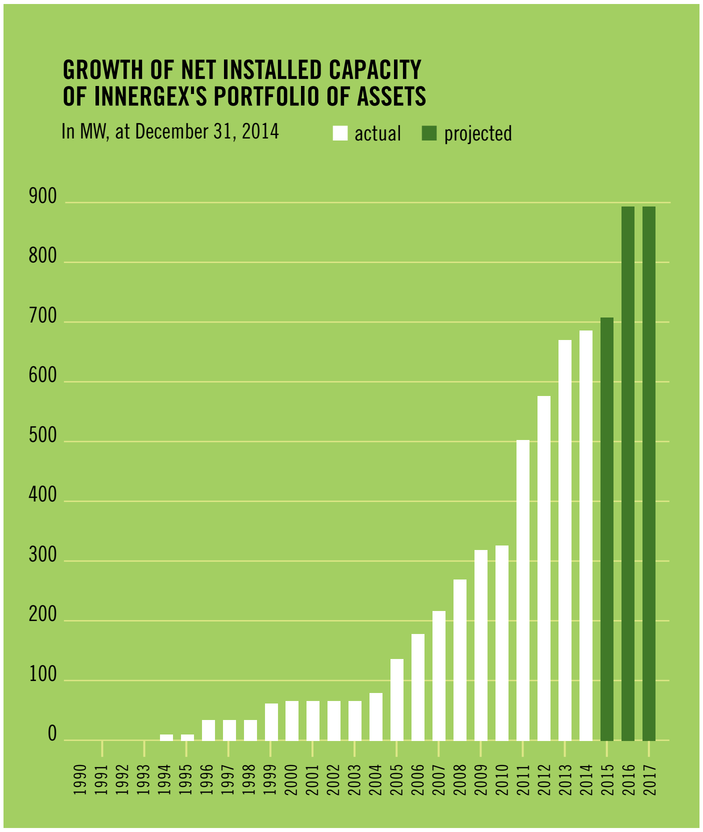
Knowing where we come from allows us to know what we are. We will apply the same recipe from the first 25 years to the next phase of our development that will lead us into international markets. We will continue to find success by being true to our way of doing business and to our values.

Jean Trudel, Chief Investment Officer

BALANCING RISK AND RETURN

FOR INNERGEX'S MANAGEMENT TEAM, IT'S ALL ABOUT BALANCE: BALANCING DEVELOPMENT PROJECTS WITH OPERATING ASSETS, BALANCING SOURCES OF ENERGY, BALANCING GEOGRAPHIC MARKETS AND, ABOVE ALL, BALANCING ECONOMIC, SOCIAL AND ENVIRONMENTAL CONSIDERATIONS.

Whether selecting prospective projects to develop or negotiating acquisitions, we must maintain a balance between incurred risks and expected returns. Over the years, Innergex has certainly developed a business model founded on rigorous risk management. However, it seeks not so much to eliminate all risks, but rather to choose and to astutely manage which risks to take, in areas where its specific expertise gives it a competitive advantage: in the incubation and development of projects. That's where it creates value. That's also where the risk-return trade-off is most attractive.



Innergex has succeeded by adapting to change and by embracing new technologies and new markets. It has shown flexibility in being able to seize the opportunities for growth that presented themselves. In the future, it will need to maintain this flexibility in order to create its own opportunities for growth.

Richard Blanchet, Senior Vice President – Development, Western Canada and Latin America

Unlike other promoters, Innergex chose to grow by developing assets with the intent of keeping and operating them for the long term. We have always remained true to our strategy and our development philosophy. Today, our diversified portfolio of assets allows us to contemplate exporting our business model to new markets.

Renaud de Batz, Senior Vice President – Hydroelectric Project Management

Since the early 1990s, intensifying competition has characterized the renewable energy market, as a result of the growing demand for this type of energy and the sharp drop in the cost of certain technologies. We are confident that Innergex has the size to address this increased competition and the attributes to continue to distinguish itself from its competitors.

Peter Grover, Senior Vice President – Wind and Solar Project Management

SUSTAINABLE by NATURE 25 YEARS

Innergex engages with its partners and stakeholders, governed by core values of integrity, responsibility, transparency, and collaboration, in a perspective of longevity and resource-sharing.

2015
A FIRST SUSTAINABLE DEVELOPMENT REPORT

At Innergex, we are very proud of our commitment to produce renewable energy exclusively.

However, we have come to know that sustainable development isn't just about what we do, but also about how we do it. Our success over the years has been founded on developing good projects, which for us means projects that are accepted by the local community, respectful of the environment, and economically viable both for us and for the public utilities we service – in other words, projects that strike a fair and reasonable balance between social, environmental, and economic considerations. As we celebrate our 25th anniversary, it is only fitting to acknowledge that our success is deeply rooted in principles of sustainability, and we are particularly pleased to be producing our first annual sustainable development report as an important means of providing transparency and being accountable to our partners and stakeholders.

AVAILABLE IN MAY 2015
at www.innergex.com

The magnitude of our projects has evolved in proportion to our skills and expertise. In 1994, we commissioned our first run-of-river hydroelectric facility with an installed capacity of 8 MW. Today, we are developing a hydroelectric project of more than 100 MW and a 150-MW wind farm, and our total installed capacity will soon reach 1,513 MW. We must stay the course and equip ourselves to maintain this growth.

François Hébert, Senior Vice President – Operations and Maintenance

One of the reasons for Innergex's sustainability over all these years is the great sense of commonality of interests among members of the management team, which drives them to work together in pursuing a common objective. This solidarity also ensures the Company's future success.

Yves Baribeault, Vice President – Legal Affairs, Operations and Projects

Innergex came out of a very strong culture of hydroelectricity in Quebec, which it also encountered and benefited from in British Columbia. Our ability to properly identify key issues in markets we are targeting will serve us, among other things, as we develop internationally.

Claude Chartrand, Vice President – Engineering

SM-1 hydroelectric facility near Sept-Îles, Quebec.

PARTNERSHIP OF A DIFFERENT KIND

THE ACQUISITION OF THE SM-1 HYDROELECTRIC FACILITY WITH THE DESJARDINS GROUP PENSION PLAN.

In June 2014, Innergex and the Desjardins Group Pension Plan created a 50-50 partnership in order to acquire the 30.5 MW SM-1 hydroelectric facility in Quebec, Canada.

In so doing, Innergex has found a partner that shares a very long-term investment horizon and enjoys a low cost of capital. In addition, it is growing its portfolio of quality assets, while optimizing the return provided by the acquisition and increasing its Free Cash Flow.

The financial structure of this partnership is innovative: *"We are very pleased to have developed a transaction structure that allows us to compete in acquiring renewable energy infrastructure assets at prevailing market prices, while leveraging the low capital cost and long-term horizon of a pension fund as well as our expertise as an operator, to achieve an attractive after-tax internal rate of return for our shareholders. We intend to replicate this structure for future acquisitions of renewable energy assets,"* states Michel Letellier, President and Chief Executive Officer of Innergex.

After 25 years, our success is founded on a solid vision and a strong entrepreneurial culture of people who have devoted themselves fully. We believe in renewable energy more than ever and we count on our people to pursue our mission.

Anne Cliche, Vice President – Human Resources

Innergex's growth over the last 25 years started with people who adhered to a sustainable development philosophy, and then turned the idea of renewable energy into 1,194 MW of gross installed capacity, from coast to coast. As the Company enters new markets and applies the lessons it has learned in developing and operating renewable energy assets, its future looks most promising.

Matt Kennedy, Vice President, Environment

Even after 25 years of existence, our mission and our values are more relevant than ever. They ignite a passion and a sense of belonging in the people at Innergex. Combined with a culture of entrepreneurship and sound risk management, this passion has proven to be an excellent catalyst for our growth and our reputation.

Nathalie Théberge, Vice-President – Corporate Legal Affairs and Secretary

25 YEARS SUSTAINABLE by NATURE

OUR PORTFOLIO OF ASSETS

DIVERSIFIED. BALANCED. AND PROMISING GROWTH FOR INVESTORS.

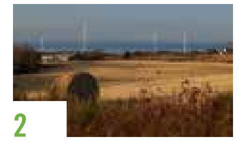
Diversification has been proven to reduce risks and improve operating performance stability. Innergex diversifies in two ways: by energy source and by geography. As a result, the Company protects itself from possible adverse conditions affecting water, wind, or sun resources. Diversification also provides the Company with the flexibility to react to favourable political and economic circumstances arising in one market, while waiting for these conditions to improve in another.

Innergex expanded into the British Columbia market in 2002 with the construction of the Rutherford Creek facility. Today, the Company operates 13 run-of-river hydroelectric facilities in this province. It also has four hydroelectric projects under construction and a 1,425 MW portfolio of prospective hydroelectric and wind projects in this region. Innergex also owns a 9.5 MW run-of-river hydroelectric facility in Idaho, USA.

Innergex commissioned its first run-of-river hydroelectric facility, at Saint-Paulin, Quebec, in 1994. In 1999, the Company expanded into the Ontario market with the commissioning of its Batawa run-of-river hydroelectric facility. Today, the Company operates 12 run-of-river hydroelectric facilities in Eastern Canada. Since 2006, it has also diversified its operations, becoming a leading wind energy producer with six wind farms in Quebec, including Viger-Denonville, the first community project to be commissioned in Quebec in 2013. Since 2012, the Company also owns and operates a 33 MW_{DC} solar farm in Ontario. Innergex currently has one wind farm under development and a 1,765 MW portfolio of prospective hydro, wind, and solar projects in the eastern region.

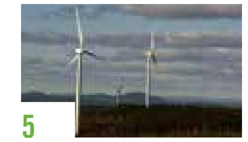
SITES IN OPERATION


1
ASHLU CREEK (BC)
DATE OF COMMISSIONING **2009**
INSTALLED CAPACITY (gross MW) **49.9**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2039**


2
BAIE-DES-SABLES (QC)
DATE OF COMMISSIONING **2006**
INSTALLED CAPACITY (gross MW) **109.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2026**


3
BATAWA (ON)
DATE OF COMMISSIONING **1999**
INSTALLED CAPACITY (gross MW) **5.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2029**


4
BROWN LAKE (BC)
DATE OF COMMISSIONING **1996**
INSTALLED CAPACITY (gross MW) **7.2**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2016**

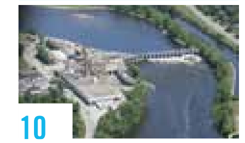

5
CARLETON (QC)
DATE OF COMMISSIONING **2008**
INSTALLED CAPACITY (gross MW) **109.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2028**


6
CHAUDIÈRE (QC)
DATE OF COMMISSIONING **1999**
INSTALLED CAPACITY (gross MW) **24.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2019***


7
DOUGLAS CREEK (BC)
DATE OF COMMISSIONING **2009**
INSTALLED CAPACITY (gross MW) **27.0**
OWNERSHIP (%) **50.01**
PPA EXPIRY **2049**

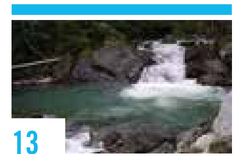

8
FIRE CREEK (BC)
DATE OF COMMISSIONING **2009**
INSTALLED CAPACITY (gross MW) **23.0**
OWNERSHIP (%) **50.01**
PPA EXPIRY **2049**


9
FITZSIMMONS CREEK (BC)
DATE OF COMMISSIONING **2010**
INSTALLED CAPACITY (gross MW) **7.5**
OWNERSHIP (%) **66.67**
PPA EXPIRY **2050**


10
GLEN MILLER (ON)
DATE OF COMMISSIONING **2005**
INSTALLED CAPACITY (gross MW) **8.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2025**


11
GROS-MORNE (I & II) (QC)
DATE OF COMMISSIONING **2011**
INSTALLED CAPACITY (gross MW) **211.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2032**


12
HORSESHOE BEND (USA)
DATE OF COMMISSIONING **1995**
INSTALLED CAPACITY (gross MW) **9.5**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2030**


13
KWOIEK CREEK (BC)
DATE OF COMMISSIONING **2014**
INSTALLED CAPACITY (gross MW) **49.9**
OWNERSHIP (%) **50.00**
PPA EXPIRY **2054**


14
L'ANSE-À-VALLEAU (QC)
DATE OF COMMISSIONING **2007**
INSTALLED CAPACITY (gross MW) **100.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2027**


15
LAMONT CREEK (BC)
DATE OF COMMISSIONING **2009**
INSTALLED CAPACITY (gross MW) **27.0**
OWNERSHIP (%) **50.01**
PPA EXPIRY **2049**


16
MAGPIE (QC)
DATE OF COMMISSIONING **2007**
INSTALLED CAPACITY (gross MW) **40.6**
OWNERSHIP (%) **99.99**
PPA EXPIRY **2032**


17
MILLER CREEK (BC)
DATE OF COMMISSIONING **2003**
INSTALLED CAPACITY (gross MW) **33.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2033**


18
MONTAGNE SÈCHE (QC)
DATE OF COMMISSIONING **2011**
INSTALLED CAPACITY (gross MW) **58.5**
OWNERSHIP (%) **38.00**
PPA EXPIRY **2031**


19
MONTMAGNY (QC)
DATE OF COMMISSIONING **1996**
INSTALLED CAPACITY (gross MW) **2.1**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2021***


20
NORTHWEST STAVE RIVER (BC)
DATE OF COMMISSIONING **2013**
INSTALLED CAPACITY (gross MW) **17.5**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2053**


21
PORTNEUF 1 (QC)
DATE OF COMMISSIONING **1996**
INSTALLED CAPACITY (gross MW) **8.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2021***


22
PORTNEUF 2 (QC)
DATE OF COMMISSIONING **1996**
INSTALLED CAPACITY (gross MW) **9.9**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2021***


23
PORTNEUF 3 (QC)
DATE OF COMMISSIONING **1996**
INSTALLED CAPACITY (gross MW) **8.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2021***


24
RUTHERFORD CREEK (BC)
DATE OF COMMISSIONING **2004**
INSTALLED CAPACITY (gross MW) **49.9**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2024**

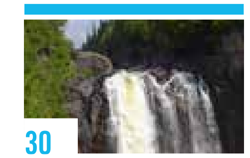

25
SAINT-PAULIN (QC)
DATE OF COMMISSIONING **1994**
INSTALLED CAPACITY (gross MW) **8.0**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2034**


26
SM-1 (QC)
DATE OF COMMISSIONING **1993/2002**
INSTALLED CAPACITY (gross MW) **30.5**
OWNERSHIP (%) **50.01**
PPA EXPIRY **2018/2027**


27
STARDALE (ON)
DATE OF COMMISSIONING **2012**
INSTALLED CAPACITY (gross MW) **33.2 DC**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2032**

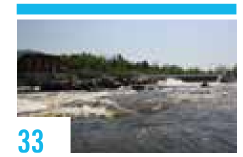

28
STOKKE CREEK (BC)
DATE OF COMMISSIONING **2009**
INSTALLED CAPACITY (gross MW) **22.0**
OWNERSHIP (%) **50.01**
PPA EXPIRY **2049**


29
TIPELLA CREEK (BC)
DATE OF COMMISSIONING **2009**
INSTALLED CAPACITY (gross MW) **18.0**
OWNERSHIP (%) **50.01**
PPA EXPIRY **2049**


30
UMBATA FALLS (ON)
DATE OF COMMISSIONING **2008**
INSTALLED CAPACITY (gross MW) **23.0**
OWNERSHIP (%) **49.00**
PPA EXPIRY **2028**


31
UPPER STAVE RIVER (BC)
DATE OF COMMISSIONING **2009**
INSTALLED CAPACITY (gross MW) **33.0**
OWNERSHIP (%) **50.01**
PPA EXPIRY **2049**


32
VIGER-DENONVILLE (QC)
DATE OF COMMISSIONING **2013**
INSTALLED CAPACITY (gross MW) **24.6**
OWNERSHIP (%) **50.00**
PPA EXPIRY **2033**


33
WINDSOR (QC)
DATE OF COMMISSIONING **1996**
INSTALLED CAPACITY (gross MW) **5.5**
OWNERSHIP (%) **100.00**
PPA EXPIRY **2016***

*contains a renewal feature

Innergex's mission is to increase our production of renewable energy by developing and operating high-quality facilities while respecting the environment and balancing the best interests of the host communities, our partners, and our investors.

TOWARDS A GREENER FUTURE

As one of the largest independent renewable power producers in Canada, Innergex assumes a leadership role in advocating for the development of a strong and sustainable renewable energy industry in Canada.

The Company continues to pursue the development of its portfolio of prospective hydro, wind, and solar projects, and it adapts to the changes in supply and demand for electricity.

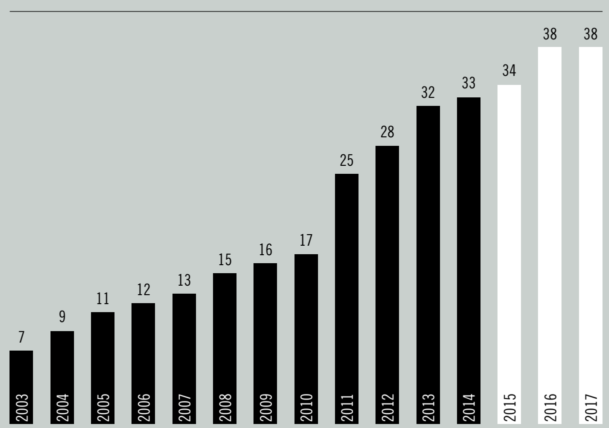
In Ontario, the procurement of new installed capacity in renewable energy today is based on a competitive procurement process that takes into account local needs and considerations, including those of municipalities and First Nations. The government's Long-Term Energy Plan is targeting 300 MW of new wind energy and 140 MW of new solar energy capacity in 2015, for which a request for proposals is currently underway, plus another 300 MW of wind energy and 150 MW of solar energy in 2016, with planned annual revisions thereafter. Innergex has a number of wind and solar projects that it continues to advance in order to submit them under these resquests for proposals. Other prospective projects in Ontario, especially in the wind sector, remain predicated on transmission grid expansion in the northern part of the province and represent more long-term growth potential.

In British Columbia, BC Hydro's Integrated Resource Plan calls for "a set of actions that will support a healthy, diverse clean energy sector and promote clean energy opportunities for First Nations," but provides no specific procurement targets for renewable energy at this time. Furthermore, the province is forecasting increasing demand for electricity and has significant plans to develop its mining and liquefied natural gas (LNG) sectors. However, last December the government announced its approval of BC Hydro's 1,100 MW Site C hydroelectric dam project, which may reduce short- and medium-term growth prospects for independent power producers. Innergex hopes to capitalize on its strong industry presence, its positive track record with local communities and First Nations, and its expertise in both hydroelectric and wind energy as it continues to advance the development of a number of prospective projects in this province, notably through partnerships and negotiated power purchase agreements.

In Quebec, Hydro-Québec Distribution completed the request for proposals it announced in December 2013 for the procurement of 450 MW of new wind energy, including 300 MW for projects in the Lower St. Lawrence and Gaspésie regions and 150 MW for projects anywhere in the province. In total, 54 bids totalling 6,627 MW were submitted in November 2014 under this very competitive request for proposals. Innergex submitted five projects totalling 813 MW, and to this day remains convinced that it presented the best possible bids based on its experience in developing wind projects in the Gaspé Peninsula, which bids were entirely cost competitive. Unfortunately, the Company's projects were not awarded any contracts. One of its projects has been placed on reserve. Furthermore, the prices of this request for proposals demonstrate the competitiveness of renewable energy in Quebec and everywhere else, even in the context of weak fossil energy prices.

In the context of its strategic planning, the Company has reiterated its commitment to remain exclusively in renewable energy. It will continue to develop its portfolio of prospective hydroelectric, wind, and solar projects in Canada and will seek to consolidate its leadership position in this country's renewable energy sector. In addition, the Company will leverage its project development and financing know-how, its capacity to create fruitful and lasting partnerships, and its ability to make value-added acquisitions to penetrate new target markets internationally, in order to replenish its growth prospects. In developing economies in Latin America, demand for electricity remains strong and governments are seeking to increase the supply of renewable energy, for which they have ample resources. More economically mature countries in Europe have adopted ambitious GHG emissions reduction targets, and governments are seeking to reduce their dependency on conventional forms of generation, both of which developments require a greater proportion of renewable energy in these countries' energy portfolios. There are a number of markets to which the Company can transpose its business model.

NUMBER OF SITES IN OPERATION
at December 31 (actual 2003-2014, projected 2015-2017)



THE DAILY COMMITMENT OF SOCIAL ACCEPTABILITY

THE HUMAN FACTOR IS AT THE HEART OF OUR DEVELOPMENT.

For 25 years now, Innergex has demonstrated its ability to create and maintain harmonious relationships with local communities. The Company has made social acceptability the cornerstone of its development strategy. What's the secret? Michel Letellier, President and CEO, explains: *"Our people in the field make all the difference. They are there from the start, well before a project gets under way, in order to gain an understanding of the needs and issues within the communities. By listening to people, choosing to develop projects that reflect their aspirations, and harmonizing the Company's own objectives with those of the communities, Innergex builds solid long-term relationships and successful projects."*

The concept of social acceptability is embodied by people who hold unique responsibilities within the Company. Innergex can count on dedicated and passionate employees in the field, to represent the Company among its stakeholders. One of these employees is Liz Scroggins, Project Coordinator and Community Liaison, who works out of the Innergex office in Pemberton, near Whistler, British Columbia. Liz's main focus is the Upper Lillooet Hydro Project, a large-scale project comprising two run-of-river hydroelectric facilities with a total installed capacity of 106.7 MW. Over the course of three years, more than 300 people will be working on the construction of this project. Since 2010, well before the project broke ground, Liz's main role has been to work closely with all of the project's many and varied stakeholders, including area residents, First Nations, recreational users, hunters, landowners, municipalities, etc. Anyone with concerns or questions about the project can talk to Liz, who makes every effort to understand their concerns so that she can address them in the best

“Basically, my job is to make everyone happy.”

Liz Scroggins,
Project Coordinator and Community Liaison

Social acceptability is not only the cornerstone of Innergex’s development strategy, it has also proven to be an outstanding catalyst for growth. Time and again, it has allowed the Company to build successful projects that align with a sustainable development approach. Whether in the form of shared economic benefits, job opportunities or co-ownership, Innergex understands that communities increasingly wish to play an active role in their socio-economic development. This trend will no doubt intensify as time goes on.

Innergex is one of the sponsors of the 9th annual Winterfest in Pemberton, B.C.

Julia Mancinelli, Environmental Manager at Innergex, and Liz Scroggins.

way possible. *“Basically, my job is to make everyone happy,”* she says with a smile. Liz has the ideal background for her position: not only does she have a bachelor’s degree in geology and a master’s in environmental science, she has also been living in Pemberton for almost 20 years.

The Upper Lillooet Hydro Project has a very high profile, and the importance of having a presence in the community is undeniable. As Liz explains, *“People have a tendency to think of Upper Lillooet as really remote, but it isn’t. Geographically, Pemberton and Whistler are very close to Vancouver, it’s an active area with lots of recreational events. People feel personally concerned and want to know what’s going on with the project.”*

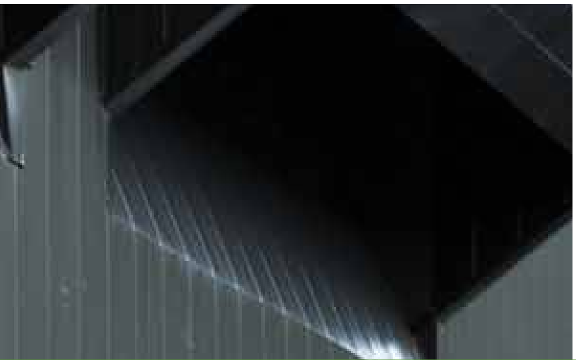
Transparency is the order of the day. For the community to view the project in a positive light, Innergex has to be very open and transparent in its interactions with stakeholders at all times. It is crucial to give people the chance to learn more about the project and how the Company does things. Innergex believes that it is very important to explain the project and how it is managed, especially with respect to the Company’s efforts to minimize any environmental impact. *“We are responsible for making sure that we do our best at all times and at every level. We care very much about Pemberton and the people who live here. If we do our job properly, we will earn their approval and their respect,”* says Liz.

This community liaison work also presents some challenges. *“We have to try to get everyone on the same wavelength,”* says Liz. *“Of course, there will always be people who don’t support the project. However, if we can engage in a respectful dialogue, people do take the time to listen, they learn, they often become more receptive and come to see things from a new perspective. The biggest challenge in my job is to create opportunities that foster this dialogue.”* In addition to having opened an office in Pemberton, Innergex posts all of its environmental activity status reports online. Innergex exemplifies the whole idea of transparency by making these reports available to the public.

Social acceptability is an integral part of the concept of sustainable development. While all Innergex employees adhere to it, there are those who, like Liz, personify the relationship the Company has with its stakeholders and embody the Company’s sustainable and respectful behaviour on a daily basis.

INVESTING IN THE FUTURE

EACH YEAR, INNERGEX FUNDS THOUSANDS OF DOLLARS IN SCHOLARSHIPS TO SUPPORT YOUNG PEOPLE IN THEIR PERSONAL DEVELOPMENT.



In 2013, Cartier Wind Energy inaugurated a scholarship program in wind turbine maintenance. For three years, six annual scholarships of $2,000 each will be awarded in two categories: three in the general category and three in the Aboriginal category. The goal of the program is to encourage the local and Aboriginal labour force by providing access to technical training at the local college (Cégep de la Gaspésie et des Îles) that can lead to quality jobs in a dynamic and promising sector.

Cartier Wind Energy is a joint venture between TransCanada and Innergex Renewable Energy that operates five wind farms with an installed capacity of 590 MW in Quebec's Gaspé Peninsula.

Each year, Innergex provides thousands of dollars in college and university scholarships for students from the communities where it operates. Today, these scholarships are an integral component of a project's impact and benefits agreement, a formal prerequisite to any development done in cooperation with First Nations. The Company considers these to be an excellent way of sharing the socio-economic benefits of its activities, which flows from its desire to behave responsibly and sustainably.

Of course, the socio-economic benefits of Innergex's projects can take many forms: jobs created during construction, royalties paid to administrative organizations, support for community events, and so on. Generally, they tend to benefit the community as a whole. The special thing about scholarships, both for the Company and for community leaders, is that they benefit individual members of the community in a direct and permanent manner.

For young recipients, scholarships can open the door to higher education, a value-added job, and greater independence. They establish a very strong and direct connection between the project and the people involved.

Note that education is one of the five sectors Innergex specifically targets in its donations and sponsorship policy, the others being the environment and sustainable development, the economic development of local communities and First Nations, community projects, and sports and health.

"Scholarships and bursaries are a small but very important component of our impact and benefits agreements, because they really drill down the benefits to the individual level. They create opportunity for our youth and really make a difference in their lives."

Curt Walker, Chief Administrative Officer of the Lil'wat Nation, British Columbia

Safety standards are integral to our work, as here at the Baie-des-Sables wind farm in Quebec.

SUSTAINABLE DEVELOPMENT MEANS TAKING RESPONSIBILITY

HEALTH, SAFETY AND ENVIRONMENTAL MANAGEMENT.

For Innergex, upholding the most rigorous health and safety standards goes far beyond simply complying with the legal and regulatory requirements. Its priority is the safety and protection of its employees on every Innergex site from coast to coast.

In this respect, the Company has adopted an Environment, Health and Safety policy and management system that formalize its commitments: maintaining a healthy and safe environment for employees; complying with laws pertaining to the protection of employees, the public and the environment; evaluating and taking into account the potential impacts of its activities; as well as minimizing or avoiding these impacts. Innergex also formalized the importance of its employees' commitment to and responsibility with respect to this policy. The Company has made great strides in implementing procedures and processes to supervise, guide and monitor its health and safety performance.

This ensures that a culture of prevention and continuous improvement is successfully put into practice. By establishing clear procedures and providing employees with appropriate training, the company can better anticipate risks faced by employees in the workplace, with the aim of limiting or eliminating them.

While the corporate objective is always to target zero occupational injuries or incidents, the people in charge nonetheless remain clear and transparent: *"Other than driving, the highest accident risk that people face in their lives is generally at work. Not only that, but a work-related accident would probably have the greatest immediate consequences for them – often permanent ones,"* says Martin Brosseau, one of Innergex's Health, Safety and Environment Managers. *"We're not in a high-risk sector, but it's important to recognize that a workplace accident, when it comes to operations like ours, can have serious consequences. We operate heavy machinery and work with high-voltage*

"Health and safety is more than a legal requirement, it's a moral responsibility."

Steven Kynoch, Manager – Environment, Health and Safety

electricity and huge volumes of water, often in challenging weather conditions, which makes it that much more important to have strict processes, a structure that works, and health and safety standards that are absolutely clear."

Given the rapid growth of the Company, Innergex also implemented a formal, structured occupational health and safety management system. It is modelled after the BS OHSAS 18001 Occupational Health and Safety Management standard, which is a recognized model for occupational risk management and prevention systems.

With this framework, the Company is not satisfied with simply complying with the applicable laws and regulations, but wishes to adhere to very high standards. *"We have to do more because we can't provide the same level of supervision as in a factory. Our internal standards are very high. For example, we have voluntarily implemented an extremely strict confined space entry procedure,"* said Martin Brosseau.

Innergex has to cope with many different challenges on a daily basis. The Company runs power stations remotely and the operators work in distant locations, often alone or in isolation. While employees are properly trained and have all the tools they need to work safely, the fact remains that part of the follow-up is based on trust, since it is not possible to supervise their day-to-day work. *"That's our biggest issue,"* says François Hébert, Senior Vice President – Operations and Maintenance. *"Our employees shouldn't just follow the procedures in place, they have to take ownership of them. Our standards must not be perceived as an imposition or an added chore. They have to be integrated as naturally as possible into our work habits and how we do things. That's our ultimate goal, that our employees take ownership of their own safety."* Thus, the Company ensures that it provides all the essential training, support and follow-up that its people need. Employees are integral to this process, since they are the ones responsible for applying the measures and complying with procedures.

Implementation of the occupational health, safety and environmental management system involves 23 elements, 75% of which are currently in place. In 2015, Innergex will develop and deploy the system's remaining elements. Afterwards, the Company plans to move from deployment to monitoring. This will consist of evaluating the performance of the management system and ensuring continuous improvement in this area. The goal is to have the system tested and proven as Innergex begins to move into new markets.

The purpose of the BS OHSAS 18001 standard is to provide businesses with a way of evaluating and certifying that their occupational health and safety management system is compatible with international management system standards (the most familiar being ISO 9001 for quality, ISO 14001 for environment and ILO-OSH 2001 for occupational health and safety).

BS OHSAS 18001 MAKES IT POSSIBLE TO:

- create the best possible working conditions across the organization;
- identify hazards and put in place controls to manage them;
- reduce workplace accidents and illness;
- engage and motivate staff with better, safer working conditions;
- demonstrate compliance to stakeholders.

Innergex's health and safety management system is modelled after the BS OHSAS 18001 standard.

"Health and safety is everyone's responsibility."

Martin Brosseau, Manager – Environment, Health and Safety

A MESSAGE FROM JEAN LA COUTURE

RENEWED BOLDNESS

JEAN LA COUTURE, CHAIRMAN OF THE BOARD, SPEAKS ABOUT INNERGEX'S 25 YEARS OF EXISTENCE, ITS RENEWED DRIVE, AND HOW THE BOARD OF DIRECTORS IS EVOLVING IN RESPONSE.

Stardale solar farm, Ontario.

BOARD COMMITTEES

	AUDIT COMMITTEE	CORPORATE GOVERNANCE COMMITTEE	NOMINATING COMMITTEE	HUMAN RESOURCES COMMITTEE
John A. Hanna	Chair	—	■	—
Jean La Couture	■	Chair	Chair	■
Richard Laflamme	—	■	■	Chair
Daniel L. Lafrance	■	—	■	■
William A. Lambert	■	■	■	—

INNERGEX RENEWABLE ENERGY INC.'S BOARD OF DIRECTORS

JOHN A. HANNA*
Principal occupation: Corporate Director
Innergex Director since: 2003

JEAN LA COUTURE* - Chairman of the Board
Principal occupation: President, Huis Clos Limitée
Innergex Director since: 2003

RICHARD LAFLAMME*
Principal occupation: Corporate Director and pension fund administrator
Innergex Director since: 2003

DANIEL L. LAFRANCE*
Principal occupation: Corporate Director
Innergex Director since: 2003

WILLIAM A. LAMBERT
Principal occupation: Corporate Director
Innergex Director since: 2007

MICHEL LETELLIER
Principal occupation: President and Chief Executive Officer of the Company
Innergex Director since: 2002

* John A. Hanna, Jean La Couture, Richard Laflamme and Daniel L. Lafrance were appointed directors of the Company on March 29, 2010 upon completion of the strategic combination of Innergex Power Income Fund and Innergex Renewable Energy Inc. Prior to the strategic combination, they had all been trustees since 2003 of Innergex Power Trust, a wholly owned subsidiary of Innergex Power Income Fund.

What does Innergex's 25th mean to you?

Innergex's 25th anniversary is the perfect time to take stock of its accomplishments. Little by little, the Company has gained expertise in three renewable energy technologies – first hydro-electricity, then wind and, more recently, solar power. The Innergex team has mastered all aspects of the project development process, from modelling to financing and construction management. Finally, our seasoned operators have perfected the operation and preventive maintenance of assets to optimize performance quality and service life.

What do you believe Innergex's greatest challenge will be over the next 25 years?

As for any growing company, the greatest challenge for Innergex will be to maintain the kind of attractive growth profile that its shareholders and other stakeholders have grown accustomed to seeing.

The Company will need to leverage the expertise it has acquired to undertake, with some measure of boldness, the next phase of its development, which will lead to establishing a foothold in new target markets internationally. It will also need to demonstrate its entrepreneurship in creating partnerships and making acquisitions in order to consolidate its leadership position in the Canadian renewable energy industry.

Innergex has the foundation to support its growth for many years to come – growth that will continue to be measured, profitable, and respectful of the environment, as well as its employees, partners, customers and suppliers.

Does a new direction for Innergex call for a change at the Board of Directors level?

The natural succession-planning process actually provides the Board with opportunities to adapt in order to better support the management team, oversee the Corporation's activities and growth, and ensure sound management of inherent risks. Such an opportunity will soon be presenting itself, as we will have two vacancies to fill this year.

The skills matrix developed by the Corporate Governance Committee in the context of succession planning, and used by the Board of Directors to evaluate the appropriateness of its make-up, has enabled us to quickly identify the skills and experience to prioritize in the search for new directors who can support the Company in its strategic planning. We are very pleased to announce that Mrs. Monique Mercier, Executive Vice-President, Corporate Affairs, Chief Legal Officer and Corporate Secretary at Telus, who is based in Vancouver, and Mr. Dalton McGuinty, former Premier of Ontario and currently Senior Advisor, Markets and Industries at PwC Canada, will be proposed for nomination as directors in anticipation of the annual meeting of shareholders on May 13, 2015.

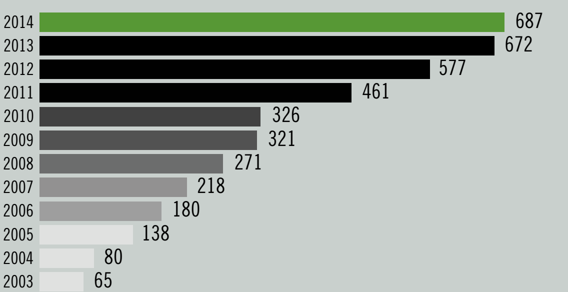
We sincerely thank John A. Hanna for his valuable contribution to the Board of Directors since Innergex's initial public offering in 2003. Given that Mr. Hanna has reached the term limit prescribed in the Charter of the Board of Directors for serving as a Director of the Company, the renewal of his mandate will not be solicited during the next annual shareholders' meeting. We wish him every success in his future endeavours.

FINANCIAL AND OPERATIONAL HIGHLIGHTS

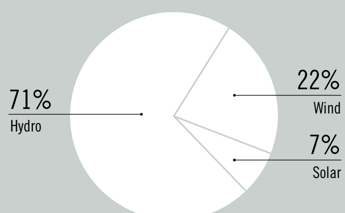
FINANCIAL OVERVIEW For the years ended December 31 (in thousands of Canadian dollars, except as noted)	2014[1]	2013[1]	2012[1]	2011[2]	2010[2]
Power generated (MWh)	**2,962,450**	**2,381,820**	2,104,945	1,905,426	1,227,435
Revenues	**241,834**	**198,259**	176,655	148,260	91,385
Adjusted EBITDA[3]	**179,562**	**148,916**	133,792	111,196	68,111
Dividend declared - $ per Series A preferred share	**1.25**	**1.25**	1.25	1.25	0.42
Dividend declared - $ per Series C preferred share[4]	**1.4375**	**1.57**	-	-	-
Dividend declared - $ per common share	**0.60**	**0.58**	0.58	0.58	0.61

1 Prepared in accordance with IFRS - excluding joint ventures.
2 Restated in accordance with IFRS - including joint ventures.
3 Defined as revenues less operating expenses, general and administrative expenses, and prospective project expenses.
4 The initial dividend payment was higher to reflect dividends accruing since the closing date of the Series C preferred share offering of December 11, 2012. The regular annual dividend amount is $1.4375.

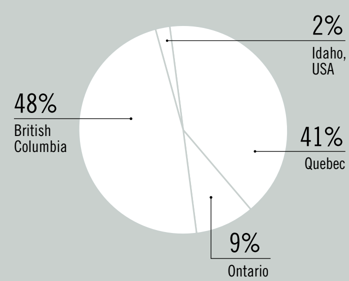
NET INSTALLED CAPACITY
At December 31
(MW)



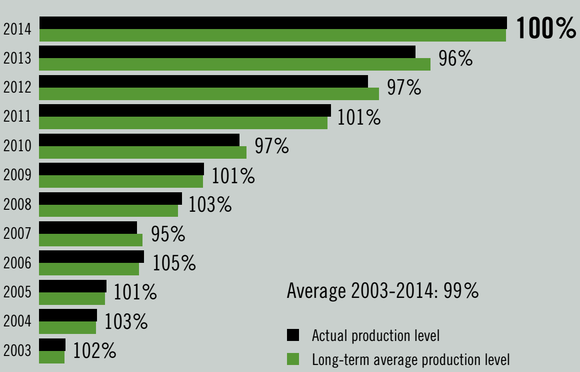
ENERGY SOURCE DIVERSIFICATION
Based on consolidated revenues



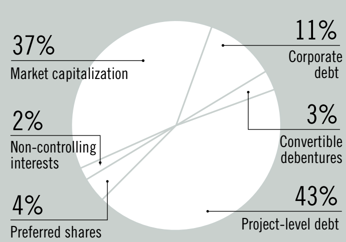
GEOGRAPHIC DIVERSIFICATION
Based on consolidated revenues



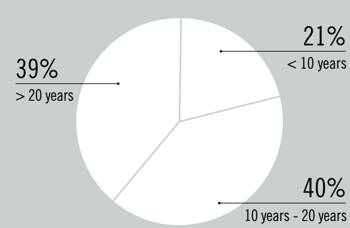
PRODUCTION PREDICTABILITY
(GWh)



CAPITAL STRUCTURE
At December 31



PPA REMAINING TERMS
Based on consolidated annualized long-term average production of operating facilities



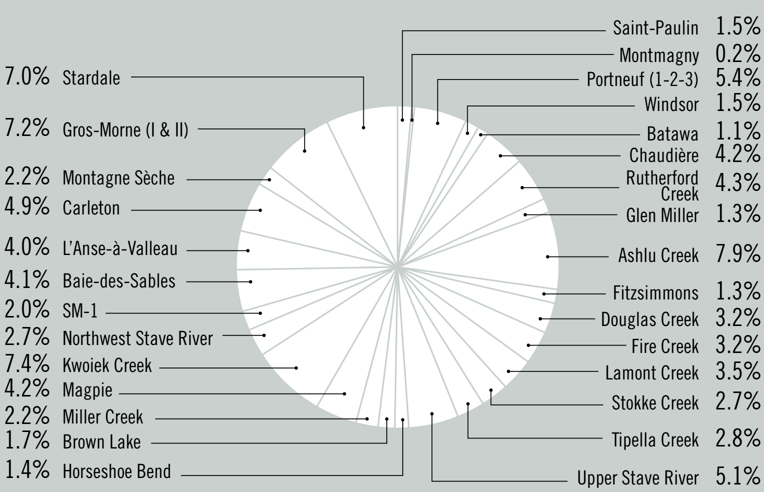
PROJECTS UNDER DEVELOPMENT

	PROJECT	LOCATION	GROSS CAPACITY (MW)	INNERGEX'S OWNERSHIP	ESTIMATED CONSTRUCTION COSTS ($M)	EXPECTED IN-SERVICE DATE
WIND	Mesgi'g Ugju's'n	QC	150.0	50.0%	340.0 [1]	2016
HYDRO	Tretheway Creek	BC	21.2	100.0%	111.5	2015
	Boulder Creek	BC	25.3	66.7%	119.2	2016
	Upper Lillooet River	BC	81.4	66.7%	315.0	2016
	Big Silver Creek	BC	40.6	100.0%	216.0	2016

[1] Preliminary estimate. Subject to change.

REVENUE BREAKDOWN BY SITE

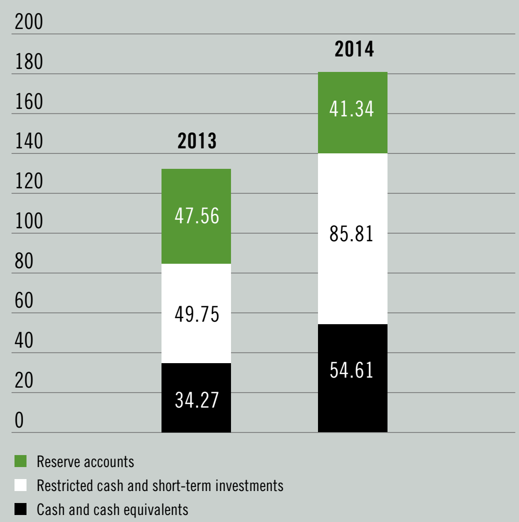
Based on consolidated revenues



CASH AND RESERVE ACCOUNTS

At December 31

($M)



2014 HIGHLIGHTS

Electricity production increased by year-over-year **24%**

Revenues rose 22% to **$242M**

88% Payout Ratio

One acquisition completed

Total net installed capacity increased 2% to **687 MW**

33 The number of operating facilities

77% The proportion of electricity produced from hydro

The electricity we produced was enough to power **247,000** Canadian households

$93M in project financing secured

REPORT CARD

As in the past, we will continue to carry out our ambitious development program, maintain a balanced capital structure, and pursue growth opportunities.

PERFORMANCE	2013		2014		2015	
Power generated[1]	2,382 GWh	+13%	2,962 GWh	+24%	Approx.	+3-5%
Revenues[1]	198.3 $M	+12%	241.8 $M	+22%	Approx.	+3-5%
Adjusted EBITDA[1]	148.9 $M	+11%	179.6 $M	+21%	Approx.	+1%
Free Cash Flow	59.0 $M		67.7 $M		---	
Payout Ratio	93%		88%		< 100%	
Number of facilities in operation at year-end	32		33		34	
Net installed capacity at year-end	672 MW		687 MW		708 MW	
Consolidated long-term average production, annualized[1]	2,883 GWh		3,050 GWh		3,131 GWh	

[1]These figures exclude the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and are accounted for using the equity method.

WE SAID WE WOULD	WE DID	WE EXPECT TO
PERFORMANCE		
Increase power generated, revenues and Adjusted EBITDA by approximately 20% as a result of the full-year contribution of the Magpie hydroelectric facility acquired in July 2013 and the contribution of the Northwest Stave River and Kwoiek Creek hydroelectric facilities commissioned at the end of 2013. The Viger-Denonville wind farm is a joint venture and accounted for using the equity method; therefore, it is excluded from these figures.	✔ Power generated increased by 24%, while revenues increased 22% and Adjusted EBITDA increased 21% as a result of the contribution of the Magpie hydroelectric facility acquired in July 2013 and the contribution of the Northwest Stave River and Kwoiek Creek hydroelectric facilities, as well as the contribution of the SM-1 hydroelectric facility acquired in June 2014, which accounted for an increase of approximately 3.0% in electricity produced and 2.5% in revenues.	Innergex expects **power generated and revenues to increase by approximately 3.0% to 5.0%** as a result mainly of the full-year contribution of the SM-1 hydroelectric facility acquired in June 2014. The commissioning of the Tretheway Creek hydroelectric facility is planned for the end of the year, therefore its contribution to the Company's revenues and adjusted EBITDA is expected to be minimal in 2015. The Company further expects to increase prospective project expenses significantly, in order to fund its growth strategy into target markets internationally. As a result, it expects only a **marginal increase in Adjusted EBITDA** in 2015 compared with 2014.
---	---	Despite an expected significant increase in prospective project expenses to fund its growth strategy, the Company expects **to maintain a Payout Ratio below 100% in 2015.**
FINANCING		
Conclude the financing for the Upper Lillooet River and Boulder Creek hydroelectric projects in the amount of approximately $370M.	✖ Innergex has not yet closed the financing for these projects. However, the interest rate on these project-level debts has been fixed through a hedging program that was completed, for all intents and purposes, in January 2014. In addition, a term sheet and commitment letter were signed at the end of 2014.	The Company intends to **conclude the financing for the Upper Lillooet River and Boulder Creek hydroelectric projects in the amount of approximately $370M** during the first half of 2015. The financing amount excludes expected realized losses on derivative financial instruments used to hedge the interest rate, which will be financed.
Conclude the financing for the Tretheway Creek hydroelectric project in the amount of approximately $70M during 2014 **and for the Big Silver Creek hydroelectric project in the amount of approximately $150M** in late 2014 or early 2015.	✔ On September 30, Innergex closed a financing for $92.9M with an interest rate of 4.99% and a 40-year term for the Tretheway Creek hydroelectric project. Innergex has not yet closed the financing for the Big Silver Creek hydroelectric project. However, the interest rate on this project-level debt has been fixed through a hedging program that was completed, for all intents and purposes, in January 2014. In addition, several proposals were received at the beginning of 2015.	The Company intends to **conclude the financing for the Big Silver Creek hydroelectric project in the amount of approximately $150M** during the first half of 2015. The financing amount excludes expected realized losses on derivative financial instruments used to hedge the interest rate, which will be financed.
Enter into a hedging program to fix the interest rate on the project-level debt for the Mesgi'g Ugju's'n wind project.	✔ In April 2014, Innergex completed, for all intents and purposes, a hedging program to fix the interest rate on the project-level financing for the Mesgi'g Ugju's'n wind project.	The Company intends to **conclude the financing for the Mesgi'g Ugju's'n wind project in the amount of approximately $280M** in 2015. The financing amount excludes expected realized losses on derivative financial instruments used to hedge the interest rate, which will be financed.

WE SAID WE WOULD	WE DID	WE EXPECT TO
Refinance the Umbata Falls hydroelectric facility in the amount of approximately $47M.	Innergex and its partner did not refinance the Umbata Falls hydroelectric facility. However, the July 2014 initial term maturity of the loan was extended to March 31, 2015. Discussions are ongoing to optimize the refinancing of this facility.	The Company and its partner intend to **refinance the Umbata Falls hydroelectric facility** in the amount of approximately $47M during the first quarter of 2015, in view of the upcoming (extended) term of the initial project financing.
---	In November, Innergex extended its revolving term credit facility from 2018 to 2019 and temporarily increased its borrowing capacity from $425M to $475M, until June 30, 2015. These modifications provide greater financing flexibility until the Corporation closes the project-level financings that remain to be put in place.	---
PROJECT DEVELOPMENT		
Proceed with the construction of the Tretheway Creek hydroelectric facility and begin construction of the Big Silver Creek hydroelectric facility.	Innergex advanced the construction of the Tretheway Creek hydroelectric facility, according to planned schedules and budgets. Innergex began construction activities at the Big Silver Creek hydroelectric facility in June 2014, according to planned schedules and budgets.	The Company intends to **advance the construction of the Tretheway Creek hydroelectric facility and begin commercial operation** at the end of 2015. The Company also intends to **advance the construction of the Big Silver Creek hydroelectric facility** during the year.
Advance the construction of the Upper Lillooet River and Boulder Creek hydroelectric facilities.	Innergex advanced the construction of the Upper Lillooet River and Boulder Creek hydroelectric facilities, according to planned schedules and budgets.	The Company intends to **advance the construction of the Upper Lillooet River and Boulder Creek hydroelectric facilities** during the year.
With its First Nations partner, **sign a power purchase agreement and proceed with the development and permitting of the Mesgi'g Ugju's'n wind project,** with the intention of starting construction in 2015.	In March, Innergex and its partner signed a 20-year power purchase agreement wih Hydro-Québec Distribution for the Mesgi'g Ugju's'n wind project. In the fall, the partners signed a turbine supply contract with Senvion SE. In October, the project obtained its government decree and preconstruction activities began shortly thereafter.	The Company and its partner intend to **begin construction of the Mesgi'g Ugju's'n wind project** in the spring of 2015.
Submit a number of potential wind projects under Hydro-Québec's 450 MW request for proposals by the September 2014 deadline.	In total, 54 bids totalling 6,627 MW were submitted under Hydro-Québec's request for proposals for 450 MW of new wind energy. Innergex submitted five bids totalling 813 MW of high-quality, cost-competitive projects. Unfortunately, the Company's projects were not awarded any contracts. However, one of them has been placed on reserve.	---
Renew the power purchase agreement for the 8.0 MW Saint-Paulin hydroelectric facility for a second 20-year term.	Innergex sent Hydro-Québec Distribution a notice of automatic renewal and subsequently filed a notice of arbitration, which it has agreed to suspend pending a decision in another arbitration proceeding already underway between Hydro-Québec and other independent power producers. In the meantime, the terms and conditions of the contract for the Saint-Paulin facility are maintained.	Innergex intends to follow the course of action underway in order to **finalize the terms and conditions of the contract for the Saint-Paulin hydroelectric facility** under the best possible terms. Innergex intends to **renew the power purchase agreement for the 5.0 MW Windsor hydroelectric facility** for a second 20-year term. To this end, it has sent an automatic renewal notice to Hydro-Québec Distribution.
---	---	Innergex intends to **submit a number of potential wind and solar projects under Ontario's 440 MW request for proposals** by the September 2015 deadline. Innergex and its In-SHUCK-ch Nation partner intend to **pursue negotiations** with BC Hydro and the British Columbia government **for power purchase agreements related to a group of hydroelectric projects.**
EXTERNAL GROWTH		
Complete the acquisition of other Hydroméga assets under terms that will ensure such acquisitions are accretive.	Innergex and its partner, the Desjardins Group Pension Plan, completed the acquisition from Hydroméga Group of Companies of the 30.5 MW SM-1 hydroelectric facility in June 2014. The reimbursement of a $25.0M deposit (plus accrued interest) made to Hydroméga in 2012 in effect terminated the letter of intent and exclusivity held by the Company with respect to other assets of Hydroméga.	---
Pursue M&A opportunities that correspond to the Company's stated mission and contribute to cash flow generation while satisfying its risk profile and return requirements.	Innergex remained active and disciplined in studying several potential acquisition targets throughout the year. It did not succeed in closing an acquisition (other than SM-1) under terms and conditions that satisfied its risk profile and return requirements.	The Company intends to **pursue M&A opportunities** that correspond to its growth strategy – **to establish a presence in target markets internationally** and to **consolidate its leadership position in the renewable energy industry in Canada** - and contribute to cash flow generation while satisfying its risk profile and return requirements.

FORWARD-LOOKING INFORMATION IN THIS DOCUMENT

The following table outlines certain Forward-Looking Information, as described on the inside cover and contained in this document, that the Company considers important to better inform readers about its potential financial performance.

Also included are the principal assumptions used to derive this information and the principal risks and uncertainties that could cause actual results to differ materially from it.

PRINCIPAL ASSUMPTIONS	PRINCIPAL RISKS AND UNCERTAINTIES
EXPECTED PRODUCTION	
For each facility, the Company 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 taken into account include, without limitations, 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 Company estimates the LTA by adding the expected LTA of all the facilities in operation that it consolidates (excludes Umbata Falls and Viger-Denonville, accounted for using the equity method).	Improper assessment of water, wind and sun resources and associated electricity production Variability in hydrology, wind regimes and solar irradiation Equipment failure or unexpected operations & maintenance activity
PROJECTED REVENUES	
For each facility, expected annual revenues are estimated by multiplying the LTA by a price for electricity stipulated in the power purchase agreement secured with a public utility or other creditworthy counterparty. These agreements stipulate a base price and, in some cases, a price adjustment depending on the month, day and hour of delivery, except for 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, power purchase agreements also contain an annual inflation adjustment based on a portion of the Consumer Price Index. On a consolidated basis, the Company estimates annual revenues by adding together the projected revenues of all the facilities in operation that it consolidates (excludes Umbata Falls and Viger-Denonville, accounted for using the equity method).	Production levels below the LTA caused mainly by the risks and uncertainties mentioned above Unexpected seasonal variability in the production and delivery of electricity Lower inflation rate than expected
PROJECTED ADJUSTED EBITDA	
For each facility, the Company estimates annual operating earnings by subtracting from the estimated revenues the budgeted annual operating costs, which consist primarily of operators' salaries, insurance premiums, operations and maintenance expenditures, property taxes, and royalties; these are predictable and relatively fixed, varying mainly with inflation except for maintenance expenditures. On a consolidated basis, the Company estimates annual Adjusted EBITDA by adding together the projected operating earnings of all the facilities in operation that it consolidates, from which it subtracts budgeted general and administrative expenses, comprised essentially of salaries and office expenses, and budgeted prospective project expenses, which are determined based on the number of prospective projects the Company chooses to develop and the resources required to do so (excludes Umbata Falls and Viger-Denonville, accounted for using the equity method).	Variability of facility performance and related penalties Changes to water and land rental expenses Unexpected maintenance expenditures

PRINCIPAL ASSUMPTIONS	PRINCIPAL RISKS AND UNCERTAINTIES
PROJECTED FREE CASH FLOW AND PAYOUT RATIO	
The Corporation estimates Free Cash Flow as projected cash flow from operations before changes in non-cash operating working capital items, less estimated maintenance capital expenditures net of proceeds from disposals, scheduled debt principal payments, preferred share dividends and the portion of Free Cash Flow attributed to non-controlling interests, plus cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to other facilities owned by the Corporation over the course of their power purchase agreement. It also adjusts for other elements, which represent cash inflows or outflows that are not representative of the Corporation's long-term cash generating capacity, such as adding back transaction costs related to realized acquisitions (which are financed at the time of the acquisition) and adding back realized losses or subtracting realized gains on derivative financial instruments used to fix the interest rate on project-level debt. The Corporation estimates the Payout Ratio by dividing the most recent declared annual common share dividend by the projected Free Cash Flow.	Adjusted EBITDA below expectations caused mainly by the risks and uncertainties mentioned above and by higher prospective project expenses Project costs above expectations caused mainly by the performance of counterparties and delays and cost overruns in the design and construction of projects Regulatory and political risk Interest rate fluctuations and financing risk Financial leverage and restrictive covenants governing current and future indebtedness Unexpected maintenance capital expenditures 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, the Company provides an estimate of project costs based on its extensive experience as a developer, directly related incremental internal costs, site acquisition costs and financing costs, which are eventually adjusted for projected costs provided by the engineering, procurement and construction (EPC) contractor retained for the project. The Company provides indications regarding scheduling and construction progress for its development projects and indications regarding its prospective projects, based on its extensive experience as a developer.	Performance of counterparties, such as the EPC contractors Delays and cost overruns in the design and construction of projects Obtainment of permits Equipment supply Interest rate fluctuations and financing risk Relationships with stakeholders Regulatory and political risks Higher-than-expected inflation
EXPECTED PROJECT FINANCING OR REFINANCING OF OPERATING FACILITIES	
The Company provides indications of its intention to secure non-recourse project-level debt financing for its development projects and to refinance operating facilities upon the end of the term of existing project-level debt, based on the expected LTA production and expected costs of each project, the expected remaining power purchase agreement term, a leverage ratio of approximately 75%-85%, as well as the Company's extensive experience in project financing and knowledge of the capital markets.	Interest rate fluctuations and financing risk Financial leverage and restrictive covenants governing current and future indebtedness
INTENTION TO SUBMIT PROJECTS UNDER REQUESTS FOR PROPOSALS	
The Company provides indications of its intention to submit projects under requests for proposals based on the state of readiness of some of its prospective projects and their compatibility with the announced terms of these requests for proposals.	Regulatory and political risks Ability of the Company to execute its strategy for building shareholder value Ability to secure new power purchase agreements
INTENTION TO GAIN A FOOTHOLD IN TARGET MARKETS INTERNATIONALLY	
The Corporation provides indications of its intention to establish a presence in target markets internationally in the coming years, based on its growth strategy.	Regulatory and political risks Ability of the Corporation to execute its strategy for building shareholder value Ability to secure new PPAs Foreign exchange fluctuations

INFORMATION FOR INVESTORS

COMMON SHARES (TSX: INE)

Innergex Renewable Energy Inc. had 100,672,000 common shares outstanding at December 31, 2014, with a closing price of $11.36 per share. The Company's shares are listed on the Toronto Stock Exchange.

SERIES A PREFERRED SHARES (TSX: INE.PR.A)

Innergex Renewable Energy Inc. currently has 3,400,000 Series A preferred shares outstanding, with a nominal value of $25 and a fixed cumulative preferential annual cash dividend of $1.25 per share, payable quarterly on the 15th day of January, April, July, and October. Series A preferred shares are not redeemable by the Company prior to January 15, 2016.

SERIES C PREFERRED SHARES (TSX: INE.PR.C)

Innergex Renewable Energy Inc. currently has 2,000,000 Series C preferred shares outstanding, with a nominal value of $25 and a fixed-rate cumulative preferential annual cash dividend of $1.4375 per share, payable quarterly on the 15th day of January, April, July, and October. Series C preferred shares are not redeemable by the Company prior to January 15, 2018.

CONVERTIBLE DEBENTURES (TSX: INE.DB)

Innergex Renewable Energy Inc. currently has convertible debentures outstanding for a total notional amount of $80.5 million, which bear interest at an annual rate of 5.75% and mature on April 30, 2017. The convertible debentures are subordinated to all other indebtedness of the Company.

TRANSFER AGENT AND REGISTRAR

For information concerning share certificates, dividend payments, a change of address, or electronic delivery of shareholder documents (such as quarterly and annual reports and proxy circulars), please contact the Company's transfer agent and registrar:

Computershare Investor Services Inc.

1500 University Street, Suite 700
Montreal, Quebec, Canada H3A 3S8
Phone: 1 800 564-6253 or 514 982-7555
Email: service@computershare.com
Website: computershare.com

DIVIDEND REINVESTMENT PLAN (DRIP)

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

CREDIT RATINGS

	STANDARD & POOR'S
Innergex Renewable Energy Inc.	BBB-
Series A Preferred Shares	P-3
Series C Preferred Shares	P-3
Convertible Debentures	--

S&P/TSX

The Company is included in the following indices:

- S&P/TSX Composite Index
- S&P/TSX Composite Dividend Index
- S&P/TSX Equity Income Index
- S&P/TSX Composite Low Volatility Index
- S&P/TSX SmallCap Index

and

- S&P/TSX Renewable Energy and Clean Technology Index

Innergex's strategy for building shareholder value is to develop or acquire high-quality facilities that generate sustainable cash flows and provide an attractive risk-adjusted return on invested capital, and to distribute a stable dividend.

INVESTOR RELATIONS

To obtain additional financial information, Company updates, or recent news releases and investor presentations, please contact:

Marie-Josée Privyk, CFA, SIPC
Director – Communications and Sustainable Development
Tel.: 450-928-2550 ext. 222 / mjprivyk@innergex.com

Or visit **www.innergex.com.**

Ce document est disponible en français.
Pour la version numérique, visitez notre site Web à www.innergex.com.
Pour la version papier, communiquez avec nous à info@innergex.com.

INNERGEX RENEWABLE ENERGY INC.

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Vancouver, British Columbia, Canada V6C 2X8

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INNERGEX
Renewable Energy.
Sustainable Development.

25 YEARS SUSTAINABLE by NATURE

Design: Contractuelle inc.

INNERGEX

Renewable Energy.
Sustainable Development.

FINANCIAL REVIEW

AT DECEMBER 31, 2014

Table of contents

Innergex Renewable Energy Inc. is a leading Canadian independent renewable power producer. Active since 1990, the Corporation develops, owns and operates run-of-river hydroelectric facilities, wind farms, and solar photovoltaic farms and carries out its operations in Quebec, Ontario and British Columbia, and in Idaho, USA. 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 symbol INE.DB.

Innergex's mission is to increase its production of renewable energy by developing and operating high-quality facilities while respecting the environment and balancing the best interests of the host communities, its partners and its investors.

2014 HIGHLIGHTS

Innergex and its partner, the three Mi'gmaq First Nations of Quebec, signed a 20-year power purchase agreement with Hydro-Québec Distribution and a turbine supply contract with Senvion SE for the 150 MW Mesgi'g Ugju's'n wind project. The project also received its government decree in the fall and preconstruction activities began shortly thereafter.

In June, Innergex and its partner, the Desjardins Group Pension Plan, completed the acquisition of the 30.5 MW SM-1 run-of-river hydroelectric facility located in Quebec, Canada. A $5.2 million capital improvement program that began in May was completed in December 2014, increasing the facility's long-term average annual production by 9%.

The Corporation closed the $92.9 million financing for the Tretheway Creek hydroelectric project. It completed, for all intents and purposes, a hedging program to fix the interest rate for its four other Development Projects until closing of the project-level financing. It also extended its revolving term credit facility from 2018 to 2019 and temporarily increased its borrowing capacity from $425 million to $475 million until June 30, 2015.

In August, the Corporation announced a partnership agreement with the In-SHUCK-ch Nation to develop six run-of-river hydroelectric projects in British Columbia, totalling 150 MW.

Construction began at the Big Silver Creek hydroelectric project in British Columbia.

2014 FINANCIAL PERFORMANCE

Electricity production increased **24%** to 2,962 GWh and was 100% of the long-term average

Revenues rose **22%** to $241.8 million compared with the same period last year

Adjusted EBITDA rose **21%** to $179.6 million compared with the same period last year

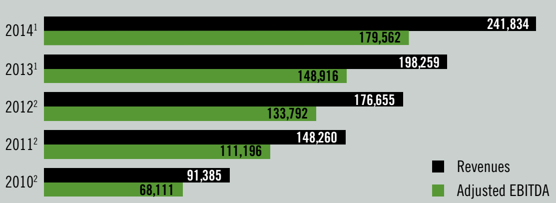
Free Cash Flow generated reached **$67.7** million

Payout ratio declined to **88%** compared with 93% last year

On May 13, 2014, the Corporation elected to grant a discount of 2.5% on the purchase price of shares issued to shareholders participating in the Dividend Reinvestment Plan (DRIP). Therefore, shares purchased under the DRIP continue to be issued from treasury and the price is the weighted-average trading price of the common shares on the Toronto Stock Exchange during the five (5) business days immediately preceding the dividend payment date, less the discount of 2.5%.

REVENUES AND ADJUSTED EBITDA

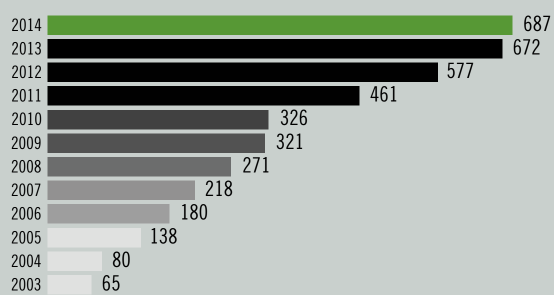
At December 31
($000s)



1 Prepared in accordance with IFRS - excluding joint ventures (IFRS 11).
2 Including joint ventures.

NET INSTALLED CAPACITY

At December 31
(MW)



INTRODUCTION

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 year ended December 31, 2014, and reflects all material events up to February 24, 2015, 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 audited consolidated financial statements and the accompanying notes for the year ended December 31, 2014. 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 www.sedar.com or on the Corporation's website at www.innergex.com.

The audited consolidated financial statements attached to this MD&A and the accompanying notes for the year ended December 31, 2014, along with the 2013 comparative figures, have been prepared in accordance with International Financial Reporting Standards ("IFRS"). Some amounts included in this MD&A have been rounded to make reading easier, which may affect some calculations.

TABLE OF CONTENTS

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

The President and Chief Executive Officer and the Chief Financial Officer and Senior Vice President of the Corporation have designed, or caused 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 accumulated and communicated by others to the President and Chief Executive Officer and the Chief Financial Officer and Senior Vice President in a timely manner, particularly during the period in which the interim and annual filings are being prepared; and (ii) the information required to be disclosed by the Corporation in its annual filings, interim filings and other reports filed or submitted by it under applicable 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 applicable to the Corporation.

In accordance with *Regulation 52-109 – Certification of Disclosure in Issuers' Annual and Interim Filings*, the President and Chief Executive Officer and the Chief Financial Officer and Senior Vice President of the Corporation have evaluated the effectiveness of the Corporation's DC&P and ICFR as at December 31, 2014, and have concluded that they were effective and that there were no material weaknesses relating to the DC&P and ICFR for the year ended December 31, 2014. During the year ended December 31, 2014, there was no change to the ICFR that has materially affected, or is reasonably likely to materially affect, the Corporation's ICFR.

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”). Forward-Looking Information can generally be identified by the use of words such as “approximately”, “may”, “will”, "could", “believes", “expects", “intends”, "should", “plans”, “potential”, "project", “anticipates”, “estimates”, “scheduled” or “forecasts”, or other comparable terminology 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, such as expected production, projected revenues, projected Adjusted EBITDA , projected Free Cash Flow, estimated project costs and expected project financing, to inform readers of the potential financial impact of expected results, of the expected commissioning of Development Projects, of the Corporation's ability to sustain current dividends and dividend increases and of its ability 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 those concerning hydrology, wind regimes and solar irradiation, performance of operating facilities, financial market conditions and the Corporation’s success in developing new facilities.

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 Corporation’s *Annual Information Form* in the “Risk Factors” section 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 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; health, safety and environmental risks; uncertainties surrounding the development of new facilities; obtainment of permits; variability of installation performance and related penalties; 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; the ability to secure new power purchase agreements or to renew any power purchase agreement; changes in governmental support to increase electricity to be generated from renewable sources by independent power producers; 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; changes in general economic conditions; regulatory and political risks; the ability to secure appropriate land; reliance on power purchase agreements; availability and reliability of transmission systems; increases in water rental cost or changes to regulations applicable to water use; assessment of water, wind and sun resources and associated electricity production; dam failure; natural disasters and *force majeure*; foreign exchange fluctuations; sufficiency of insurance coverage limits and exclusions; a credit rating that may not reflect actual performance of the Corporation or a lowering (downgrade) of the credit rating; potential undisclosed liabilities associated with acquisitions; integration of the facilities and projects acquired and to be acquired; failure to realize the anticipated benefits of acquisitions; reliance on shared transmission and interconnection infrastructure; and the fact that revenues from the Miller Creek facility will vary based on the spot price of electricity.

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 since no assurance can be given that it will prove to be correct. Forward-Looking Information contained herein is made 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 legislation.

Forward-Looking Information in this MD&A

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

Principal Assumptions	Principal Risks and Uncertainties
Expected production For each facility, the Corporation determines a long-term average annual level of electricity production ("LTA") over the expected life of the facility, based on engineers' studies that take into consideration a number of important factors: for hydroelectricity, the historically observed flows of the river, the operating head, the technology employed and the reserved aesthetic and ecological flows; for wind energy, the historical wind and meteorological conditions and turbine technology; and for solar energy, the historical solar irradiation conditions, panel technology and expected solar panel degradation. Other factors taken into account 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 long-term average. On a consolidated basis, the Corporation estimates the LTA by adding together the expected LTA of all the facilities in operation that it consolidates (excludes Umbata Falls and Viger-Denonville, which are accounted for using the equity method).	Improper assessment of water, wind and sun resources and associated electricity production Variability in hydrology, wind regimes and solar irradiation Equipment failure or unexpected operations and maintenance activity
Projected revenues For each facility, expected annual revenues are estimated by multiplying the LTA by a price for electricity stipulated in the power purchase agreement secured with a public utility or other creditworthy counterparty. These agreements stipulate a base price and, in some cases, a price adjustment depending on the month, day and hour of delivery, except for 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, power purchase agreements 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 all the facilities in operation that it consolidates (excludes Umbata Falls and Viger-Denonville, which are accounted for using the equity method).	Production levels below the LTA caused mainly by the risks and uncertainties mentioned above Unexpected seasonal variability in the production and delivery of electricity Lower-than-expected inflation rate
Projected Adjusted EBITDA For each facility, the Corporation estimates annual operating earnings by subtracting from the estimated revenues the budgeted annual operating costs, which consist primarily of operators' salaries, insurance premiums, operations and maintenance expenditures, property taxes and royalties; these are predictable and relatively fixed, varying mainly with inflation (except for maintenance expenditures). On a consolidated basis, the Company estimates annual Adjusted EBITDA by adding together the projected operating earnings of all the facilities in operation that it consolidates*, from which it subtracts budgeted general and administrative expenses, comprised essentially of salaries and office expenses, and budgeted prospective project expenses, which are determined based on the number of prospective projects the Corporation chooses to develop and the resources required to do so. * Excludes Umbata Falls and Viger-Denonville, which are accounted for using the equity method.	Variability of facility performance and related penalties Changes to water and land rental expenses Unexpected maintenance expenditures Changes in the purchase price of electricity upon renewal of a PPA
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, the Corporation provides an estimate of project costs based on its extensive experience as a developer, directly related incremental internal costs, site acquisition costs and financing costs, which are eventually adjusted for the projected costs provided by the engineering, procurement and construction ("EPC") contractor retained for the project. The Corporation provides indications regarding scheduling and construction progress for its Development Projects and indications regarding its Prospective Projects, based on its extensive experience as a developer.	Performance of counterparties, such as the EPC contractors Delays and cost overruns in the design and construction of projects Obtainment of permits Equipment supply Interest rate fluctuations and financing risk Relationships with stakeholders Regulatory and political risks Higher-than-expected inflation
Projected Free Cash Flow The Corporation estimates Free Cash Flow as projected cash flow from operations before changes in non-cash operating working capital items, less estimated maintenance capital expenditures net of proceeds from disposals, scheduled debt principal payments, preferred share dividends and the portion of Free Cash Flow attributed to non-controlling interests, plus cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to other facilities owned by the Corporation over the course of their power purchase agreement. It also adjusts for other elements, which represent cash inflows or outflows that are not representative of the Corporation's long-term cash generating capacity, such as adding back transaction costs related to realized acquisitions (which are financed at the time of the acquisition) and adding back realized losses or subtracting realized gains on derivative financial instruments used to fix the interest rate on project-level debt.	Adjusted EBITDA below expectations caused mainly by the risks and uncertainties mentioned above and by higher prospective project expenses Projects costs above expectations caused mainly by the performance of counterparties and delays and cost overruns in the design and construction of projects Regulatory and political risk Interest rate fluctuations and financing risk Financial leverage and restrictive covenants governing current and future indebtedness Unexpected maintenance capital expenditures

Principal Assumptions	Principal Risks and Uncertainties
Expected project financing or refinancing of Operating Facilities The Corporation provides indications of its intention to secure non-recourse project-level debt financing for its Development Projects and to refinance its Operating Facilities when the term of the existing project-level debt ends, based on the expected costs and revenues of each project, the expected remaining PPA term, an initial leverage ratio of approximately 75%-85% and the Corporation's extensive experience in project financing and knowledge of capital markets.	Interest rate fluctuations and financing risk Financial leverage and restrictive covenants governing current and future indebtedness
Intention to submit projects under requests for proposals The Corporation provides indications of its intention to submit projects under requests for proposals based on the state of readiness of some of its Prospective Projects and their compatibility with the announced terms of these requests for proposals.	Regulatory and political risks Ability of the Corporation to execute its strategy for building shareholder value Ability to secure new PPAs
Intention to gain a foothold in target markets internationally The Corporation provides indications of its intention to establish a presence in target markets internationally in the coming years, based on its growth strategy.	Regulatory and political risks Ability of the Corporation to execute its strategy for building shareholder value Ability to secure new PPAs Foreign exchange fluctuations

NON IFRS MEASURES

This MD&A has 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. Innergex believes that 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. Adjusted EBITDA, Free Cash Flow and Payout Ratio are not measures recognized by IFRS and have no standardized meaning prescribed by IFRS. References in this document to “Adjusted EBITDA” are to revenues less operating expenses, general and administrative expenses and prospective project expenses. 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 cash receipts by the Harrison Hydro Limited Partnership for the wheeling services to be provided to other facilities owned by the Corporation over the course of their PPA, 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) and realized losses or gains on derivative financial instruments used to hedge the interest rate on project-level debt. References to “Payout Ratio” are to dividends declared on common shares divided by Free Cash Flow. Readers are cautioned that Adjusted EBITDA should not be construed as an alternative to net earnings and Free Cash Flow should not be construed as an alternative to cash flows from operating activities, as determined in accordance with IFRS.

ADDITIONAL INFORMATION AND UPDATES

Additional and updated information on the Corporation is available through its regular press releases, quarterly financial statements and *Annual Information Form*, which can be found on the Corporation's website at www.innergex.com and on the SEDAR website at www.sedar.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.

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

OVERVIEW

The Corporation is a developer, owner and operator of renewable power-generating facilities with a focus on hydroelectric, wind power and solar photovoltaic ("PV") projects that benefit from low operating and management costs and simple, proven technologies.

Portfolio of Assets

As at the date of this MD&A, the Corporation owns interests in three groups of power-generating projects:

- 33 facilities in commercial operation (the "Operating Facilities"). Commissioned between November 1994 and January 2014, the facilities have a weighted average age of approximately 7.2 years. They sell the generated power under long-term Power Purchase Agreements ("PPA") that have a weighted average remaining life of 18.5 years (based on gross long-term average production);
- Five projects scheduled to begin commercial operation between 2015 and 2016 (the "Development Projects"). Construction is ongoing at four of the projects; and
- Numerous projects that have secured land rights, for which an investigative permit application has been filed or for which a proposal has either been or could be submitted under a Request for Proposal or a Standing Offer Program (collectively the "Prospective Projects"). These projects are at various stages of development.

The following chart diagrams the Corporation's direct and indirect interests in the Operating Facilities, Development Projects and Prospective Projects.

INNERGEX

	Operating Facilities	Development Projects	Prospective Projects
Hydro			
Gross capacity:	547.0 MW	168.5 MW	1,020.0 MW
Net capacity[1]:	417.7 MW	132.9 MW	970.0 MW
Wind			
Gross capacity:	614.1 MW	150.0 MW	2,270.0 MW
Net capacity[1]:	236.3 MW	75.0 MW	2,180.0 MW
Solar			
Gross capacity:	33.2 MW	-	40.0 MW
Net capacity[1]:	33.2 MW	-	40.0 MW
Total			
Gross capacity:	1,194.3 MW	318.5 MW	3,330.0 MW
Net capacity[1]:	687.2 MW	207.9 MW	3,190.0 MW

1. Net capacity represents the proportional share of the total capacity attributable to Innergex, based on its ownership interest in these facilities and projects. The remaining capacity is attributable to the partners' ownership share.

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

BUSINESS STRATEGY

The Corporation's strategy for building shareholder value is to develop or acquire high-quality renewable power production facilities that generate sustainable cash flows and provide an attractive risk-adjusted return on invested capital and to distribute a stable dividend.

Produce Only Renewable Energy

The Corporation is committed to producing electricity exclusively from renewable energy sources.

Develop Sustainably

In conducting its business, the Corporation strives to achieve a balance between economic, social and environmental considerations and is committed to planning, deciding, managing, and operating through the lens of sustainability.

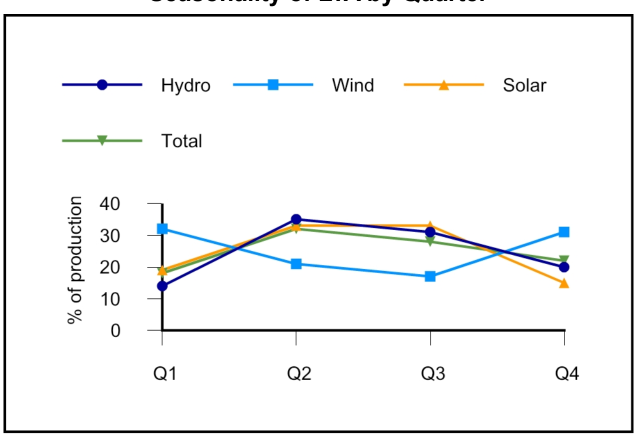
Maintain Diversification of Energy Sources

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 water flows, wind regimes or solar irradiation in any given year could have an impact on the Corporation's revenues and hence on its profitability. Innergex owns interests in 26 hydroelectric facilities, which draw on 23 watersheds, six wind farms and one solar farm, providing significant diversification in terms of operating revenue sources. Furthermore, the nature of hydroelectric, wind and solar power generation partially offsets any seasonal variations, as illustrated in the following table and charts:

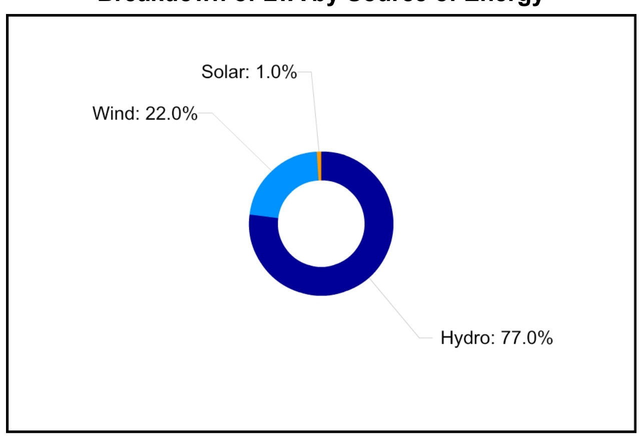
Consolidated long-term average production[1]									
In GWh and %	Q1		Q2		Q3		Q4		Total
HYDRO	321.9	14%	815.9	35%	724.3	31%	472.8	20%	2,334.9
WIND	213.6	32%	142.8	21%	112.8	17%	207.3	31%	676.5
SOLAR[2]	7.3	19%	12.5	33%	12.6	33%	5.8	15%	38.2
Total	542.8	18%	971.2	32%	849.7	28%	685.8	22%	3,049.5

1. Annualized long-term average production ("LTA") for the facilities in operation at February 24, 2015. 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, which is presented in the "Investments in Joint Ventures" section.
2. Solar farm LTA diminishes over time due to expected solar panel degradation.

Seasonality of LTA by Quarter



Breakdown of LTA by Source of Energy



Develop Strategic Relationships

Strategic relationships and partnerships are an important component of the Corporation's business strategy. When the Corporation teams up with a strategic or financial partner, the Corporation and the partner share ownership of the projects concerned. Current strategic partners include TransCanada Energy Ltd. (owner of 62% of the Baie-des-Sables, L'Anse-à-Valleau, Carleton, Montagne Sèche and Gros-Morne wind farms), the Ojibways of the Pic River First Nations (owner of 51% of the Umbata Falls facility), the Kanaka Bar Indian Band (owner of 50% of the Kwoiek Creek facility), the Rivière-du-Loup Regional County Municipality (owner of 50% of the Viger-Denonville community wind farm), Ledcor Power Group Ltd. (owner of $33^1/_3$% of the Fitzsimmons Creek facility, the Boulder Creek and Upper Lillooet River Development Projects as well as other Creek Power Inc. Prospective Projects), the Mi'gmawei Mawiomi (or the Mi'gmaq First Nations of Quebec) (owner of 50% of the Mesgi'g Ugju's'n wind Development Project) and the Minganie Regional County Municipality (owner of 0.001% of the common units and 30% of the voting units of the Magpie hydroelectric facility). Current financial partners include CC&L Harrison Hydro Project Limited Partnership and LPF (Surfside) Development L.P. (owners of 34.99% and 15.00% of Harrison Hydro Limited Partnership respectively) as well as the Desjardins Group Pension Plan (owner of 49.99% of the SM-1 hydroelectric facility).

Pursue Opportunities for Organic Growth

Growing awareness and concern over issues such as climate change, access to clean energy, energy security, energy efficiency and the environmental impacts of conventional fossil fuels are leading governments around the world to increase their demand for and commitments to the development of renewable energy supply. Consequently, the Corporation believes that the outlook for the renewable energy industry is promising.

Key Growth Factors

The Corporation's future growth will be affected by the following key factors:

- Demand for renewable energy;
- Stable and long-term government policies for the procurement of new renewable energy capacity, whether through requests for proposals or other mechanisms;
- Its capacity to evaluate and secure the best prospective sites for the development of new projects in cooperation with local communities;
- Its ability to enter into attractive PPAs and obtain the required environmental and other permits;
- Its ability to adequately forecast total construction costs, expected revenues and expected expenses for each project;
- Its ability to make accretive acquisitions; and
- Its ability to finance its growth.

Key Geographic Markets

In Quebec, in December 2014, Hydro-Québec completed a request for proposals for the procurement of 450 MW of new wind energy, including 300 MW for projects in the Lower Saint Lawrence and Gaspésie regions and 150 MW for projects anywhere in the province. Although the Corporation submitted several projects, it was not awarded any contracts. The Corporation remains confident in the long-term viability of the small hydro and wind energy sectors in this province and has a number of projects that it continues to advance for future renewable energy procurement opportunities. Furthermore, the prices of the recent request for proposals demonstrate the competitiveness of renewable energy in Quebec, even in the context of weak fossil fuel prices and large hydroelectric dam procurement capabilities.

In Ontario, the government has instituted a competitive procurement process that will take into account local needs and considerations, including those of municipalities and First Nations. It is currently planning new capacity procurement for 300 MW of wind energy and 140 MW of solar energy in 2015 and another 300 MW of wind energy and 150 MW of solar energy in 2016, with planned annual revisions thereafter. The Corporation has a number of wind and solar projects that it continues to advance in preparation for submissions under these competitive bid processes. Other prospective projects in Ontario, especially in the wind sector, remain predicated on transmission grid expansion in the northern part of the province and represent longer-term growth potential.

In British Columbia, while the government has stated its support for a healthy, diverse clean energy sector and clean energy opportunities for First Nations, it has provided no specific procurement targets for renewable energy at this time. Furthermore, the province is forecasting increasing demand for electricity and has significant plans to develop its mining and liquefied natural gas (“LNG”) sectors. In December 2014, the government announced its approval of BC Hydro's 1,100 MW Site-C hydroelectric dam project, which is scheduled to reach commercial operation in 2024 and which may reduce some prospects for independent power producers. Site-C is a component of BC Hydro's Integrated Resource Plan (IRP), which was approved by the BC government in November 2013 and is scheduled to be revised in the Fall of 2015. The IRP is a flexible long-term strategic plan to meet this province's growth in electricity demand over the next 20 years. The Corporation continues to advance the development of several Prospective Projects for future renewable energy procurement opportunities in this province.

In the United States, the Corporation will continue to selectively assess potential opportunities, particularly in light of the current U.S. administration's focus on addressing climate change and reducing GHG emissions, as well as the existence of renewable portfolio standards in several states and the increasing procurement of renewable energy. According to the US Energy Information Association (EIA), electricity generation from renewable energy is expected to rise from 12% in 2012 to 16% by 2040. In the short term, generation from renewable resources is expected to grow in response to federal tax credits and state-level policies. However, in the long term, renewable generation growth is expected to be driven by increasing cost competitiveness with other non-renewable technologies. In many markets across the US, wind and solar energy are already among the least costly new generation sources, even compared with currently low-cost natural gas.

To replenish its sources of long-term growth, the Corporation has identified a number of target markets internationally in which it expects to gain a foothold in the coming years. In developing economies in Latin America, demand for electricity remains strong and governments are seeking to increase the production of renewable energy, of which they have an ample supply. More economically mature countries in Europe have adopted ambitious GHG emissions reduction targets and governments are seeking to reduce their dependency on conventional forms of generation, both of which developments require a greater proportion of renewable energy in these countries' energy portfolios. There are a number of markets to which the Corporation believes it can largely transpose its business model for developing and operating renewable energy assets.

Pursue Growth Opportunities Through Acquisitions

Acquisitions are another important component of the Corporation's business strategy. More specifically, the Corporation will seek acquisitions that will enable it to gain a foothold and develop a critical mass in identified target markets internationally. It will also seek acquisitions in order to consolidate its leadership position in the Canadian renewable energy industry. As it has done in the past, Innergex will continue to focus on hydroelectric, wind and solar power generation assets. The Corporation could also grow through expansion into other forms of renewable energy production if profitable opportunities arise.

Maintain Capacity for Delivering Results

The Corporation does business in a competitive sector. The experience and dedication of its management team constitute its strongest asset. Through careful management, it has established a track record of completing projects by the commercial operation start date specified in their PPA while adhering to the established construction budgets. The Corporation's employees possess the specialized knowledge and skills necessary to carry out its business. The Corporation can also rely on a network of technical, financial and legal partners and has proved its ability to complement its internal capabilities with efficient use of external consultants when required. In addition, the Corporation retains the services of several engineering firms to assist with the feasibility analysis of its projects. As at December 31, 2014, the Corporation employed a total of 181 persons (including Cartier Wind Energy employees).

Use Key Performance Indicators

The Corporation measures its performance using key performance indicators that include or could include comparing power generated in megawatt-hours (“MWh”) and gigawatt-hours (“GWh”) with a long-term average, Adjusted EBITDA and Adjusted EBITDA Margin, Free Cash Flow and Payout Ratio. These indicators are not recognized measures under IFRS, have no standardized meaning prescribed by IFRS and therefore may not be comparable with those presented by other issuers. 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. These indicators also facilitate the comparison of results over different periods. Please refer to the "Non-IFRS Measures" section for more information.

Dividend Policy

The Corporation intends to distribute an annual dividend of $0.62 per common share, payable quarterly.

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 tests imposed under corporate law for the declaration of dividends and other relevant factors.

MARKET TRENDS

Renewable power producers are involved in the generation of electricity from renewable energy sources including hydro, wind, solar, landfill gas and geothermal sources.

While traditional regulated utilities continue to dominate North American electricity generation markets, the growing importance of the role played by independent power producers in meeting future electricity needs is now acknowledged and the benefits of their power output have increasingly been recognized by government authorities and policymakers in recent years.

There are several factors that explain the growing role played by independent power producers in supplying renewable power in North America, including: the growing demand for energy; increasing awareness of the benefits of renewable energy in addressing the impacts of climate change; the increase in government-sponsored incentives to develop renewable energy capacity; the availability of long-term renewable energy purchase contracts with highly creditworthy counterparties, allowing independent power producers to develop new projects in a low-risk environment with the expectation of stable long-term contractual cash flows; the implementation of non-discriminatory access to transmission systems, providing independent power producers with access to regional electricity markets; and the rapidly improving cost-competitiveness of renewable energy and efficiency of independent power producers. While the plentiful supply of natural gas in recent years has resulted in low market prices that have increased the attractiveness of this source of energy for producing electricity in many parts of the world, technological improvements and economies of scale have significantly reduced the costs of renewable energy procurement, in particular wind and solar power. In many markets, electricity produced from these sources is cost-competitive with energy produced from natural gas and its cost is much more stable over the long run because it is not subject to fluctuations in the price of the underlying resource year over year.

Renewable Power in Canada

Over the past few years, the significant growth in renewable power generation in Canada has resulted from: rising electricity and fossil fuel prices; the increased cost of large-scale hydroelectric sites; public concern over nuclear power generation, air quality, and greenhouse gases; improvements in renewable energy technologies; and shorter construction lead times for some renewable energy projects. Renewable electricity generation in Canada is also supported by federal and provincial incentives, such as long-term fixed price contracts, accelerated depreciation and Renewable Portfolio Standards, which are explained below.

In response to the long-term trend toward stronger environmental protection policies, many provincial governments have introduced Renewable Portfolio Standards (“RPS”), which typically set a target for an increased component of renewable energy in their electricity generation supply mix in order to reduce greenhouse gas emissions over time. These RPS typically reflect the distinct resource issues associated with electricity generation, given the provinces' respective electricity industry structures and geographical conditions. While RPS are sometimes applied and implemented as goals or targets rather than mandatory requirements, provincial authorities or their utilities are using RPS to source renewable generation resources and, in some cases, offer PPAs through competitive bidding processes. The competitive bidding process seeks to ensure that the RPS are achieved at the lowest possible cost and with the highest probability of project completion. By simplifying the negotiation and financing processes and decreasing the transactional costs for obtaining a long-term PPA, these mechanisms can contribute to meeting renewable energy generation goals. Several provinces have set a specific target percentage of electricity to be generated from renewable sources, including British Columbia (93% of total electricity from clean or renewable resources), Ontario (increase hydro energy capacity to 9,300 MW and to develop 10,700 MW of wind, solar and bioenergy installed capacity by 2021) and Quebec (develop 4,000 MW of wind energy capacity by 2015 and an additional 100 MW of wind energy for every 1,000 MW of additional hydroelectric power).

Canada enjoys a unique abundance of hydrological resources. With an estimated installed hydroelectric capacity of more than 74,000 MW, it is the third largest hydroelectric energy producer in the world. Furthermore, according to the Canadian Hydropower Association, the country has an undeveloped, technically feasible potential estimated at 163,000 MW. Despite the competition for appropriate sites and the challenges associated with power transmission over great distances, the low operational costs and long project lives of these facilities suggest that hydroelectric power generation will remain a major affordable supply source for many years. Transmission corridors in Canada have traditionally run directly from major generation facilities to major demand centres, meaning that strategic investments in new transmission corridors will play an important role in the development of hydroelectric projects and other isolated renewable energy generation projects.

Over the last few years, according to the National Energy Board, wind power has become commercially viable and emerged as the fastest growing segment of the renewable power industry in Canada. The Canadian Wind Energy Association ranks Canada as the fifth largest producer of wind energy in the world, with an installed wind power capacity of more than 9,700 MW and approximately 1,500 MW of new wind energy to be commissioned annually over the next few years. Several reasons explain the robustness of the wind energy industry, including the improving cost-competitiveness of wind energy due to economies of scale and technological improvements, provincial RPS, relatively short construction time lines, favourable wind resources, including strong winds across a wide range of rural areas and vast shorelines, and provincial renewable energy RFPs. The usual challenges of resource availability and transmission exist in Canada and, in some areas, access to transmission lines with available capacity is an economic or regulatory consideration.

A solar energy industry has emerged in Canada in recent years, particularly in Ontario. According to the Ontario Independent Electricity System Operator (IESO), at the end of the third quarter of 2014, the Ontario Power Authority was managing 1,235 MW of solar PV installed capacity in commercial operation with an additional 939 MW of capacity under development. While more expensive than conventional and other renewable sources of energy, production costs for solar energy continue to decline due to technological improvements and economies of scale. The Ontario government has announced its intention to support its solar energy industry and is currently planning new procurement of 140 MW of solar energy in 2015 and another 150 MW in 2016.

SELECTED ANNUAL INFORMATION

	Year ended December 31		
	2014	2013	2012
			(restated)[3]
Power generated (MWh)	2,962,450	2,381,820	2,104,945
LTA production (MWh)	2,964,070	2,502,562	2,169,182
Revenues	241,834	198,259	176,655
Adjusted EBITDA	179,562	148,916	133,792
Adjusted EBITDA margin	74.3%	75.1%	75.7%
Net (loss) earnings	(84,378)	45,431	(5,383)
Net (loss) earnings attributable to owners of the parent	(54,853)	48,170	1,405
($ per common share - basic)	(0.63)	0.43	(0.03)
($ per common share - diluted)	(0.63)	0.43	(0.03)
Weighted average number of common shares (in 000s)	98,341	94,694	86,557
Total assets	2,716,015	2,377,074	2,296,440
Current liabilities	202,035	106,051	138,561
Long-term debt	1,610,800	1,313,718	1,166,782
Other long-term liabilities	260,937	211,539	223,510
Liability portion of convertible debentures	80,018	79,831	79,655
Total non-current liabilities	1,951,755	1,605,088	1,469,947
Non-controlling interests	47,411	81,429	107,611
Equity attributable to owners	514,814	584,506	580,321
Dividends declared on Class A Preferred Shares ($/share)	1.25	1.25	1.25
Dividends declared on Class C Preferred Shares ($/share)[1]	1.4375	1.570425	—
Dividends declared on common shares ($/share)	0.60	0.58	0.58
Dividends declared on common shares	59,549	54,967	50,693
Free Cash Flow[2]	67,744	58,982	43,897
Payout Ratio[2]	88%	93%	115%

1. The regular annual dividend is $1.4375; the initial dividend in 2013 was higher to reflect dividends accrued since the closing date of the Series C Preferred Shares offering of December 11, 2012.
2. For more information on the calculation and explanation of the Corporation's Free Cash Flow and Payout Ratio, please refer to the "Free Cash Flow and Payout Ratio" section.
3. The 2012 financial statements were restated following the adoption in 2013 of IFRS 11 Joint Arrangements.

Comparison between 2014, 2013 and 2012

For the year ended December 31, 2014, the increases in power generated, revenues and Adjusted EBITDA are attributable mainly to the full-year contribution of the Magpie hydroelectric facility acquired in July 2013, the addition of the Kwoiek Creek and Northwest Stave River hydroelectric facilities commissioned at the end of 2013 and the addition of the SM-1 hydroelectric facility acquired in June 2014. The change from net earnings of $45.4 million to a net loss of $84.4 million is due mainly to a $121.7 million unrealized net loss on derivative financial instruments compared with an unrealized net gain of $45.2 million in 2013 resulting from a decrease in benchmark interest rates during the year. The increase in long-term debt is attributable mainly to drawings under the revolving term credit facility to fund construction costs of the Corporation's five Development Projects and to the addition of the SM-1 and Tretheway Creek project-level debts. The decrease in equity attributable to owners and non-controlling interests is due mainly to the recognition of a net loss and the declaration of dividends on preferred and common shares in 2014. The increase in Free Cash Flow, which is attributable mainly to an increase in Adjusted EBITDA, more than offset the increase in dividends resulting from the greater number of shares outstanding, yielding a lower Payout Ratio of 88%.

For the year ended December 31, 2013, the increases in power generated, revenues and Adjusted EBITDA are attributable mainly to the full-year contribution of the Stardale solar farm commissioned in May 2012, the full-year contribution of the Brown Lake and Miller Creek hydroelectric facilities acquired in October 2012, the additional capacity at the Gros-Morne wind farm since November 2012, and the addition of the Magpie hydroelectric facility acquired in July 2013. The change from a net loss of $5.4 million to net earnings of $45.4 million is due mainly to the reasons mentioned above as well as an unrealized net gain on derivative financial instruments of $45.2 million resulting from an increase in benchmark interest rates during the year, compared with an unrealized gain of $7.8 million in 2012. The increase in long-term debt is attributable mainly to the addition of the $72.0 million Northwest Stave River and the $63.3 million Magpie debts and to the increase in the Carleton debt upon refinancing. The decrease in non-controlling interests is due mainly to a distribution made by the Harrison Hydro Limited Partnership in 2013. The increase in Free Cash Flow is attributable mainly to greater cash flows from operating activities before changes in non-cash operating working capital items, yielding a lower Payout Ratio of 93%.

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

Impact on net (loss) earnings of the unrealized net loss (gain) and realized net loss on derivative financial instruments	Year ended December 31		
	2014	2013	2012
			(restated)
Net (loss) earnings	(84,378)	45,431	(5,383)
Add (Subtract): Unrealized net loss (gain) on derivative financial instruments	121,685	(45,249)	(7,791)
Add: Realized net loss on derivative financial instruments	8,366	3,259	14,127
(Subtract) Add: Income tax provision related to above items	(32,096)	11,127	(1,647)
Add (Subtract): Share of unrealized and realized net loss or gain on derivative financial instruments of joint ventures, net of related income tax provision	2,804	(1,951)	(408)
	16,381	12,617	(1,102)

Excluding the realized net losses on derivative financial instruments, the unrealized net losses or gains on derivative financial instruments and the related income taxes, the Corporation would have recorded net earnings of $16.4 million for the year ended December 31, 2014, compared with net earnings of $12.6 million in 2013 and a net loss of $1.1 million in 2012.

DEVELOPMENTS IN 2014

Normal Course Issuer Bid Implemented

On March 20, 2014, the Corporation announced it was proceeding with a normal course issuer bid ("NCIB"), which enables it to purchase for cancellation up to 1 million (or approximately 1%) of its issued and outstanding common shares between March 24, 2014, and March 23, 2015. As at the date of this MD&A, the Corporation has not purchased any shares for cancellation under this NCIB.

Progress on the 150 MW Mesgi'g Ugju's'n Wind Project in Quebec

On March 24, 2014, Innergex and its partner announced that Mesgi’g Ugju’s’n (MU) Wind Farm, L.P. had signed a 20-year power purchase agreement with Hydro-Québec Distribution for the 150 MW Mesgi'g Ugju's'n wind project located in the Gaspé Peninsula in Quebec, Canada. This entity is controlled 50-50 by the three Mi’gmaq First Nations of Quebec – Gesgapegiag, Gespeg and Listuguj – and by Innergex, which is also responsible for managing the construction and operation of the wind farm.

On October 16, 2014, the Corporation announced that the government decree for the project had been obtained from the Quebec government, marking the conclusion of the project's environmental approval process and giving the green light for construction to begin. During the third quarter of 2014, the partners also signed a turbine supply contract with Senvion SE. For more information on the Mesgi'g Ugju's'n project, please refer to the "Development Projects" section.

2.5% Discount Granted on the Purchase Price of Shares Issued Under the Dividend Reinvestment Plan (DRIP)

On May 13, 2014, the Corporation elected to grant a 2.5% discount on the purchase price of shares issued to shareholders participating in the DRIP. Accordingly, shares purchased under the DRIP continue to be issued from treasury and the price is the weighted average trading price of the common shares on the Toronto Stock Exchange during the five (5) business days immediately preceding the dividend payment date, less the 2.5% discount. Any decision by the Corporation to change either the purchase method for the shares or the discount granted on the purchase price of shares issued from treasury will be communicated by press release.

Acquisition of the 30.5 MW SM-1 Hydroelectric Facility in Quebec

On June 20, 2014, Innergex and Desjardins Group Pension Plan ("Desjardins") announced they had completed the acquisition from Hydroméga Group of Companies ("Hydroméga") of the 30.5 MW Sainte-Marguerite-1 ("SM-1") run-of-river hydroelectric facility located near Sept-Îles in Quebec, Canada.

Partnership with Desjardins

The Corporation and Desjardins respectively own 50.01% and 49.99% of the common units of Innergex Sainte-Marguerite, S.E.C. ("SM-1 L.P."). SM-1 L.P. acquired the SM-1 hydroelectric facility for the final purchase price of approximately $80.1 million, plus assumption of $30.8 million in non-recourse project-level debt carrying a fixed interest rate of 7.4% and maturing in 2025. This debt was adjusted to fair market value of $37.5 million upon consolidation by the Corporation. For more information on debts related to SM-1, please refer to the "Financial Position" section.

Innergex and the In-SHUCK-ch Nation Sign a Partnership Agreement to Develop Six Hydro Projects in British Columbia

On August 12, 2014, the Corporation announced it had agreed with the In-SHUCK-ch Nation on the commercial terms for a 50-50 partnership to develop six run-of-river hydroelectric projects. Totaling approximately 150 MW, these projects are spread on six creeks located within the Nation's traditional territories. The partners are currently in discussions with the Province of British Columbia and BC Hydro to explore ways to ensure the viability of these projects through long-term power purchase agreements with BC Hydro.

Tretheway Creek Hydroelectric Project Financing Completed

On September 30, 2014, the Corporation closed a $92.9 million non-recourse construction and term project financing for the Tretheway Creek run-of-river hydroelectric project located in British Columbia. The loan will carry a fixed interest rate of 4.99%; upon the start of the project's commercial operation, the loan will convert into a 40-year term loan and the principal will begin to be amortized over a 35-year period, starting in the sixth year. The financing has been fully underwritten by National Bank Financial Inc. and Sun Life Assurance Company of Canada, with National Bank of Canada and Sun Life Assurance Company of Canada as lenders. Concurrent with the closing of the financing, the Corporation settled the bond forward contracts used to hedge the interest rate prior to the close of financing in order to protect the expected returns on the project, giving rise to an $8.4 million realized loss on derivative financial instruments. This is equivalent to a fixed interest rate of approximately 5.61% on the loan and well within the parameters of the economic model for this project. For more information on the Tretheway Creek financing, please refer to the "Financial Position" section.

Revolving Term Credit Facility Extended and Temporarily Increased

On November 6, 2014, the Corporation executed an amending agreement to extend its revolving term credit facility from 2018 to 2019 and to temporarily increase its borrowing capacity by $50 million until June 30, 2015, from $425 million to $475 million. These changes will provide greater financing flexibility until the Corporation closes the project-level financings that remain to be put in place.

Results of the Quebec Request for Proposals for 450 MW of New Wind Energy

On December 16, 2014, Hydro-Québec Distribution announced the winning bids under the call for proposals for 450 MW of new wind energy. In all, 54 bids representing 6,627 MW were submitted under this very competitive process. Innergex submitted five projects totalling 813 MW that were located in the Gaspé Peninsula and Lower Saint Lawrence region. The projects that the Corporation had submitted were not awarded a contract.

The Corporation believes that it presented the best possible bids based on its experience in developing wind projects in the Gaspé Peninsula and that they would have resulted in successful projects for both its community partners and its shareholders. These bids were cost-competitive when compared with the pricing of the winning bids. One of its projects has been placed on reserve, should any of the winning bids not be realized.

Significantly, the prices of this request for proposals demonstrate the competitiveness of renewable energy in Quebec and elsewhere, even in a context of low fossil fuel prices.

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

DEVELOPMENT PROJECTS

The Corporation currently has five projects that are expected to reach commercial operation between 2015 and 2016.

PROJECTS UNDER CONSTRUCTION	Ownership %	Gross installed capacity (MW)	Expected COD[1]	Gross estimated LTA[2, 3] (GWh)	PPA term (years)	Total project costs		Expected year-one	
						Estimated[2] ($M)	As at Dec. 31 ($M)	Revenues[2] ($M)	Adjusted EBITDA[2] ($M)
HYDRO (British Columbia)									
Tretheway Creek	100.0	21.2	2015	81.0	40	111.5	73.4	9.0	7.5
Upper Lillooet River	66.7	81.4	2016	334.0	40	315.0 [4]	127.7 [4]	33.0 [4]	27.5 [4]
Boulder Creek	66.7	25.3	2016	92.5	40	119.2 [4]	38.9 [4]	9.0 [4]	7.5 [4]
Big Silver Creek	100.0	40.6	2016	139.8	40	216.0	71.8	18.0	15.0
		168.5		647.3		761.7	311.8	69.0	57.5

1. Commercial operation date.
2. This information is intended to inform readers of the projects' potential impact on the Corporation's results.
3. Upon commissioning, LTA figures may be updated to reflect design optimization or constraints or selection of different turbines. Actual results may vary. Please refer to the “Forward-Looking Information” section for more information.
4. Corresponding to 100% of this facility.

Tretheway Creek

The construction of this hydroelectric facility began in October 2013. As at the date of this MD&A, construction of the intake was well under way, and installation of the penstock was almost complete; first stage concrete for the powerhouse foundation was complete and installation of the powerhouse superstructure and bridge crane were complete; gates and control equipment had been procured and delivery was expected to begin soon; and turbine and generator delivery was expected during the second quarter of 2015. On September 30, 2014, the Corporation closed a $92.9 million non-recourse construction and term project financing for the project. Commercial operation of the facility is expected to begin before the end of 2015.

Upper Lillooet River and Boulder Creek (the "Upper Lillooet Hydro Project")

The construction of the Upper Lillooet River and Boulder Creek hydroelectric facilities began in October 2013. As at the date of this MD&A, clearing for the joint transmission line and pole installation were in progress; pouring of the concrete for the Upper Lillooet River and Boulder Creek powerhouses was also progressing; and excavation and consolidation of both tunnels were under way. In November, the cofferdam construction and river diversion at Upper Lillooet River were successfully completed. As planned, construction activities have been halted for the winter period and will resume in the spring of 2015. In January 2014, a hedging program was for all intents and purposes completed to fix the interest rate for these projects' financing through the use of derivative financial instruments until the closing of the project-level financing; this effectively eliminates the projects' exposure to interest rate fluctuations.

On March 27, 2014, the Corporation announced it had reached agreements with BC Hydro regarding the Upper Lillooet Hydro Project, pursuant to which the higher installed capacities of the Upper Lillooet River and Boulder Creek projects were confirmed and the North Creek project was cancelled. These changes had been requested by the Corporation in early 2013. Also pursuant to these agreements, the commercial operation date for the Boulder Creek project will occur no earlier than July 1, 2016.

Big Silver Creek

Construction of this hydroelectric facility began in June 2014. As of the date of this MD&A, construction of the penstock and excavation of the tunnel were ongoing; pouring of the concrete for the powerhouse foundation was well advanced; design and procurement of electrical equipment was ongoing; and procurement of the turbines was under way. In January 2014, a hedging program was for all intents and purposes completed to fix the interest rate for this project's financing through the use of derivative financial instruments until the closing of the project-level financing. This effectively eliminates the project's exposure to interest rate fluctuations.

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

PROJECTS UNDER PRE-CONSTRUCTION	Ownership %	Gross installed capacity (MW)	Expected COD[1]	Gross estimated LTA[2,3] (GWh)	PPA term (years)	Total project costs		Expected year-one	
						Estimated[2,3] ($M)	As at Dec. 31 ($M)	Revenues[2] ($M)	Adjusted EBITDA[2] ($M)
WIND (Quebec)									
Mesgi'g Ugju's'n	50.0	150.0	2016	515.0	20	340.0 [4]	9.4 [4]	55.0 [4]	48.0 [4]
		150.0		515.0		340.0	9.4	55.0	48.0

1. Commercial operation date.
2. This information is intended to inform readers of the projects' potential impact on the Corporation's results.
3. Upon commissioning, LTA and estimated project cost may be updated to reflect design optimization or constraints or selection of different turbines. Estimates are preliminary until the EPC contractor has been selected. Actual results may vary. Please refer to the “Forward-Looking Information” section for more information.
4. Corresponding to 100% of this facility.

Mesgi'g Ugju's'n

As at the date of this MD&A, pre-construction activities such as tree clearing have been completed. The partners expect to select an engineering, procurement and construction contractor at the end of the first quarter of 2015. Construction is expected to start in the spring of 2015 and commercial operation is expected to begin at the end of 2016. In April 2014, a hedging program was for all intents and purposes completed to fix the interest rate for this project's financing through the use of derivative financial instruments until the closing of the project-level financing. This effectively eliminates the project's exposure to interest rate fluctuations. The euro portion of the turbine supply contract has been hedged with a foreign exchange forward contract.

The cost of the Mesgi'g Ugju's'n wind project is currently estimated at approximately $340.0 million and at least 70% of it will be financed with non-recourse, fixed-rate project-level debt. The $25.0 million reduction in the Corporation's estimated project costs reflects the use of larger turbines and the increase in expected Adjusted EBITDA reflect lower operating costs than initially expected. The wind farm is expected to have a long-term average annual production of approximately 515,000 MWh, enough to power more than 30,000 Quebec households each year. All the electricity the facility will produce is covered by a 20-year fixed-price power purchase agreement with Hydro-Québec, which provides for an annual adjustment to the selling price based on a portion of the Consumer Price Index. In its first full year of operation, the MU wind farm is expected to generate revenues and Adjusted EBITDA of approximately $55.0 million and $48.0 million respectively.

The partners will share in the distributions from the project in varying proportions, based in part on their initial equity investment. Initially, the Corporation expects to fund a majority of the equity investment required for this project; as a result, it expects to receive approximately 75% of the project's cash flows during the first year. However, during the first 15 years of operation, the Mi’gmaq First Nations of Quebec will have the right to gradually increase their equity investment in the project up to 65% (by purchasing portions of the Corporation's equity at a price based on the present value of future cash flows using a predetermined rate of return) and therefore receive a higher proportion of cash flows. In any event, starting in the 16th year, the Corporation will receive no less than 35% and no more than 40% of the project's annual cash flows for the remaining life of the project.

PROSPECTIVE PROJECTS

With a combined potential net installed capacity of 3,190 MW (gross 3,330 MW), all the Prospective Projects are in the preliminary development stage. Some Prospective Projects are targeted toward specific future requests for proposals, such as the current request for proposals for new wind and solar energy in Ontario, or Standing Offer Programs, such as the one in British Columbia. Other Prospective Projects will be available for future requests for proposals yet to be announced or are targeted toward negotiated power purchase agreements with public utilities or other creditworthy counterparties. There is no certainty that any Prospective Project will be realized.

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

OPERATING RESULTS

Production of electricity for the year was 100% of the long-term average due mainly to average water flows, wind regimes and solar regimes for the year overall.

Production increased 24%, revenues increased 22% and Adjusted EBITDA increased 21% in 2014. The increase in production and revenues is attributable mainly to the full-year contribution of the Magpie hydroelectric facility acquired in July 2013, the addition of the Kwoiek Creek and Northwest Stave River facilities commissioned at the end of 2013 and the addition of the SM-1 hydroelectric facility acquired in June 2014. When compared with the increase in production, the slightly smaller increase in revenues is attributable to the addition of the Magpie and SM-1 facilities, for which the selling price is lower than for most of the Corporation's other facilities.

The Corporation's operating results for year ended December 31, 2014, are compared with the operating results for the same periods in 2013.

Electricity Production

When evaluating its operating results, a key performance indicator for the Corporation is to compare actual electricity generation with a long-term average ("LTA") for each hydroelectric facility, wind farm and solar farm. These long-term averages are determined to allow long-term forecasting of the expected power generation for each of the Corporation's facilities.

Year ended December 31	2014				2013			
	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Average price ($/MWh)[2]	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Average price ($/MWh)[2]
HYDRO								
Quebec	606,071	614,205	99%	75.97	467,645	444,014	105%	80.76
Ontario	84,333	74,544	113%	68.45	83,040	74,544	111%	68.26
British Columbia	1,509,737	1,513,591	100%	76.71	1,062,730	1,221,997	87%	75.73
United States	45,083	46,800	96%	75.38	41,956	46,800	90%	71.82
Subtotal	2,245,224	2,249,140	100%	76.17	1,655,371	1,787,355	93%	76.68
WIND								
Quebec	677,107	676,489	100%	79.71	686,380	676,490	101%	79.40
SOLAR								
Ontario	40,119	38,441	104%	420.00	40,069	38,717	103%	420.00
Total	2,962,450	2,964,070	100%	81.64	2,381,820	2,502,562	95%	83.24

1. The Umbata Falls hydroelectric facility and the Viger-Denonville wind farm are treated as joint ventures and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for the sake of consistency, their electricity production figures have been excluded from the production table. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.
2. Including all payment adjustments related to the month, day and hour of delivery, to environmental attributes and to the ecoENERGY Initiative, as applicable.

During the year ended December 31, 2014, the Corporation's facilities produced 2,962 GWh of electricity or 100% of the LTA of 2,964 GWh. Overall, the hydroelectric facilities produced 100% of their LTA, mainly due to normal or above-average water flows at most facilities for the year as a whole, and to above-average water flows in British Columbia during the fourth quarter, which offset below-average water flows in the province during the first three quarters. Overall, the wind farms produced 100% of their LTA, as above-average wind regimes during the first and third quarters offset below-average wind regimes during the second and fourth quarters. The Stardale solar farm produced 104% of its LTA, as above-average solar regimes during the first three quarters offset below-average solar regimes during the fourth quarter. For more information on operating segment results, please refer to the "Segment Information" section.

The production increase of 24% compared with the same period last year is attributable mainly to the full-year contribution of the Magpie hydroelectric facility acquired in July 2013, the addition of the Kwoiek Creek and Northwest Stave River facilities commissioned at the end of 2013 and the addition of the SM-1 hydroelectric facility acquired in June 2014.

The overall performance of the Corporation's facilities for the year ended December 31, 2014, demonstrates the benefits of geographic diversification and the complementarity of hydroelectric, wind and solar power generation.

Additional Information

Power Purchase Agreements

The 33 Operating Facilities sell the generated power under long-term PPAs to rated public utilities or other creditworthy counterparties. For Operating Facilities in Quebec, Ontario and British Columbia, PPAs include a base price and, in some cases, a price adjustment depending on the month, day and hour of delivery, except for the Miller Creek hydroelectric facility, for which the price is based on a formula using the Platts Mid-C pricing indices (this facility accounted for 2% of revenues in 2014). For the Horseshoe Bend hydroelectric facility located in Idaho, USA, 85% of the price is fixed and 15% is adjusted annually as determined by the Idaho Public Utility Commission.

Portneuf

In addition to revenue from the power generated at the three Portneuf facilities, the Corporation receives cash payments from Hydro-Québec to compensate for the partial diversion of the water flow that would have otherwise been available to the Corporation's plants. These payments are based on long-term average annual water flows over 20 years. Although these facilities are exempt from annual hydrological variations under the “virtual energy” provisions included in the long-term PPAs with Hydro-Québec, they must remain in operation in order to receive financial compensation. As such, the payments are contingent on turbine availability and maximum production with the water resources made available by Hydro-Québec.

Inflation Protection

Most of the Corporation's PPAs for Operating Facilities include a clause that adjusts for the effects of inflation:
- all PPAs for Quebec hydroelectric facilities except Magpie and the second PPA (22 MW) for SM-1 provide for an annual CPI-based power rate increase of between 3% and 6%;
- the PPA for the Magpie hydroelectric facility provides for an annual power rate increase of 1%;
- the second PPA (22 MW) for the SM-1 hydroelectric facility provides for an annual power rate increase of 2%;
- the PPAs for the Glen Miller and Umbata Falls hydroelectric facilities provide for an annual power rate adjustment based on 15% of the CPI;
- all PPAs for British Columbia hydroelectric facilities except Kwoiek Creek, Brown Lake and Miller Creek provide for an annual power rate adjustment based on 50% of the CPI; for the six facilities owned by Harrison Hydro Limited Partnership, this inflation protection is partly offset by the inflation component of the real-return bonds;
- the PPA for the Kwoiek Creek hydroelectric facility in British Columbia provides for an annual power rate adjustment based on 30% of the CPI;
- the PPA for the Brown Lake hydroelectric facility in British Columbia provides for an annual power rate increase of 3%;
- all PPAs for Quebec wind farms provide for an annual power rate adjustment based on approximately 20% of the CPI.

Power Purchase Agreements Coming Up for Renewal

The PPA for the 8.0 MW St-Paulin hydroelectric facility reached the end of its initial 20-year term in November 2014. The Corporation had sent Hydro-Québec a notice of automatic renewal of the PPA for an additional 20-year term. Following initial discussions, the Corporation and Hydro-Québec could not reach agreement on the renewal terms and conditions and the Corporation subsequently filed a notice of arbitration. The Corporation has agreed with Hydro-Québec to suspend its arbitration proceeding until a decision is made in another arbitration proceeding already under way between Hydro-Québec and other independent power producers. In the meantime, Hydro-Québec has agreed to maintain the terms and conditions of the St-Paulin PPA until 30 days following the decision in this other arbitration proceeding.

The PPA for the 5.5 MW Windsor hydroelectric facility will reach the end of its initial 20-year term in January 2016 and the Corporation has sent Hydro-Québec a notice of automatic renewal of the PPA for an additional 20-year term.

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

Financial Results

	Year ended December 31			
	2014		2013	
Revenues	241,834	100.0%	198,259	100.0%
Operating expenses	41,512	17.2%	33,947	17.1%
General and administrative expenses	15,064	6.2%	11,194	5.6%
Prospective project expenses	5,696	2.4%	4,202	2.1%
Adjusted EBITDA	179,562	74.3%	148,916	75.1%
Finance costs	86,537		65,158	
Other net expenses (revenues)	7,797		(392)	
Depreciation and amortization	74,092		69,160	
Share of loss (earnings) of joint ventures[1]	701		(6,053)	
Unrealized net loss (gain) on derivative financial instruments	121,685		(45,249)	
(Recovery of) income tax expense	(26,872)		20,861	
Net (loss) earnings	(84,378)		45,431	
Net (loss) earnings attributable to:				
Owners of the parent	(54,853)		48,170	
Non-controlling interests	(29,525)		(2,739)	
	(84,378)		45,431	
Basic net (loss) earnings per share	(0.63)		0.43	

1. The Umbata Falls hydroelectric facility and Viger Denonville wind farm are treated as joint ventures and the Corporation's interests in these facilities are required to be accounted for using the equity method. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

Revenues

For the year ended December 31, 2014, the Corporation recorded revenues of $241.8 million, compared with $198.3 million in 2013. This 22% increase is attributable mainly to the full-year contribution of the Magpie hydroelectric facility acquired in July 2013, the addition of the Kwoiek Creek and Northwest Stave River facilities commissioned at the end of 2013 and the addition of the SM-1 hydroelectric facility acquired in June 2014. Furthermore, when compared with the increase in production, the smaller increase in revenues is attributable to the addition of the Magpie and SM-1 facilities, for which the selling price is lower than for most of the Corporation's other facilities.

Expenses

Operating expenses consist primarily of the operators' salaries, insurance premiums, expenditures related to operation and maintenance, property taxes and royalties. For the year ended December 31, 2014, the Corporation recorded operating expenses of $41.5 million ($33.9 million in 2013). This 22% increase is due mainly to the Corporation operating a greater number of facilities in 2014 than in 2013 following the addition of the Magpie, Kwoiek Creek, Northwest Stave River and SM-1 hydroelectric facilities.

General and administrative expenses consist primarily of salaries, professional fees and office expenses. For the year ended December 31, 2014, general and administrative expenses totalled $15.1 million ($11.2 million in 2013). This increase of 35% reflects the Corporation's larger number of facilities in operation, larger number of employees, normal salary increases, and higher professional fees.

Prospective project expenses include the costs incurred for the development of Prospective Projects. They result from the number of Prospective Projects that the Corporation chooses to advance and the resources required to do so. For the year ended December 31, 2014, prospective project expenses totalled $5.7 million ($4.2 million in 2013). This increase of 36% is related mainly to the 2014 request for proposals in Quebec and the current request for proposals in Ontario.

Adjusted EBITDA

When evaluating its financial results, a key performance indicator for the Corporation is to measure Adjusted EBITDA, which is defined as revenues less operating expenses, general and administrative expenses and prospective project expenses. For the year ended December 31, 2014, the Corporation recorded Adjusted EBITDA of $179.6 million, compared with $148.9 million for the same period last year. This 21% increase remains in line with the increase in revenues, while the reduction in Adjusted EBITDA Margin from 75.1% to 74.3% results mainly from higher general and administrative expenses as well as higher prospective project expenses.

Finance Costs

Finance costs include interest on long-term debt and convertible debentures, inflation compensation interest, amortization of financing fees, amortization of the revaluation of long-term debt and convertible debentures, accretion expenses on other liabilities and other finance costs. For the year ended December 31, 2014, finance costs totalled $86.5 million ($65.2 million in 2013). This increase is due mainly to the expensing of interest on the Kwoiek Creek and Northwest Stave River loans now that the facilities are in operation, to the addition of project-level debt related to the Magpie acquisition in July 2013 and the SM-1 acquisition in June 2014 and to greater inflation compensation interest on the real return bonds owing to higher inflation during this period compared with the same period last year.

As at December 31, 2014, 91% of the Corporation's outstanding debt, including convertible debentures, was fixed or hedged against interest rate movements (98% as at December 31, 2013). The decrease stems from the increased drawings on the revolving term credit facility to pay for construction costs prior to closing the financing for the five Development Projects.

The effective all-in interest rate on the Corporation's debt and convertible debentures was 5.33% as at December 31, 2014 (5.46% as at December 31, 2013). The decrease stems mainly from a lower interest rate on the revolving term credit facility, the addition of the Northwest Stave River loan, which bears a fixed interest rate of 5.30%, the addition of the Magpie project debt, which bears an all-in interest rate of 4.37%, the addition of the SM-1 project debt, which bears a fixed interest rate of 3.30% following its adjustment to fair market value upon consolidation and the addition of the Tretheway Creek project debt, which bears a fixed interest rate of 4.99%. These items were partly offset by the addition of the debenture on the SM-1 facility, which bears a fixed interest rate of 8.00%.

Other Net Expenses (Revenues)

Other net expenses or revenues include transaction costs, realized losses on derivative financial instruments, realized losses on foreign exchange, gain on contingent considerations, loan impairment, settlement of claims received in connection with an acquisition, write-off of project development costs, and other net revenues. For the year ended December 31, 2014, the Corporation recorded other net expenses of $7.8 million (other net revenues of $0.4 million in 2013). The change stems mainly from the realized loss on derivative financial instruments of $8.4 million related to the settlement of the Tretheway Creek bond forward contracts concurrently with the closing of the long-term financing for this project. This loss is a result of a decrease in benchmark interest rates between the date the bond forwards were entered into (between August and September 2013) and the settlement date (September 30, 2014) and is compensated for by the Tretheway Creek fixed interest rate of 4.99% for its 40-year term loan. In 2013, other net revenues included a $3.3 million realized loss on the Northwest Stave River bond forwards that was partially offset by a $2.0 million claims settlement received.

Depreciation and Amortization

For the year ended December 31, 2014, depreciation and amortization expenses totalled $74.1 million ($69.2 million in 2013). This increase is attributable mainly to the larger asset base resulting from the addition of the Magpie and SM-1 hydroelectric facilities and the start of operations of the Kwoiek Creek and Northwest Stave River hydroelectric facilities.

Share of Loss (Earnings) of Joint Ventures

For the year ended December 31, 2014, the Corporation recorded a share of loss of joint ventures of $0.7 million (share of earnings of joint ventures of $6.1 million in 2013). Please refer to the "Investments in Joint Ventures" section for more information.

Derivative Financial Instruments

The Corporation uses derivative financial instruments to manage its exposure to the risk of rising interest rates on its existing and upcoming debt financing and its exposure to the risk of rising foreign currencies on its equipment purchases (“Derivatives”), thereby protecting the economic value of its projects. Innergex also has derivative financial instruments embedded in some of its PPAs (the minimum 3% inflation clause applied to the selling price). The Corporation does not own or issue financial instruments for speculative purposes. Since bond forwards are linked to long-term bonds and interest rate swaps are entered into for a term equal in length to the underlying debt amortization schedule, which can reach 30 years, a Derivative's fair market value can be very sensitive to quarter-to-quarter changes in long-term interest rates.

Since October 2014, the Corporation has used hedge accounting in the treatment of new derivative financial instruments in order to reduce the fluctuations in net earnings or losses resulting from unrealized gains or losses on these derivative financial instruments during a given period. Under hedge accounting, most of the unrealized gains or losses on Derivatives that arise from a decrease or increase in the benchmark interest rate will be recorded in other comprehensive income, while only the portion of the unrealized gain or loss related to the "ineffectiveness" of the Derivate will be recorded in net earnings.

For the year ended December 31, 2014, the Corporation recognized an unrealized net loss on derivative financial instruments of $121.7 million due mainly to the decrease in benchmark interest rates since the end of 2013. For the corresponding period last year, Innergex recognized an unrealized net gain on derivative financial instruments of $45.2 million, due mainly to the increase in benchmark interest rates since December 31, 2012.

For the year ended December 31, 2014, the Corporation recognized a $1.2 million unrealized net loss on foreign exchange forward contracts, which are used to secure the exchange rate on planned equipment purchases for the Mesgi'g Ugju's'n wind project. These contracts will expire during 2015, which will result in a realized gain or loss on derivative financial instruments; this gain or loss will serve to offset higher or lower equipment costs for the project. The Corporation also has foreign exchange forward contracts embedded in the turbine supply agreement for an amount equivalent to offset the foreign exchange forward contracts.

In January 2014, the Corporation completed a hedging program to fix the interest rate on future project-level debt for the Upper Lillooet River, Boulder Creek, Tretheway Creek and Big Silver Creek Development Projects. In April 2014, the Corporation completed a hedging program to fix the interest rate on the future project-level debt for the Mesgi'g Ugju's'n Development Project. In September 2014, the Corporation closed a $92.9 million financing and concurrently settled the corresponding bond forward contracts for the Tretheway Creek hydroelectric project . As at the date of this MD&A, the Corporation had entered into derivative financial instruments totalling $535.0 million. Upon the closing of each fixed-rate or interest-swapped long-term financing, the Corporation will settle the corresponding derivative financial instruments, which will result in a realized gain or loss on derivative financial instruments. These gains or losses will serve to offset a higher or lower interest rate on the project-level debt. In the case of the Tretheway Creek project financing, the realized net loss of $8.4 million is offset by the lower interest rate of 4.99% on the project debt. As at December 31, 2014, the Derivatives to be settled upon the closing of financing had a negative market value of $90.5 million.

(Recovery of) Income Tax Expense

For the year ended December 31, 2014, the Corporation recorded a current income tax expense of $3.0 million ($2.6 million in 2013) and a deferred income tax recovery of $29.9 million (income tax expense of $18.2 million in 2013). The difference in the deferred income tax is due primarily to a realized loss and an unrealized net loss on derivative financial instruments, compared with a lower realized loss and an unrealized net gain on derivative financial instruments for the same period last year.

Net (Loss) Earnings

For the year ended December 31, 2014, the Corporation recorded a net loss of $84.4 million (basic and diluted net loss of $0.63 per share), compared with a net earnings of $45.4 million (basic and diluted net earnings of $0.43 per share) in 2013.

Main items contributing to the net loss for the year ended December 31, 2014, compared with the net earnings for the corresponding period in 2013		
Main items – Positive impact	Change	Explanation
Revenues	43,575	Due mainly to the increase in production from the greater number of facilities in operation.
Deferred recovery of income tax	48,129	Due mainly to a realized loss and an unrealized net loss on derivative financial instruments in 2014, compared with a smaller realized loss and an unrealized net gain on derivative financial instruments in 2013.
Main items – Negative impact	Change	Explanation
Unrealized net loss on derivative financial instruments	166,934	Due mainly to a decrease in benchmark interest rates during the year, compared with an increase in benchmark interest rates during the same period last year.
Finance costs	21,379	Due mainly to the expensing of interest on the Kwoiek Creek and Northwest Stave River loans following their commissioning, the addition of project-level debt related to Magpie and SM-1 and higher inflation compensation interest on the real return bond.
Other net expenses (revenues)	8,189	Due mainly to a greater realized net loss on derivatives resulting from the settlement of the Tretheway Creek bond forwards upon closing of the project financing during the third quarter of 2014, compared with a smaller realized net loss on the Northwest Stave River bond forwards and the receipt of a claim settlement in 2013.

Non-controlling Interests

Non-controlling interests are related to the six hydroelectric facilities of the Harrison Hydro Limited Partnership, the Creek Power Inc. subsidiaries, the Kwoiek Creek Resources Limited Partnership, the Mesgi'g Ugju's'n (MU) Wind Farm, L.P., the Magpie Limited Partnership, the Innergex Sainte-Marguerite S.E.C. entity and their respective general partners. For the year ended December 31, 2014, the Corporation allocated losses of $29.5 million to non-controlling interests (losses of $2.7 million in 2013). Please refer to the "Non-Wholly Owned Subsidiaries" section for more information.

Number of Shares Outstanding

Weighted average number of common shares outstanding (000s)	Year ended December 31	
	2014	2013
Weighted average number of common shares	98,341	94,694
Effect of dilutive elements on common shares[1]	210	86
Diluted weighted average number of common shares	98,551	94,780

1. For the year ended December 31, 2014, 1,640,000 of 3,470,684 stock options (2,013,420 of 3,073,684 in 2013) and 7,558,684 shares that can be issued on conversion of convertible debentures (7,558,684 in 2013) were excluded from the calculation of the diluted weighted average number of shares outstanding as the exercise price was above the common shares' average market price.

As at December 31, 2014, the Corporation had a total of 100,672,000 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares, 2,000,000 Series C Preferred Shares and 3,470,684 stock options outstanding. As at December 31, 2013, it had 95,654,911 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares, 2,000,000 Series C Preferred Shares and 3,073,684 stock options outstanding. The increase in the number of common shares since December 31, 2013, is attributable mainly to the issuance of 4,027,051 shares following the SM-1 acquisition and to the Dividend Reinvestment Plan ("DRIP").

As at the date of this MD&A, the Corporation had a total of 100,929,613 common shares, 80,500 convertible debentures, 3,400,000 Series A Preferred Shares, 2,000,000 Series C Preferred Shares and 3,470,684 stock options outstanding. The increase in the number of common shares since December 31, 2014, is attributable to the DRIP.

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

LIQUIDITY AND CAPITAL RESOURCES

For the year ended December 31, 2014, the Corporation generated cash flows from operating activities of $87.6 million, compared with $122.3 million for the same period last year. During this period, the Corporation generated funds from financing activities of $201.0 million and used funds for investing activities of $268.4 million, mainly to pay for the construction of its five Development Projects and the acquisition of the SM-1 hydroelectric facility. As at December 31, 2014, the Corporation had cash and cash equivalents amounting to $54.6 million, compared with $34.3 million as at December 31, 2013.

Cash Flows from Operating Activities

For the year ended December 31, 2014, cash flows generated by operating activities totalled $87.6 million ($122.3 million generated in 2013). The change is attributable mainly to a negative net change of $43.5 million in non-cash operating working capital items.

Cash Flows from Financing Activities

For the year ended December 31, 2014, cash flows generated by financing activities totalled $201.0 million ($5.4 million used in 2013). The change is attributable mainly to a $256.7 million net increase in long-term debt, reflecting drawings on the revolving term credit facility to pay for construction activity of the five Development Projects as well as the addition of the Tretheway Creek project-level debt and the SM-1 subordinate debenture.

Use of Financing Proceeds	Year ended December 31	
	2014	2013
Proceeds from issuance of long-term debt	379,901	186,627
Repayment of long-term debt	(120,590)	(145,321)
Payment of deferred financing costs	(2,580)	(3,066)
Generation of financing proceeds	256,731	38,240
Payment of other liabilities	(361)	—
Payment of issuance cost of common and preferred shares	(82)	(353)
Cash acquired on business acquisitions	—	1,885
Business acquisitions	(38,368)	(28,577)
(Increase) decrease in restricted cash and short-term investments	(36,062)	38,066
Loans to related parties	—	(6,798)
Net funds withdrawn from the reserve accounts	6,538	527
Additions to property, plant and equipment	(205,460)	(103,680)
Additions to intangible assets	—	(27)
Additions to project development costs	(24,955)	(27,799)
Withdrawals from (investments in) joint ventures	2,259	(2,923)
Reductions (additions) to other long-term assets	27,480	(2,962)
Net use of financing proceeds	(269,011)	(132,641)
Reduction of working capital	(12,280)	(94,401)

In the year ended December 31, 2014, the Corporation borrowed $379.9 million to pay for construction of the Upper Lillooet River, Boulder Creek, Tretheway Creek, and Big Silver Creek projects, for the pre-construction development of the Mesgi'g Ugju's'n project and for the acquisition of the SM-1 hydroelectric facility and to repay long-term debts. It also increased restricted cash by $36.1 million, as use of cash to pay for construction costs related to the Kwoiek Creek and Northwest Stave River facilities was more than offset by the addition $49.1 million corresponding to the unused proceeds from the Tretheway Creek project financing. During the corresponding period of 2013, the Corporation borrowed $186.6 million and used $94.4 million of its working capital to pay for the construction of the Gros-Morne, Kwoiek Creek and Northwest Stave River projects, for the pre-construction activities related to its Development Projects and for the acquisition of the Magpie hydroelectric facility and to repay long-term debts and to reduce drawings under the revolving term credit facility.

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

Cash Flows from Investing Activities

For the year ended December 31, 2014, cash flows used by investing activities amounted to $268.4 million ($132.2 million in 2013). During this period, additions to property, plant and equipment accounted for a $205.5 million outflow ($103.7 million outflow in 2013), an increase in restricted cash and short-term investments accounted for a $36.1 million outflow ($38.1 million inflow in 2013), additions to project development costs accounted for a $25.0 million outflow ($27.8 million outflow in 2013) and the acquisition of the SM-1 hydroelectric facility accounted for a $38.4 million outflow ($28.6 million outflow in 2013 for the acquisition of Magpie). These items were partly offset by a decrease in other long-term assets, which accounted for a $27.5 million inflow ($3.0 million outflow in 2013) due mainly to the reimbursement of the loan to the seller of SM-1, by a withdrawal of funds from the reserve accounts, which accounted for a $6.5 million inflow ($0.5 in 2013), and by a reduction in investments in joint ventures, which accounted for a $2.3 million inflow ($2.9 million outflow in 2013).

Cash and Cash Equivalents

For the year ended December 31, 2014, cash and cash equivalents increased by $20.3 million (decreased by $15.2 million in 2013) as a net result of its operating, financing and investing activities. As at December 31, 2014, the Corporation had cash and cash equivalents amounting to $54.6 million ($34.3 million as at December 31, 2013).

DIVIDENDS

The following dividends were declared by the Corporation:

	Year ended December 31	
	2014	2013
Dividends declared on common shares[1]	59,549	54,967
Dividends declared on common shares ($/share)[1]	0.60	0.58
Dividends declared on Series A Preferred Shares	4,250	4,250
Dividends declared on Series A Preferred Shares ($/share)	1.25	1.25
Dividends declared on Series C Preferred Shares[2]	2,875	3,141
Dividends declared on Series C Preferred Shares ($/share)[2]	1.437500	1.570425

1. On February 25, 2014, the Board of Directors increased the annual dividend from $0.58 to $0.60 per common share, payable quarterly. On June 20, 2014, the Corporation issued 4,027,051 new common shares to pay for the acquisition of the SM-1 hydroelectric facility.
2. The initial dividend payment in the first quarter of 2013 was higher to reflect dividends accrued since the closing date of the Series C Preferred Share offering of December 11, 2012. The regular annual dividend amount is $1.4375.

The following dividends will be paid by the Corporation on April 15, 2015:

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
02/24/2015	3/31/2015	4/15/2015	0.1550	0.3125	0.359375

On February 24, 2015, the Board of Directors increased the annual dividend that the Corporation intends to distribute from $0.60 to $0.62 per common share, payable quarterly.

FINANCIAL POSITION

As at December 31, 2014, the Corporation had $2,716 million in total assets, $2,154 million in total liabilities, including $1,645 million in long-term debt, and $562 million in shareholders' equity.

Also at December 31, 2014, the Corporation had a working capital ratio of 0.91:1.00 (1.18:1.00 as at December 31, 2013). In addition to cash and cash equivalents amounting to $54.6 million, the Corporation had restricted cash and short-term investments of $85.8 million and reserve accounts of $41.3 million at the year-end.

The explanations below highlight the most significant changes in balance sheet items during the year ended December 31, 2014.

Assets

Highlights of significant changes in total assets during the year ended December 31, 2014

- A $56.4 million net increase in cash and cash equivalents and restricted cash and short-term investments, due mainly to the addition of the Tretheway Creek project-level debt, which more than offset the amounts drawn to pay for construction of the Kwoiek Creek and Northwest Stave River projects;
- A $15.5 million increase in accounts receivable, as explained in the "Working Capital Items" section below;
- A $312.4 million increase in property, plant and equipment, due mainly to construction of the Tretheway Creek, Boulder Creek, Upper Lillooet River and Big Silver Creek projects and to the addition of the SM-1 hydroelectric facility acquired in June 2014;
- A $21.2 million increase in intangible assets, due mainly to the transfer of the Big Silver Creek project out of project development costs and into property, plant and equipment and intangible assets now that construction of the project has begun and to the addition of the SM-1 hydroelectric facility acquired in June 2014;
- A $20.6 million decrease in project development costs, due mainly to the transfer of the Big Silver Creek project out of project development costs and into property, plant and equipment and intangible assets now that construction of the project has begun; and
- A $27.5 million decrease in other long-term assets, due mainly to the reimbursement of the $25.0 million loan to the seller of SM-1, plus accrued interest, concurrent with the closing of the acquisition of the SM-1 hydroelectric facility in June 2014.

Working Capital Items

As at December 31, 2014, working capital was negative at $17.4 million with a working capital ratio of 0.91:1.00. As at December 31, 2013, working capital was positive at $19.1 million with a working capital ratio of 1.18:1.00. The decrease in the working capital ratio over this period is due to a $6.8 million decrease in loans to related parties and a $4.6 million decrease in the current portion of derivative financial instrument assets, a $91.2 million increase in the current liability portion of derivative financial instruments and a $7.2 million increase in the current portion of long-term debt, which are explained separately below. These items were partly offset by a $36.1 million increase in restricted cash and short-term investments, a $15.5 million increase in accounts receivable, a $20.3 million increase in cash and cash equivalents and a $2.7 million decrease in accounts payable, also explained separately below.

The Corporation considers its current level of working capital to be sufficient to meet its needs. The Corporation can also use its $475.0 million revolving term credit facility if necessary. As at December 31, 2014, the Corporation had drawn $321.9 million and US$13.9 million as cash advances, while $31.1 million had been used for issuing letters of credit.

Restricted cash and short-term investments are related to the Harrison Hydro L.P., the Kwoiek Creek loan, the Northwest Stave River loan and the Tretheway Creek loan. As at December 31, 2014, restricted cash and short-term investments amounted to $85.8 million, of which $6.7 million was related to the Harrison Hydro L.P., $23.5 million to the Kwoiek Creek loan, $6.5 million to the Northwest Stave River loan and $49.1 million to the Tretheway Creek loan ($49.7 million as at December 31, 2013, of which $6.7 million was related to the Harrison Hydro L.P., $31.5 million to the Kwoiek Creek loan and $11.6 million to the Northwest Stave River loan). The increase stems mainly from the addition of the Tretheway Creek loan, which more than offset amounts drawn to pay for construction of the Kwoiek Creek and Northwest Stave River projects.

Accounts receivable increased from $19.8 million as at December 31, 2013, to $35.3 million as at December 31, 2014, due mainly to revenues generated.

Loans to related parties decreased from $6.8 million as at December 31, 2013, to nil as at December 31, 2014, as the Harrison Hydro L.P. declared a distribution during the first quarter of 2014 that resulted in a $6.8 million decrease in loans to related parties and a corresponding decrease in non-controlling interests with no impact on net earnings or cash flows.

Accounts payable and other payables: decreased from $48.3 million as at December 31, 2013, to $45.6 million as at December 31, 2014, due mainly to payments made in relation to the construction of the Kwoiek Creek and Northwest Stave River facilities, partly offset by an increase in accounts payable related to the construction of the Tretheway Creek facility.

Derivative financial instruments included in current liabilities increased from $12.9 million as at December 31, 2013, to $104.1 million as at December 31, 2014, due mainly to the increase in bond forward contracts entered into to hedge the interest rate on future project-level financing for the Development Projects and to the decrease in benchmark interest rates during the year. These short-term Derivatives will be financed upon closing of the long-term project-level debt in the coming months.

Portion of long-term debt included in current liabilities increased from $26.6 million as at December 31, 2013, to $33.8 million as at December 31, 2014, due mainly to the addition of the SM-1 project-level debt and to a cash call from the Harrison Hydro L.P. to its limited partners during the second quarter of 2014.

Reserve Accounts

Reserve accounts consist of a hydrology/wind reserve, established at the start of commercial operation at a facility to compensate for the variability of cash flows related to fluctuations in hydrology or wind regime and to other unpredictable events, and a major maintenance reserve, established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity. The Corporation had $41.3 million in reserve accounts as at December 31, 2014, compared with $47.6 million as at December 31, 2013. The decrease stems mainly from the replacement of certain reserves with less costly letters of credit.

The availability of funds in the hydrology/wind and major maintenance reserve accounts may be restricted by credit agreements.

Property, Plant and Equipment

Property, plant and equipment are comprised mainly of hydroelectric facilities, wind farms and a solar farm that are either in operation or under construction. They are recorded at cost less accumulated depreciation and accumulated impairment losses. The Corporation had $1,896 million in property, plant and equipment as at December 31, 2014, compared with $1,583 million as at December 31, 2013. The increase stems mainly from the ongoing construction of the Upper Lillooet River, Boulder Creek and Tretheway Creek projects, from the transfer out of project development costs and ongoing construction of the Big Silver Creek project and from the addition of the SM-1 hydroelectric facility acquired in June 2014. This increase was partly offset by depreciation.

Intangible Assets

Intangible assets consist of various power purchase agreements, permits and licenses. They also include the extended warranty for the Montagne Sèche and Gros-Morne wind farm turbines. The Corporation had $487.3 million in intangible assets as at December 31, 2014, compared with $466.1 million as at December 31, 2013. The increase stems mainly from the transfer of $23.2 million in intangible assets related to the Big Silver Creek project out of project development costs now that construction of the project has begun and from the addition of $19.2 million in intangible assets related to the SM-1 hydroelectric facility acquired in June 2014. The increase was partly offset by amortization.

Project Development Costs

Project development costs are the costs to acquire and develop Development Projects and to acquire Prospective Projects. Depending on their nature, these costs are transferred either to property, plant and equipment or to intangible assets once the project reaches the construction phase. The Corporation had $61.0 million in project development costs as at December 31, 2014, compared with $81.6 million as at December 31, 2013. The decrease stems mainly from the transfer of the Big Silver Creek project out of project development costs and into property, plant and equipment and intangible assets now that construction of the project has begun, partly offset by pre-construction activities of the Mesgi'g Ugju's'n project.

Investments in Joint Ventures

Investments in joint ventures represent the Corporation's ownership portion of joint ventures, which are accounted for using the equity method. As at December 31, 2014, the Corporation had $14.5 million in investments in joint ventures ($24.6 million as at December 31, 2013). This $10.1 million decrease reflects the recognition of a distribution and a reimbursement of an equity investment made at the joint venture level during the year. Please refer to the "Investments in Joint Ventures" section for more information.

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

Other Long-Term Assets

Other long-term assets consist of security deposits, investments and loans to third parties. The Corporation had $5.8 million in other long-term assets as at December 31, 2014, compared with $33.2 million as at December 31, 2013. The decrease stems mainly from the reimbursement of the $25.0 million loan to the seller of SM-1, plus accrued interest, concurrent with the closing of the acquisition of the SM-1 hydroelectric facility in June 2014.

Liabilities and Shareholders' Equity

Derivative Financial Instruments and Risk Management

The Corporation uses derivative financial instruments to manage its exposure to the risk of increasing interest rates on its debt financing and its exposure to the risk of rising foreign currencies on its equipment purchases. The Corporation does not own or issue any Derivatives for speculation purposes. Since October 2014, the Corporation has used hedge accounting in the treatment of new derivative financial instruments, in order to reduce the fluctuations in net earnings or losses resulting from unrealized gains or losses on these derivative financial instruments during a given period. Under hedge accounting, most of the unrealized gains or losses on Derivatives that arise from a decrease or increase in the benchmark interest rate will be recorded in other comprehensive income, while only the portion of the unrealized gain or loss related to the "ineffectiveness" of the Derivative will be recorded in net earnings.

Interest rate swap contracts allow the Corporation to eliminate the risk of interest rate increases in actual floating-rate debts, which totalled $510.8 million as at December 31, 2014. Consequently, as at December 31, 2014, interest rate swaps related to outstanding debts combined with the $981.3 million in existing fixed-rate debts and $80.0 million in convertible debentures mean that 91% of outstanding debts, including those of joint ventures, are protected from interest rate increases.

Bond forward contracts allow the Corporation to eliminate the risk of interest rate increases in planned long-term debt that it will need to secure for its Development Projects. As at the date of this MD&A, the Corporation had entered into bond forward contracts totalling $535.0 million ($340.0 million as at December 31, 2013) for the Upper Lillooet River, Boulder Creek, Big Silver Creek and Mesgi'g Ugju's'n Development Projects. Upon closing each fixed-rate or interest-swapped long-term financing, the Corporation will settle the corresponding derivative financial instruments, which will result in a realized gain or loss on derivative financial instruments. These gains or losses will serve to offset a higher or lower interest rate on the project-level debt. In September 2014, the Corporation closed a $92.9 million financing for the Tretheway Creek hydroelectric project. The concurrent settlement of the Tretheway Creek bond forward contracts gave rise to an $8.4 million realized loss on derivative financial instruments. This loss is a result of a decrease in benchmark interest rates between the date the bond forwards were entered into (between August and September 2013) and the settlement date (September 30, 2014) and is compensated by the low fixed interest rate of 4.99% for this 40-year term loan. As at December 31, 2014, the Derivatives to be settled upon closing of the project financings had a negative market value of $90.5 million.

Outstanding Interest Rate Derivative FInancial Instruments	Maturity	Early termination option	December 31, 2014	December 31, 2013
Contracts for which hedge accounting is not used				
Bond forwards, from 2.74% to 3.32% (3.04% to 3.27% in 2013)	2015	None	535,000	340,000
Interest rate swaps, from 3.96% to 4.09%	2015	None	15,000	15,000
Interest rate swap, 4.27%	2016	None	3,000	3,000
Interest rate swaps, 4.27% to 4.41%	2018	None	82,600	82,600
Interest rate swaps, 2.94% to 4.93%, amortizing	2026	None	49,718	52,539
Interest rate swaps, from 3.35% to 3.60%, amortizing	2027	None	37,506	39,807
Interest rate swap, 3.74%, amortizing	2030	None	93,511	97,723
Interest rate swap, 4.22%, amortizing	2030	2016	27,485	28,803
Interest rate swap, 4.25%, amortizing	2031	2016	43,360	45,417
Interest rate swap, 4.61%, amortizing	2035	2025	100,463	102,818
Interest rate swap, 2.85%, amortizing	2041	2016	19,313	19,591
Sub-total			1,006,956	827,298
Contract for which hedge accounting is used				
Interest rate swaps from 2.30% to 2.33%	2024	2019	40,000	—
Total			1,046,956	827,298

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

Foreign exchange forward contracts allow the Corporation to eliminate the risk of foreign exchange increases in planned equipment purchases for its Development Projects in currencies other than the Canadian dollar. As at the date of this MD&A, the Corporation had entered into euro foreign exchange forward contracts totalling $78.4 million (nil at December 31, 2013) to eliminate the risk of a euro appreciation versus the Canadian dollar on equipment purchases for the Mesgi'g Ugju's'n project. These contracts will mature in 2015, resulting in a realized gain or loss on derivative financial instruments that will serve to offset higher or lower equipment costs for the project.

Outstanding Foreign Exchange Derivative FInancial Instruments	Maturity	Early termination option	December 31, 2014	December 31, 2013
Foreign exchange forwards, CAD1.43/Euro	2015	None	78,400	—

Derivatives had a net negative value of $145.8 million at December 31, 2014 (negative $24.4 million at December 31, 2013). This change is due mainly to a decrease in benchmark interest rates since the end of 2013. The estimated impact of a 0.1% interest rate increase would decrease the interest rate derivatives-related liability by $14.6 million. Conversely, a 0.1% interest rate decrease would increase the interest rate derivatives-related liability by $14.9 million. Furthermore, the estimated impact of a $0.01 increase in the value of the Canadian dollar versus the euro would decrease the foreign exchange-related liability by $0.8 million. Conversely, a $0.01 decrease in the value of the Canadian dollar versus the euro would increase the foreign exchange-related liability by $0.8 million. These figures exclude the impact of derivatives used to hedge loans of the Corporation's joint ventures. For information on the impact of derivative financial instruments used in the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

Some interest rate swaps have embedded early termination options that are exercisable only on their underlying debt's maturity date. The triggering of these options could pose a liquidity risk. Should the early termination option be triggered, a presumed realized loss would be offset by the savings realized on future interest expenses, as a negative swap value would be the result of an environment in which interest rates were lower than the rate embedded in the swap.

The Corporation has recorded Derivatives using an estimated credit-adjusted mark-to-market valuation that is determined by increasing the swap-based discount rates used to calculate the estimated mark-to-market valuation by an estimated credit spread for the relevant term and counterparty for each Derivative. In the case of Derivatives that Innergex accounts for as assets (i.e. Derivatives for which the counterparties owe Innergex), the credit spread for the bank counterparty was added to the swap-based discount rate to determine the estimated credit-adjusted value. In the case of Derivatives accounted for as liabilities (i.e. Derivatives for which Innergex owes the counterparties), Innergex's credit spread was added to the swap-based discount rate. As at December 31, 2014, all bond forward contracts, interest rate swaps and foreign exchange forward contracts were accounted for as liabilities and credit spreads from 0.63% to 2.37% were added to the discount rates. The estimated credit-adjusted values of the Derivatives are subject to changes in credit spreads of Innergex and its counterparties.

As at December 31, 2014, the fair market value of the derivative financial instruments related to some PPAs with Hydro-Québec was positive at $5.4 million ($6.6 million as at December 31, 2013). These instruments represent the value attributed to the minimum inflation clauses of 3% per year included in these PPAs.

Accrual for Acquisition of Long-Term Assets

Accrual for acquisition of long-term assets consists of long-term debt commitments that have been secured and will be drawn to finance the Corporation's projects currently under construction or under development. As at December 31, 2014, accrual for acquisition of long-term assets totalled $25.3 million ($9.9 million as at December 31, 2013). The $15.5 million increase results mainly from expenses accruing for the Boulder Creek, Upper Lillooet River and Big Silver Creek projects currently under construction, partly offset by the removal of expenses related to the Tretheway Creek project now that the financing for this project has been secured.

Long-Term Debt

As at December 31, 2014, long-term debt totalled $1,645 million ($1,340 million as at December 31, 2013). The $304.2 million increase results mainly from the addition of the SM-1 debts in the amount of $78.3 million, the addition of the Tretheway Creek debt in the amount of $92.9 million and drawings under the revolving term credit facility to fund construction costs of the Upper Lillooet River, Boulder Creek and Big Silver Creek projects and pre-construction development costs of the Mesgi'g Ugju's'n project until the project-level financing for each of these projects is secured and the revolving term credit facility can be paid down. This increase was partly offset by the scheduled repayment of project-level debts and the reduction of drawings under the revolving term credit facility with the reimbursement of the $25.0 million loan to the seller of SM-1, plus accrued interest of $3.5 million.

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

Since the beginning of the 2014 fiscal year, the Corporation and its subsidiaries have met all the financial and non-financial conditions related to their credit agreements, trust indentures and PPAs, with the exception of the Rutherford Creek facility, which made a distribution to the Corporation while it wasn't meeting one of its financial ratios. The amount was subsequently reimbursed and at no time did the situation constitute a default event. Were they not met, certain financial and non-financial covenants included in the credit agreements or trust indentures 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.

Outstanding Long-term Debt	Effective all-in interest rate	Maturity	Note	Year ended December 31 2014	2013
Prime rate advances		2019		20	20
Bankers' acceptances		2019		321,880	170,480
LIBOR advances, US$13,900		2019		16,125	14,784
Revolving term credit facility	4.85%		i)	338,025	185,284
Term loans					
Harrison Hydro Limited Partnership, term loan	--	2015	ii)	1,750	—
Hydro-Windsor, fixed rate	8.25%	2016	iii)	2,145	3,186
Fitzsimmons Creek, floating rate	3.98%	2016	iv)	21,430	21,791
Magpie, fixed rate	2.33%	2017	v)	850	1,156
Magpie, non-interest bearing debenture	5.30%	2017	vi)	1,094	1,399
Montagne-Sèche, floating rate	5.97%	2021	vii)	27,485	28,803
Rutherford Creek, fixed rate	6.88%	2024	viii)	42,677	45,757
Magpie, fixed rate	6.16%	2025	ix)	5,262	5,497
Ashlu Creek, floating rate	6.14%	2025	x)	96,695	98,822
SM-1, fixed rate	3.30%	2025	xi)	35,899	—
L'Anse-à-Valleau, floating rate	6.03%	2026	xii)	38,716	41,188
Carleton, floating rate	5.41%	2027	xiii)	48,997	51,712
Stardale, floating rate	5.79%	2030	xiv)	101,643	106,220
Magpie, fixed rate	4.37%	2031	xv)	54,452	56,566
Kwoiek Creek, fixed rate	5.08%	2052	xvi)	168,500	168,500
Northwest Stave River, fixed rate	5.30%	2053	xvii)	71,972	71,972
Kwoiek Creek, fixed rate subordinated term loan	10.07%	2054	xviii)	3,662	3,662
Tretheway Creek, fixed rate	4.99%		xix)	92,916	—
SM-1 fixed rate subordinated debenture	8.00%	2064	xx)	42,401	—
Other loans		2017-2019		136	116
Bonds					
Harrison Hydro L.P.'s facilities, real return	5.77%	2049	xxi)	225,014	223,049
Harrison Hydro L.P.'s facilities, fixed rate	6.61%	2049	xxii)	209,485	211,681
Harrison Hydro L.P.'s facilities, real return	6.84%	2049	xxiii)	27,820	27,031
Project-level debt				1,321,001	1,168,108
Deferred financing costs				(14,427)	(13,025)
Total long-term debt				1,644,599	1,340,367
Current portion of long-term debt				(33,799)	(26,649)
Long-term portion of long-term debt				1,610,800	1,313,718

Explanatory notes:

i) a $475.0 million **revolving term credit facility** secured by a first-ranking hypothec on 12 Innergex assets and by various security interests granted by some of its subsidiaries. In November 2014, the Corporation temporarily increased the facility until June 30, 2015, from $425.0 to $475.0 million. The facility will mature in 2019 and is not amortized. Advances are made in the form of bankers' acceptances ("BA"), prime-rate advances, U.S. base-rate advances, LIBOR advances or letters of credit. In all cases, interest is calculated at the prevailing benchmark rate plus an additional margin based on Innergex's ratio of adjusted consolidated senior debt to adjusted EBITDA. As at December 31, 2014, $338.0 million was due under this facility and $31.1 million was used for the issuance of letters of credit; thus the unused and available portion of the revolving credit term facility totalled $105.9 million. The carrying value of the assets of the Corporation and subsidiaries given as securities under this facility is approximately $803.3 million. As at December 31, 2014, the all-in interest rate was 4.85% after accounting for the interest rate swaps;

ii) $3.5 million term loans maturing in 2015 and made by the partners to **Harrison Hydro Limited Partnership**. The partners' loans amounted to $1.75 million at December 31, 2014. The Corporation's loan, which amounted to $1.75 million, was eliminated in the consolidation process. The loans are non-interest bearing;

iii) a 20-year non-recourse term loan maturing in 2016 and secured by the **Hydro-Windsor** hydroelectric facility. The loan is repayable in monthly blended payments of principal and interest totalling $105. The principal payments are set to $1.1 million for 2015. The loan bears interest at an effective fixed interest rate of 8.25%;

iv) a five-year non-recourse term loan maturing in 2016 and secured by the **Fitzsimmons Creek** hydroelectric facility. The loan's monthly principal payments are variable, based on a 30-year amortization period, and are set to $295 for 2015. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2014, the all-in effective interest rate was 3.98% after accounting for the interest rate swap;

v) a $1.2 million bridge loan maturing in 2017 assumed as part of the acquisition of the **Magpie** hydroelectric facility. The loan is repayable in monthly blended payments of principal and interest totaling $27. The principal payments are set to $288 for 2015. The loan was accounted for at its fair market value of $1.3 million on the date of the Magpie acquisition and bears interest at an effective fixed interest rate of 2.33%;

vi) a $2.0 million debenture maturing on December 31, 2017 assumed as part of the acquisition of the **Magpie** hydroelectric facility, bearing no interest and repayable in annual installments of $400. The debenture was accounted for at its fair market value of $1.8 million on the date of the Magpie acquisition and bears interest at an effective rate of 5.30%;

vii) a non-recourse term loan maturing in 2021 and secured by the Corporation's 38% interest in the **Montagne Sèche** wind farm. In May 2014, the credit agreement was amended to extend the loan to 2021 and reduce the applicable credit margin. The loan's quarterly principal payments began on March 31, 2012; they are variable, based on an 18.5-year amortization period, and set to $1.4 million for 2015. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2014, the all-in effective interest rate was 5.97% after accounting for the interest rate swap;

viii) a 20-year non-recourse term loan maturing in 2024 and secured by the **Rutherford Creek** hydroelectric facility. The loan's monthly blended payments of principal and interest totalling $511 began on July 1, 2012. The principal payments are set to $3.3 million for 2015. The loan bears interest at a fixed rate of 6.88%;

ix) a $3.0 million convertible debenture maturing in 2025 assumed as part of the acquisition of the **Magpie** hydroelectric facility. The convertible debenture was accounted for at its fair market value of $5.5 million on the date of the Magpie acquisition for an effective rate of 6.16%. It entitles the Minganie Regional County Municipality to a 30% interest in the facility upon conversion of the debenture on or before January 1, 2025;

x) a 15-year non-recourse term loan maturing in 2025 and secured by the **Ashlu Creek** hydroelectric facility. The loan's quarterly principal payments are variable, based on a 25-year amortization period, and set to $2.5 million for 2015. The loan bears interest at the BA rate or prime-rate plus an applicable credit margin. As at December 31, 2014, the all-in effective interest rate was 6.14% after accounting for the interest rate swaps;

xi) a $30.8 million term loan maturing in 2025 and secured by the **SM-1** hydroelectric facility acquired in June 2014. The loan is repayable in monthly blended payments of principal and interest totalling $360, increasing over the years. The principal payments are set to $2.3 million for 2015. The loan was accounted for at its fair market value of $37.5 million on the date of the SM-1 acquisition and bears interest at an effective rate of 3.30%;

xii) a 18.5-year non-recourse term loan maturing in 2026 and secured by the Corporation's 38% interest in the **L'Anse-à-Valleau** wind farm. The loan's quarterly principal payments are variable, based on an 18.5-year amortization period, and set to $2.6 million for 2015. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2014, the all-in interest rate was 6.03% after accounting for the interest rate swap;

xiii) a 14-year non-recourse term loan secured on June 26, 2013, and maturing in 2027, to refinance the Corporation's 38% interest in the **Carleton** wind farm. The loan's quarterly principal payments are variable, based on a 14-year amortization period starting on June 26, 2013, and set to $3.2 million for 2015. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2014, the all-in effective interest rate was 5.41% after accounting for the interest rate swaps;

xiv) an 18-year non-recourse term loan maturing in 2030 and secured by the **Stardale** solar farm. The loan's quarterly principal payments are variable based on an 18-year amortization period and set to $4.8 million for 2015. The loan bears interest at the BA rate plus an applicable credit margin. As at December 31, 2014, the all-in effective interest rate was 5.79%;

xv) a $49.3 million non-recourse term loan maturing in 2031 and secured by the **Magpie** hydroelectric facility acquired in July 2013. The loan is repayable in monthly blended payments of principal and interest totalling $379. The principal payments are set to $1.6 million for 2015. It was accounted for at its fair market value of $57.4 million on the date of the Magpie acquisition and bears interest at an effective fixed interest rate of 4.37%;

xvi) a $168.5 million non-recourse construction and term loan maturing in 2052 and secured by the **Kwoiek Creek** hydroelectric facility. It was converted into a term loan in February 2015 and the principal will be amortized over a 36-year period, ending in 2052. The loan bears interest at a fixed rate of 5.08%;

xvii) a $72.0 million non-recourse construction and term loan maturing in 2053 and secured by the **Northwest Stave River** hydroelectric facility. It was converted into a term loan in February 2015 and the principal will be amortized over a 35-year period ending in 2053. The loan bears interest at a fixed rate of 5.30%;

xviii) a subordinated non-recourse term loan made by the Corporation's partner to Kwoiek Creek Resources Limited Partnership (“KCRLP”), the owner of the **Kwoiek Creek** hydroelectric project. As per the agreements related to the project, both partners can participate in the financing of the project. The partner's loan made to KCRLP amounted to $3.7 million at December 31, 2014. The Corporation's subordinated non-recourse term loan made to KCRLP, which was eliminated in the financial statement consolidation process, amounted to $56.7 million as at December 31, 2014. These loans bear interest at a rate of 10.07%;

xix) a $92.9 million non-recourse construction and term project financing for the **Tretheway Creek** hydroelectric project. It will convert into a 40-year term loan following the start of the facility's commercial operation and the principal will begin to be amortized over a 35-year period, starting in the sixth year. The loan bears interest at a fixed rate of 4.99%;

xx) a $42.4 million subordinated debenture maturing in 2064 and issued to Desjardins Group Pension Plan by the SM-1 L.P., owner of the **SM-1** hydroelectric facility. The debenture has no predetermined repayment schedule. Initial proceeds at the time of the acquisition of the SM-1 hydroelectric facility were $40.9 million. In December 2014, an additional $1.5 million was subscribed to fund the recently completed capital improvement program at this facility. The debenture bears interest at a fixed rate of 8.0%;

xxi) a senior real return bond maturing in 2049 secured by **Harrison Hydro L.P.'s** facilities. The bond is repayable by semi-annual blended payments of principal and interest totalling $5.8 million before CPI adjustment ($6.5 million including CPI adjustment in 2014). On December 1, 2031, the payment amount decreases to $4.5 million before CPI adjustment. The principal payments are set to $5.5 million including the CPI adjustment for 2015. The bond bears interest at a fixed rate adjusted by an inflation ratio and an inflation compensation interest factor. Both inflation adjustments are based on the non-seasonally adjusted CPI. As at December 31, 2014, the all-in effective interest rate was 5.77%;

xxii) a senior fixed bond maturing in 2049 secured by **Harrison Hydro L.P.'s** facilities. The bond is repayable by semi-annual blended payments of principal and interest totalling $8.1 million. On September 1, 2031, the payment amount decreases to $6.7 million. The principal payments are set to $3.1 million for 2015. The bond bears interest at an effective fixed interest rate of 6.61%;

xxiii) a junior real return bond maturing in 2049 secured by **Harrison Hydro L.P.'s** facilities but second ranking to the bonds described in xxi) and xxii). Quarterly interest payments amount to $291 before CPI adjustment ($328 including CPI adjustment in 2014). Principal payments do not commence until June 1, 2017, on which date the quarterly blended payments of principal and interest will amount to $389 before CPI. The bond bears interest at a fixed rate adjusted by an inflation ratio and an inflation compensation interest factor. Both inflation adjustments are based on the non-seasonally adjusted CPI. As at December 31, 2014, the all-in effective interest rate was 6.84%.

Convertible Debentures

On March 16, 2010, the Corporation completed the issuance of Convertible Debentures for a total notional amount of $80.5 million. As at December 31, 2014, the debt portion of the Convertible Debentures was $80.0 million and the equity portion was $1.3 million ($79.8 million and $1.3 million respectively as at December 31, 2013).

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

The Convertible Debentures bear interest at an annual rate of 5.75% and will mature on April 30, 2017. Each Convertible Debenture is convertible into common shares of the Corporation at the option of the holder at any time prior to the earlier of April 30, 2017, or the redemption date specified by the Corporation. The conversion price is $10.65 per common share, being a conversion rate of approximately 93.8967 common shares per thousand dollars of principal amount of convertible debentures. Holders converting their Convertible Debentures will receive accrued and unpaid interest thereon for the period from the last interest payment date on their Convertible Debentures to the date of conversion. The Convertible Debentures are subordinated to all other indebtedness of the Corporation. For more information about the issuance of the Convertible Debentures, please refer to the *Short Form Prospectus* dated February 25, 2010, available on Innergex's website at www.innergex.com and on the SEDAR website at www.sedar.com.

Preferred Shares

On September 14, 2010, the Corporation issued a total of 3,400,000 Series A Preferred Shares at $25.00 per share for aggregate gross proceeds of $85.0 million. For the initial five-year period up to but excluding January 15, 2016, the holders of Series A Preferred Shares are entitled to receive fixed cumulative preferential cash dividends as and when declared by the Board of Directors. The dividends are payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to $1.25 per share.

On January 15, 2016, and on January 15 every five years thereafter, holders of Series A Preferred Shares have the right to convert all or any of their Series A Preferred Shares into the Series B Preferred Shares of the Corporation on the basis of one Series B Preferred Share for each Series A Preferred Share converted, subject to certain conditions. The holders of Series B Preferred Shares will be entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board of Directors. The dividends on Series B Preferred Shares will be payable quarterly at an annual rate equal to the Treasury Bill rate for the preceding quarterly plus 2.79%, as determined on the 30th day prior to the first day of the applicable quarterly floating rate period, multiplied by $25.00. The Series A Preferred Shares and the Series B Preferred Shares will not be redeemable by the Corporation prior to January 15, 2016.

On December 11, 2012, the Corporation issued a total of 2,000,000 Cumulative Redeemable Fixed-Rate Preferred Shares Series C at $25.00 per share for aggregate gross proceeds of $50.0 million. Holders of the Series C Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends as and when declared by the Board of Directors. The dividends will be payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to $1.4375 per share. The Series C Preferred Shares will not be redeemable by the Corporation prior to January 15, 2018. They do not have a fixed maturity date and are not redeemable at the option of the holders.

The Series A Preferred Shares and the Series C Preferred Shares are rated P-3 by S&P.

For more information about the Series A Preferred Shares, please refer to the *Short Form Prospectus* dated September 7, 2010, and for more information about the Series C Preferred Shares, please refer to the *Short Form Prospectus* dated December 4, 2012, both of which are available on Innergex's website at www.innergex.com and on the SEDAR website at www.sedar.com.

Shareholders' Equity

As at December 31, 2014, the Corporation's shareholders' equity totalled $562.2 million, including $47.4 million of non-controlling interests, compared with $665.9 million, including $81.4 million of non-controlling interests, as at December 31, 2013. This $103.7 million decrease in total shareholders' equity is attributable mainly to the recognition of a $84.4 million net loss and to dividends declared on preferred and common shares of $66.7 million, partly offset by the issuance to the seller of SM-1 of 4,027,051 common shares of the Corporation at a price of $10.36 per share in June 2014 to pay for the acquisition of the SM-1 hydroelectric facility, giving total net proceeds of $41.7 million.

Contractual Obligations

As at December 31, 2014	Total	Under 1 year	1 to 3 years	4 to 5 years	Thereafter
Long-term debt including convertible debentures	1,786,157	34,170	169,156	413,421	1,169,410
Interest on long-term debt and convertible debentures	1,456,248	89,445	167,851	144,150	1,054,802
Others	18,115	1,950	2,919	1,843	11,403
Purchase (Contractual) obligations[1]	558,858	292,419	221,970	3,895	40,574
Total contractual obligations	3,819,378	417,984	561,896	563,309	2,276,189

1. Purchase obligations are derived mainly from engineering, procurement and construction contracts.

Contingencies

An acquisition realized in 2011 provides for the potential payment of additional amounts to the vendors over a period commencing on the acquisition date and ending on the 40th anniversary of the last project under development to achieve commercial operation (or to April 4, 2061, if earlier). The deferred payments are effectively intended to provide for a potential sharing of the value created if the projects perform better than the Corporation expects and would result in incremental accretion to the Corporation net of these payments. The maximum aggregate amount of all deferred payments under this acquisition is limited to a present value amount of $35.0 million as at the acquisition date.

In connection with another acquisition, the Corporation agreed to pay contingent considerations based upon future events for a period of three years after April 20, 2011. In 2014, there was no contingent consideration to be paid in connection with this acquisition.

In connection with the Magpie Acquisition, the Corporation assumed an obligation to pay contingent consideration to the Minganie Regional County Municipality until the convertible debenture issued by Magpie Limited Partnership is converted. Upon conversion, the Minganie Regional County Municipality will be entitled to a participation of 30% in Magpie Limited Partnership.

Off-Balance-Sheet Arrangements

As at December 31, 2014, the Corporation had issued letters of credit totalling $43.3 million to meet its obligations under its various PPAs and other agreements. Of this amount, $31.1 million was issued under its revolving term credit facility and the remainder under the projects' non-recourse credit facilities. As at that date, Innergex had also issued a total of $11.0 million in corporate guarantees to support the construction of the Gros-Morne wind farm and the performance of the Brown Lake hydroelectric facility.

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

FREE CASH FLOW AND PAYOUT RATIO

Free Cash Flow

When evaluating its operating results, a key performance indicator for the Corporation is the cash flows available for distribution to common shareholders and for reinvestment to fund the Corporation's growth. Free Cash Flow is a non-IFRS measure that the Corporation calculates as 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 and preferred share dividends declared. It also subtracts the portion of Free Cash Flow attributed to non-controlling interests regardless of whether an actual distribution to non-controlling interests is made in order to reflect the fact that such distribution may not occur in the period the Free Cash Flow is generated, and adds back cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to other facilities owned by the Corporation over the course of their PPAs. The Corporation also adjusts for other elements that represent cash inflows or outflows that are not representative of the Corporation's long-term cash generating capacity. Such adjustments include adding back transaction costs related to realized acquisitions (which are financed at the time of the acquisition) and adding back realized losses or subtracting realized gains on derivative financial instruments used to hedge the interest rate on project-level debt prior to securing such debt.

Free Cash Flow and Payout Ratio calculation	Year ended December 31		
	2014	2013	2012
			(restated)[4]
Cash flows from operating activities	87,578	122,286	60,907
Add (Subtract) the following items:			
Changes in non-cash operating working capital items	13,218	(30,283)	(601)
Maintenance capital expenditures net of proceeds from disposals	(2,851)	(2,441)	(2,788)
Scheduled debt principal payments	(29,190)	(26,520)	(19,996)
Free Cash Flow attributed to non-controlling interests[1]	(4,865)	(5,453)	(5,666)
Dividends declared on Preferred shares	(7,125)	(7,391)	(4,250)
Cash receipt for wheeling services to be provided by the Harrison Hydro L.P. to other facilities[2]	2,092	4,916	—
Adjust for the following elements:			
Transaction costs related to realized acquisitions	521	609	2,164
Realized losses on derivative financial instruments	8,366	3,259	14,127
Free Cash Flow	67,744	58,982	43,897
Dividends declared on common shares	59,549	54,967	50,693
Payout Ratio - before the impact of the DRIP	88%	93%	115%
Dividends declared on common shares and paid in cash[3]	49,358	36,982	47,758
Payout Ratio - after the impact of the DRIP	73%	63%	109%

1. The portion of Free Cash Flow attributed to non-controlling interests is subtracted, regardless of whether or not 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.
2. The $2.1 million and $4.9 million represent cash receipts by the Harrison Hydro L.P. for the wheeling services to be provided to the Tretheway Creek and Northwest Stave River facilities respectively, 49.99% of which was included in the Free Cash Flow attributed to non-controlling interests.
3. Represents dividends declared on common shares outstanding that were not registered in the DRIP at the time of the declaration; the dividends declared on common shares registered in the DRIP were paid in common shares.
4. The 2012 financial statements were restated following the adoption in 2013 of IFRS 11 Joint Arrangements.

For the year ended December 31, 2014, the Corporation generated Free Cash Flow of $67.7 million, compared with $59.0 million for the same period last year. This increase is due mainly to higher Adjusted EBITDA, partly offset by higher finance costs.

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

Payout Ratio

The Payout Ratio represents the dividends declared on common shares divided by Free Cash Flow. The Corporation believes it is a measure of its ability to sustain current dividends and dividend increases as well as its ability to fund its growth.

For the year ended December 31, 2014, the dividends on common shares declared by the Corporation corresponded to 88% of Free Cash Flow, compared with 93% for the corresponding prior 12-month period. This positive change is due mainly to the increase in Free Cash Flow explained above, which more than offset the increase in dividends resulting from the higher number of common shares outstanding by virtue of the DRIP and from the issuance of 4,027,051 common shares of the Corporation in June 2014 to pay for the acquisition of the SM-1 hydroelectric facility.

The Payout Ratio reflects the Corporation's decision to invest each year in advancing the development of its Prospective Projects, 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. For the year ended December 31, 2014, the Corporation incurred prospective project expenses of $5.7 million, compared with $4.2 million for the corresponding prior period. This 36% increase is attributable mainly to the recent request for proposals in Quebec and the current request for proposals in Ontario. Excluding these discretionary expenses, the Corporation's Payout Ratio would be approximately 7% lower for the year ended December 31, 2014, and approximately 6% lower for the corresponding prior period.

Furthermore, the Corporation does not expect to require additional equity in order to complete its current five Development Projects, given the anticipated increase in cash flows from operations once these projects have been commissioned, the project-level financing that the Corporation intends to secure for these projects and the additional equity provided by the DRIP.

On February 24, 2015, the Board of Directors increased the annual dividend that the Corporation intends to distribute from $0.60 to $0.62 per common share, payable quarterly.

PROJECTED FINANCIAL PERFORMANCE

As at the date of this MD&A, the Corporation has 33 Operating Facilities with a net installed capacity of 687 MW (gross 1,194 MW) and annualized consolidated long-term average production of 3,050 GWh. The Corporation is also pursuing the development of five Development Projects with power purchase agreements.

Outlook for 2015

	2015		2014		2013	
Power Generated (GWh)	approx.	+3-5%	2,962	+24%	2,382	+13%
Revenues	approx.	+3-5%	241,834	+22%	198,259	+12%
Adjusted EBITDA	approx.	+1%	179,562	+21%	148,916	+11%
Number of facilities in operation	34		33		32	
Net installed capacity (MW)	708		687		672	
Consolidated LTA production, annualized (GWh)	3,130		3,050		2,883	

The increase in installed capacity and in the number of facilities in operation in 2015 reflects the expected commissioning of the Tretheway Creek hydroelectric facility before year-end. Projected increases in production and revenues reflect production levels in line with the long-term average as well as the full-year contribution of the SM-1 hydroelectric facility acquired in June 2014. The more modest increase in Adjusted EBITDA reflects a significant increase in expected Prospective Project expenses as the Corporation will fund its expansion into target markets internationally.

Outlook for 2017

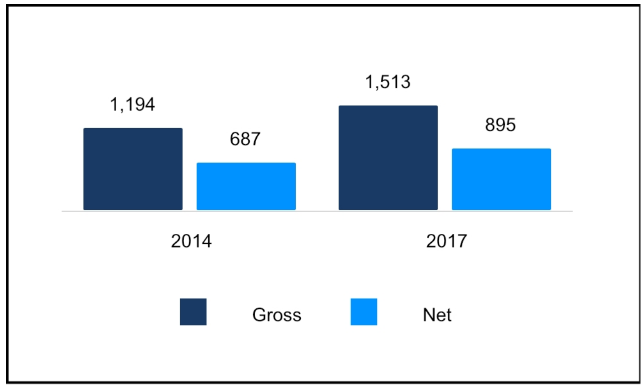
The Corporation makes certain projections to provide readers with an indication of its business activities and operating performance once the five existing Development Projects have been commissioned. Please refer to the "Development Projects" section for more information on these projects. These projections do not take into account possible acquisitions, divestments or additional Development Projects following the award of any new power purchase agreements.

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

Projected Installed Capacity

The Corporation believes that installed capacity provides a good indication of the size and magnitude of its operations. Once the five existing Development Projects have been commissioned, the Corporation expects its net installed capacity to increase from 687 MW (gross 1,194 MW) at the date of this MD&A to 895 MW (gross 1,513 MW) at the end of 2016, corresponding to a 30% increase (gross 27%). Net installed capacity reflects the fact that some of the Corporation's Operating Facilities are not wholly-owned. Installed capacity includes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method.

Gross and Net Installed Capacity (MW)



Projected Long-Term Average Production (LTA)

A key performance indicator for the Corporation is to compare actual electricity generation with the expected LTA production for each facility. Once the five existing Development Projects have been commissioned, the Corporation expects its annualized consolidated LTA production to increase from 3,050 GWh at the date of this MD&A to 4,211 GWh starting in 2017, corresponding to a 38% increase. Consolidated LTA production is presented in accordance with revenue recognition accounting rules under IFRS and excludes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method.

Annualized Consolidated LTA Production

	As at the date of this MD&A	Starting in 2017
Hydro	2,334.9	2,982.2
Wind	676.5	1,191.5
Solar[1]	38.2	37.6
Total	3,049.5	4,211.3

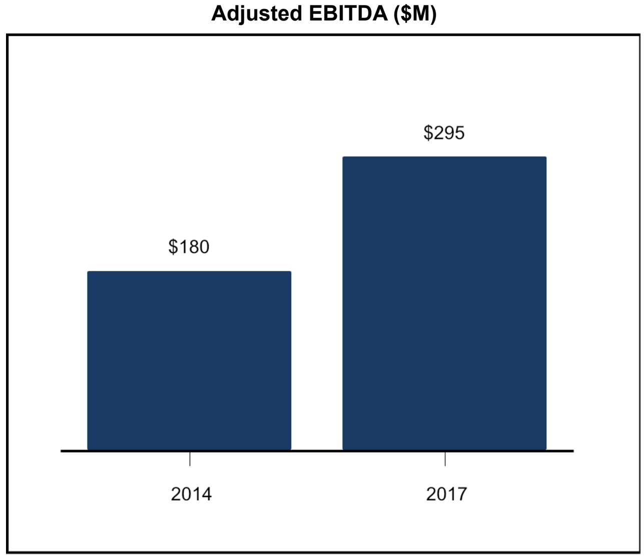
1. Solar farm LTA diminishes over time due to expected solar panel degradation

Projected Adjusted EBITDA

A key performance indicator for the Corporation is Adjusted EBITDA generation. Once the five Development Projects have been commissioned, the Corporation expects to generate annualized Adjusted EBITDA starting in 2017 of approximately $295.0 million (adjusted for an inflation component thereafter), compared with $179.6 million in 2014. This represents an annual compound growth rate of approximately 18% for the 2014-2017 period. Adjusted EBITDA is presented in accordance with revenue recognition accounting rules under IFRS and excludes the Umbata Falls and Viger-Denonville facilities that are treated as joint ventures and accounted for using the equity method. The annual Adjusted EBITDA for these facilities combined attributable to the Corporation is approximately $8.0 million.

It should be noted that Adjusted EBITDA does not take into account the impact of interest and principal payments on the Corporation's existing debt and on the project-level debt financing it expects to put in place to finance the construction of its five Development Projects.

Adjusted EBITDA ($M)

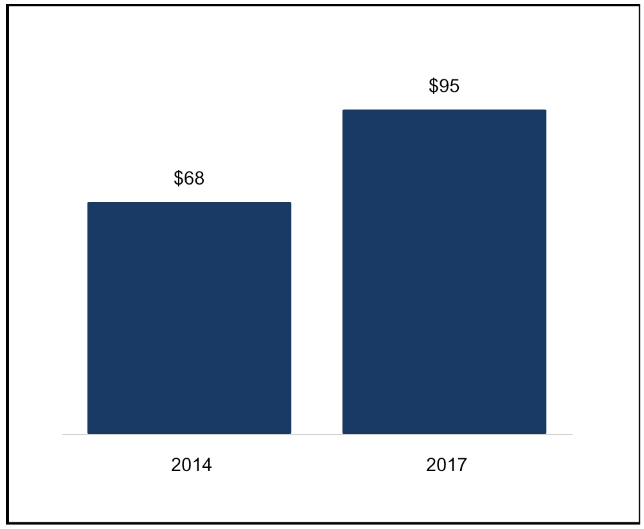


Projected Free Cash Flow

Another key performance indicator for the Corporation is the Free Cash Flow generated from its operations and available for distribution to common shareholders and for reinvestment to fund its growth. Once the five existing Development Projects have been commissioned, the Corporation expects to generate Free Cash Flow in 2017 of approximately $95.0 million, compared with $67.7 million in 2014. This represents an annual compound growth rate of approximately 12% for the 2014-2017 period and will reflect the cash flows generated by the Corporation's 38 Operating Facilities at that time, after taking into account maintenance capital expenditures, scheduled debt principal payments, preferred share dividends and the portion of Free Cash Flow attributed to non-controlling interests.

For more information on the principal assumptions used in determining projected financial information and the principal risks and uncertainties related thereto, please refer to the "Forward-Looking Information" section.

Free Cash Flow ($M)



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

SEGMENT INFORMATION

Geographic Segments

As at December 31, 2014, the Corporation had interests in 25 hydroelectric facilities, six wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the year ended December 31, 2014, the revenues generated by the Horseshoe Bend hydroelectric facility in the United States totalled $3.4 million ($3.0 million in 2013), corresponding to a contribution of 1.4% (1.5% in 2013) to the Corporation's consolidated revenues for this period. The increase is due mainly to improved water flows and higher selling prices, compared with the same period last year.

Operating Segments

As at December 31, 2014, the Corporation had four operating segments: hydroelectric generation, wind power generation, solar power generation and site development.

Through its hydroelectric, wind power and solar power generation segments, the Corporation sells electricity produced by its hydroelectric, wind and solar facilities to publicly owned utilities or other creditworthy counterparties. Through its site development segment, Innergex analyzes potential sites and develops hydroelectric, wind and solar facilities up to the commissioning stage.

The accounting policies for these segments are the same as those described in the “Significant Accounting Policies” section of the Corporation's audited consolidated financial statements for the year ended December 31, 2014. The Corporation evaluates performance based on Adjusted EBITDA and accounts for inter-segment and management sales at cost. Any transfers of assets from the site development segment to the hydroelectric, wind or solar power generation segments are accounted for at cost.

The operations of the Corporation's operating segments are conducted by different teams, as each segment has different skill requirements.

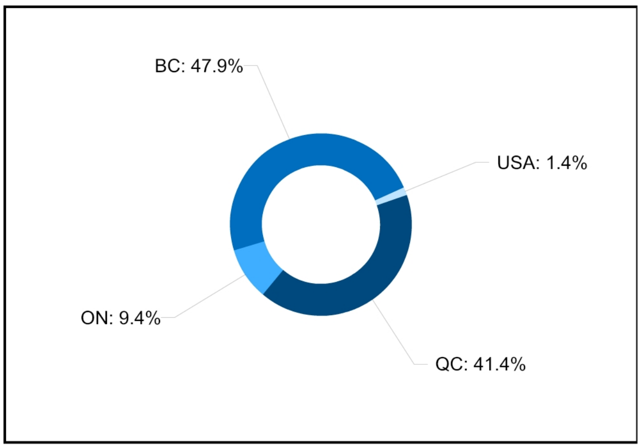
SUMMARY OPERATING RESULTS Year ended December 31, 2014	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Power generated (MWh)	2,245,224	677,107	40,119	—	2,962,450
Revenues	171,029	53,971	16,834	—	241,834
Expenses:					
Operating expenses	30,828	9,538	1,146	—	41,512
General and administrative expenses	8,205	3,798	159	2,902	15,064
Prospective project expenses	—	—	—	5,696	5,696
Adjusted EBITDA	131,996	40,635	15,529	(8,598)	179,562
Year ended December 31, 2013					
Power generated (MWh)	1,655,371	686,380	40,069	—	2,381,820
Revenues	126,932	54,499	16,828	—	198,259
Expenses:					
Operating expenses	22,849	9,939	1,159	—	33,947
General and administrative expenses	7,373	2,140	317	1,364	11,194
Prospective project expenses	—	—	—	4,202	4,202
Adjusted EBITDA	96,710	42,420	15,352	(5,566)	148,916

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

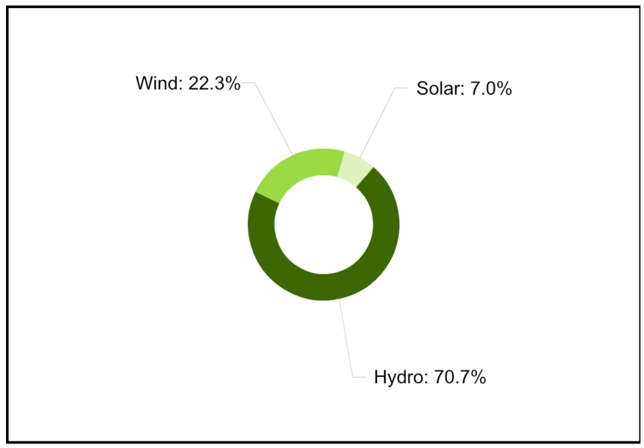
SUMMARY BALANCE SHEET As at December 31, 2014	Hydroelectric Generation	Wind Power Generation	Solar Power Generation	Site Development	Total
Goodwill	8,269	—	—	—	8,269
Total assets	1,752,495	352,723	120,957	489,840	2,716,015
Total liabilities	1,241,530	238,450	111,814	561,996	2,153,790
Acquisition of property, plant and equipment during the year	123,185	549	161	223,405	347,300
As at December 31, 2013					
Goodwill	8,269	—	—	—	8,269
Total assets	1,449,527	387,062	128,146	412,339	2,377,074
Total liabilities	949,570	248,594	116,085	396,890	1,711,139
Acquisition of property, plant and equipment during the year	66,581	1,213	100	89,501	157,395

Breakdown of 2014 Revenues

By Region



By Operating Segment



Hydroelectric Generation Segment

For the year ended December 31, 2014, this segment produced 100% of the LTA and generated revenues of $171.0 million, compared with production at 93% of the LTA and revenues of $126.9 million for the same period last year. Water flows varied from quarter to quarter and for the year overall were in line with the average in Quebec and British Columbia, above average in Ontario and slightly below average at the United States facility. In British Columbia in particular, high amounts of precipitations during the fourth quarter resulted in above-average water flows, which offset below-average water flows experienced during the first three quarters. The revenue increase of 35% stems mainly from production reaching the LTA and from the full-year contribution of the Magpie facility acquired in July 2013, the addition of the Kwoiek Creek and Northwest Stave River facilities commissioned at the end of 2013 and the addition of the SM-1 facility acquired in June 2014.

The increase in total assets since December 31, 2013, is attributable mainly to the increase in property, plant and equipment relating to the transfer of the Kwoiek Creek facility from the Site Development segment and the addition of the SM-1 facility acquired in June 2014, partly offset by depreciation of property, plant and equipment and amortization of intangible assets.

The increase in total liabilities since December 31, 2013, is attributable mainly to the transfer of the Kwoiek Creek loan from the Site Development segment, the addition of the SM-1 facility and the increase in derivative financial instruments resulting from a decrease in the benchmark interest rate during the year, partly offset by the scheduled repayment of long-term debt.

Wind Power Generation Segment

For the year ended December 31, 2014, this segment produced 100% of the LTA and generated revenues of $54.0 million, compared with production at 101% of the LTA and revenues of $54.5 million for the same period last year. This level of production stems mainly from wind regimes in line with the average for the year overall, as above-average wind regimes during the first and third quarters offset below-average wind regimes during the second and fourth quarters. The relatively stable revenues stems mainly from production levels and prices that were similar to those for the same period last year.

The decrease in total assets since December 31, 2013, is attributable mainly to depreciation of property, plant and equipment and amortization of intangible assets.

The decrease in total liabilities since December 31, 2013, is attributable mainly to the scheduled repayment of long-term debt.

Solar Power Generation Segment

For the year ended December 31, 2014, this segment produced 104% of the LTA and generated revenues of $16.8 million, compared with production at 103% of the LTA and revenues of $16.8 million for the same period last year. This production level stems from above-average solar regimes during the first three quarters of the year, which offset below-average solar regimes during the fourth quarter. The relatively stable revenues stem mainly from production levels and prices that were similar to those for the same period last year.

The decrease in total assets since December 31, 2013, results mainly from depreciation of property, plant and equipment and from amortization of intangible assets.

The decrease in total liabilities since December 31, 2013, results mainly from scheduled repayment of long-term debt.

Site Development Segment

For the year ended December 31, 2014, site development expenses were $8.6 million, compared with $5.6 million in 2013. The increase is due mainly to higher prospective project expenses related to the 2014 request for proposals in Quebec and the ongoing request for proposals in Ontario.

The increase in total assets since December 31, 2013, is attributable mainly to payments made for costs incurred for the construction of the Upper Lillooet River, Boulder Creek, Tretheway Creek and Big Silver Creek projects and pre-construction activities of the Mesgi'g Ugju's'n project, partly offset by the transfer of the Kwoiek Creek facility to the hydroelectric generation segment.

The increase in total liabilities since December 31, 2013, is attributable mainly to the increase in derivative financial instruments following the Corporation's completion of the hedging program to fix the interest rate on future project-level debt for its Development Projects and to the addition of the Tretheway Creek project financing, partly offset by the transfer of the Kwoiek Creek loan to the hydroelectric generation segment.

QUARTERLY FINANCIAL INFORMATION

	Three-months ended			
(in millions of dollars, unless otherwise stated)	Dec. 31, 2014	Sept. 30, 2014	June 30, 2014	Mar. 31, 2014
Power generated (MWh)	819,903	826,617	898,722	417,209
Revenues	68.2	66.4	69.6	37.6
Adjusted EBITDA	48.7	51.7	53.8	25.3
Unrealized net loss on derivative financial instruments	(49.6)	(6.9)	(29.1)	(36.0)
Net loss	(27.6)	(4.5)	(14.2)	(38.1)
Net loss attributable to owners of the parent	(18.9)	(0.7)	(7.8)	(27.4)
Net loss attributable to owners of the parent ($ per share – basic and diluted)	(0.21)	(0.02)	(0.10)	(0.30)
Dividends declared on preferred shares	1.8	1.8	1.8	1.8
Dividends declared on common shares	15.1	15.1	15.0	14.4
Dividends declared on common shares, $ per share	0.150	0.150	0.150	0.150

	Three-months ended			
(in millions of dollars, unless otherwise stated)	Dec. 31, 2013	Sept. 30, 2013	June 30, 2013	Mar. 31, 2013
Power generated (MWh)	496,613	706,495	792,541	386,171
Revenues	41.4	58.0	63.2	35.7
Adjusted EBITDA	25.6	46.7	51.3	25.4
Unrealized net gain on derivative financial instruments	11.7	2.4	27.3	3.8
Net earnings (loss)	3.4	11.1	31.0	(0.2)
Net earnings attributable to owners of the parent	6.3	10.8	28.3	2.8
Net earnings attributable to owners of the parent ($ per share – basic and diluted)	0.05	0.09	0.28	0.01
Dividends declared on preferred shares	1.8	1.8	1.8	2.0
Dividends declared on common shares	13.9	13.8	13.7	13.6
Dividends declared on common shares, $ per share	0.145	0.145	0.145	0.145

Comparing the results for the most recent quarters illustrates the seasonality that is characteristic of the Corporation's production and the variability of power generated, revenues and Adjusted EBITDA from quarter to quarter. As the Corporation's annualized consolidated LTA is 77% hydroelectric, this seasonality can be explained by water flows that are normally at their highest in the second quarter due to the snow melt season and at their lowest in the first quarter due to the cold temperatures, which limit precipitation in the form of rain. However, premiums for the electricity generated during the coldest months of the year included in some PPAs of the Corporation's hydroelectric facilities attenuate this seasonality. Wind regimes are generally best in the first quarter, while solar irradiation is at its highest during the summer months and at its lowest during the winter months.

Readers may expect the net earnings or losses to reflect this seasonality characteristic of run-of-river hydroelectric facilities, wind farms and solar farms. However, other factors also influence these figures, some of which have a relatively stable quarter-to-quarter impact while others are more variable. For the Corporation, the factor responsible for the largest fluctuations in net earnings (loss) is the change in the market value of derivative financial instruments. Historical analysis of net earnings (loss) should therefore take this factor into account. It is important to bear in mind that changes in the market value of derivative financial instruments result from interest rate fluctuations and do not have an impact on the Corporation's Adjusted EBITDA, finance costs, cash flows from operating activities, Free Cash Flow and Payout Ratio.

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

FOURTH QUARTER RESULTS

Electricity Production

Three months ended December 31	2014				2013			
	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Average price ($/MWh)[2]	Production (MWh)[1]	LTA (MWh)	Production as a % of LTA	Average price ($/MWh)[2]
HYDRO								
Quebec	184,296	181,486	102%	77.77	143,454	144,310	99%	74.25
Ontario	26,256	21,212	124%	70.28	24,950	21,212	118%	69.81
British Columbia	404,151	264,831	153%	83.86	121,619	224,900	54%	87.14
United States	2,752	5,223	53%	78.64	2,845	5,223	54%	72.23
Subtotal	617,455	472,752	131%	81.44	292,868	395,645	74%	79.20
WIND								
Quebec	197,162	207,276	95%	79.75	197,884	207,276	95%	79.38
SOLAR								
Ontario	5,286	5,824	91%	420.00	5,861	5,866	100%	420.00
Total	819,903	685,852	120%	83.22	496,613	608,787	82%	83.29

1. The Umbata Falls hydroelectric facility and the Viger-Denonville wind farm are treated as joint ventures and accounted for using the equity method; their revenues are not included in the Corporation's consolidated revenues and, for the sake of consistency, their electricity production figures have been excluded from the production table. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.
2. Including all payment adjustments related to the month, day and hour of delivery, to environmental attributes and to the ecoENERGY Initiative, as applicable.

During the three-month period ended December 31, 2014, the Corporation's facilities produced 820 GWh of electricity or 120% of the LTA of 686 GWh. Overall, the hydroelectric facilities produced 131% of their LTA, due mainly to above-average water flows in British Columbia and also in Ontario. Production at the facility in the United States was affected by below-average water flows and a scheduled month-long shut down to inspect and de-sand the sediment basin. Overall, the wind farms produced 95% of their LTA due to below-average wind regimes. The Stardale solar farm produced 91% of its LTA due mainly to below-average solar regimes.

Financial Results

Revenues

For the three-month period ended December 31, 2014, the Corporation recorded revenues of $68.2 million, compared with $41.4 million in 2013, due mainly to above-average water flows in British Columbia, compared with below-average water flows in the same period last year, and to the addition of the Kwoiek Creek and Northwest Stave River facilities commissioned at the end of 2013 and the addition of the SM-1 hydroelectric facility acquired in June 2014.

Expenses

For the three-month period ended December 31, 2014, the Corporation recorded operating expenses of $12.9 million ($11.0 million in 2013), general and administrative expenses of $5.1 million ($2.9 million in 2013) and prospective project expenses of $1.5 million ($1.9 million in 2013). The increase in expenses compared with the same period last year is due mainly to the Corporation operating a greater number of facilities.

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

	Three months ended December 31			
	2014		2013	
Revenues	68,215	100.0%	41,365	100.0%
Operating expenses	12,874	18.9%	11,045	26.7%
General and administrative expenses	5,101	7.5%	2,873	6.9%
Prospective project expenses	1,492	2.2%	1,882	4.5%
Adjusted EBITDA	48,748	71.5%	25,565	61.8%
Finance costs	20,723		16,101	
Other net revenues	(66)		(819)	
Depreciation and amortization	17,662		17,154	
Share of earnings of joint ventures[1]	(481)		(1,531)	
Unrealized net loss (gain) on derivative financial instruments	49,574		(11,689)	
(Recovery of) income tax expense	(11,096)		2,926	
Net (loss) earnings	(27,568)		3,423	
Net (loss) earnings attributable to:				
Owners of the parent	(18,876)		6,285	
Non-controlling interests	(8,692)		(2,862)	
	(27,568)		3,423	
Basic net (loss) earnings per share	(0.21)		0.05	

1. The Umbata Falls hydroelectric facility and Viger Denonville wind farm are treated as joint ventures and the Corporation's interests in these facilities are required to be accounted for using the equity method. For more information on the Corporation's joint ventures, please refer to the "Investments in Joint Ventures" section.

Adjusted EBITDA

For the three-month period ended December 31, 2014, the Corporation recorded Adjusted EBITDA of $48.7 million, compared with $25.6 million in 2013, due mainly to above-average production as described above.

Finance Costs

During the fourth quarter, finance costs were $20.7 million million ($16.1 million in 2013) due mainly to the increase in project-level debt from the greater number of facilities in operation.

Depreciation and Amortization

During the fourth quarter, depreciation and amortization expense totalled $17.7 million ($17.2 million in 2013) due mainly to the greater number of facilities in operation.

Net Earnings (Loss)

For the three-month period ended December 31, 2014, the Corporation recorded a net loss of $27.6 million (basic and diluted net loss per share of $0.21), compared with net earnings of $3.4 million in 2013 (basic and diluted net earnings per share of $0.05). This variation is due mainly to an unrealized net loss on derivative financial instruments of $49.6 million, compared with an unrealized net gain of $11.7 million in 2013, which offset the increase in Adjusted EBITDA in the fourth quarter of 2014. Excluding the unrealized loss or gain on derivative financial instruments and the related income taxes, the Corporation would have recognized net earnings of $11.2 million for the fourth quarter ended December 31, 2014, compared with a net loss of $5.5 million in 2013.

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

INVESTMENTS IN JOINT VENTURES

The Corporation's material joint ventures at the end of the reporting period were Umbata Falls Limited Partnership ("Umbata Falls, L.P.") (49% interest) and Parc éolien communautaire Viger-Denonville, s.e.c. (Viger-Denonville, L.P.) (50% interest). A summary of the electricity production and financial information for the Corporation's material joint ventures is presented below. The summarized financial information corresponds to amounts shown in the joint ventures' financial statements prepared in accordance with IFRS.

Electricity Production

Three months ended December 31	2014				2013			
	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Average price ($/MWh)[2]	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Average price ($/MWh)[2]
Umbata Falls	51,638	33,037	156%	84.48	51,695	33,037	156%	65.40
Viger-Denonville[3]	20,752	20,300	102%	148.55	8,720	8,809	99%	148.53

Year ended December 31	2014				2013			
	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Average price ($/MWh)[2]	Production (MWh)[1]	LTA (MWh)[1]	Production as a % of LTA	Average price ($/MWh)[2]
Umbata Falls	127,394	109,101	117%	84.41	154,750	109,101	142%	78.02
Viger-Denonville[3]	74,595	72,400	103%	148.55	8,720	8,809	99%	148.50

1. Corresponds to 100% of the facility's electricity production and LTA.
2. Including payments received from the ecoENERGY Initiative for Umbata Falls.
3. The Viger-Denonville wind farm was commissioned in November 2013.

Umbata Falls, L.P.

Summary Statements of Earnings and Comprehensive Income – Umbata Falls, L.P.

	Year ended December 31	
	2014	2013
Revenues	10,754	12,073
Operating and general and administrative expenses	859	746
Adjusted EBITDA	9,895	11,327
Finance costs	2,443	2,501
Other net revenues	(38)	(34)
Depreciation and amortization	4,015	4,024
Unrealized net loss (gain) on derivative financial instruments	3,844	(4,694)
Net (loss) earnings and comprehensive (loss) income	(369)	9,530

For the year ended December 31, 2014, production was 117% of the LTA. However, revenues and Adjusted EBITDA were lower than for the same period last year due mainly to lower production levels compared with the same period last year. The net loss is attributable to lower Adjusted EBITDA and to an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates since the end of 2013, compared with an unrealized net gain on derivative financial instruments resulting from the increase in benchmark interest rates during the same period last year.

Summary Statements of Financial Position – Umbata Falls, L.P.

As at	December 31, 2014	December 31, 2013
Current assets	4,229	3,685
Non-current assets	72,116	75,864
Current liabilities	46,824	47,972
Non-current liabilities	5,749	1,852
Partners' equity	23,772	29,725

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

The reduction in partners' equity stems mainly from a distribution of $5.3 million during the year and from the net loss generated for the year. The July 2014 term maturity of the Umbata Falls loan, recorded in the current portion of long-term debt, was extended to December 31, 2014 and again to March 31, 2015. Umbata Falls, L.P. expects to refinance the outstanding balance during the first quarter of 2015. Also, Umbata Falls, L.P. uses a derivative financial instrument to manage its exposure to the risk of increasing interest rates on its debt financing and does not own or issue any Derivatives for speculation purposes. An interest-rate swap totalling $45.5 million used to hedge the interest rate on 100% of the Umbata Falls loan had a net negative value of $6.9 million at December 31, 2014 (negative $3.0 million at December 31, 2013). This negative variation is due mainly to a decrease in benchmark interest rates since the end of 2013. The estimated impact of a 0.1% interest rate increase would decrease the interest rate swap-related liability by $0.5 million, Conversely, a 0.1% interest rate decrease would increase the interest rate swap-related liability by $0.5 million.

Viger-Denonville, L.P.

Summary Statements of Earnings and Comprehensive Income – Viger-Denonville, L.P.

	Year ended December 31	
	2014	2013
Revenues	11,081	1,295
Operating and general and administrative expenses	1,818	131
Adjusted EBITDA	9,263	1,164
Finance costs	3,570	231
Other net revenues	(69)	(3,720)
Depreciation and amortization	2,933	369
Unrealized net loss on derivative financial instruments	3,838	1,517
Net (loss) earnings and comprehensive (loss) income	(1,009)	2,767

For the year ended December 31, 2014, production was 103% of the LTA. Revenues and Adjusted EBITDA reflect the operation of the Viger-Denonville wind farm since it was commissioned in November 2013. The net loss for the year reflects an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates since the end of 2013. For the same period last year, the net results reflect a realized gain on foreign exchange contracts and a realized gain on derivative financial instruments resulting from the settlement of the bond forward contracts upon closing of the long-term financing for the project, both of which are recorded in other net revenues, partly offset by unrealized net losses on derivative financial instruments.

Summary Statements of Financial Position – Viger-Denonville, L.P.

As at	December 31, 2014	December 31, 2013
Current assets	5,960	9,221
Non-current assets	62,452	63,940
Current liabilities	4,002	8,200
Non-current liabilities	58,588	44,813
Partners' equity	5,822	20,148

The reduction in partners' equity stems mainly from a reimbursement of equity investment of $4.5 million once the project financing was fully drawn and from a distribution of $8.8 million made during the year. In addition, Viger-Denonville, L.P. uses a derivative financial instrument to manage its exposure to the risk of increasing interest rates on its debt financing and does not own or issue any Derivatives for speculation purposes. An interest-rate swap totalling $56.7 million used to hedge the interest rate of the Viger-Denonville loan had a net negative value of $4.7 million at December 31, 2014 (negative $0.9 million at December 31, 2013). This negative variation is due mainly to a decrease in benchmark interest rates since the end of 2013. The estimated impact of a 0.1% interest rate increase would decrease the interest rate swap-related liability by $0.4 million, Conversely, a 0.1% interest rate decrease would increase the interest rate swap-related liability by $0.5 million.

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

NON-WHOLLY OWNED SUBSIDIARIES

Summarized financial information regarding each of the Corporation's subsidiaries that has material non-controlling interests is set out below. Amounts are shown before intragroup eliminations.

Harrison Hydro Limited Partnership ("Harrison Hydro L.P.") and Its Subsidiaries

The Corporation owns a 50.01% interest in Harrison Hydro Limited Partnership, which has interests in six hydroelectric facilities: Douglas Creek, Fire Creek, Lamont Creek, Stokke Creek, Tipella Creek and Upper Stave River.

Summary Statements of Earnings and Comprehensive Income – Harrison Hydro L.P.

	Year ended December 31	
	2014	2013
Revenues	49,671	47,196
Adjusted EBITDA	37,929	36,094
Net loss and comprehensive loss	(9,544)	(8,201)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(5,367)	(4,751)
Non-controlling interests	(4,177)	(3,450)
	(9,544)	(8,201)

For the year ended December 31, 2014, the increase in revenues and Adjusted EBITDA is due mainly to higher production levels compared with the same period last year, however they remained below the LTA as a result of below-average water flows at these facilities. The net losses are attributable mainly to production below the LTA and to greater inflation compensation interest on the real return bonds of $6.7 million for the year ($1.9 million in 2013) as a result of higher inflation.

Summary Statements of Financial Position – Harrison Hydro L.P.

As at	December 31, 2014	December 31, 2013
Current assets	31,079	30,143
Non-current assets	646,421	662,749
Current liabilities	19,582	13,925
Non-current liabilities	462,609	460,511
Equity attributable to owners	118,325	130,497
Non-controlling interests	76,984	87,959

As at December 31, 2014, the decrease in non-current assets is due mainly to depreciation of fixed assets. Furthermore, Harrison Hydro L.P. distributed $13.6 million in 2013. The distribution was made in the form of non-interest bearing loans of $6.8 million each to the Corporation and its partners, which were presented as loans to partners at December 31, 2013. On January 1, 2014, these loans were reimbursed directly from distributions from Harrison Hydro L.P. and a corresponding decrease in non-controlling interests was recorded in 2014 with no impact to cash flows. The decrease in equity attributable to owners is due mainly to the recognition of a net loss for the year and to the $6.8 million distribution made during the first quarter.

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

Creek Power Inc. and Its Subsidiaries

The Corporation owns a 66 2/3% interest in Creek Power Inc., which has interests in the Fitzsimmons Creek hydroelectric facility and the Upper Lillooet River and Boulder Creek Development Projects. For more information on these projects, please refer to the "Development Projects" sections.

Summary Statements of Earnings and Comprehensive Income – Creek Power Inc.

	Year ended December 31	
	2014	2013
Revenues	3,053	2,346
Adjusted EBITDA	1,217	(20)
Net (loss) earnings and comprehensive (loss) income	(46,588)	2,331
Net (loss) earnings and comprehensive (loss) income attributable to:		
Owners of the parent	(31,034)	1,570
Non-controlling interest	(15,554)	761
	(46,588)	2,331

For the year ended December 31, 2014, the net loss is due mainly to greater unrealized net losses on derivative financial instruments resulting from the greater number of derivative financial instruments entered into as well as the decrease in benchmark interest rates, compared with the same period last year. Derivative financial instruments include interest rate swaps used to fix the interest rate on the Fitzsimmons Creek financing and bond forward contracts used to fix the interest rate for the Upper Lillooet River and Boulder Creek projects' financing until closing of the non-recourse project-level debt.

Summary Statements of Financial Position – Creek Power Inc.

As at	December 31, 2014	December 31, 2013
Current assets	8,707	6,593
Non-current assets	218,832	67,349
Current liabilities	78,882	13,547
Non-current liabilities	204,384	69,534
Deficit attributable to owners	(40,931)	(9,897)
Non-controlling interest (deficit)	(14,796)	758

The increase in balance sheet items is due mainly to construction spending for the Upper Lillooet River and Boulder Creek projects. The increase in current liabilities is also due to the bond forward contracts entered into to hedge the interest rate on future project-level financing for these projects. The greater deficit attributable to owners and negative value of non-controlling interest are due mainly to the recognition of a net loss in 2014.

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

Kwoiek Creek Resources Limited Partnership

The Corporation owns a 50.0% interest in Kwoiek Creek Resources Limited Partnership, which owns the Kwoiek Creek hydroelectric facility.

Summary Statements of Earnings and Comprehensive Income – Kwoiek Creek Resources Limited Partnership

	Year ended December 31	
	2014	2013
Revenues	17,969	7
Adjusted EBITDA	14,271	(11)
Net (loss) earnings and comprehensive (loss) income	(1,266)	7
Net (loss) earnings and comprehensive (loss) income attributable to:		
Owners of the parent	(414)	13
Non-controlling interest	(852)	(6)
	(1,266)	7

For the year ended December 31, 2014, revenues and Adjusted EBITDA reflect the operation of the Kwoiek Creek hydroelectric facility, which was commissioned effective January 1, 2014. The net loss is attributable mainly to the recording as an expense of the distributions on the preferred units held by the Corporation and the interest on the subordinated term loans held by the Corporation's partner.

Summary Statements of Financial Position – Kwoiek Creek Resources Limited Partnership

As at	December 31, 2014	December 31, 2013
Current assets	28,098	34,019
Non-current assets	177,749	177,928
Current liabilities	8,362	23,694
Non-current liabilities	213,399	202,901
Deficit attributable to owners	(7,928)	(7,514)
Non-controlling interests deficit	(7,986)	(7,134)

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

Mesgi'g Ugju's'n (MU) Wind Farm, L.P. ("Mesgi'g Ugju's'n")

The Corporation owns a 50% interest in Mesgi'g Ugju's'n (MU) Wind Farm, L.P., which owns the Mesgi'g Ugju's'n wind project. For more information on this project, please refer to the "Development Projects" section. The Mesgi'g Ugju's'n subsidiary began operating on March 21, 2014.

Summary Statement of Earnings and Comprehensive Income – Mesgi'g Ugju's'n

	Since March 21, 2014
Revenues	—
Adjusted EBITDA	(6)
Net loss and comprehensive loss	(17,064)
Net loss and comprehensive loss attributable to:	
Owners of the parent	(9,505)
Non-controlling interest	(7,559)
	(17,064)

Since the subsidiary began operations in March 2014 to December 31, 2014, the recognition of a net loss is due mainly to an unrealized net loss on derivative financial instruments resulting from the decrease in benchmark interest rates since the beginning of the period. Derivative financial instruments in the form of bond forward contracts are used to fix the interest rate on the Mesgi'g Ugju's'n project-level financing until closing of this financing.

Summary Statement of Financial Position – Mesgi'g Ugju's'n

As at	December 31, 2014
Current assets	4,907
Non-current assets	11,807
Current liabilities	21,688
Non-current liabilities	1,140
Equity attributable to owners	(855)
Non-controlling interest deficit	(5,259)

Current liabilities reflect the derivative financial instruments entered into to fix the interest rate on the Mesgi'g Ugju's'n project-level financing until closing of this financing. The negative values for equity attributable to owners and non-controlling interest are due to the recognition of a net loss in 2014.

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

Innergex Sainte-Marguerite, S.E.C. ("SM-1 L.P.")

Since June 20, 2014, the Corporation owns 50.01% of the common units and all of the preferred units of SM-1 L.P., which owns the SM-1 hydroelectric facility.

Summary Statements of Earnings and Comprehensive Income – SM-1 L.P.

	Since June 20, 2014
Revenues	4,821
Adjusted EBITDA	3,473
Net loss and comprehensive loss	(2,763)
Net loss and comprehensive loss attributable to:	
Owners of the parent	(1,382)
Non-controlling interest	(1,381)
	(2,763)

From June 20, 2014 to December 31, 2014, revenues and Adjusted EBITDA reflect the acquisition of the SM-1 hydroelectric facility. The net loss is attributable mainly to the recording as an expense of the distributions on the preferred units held by the Corporation and the interest on the $42.4 million debenture held by the Corporation's partner. However, the interest on this debenture will essentially be accrued and compounded until the facility's project-level debt has been repaid.

Summary Statements of Financial Position – SM-1 L.P.

As at	December 31, 2014
Current assets	2,286
Non-current assets	138,217
Current liabilities	6,283
Non-current liabilities	120,485
Equity attributable to owners	15,111
Non-controlling interests deficit	(1,376)

RISKS AND UNCERTAINTIES

The Corporation is exposed to various risks and uncertainties and has outlined below those that it considers material. Additional risks and uncertainties are discussed in the "Risk Factors" section of the Corporation's most recent *Annual Information Form* available on SEDAR at www.sedar.com. There may also exist additional risks and uncertainties that are not presently known to the Corporation or that are currently believed to be immaterial that may adversely affect the Corporation's business.

Ability of the Corporation to Execute its Strategy for Building Shareholder Value

The Corporation's strategy for building shareholder value is to acquire or develop high-quality facilities that generate sustainable cash flows and provide an attractive risk-adjusted return on invested capital, and to distribute a stable dividend. However, there is no certainty that the Corporation will be able to acquire or develop high-quality power production facilities at attractive prices to supplement its growth.

The successful execution of this strategy requires careful timing and business judgment as well as the resources to complete the development of power generating facilities. The Corporation may underestimate the costs necessary to bring power generating facilities into commercial operation or may be unable to quickly and efficiently integrate new acquisitions into its existing operations.

Ability to Raise Additional Capital and the State of the Capital Market

Future development and construction of new facilities and the development of the Development Projects and Prospective Projects and other capital expenditures will be financed out of cash generated from the Corporation's Operating Facilities, borrowings or the issuance and sale of additional equity. To the extent that external sources of capital, including issuance of additional securities of the Corporation, become limited or unavailable, the Corporation's ability to make necessary capital investments to construct existing or future projects or to maintain existing or future facilities would be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund further development or expansion. There are numerous renewable energy projects to be constructed in the coming years that will result in competition for capital. In addition, payment of dividends may impair the Corporation's ability to finance its ongoing and future projects.

Furthermore, the Corporation's capital-raising efforts could involve the issuance and sale of additional Common Shares, or debt securities convertible into its Common Shares, which, depending on the price at which such shares or debt securities are issued or converted, could have a material dilutive effect on holders of the Corporation's Common Shares and adversely impact the trading price of the Corporation's Common Shares.

Liquidity Risks Related to Derivative Financial Instruments

Derivative financial instruments are entered into with major financial institutions and their effectiveness is dependent on the performance of these institutions. Failure by one of them to perform its obligations could involve a liquidity risk. Liquidity risks related to derivative financial instruments also include the settlement of bond forward contracts on their maturity dates and the early termination option included in some interest rate swap contracts. The Corporation uses derivative financial instruments to manage its exposure to the risk of an increase in interest rates on its debt financing or of foreign currency variation. The Corporation does not own or issue financial instruments for speculation purposes.

Variability in Hydrology, Wind Regimes and Solar Irradiation

The amount of electricity generated by the Corporation's hydroelectric facilities depends on the availability of water flows. There is no certainty that the long-term availability of such resources will remain unchanged. The Corporation's revenues may be significantly affected by events that impact the hydrological conditions of the Corporation's hydroelectric project facilities such as low and high water flows within the watersheds on which the Corporation's hydroelectric facilities are located. In the event of severe flooding, the Corporation's hydroelectric facilities may be damaged. Similarly, the amount of electricity generated by the Corporation's wind farms will depend on the availability of wind, which is naturally variable. A reduced or increased amount of wind at the location of one of the wind farms over an extended period may reduce the production from such facility and may reduce the Corporation's revenues and profitability. Finally, the amount of electricity generated by the Corporation's solar farms will depend on the availability of solar irradiation, which is naturally variable. Lower solar irradiation levels at any of the Corporation's solar farms over an extended period may reduce the production from such facilities and the Corporation's revenues and profitability.

Delays and Cost Overruns in the design and construction of projects

Delays and cost overruns may occur in completing the construction of the Development Projects, the Prospective Projects and future projects that the Corporation will undertake. A number of factors that could cause such delays or cost overruns include, without limitation, permitting delays, construction pricing escalation, changing engineering and design requirements, the performance of contractors, labour disruptions, adverse weather conditions and the availability of financing. Even when complete, a facility may not operate as planned due to design or manufacturing flaws, which may not all be covered by warranty. Mechanical breakdown could occur in equipment after the period of warranty has expired, resulting in loss of production as well as the cost of repair. In addition, if the Development Projects are not brought into commercial operation within the delay stipulated in their PPA, the Corporation may be subject to penalty payments or the counterparty may be entitled to terminate the related PPA.

Health, Safety and Environmental Risks

The ownership, construction and operation of the Corporation's power generation assets carry an inherent risk of liability related to worker health and safety and the environment, including the risk of government imposed orders to remedy unsafe conditions and/or to remediate or otherwise address environmental contamination, potential penalties for contravention of health, safety and environmental laws, licenses, permits and other approvals and potential civil liability. Compliance with health, safety and environmental laws (and any future changes) and the requirements of licenses, permits and other approvals remain material to the Corporation's business. The Corporation has incurred and will continue to incur significant capital and operating expenditures to comply with health, safety and environmental laws and to obtain and comply with licenses, permits and other approvals and to assess and manage its potential liability exposure. Nevertheless, the Corporation may become subject to government orders, investigations, inquiries or other proceedings (including civil claims) relating to health, safety and environmental matters. The occurrence of any of these events or any changes, additions to or more rigorous enforcement of, health, safety and environmental laws, licenses, permits or other approvals could have a significant impact on the Corporation's operations and/or give rise to additional material and unanticipated expenditures. As a result, no assurances can be given that additional environmental and workers' health and safety issues relating to presently known or unknown matters will not require unanticipated expenditures, or result in fines, penalties or other consequences (including changes to operations) material to its business and operations.

Uncertainties Surrounding the Development of New Facilities

The Corporation participates in the development and construction of new power generating facilities. These facilities have greater uncertainty surrounding future profitability than existing Operating Facilities with established track records. In certain cases many factors affecting costs are not yet determined, such as land royalty payments, water royalties or municipal taxes. In other cases, the Corporation is required to advance funds and post-performance bonds in the course of developing these facilities. In the event that some of these facilities are not completed or do not operate according to specifications or that unforeseen costs or taxes are incurred, the Corporation could be adversely affected.

Obtainment of Permits

The Corporation does not currently hold all the approvals, licenses and permits required for the construction and operation of the Development Projects or the Prospective Projects, including environmental approvals and permits necessary to construct and operate the Development Projects or the Prospective Projects. The failure to obtain or delays in obtaining all necessary licenses, approvals or permits, including renewals thereof or modifications thereto, could result in construction of the Development Projects or the Prospective Projects being delayed or not being completed or commenced. There can be no assurance that any one Prospective Project will result in any actual operating facility. In addition, delays may occur in obtaining necessary government approvals required for future power projects.

From time to time, and in order to secure long lead times required for ordering equipment, the Corporation may place orders for equipment and make deposits thereon or advance projects prior to obtaining all requisite permits and licences. The Corporation takes such actions only when it reasonably believes that such licences or permits will be forthcoming in due course prior to the requirement to expend the full amount of the purchase price. However, any delay in permitting could adversely affect the Corporation.

Environmental permits to be issued in connection with any of the Development Projects or the Prospective Projects may contain conditions that need to be satisfied prior to obtaining a PPA, to start construction, during construction and during and after the operation of the Development Projects. It is not possible to predict the conditions imposed by such permits or the cost of any mitigating measures required by such permits.

Variability of Installation Performance and Related Penalties

The ability of the Corporation's facilities to generate the maximum amount of power that can be sold to Hydro-Québec, BC Hydro and the OPA or other purchasers of electricity under PPAs is an important determinant of the Corporation's revenues. If one of the Corporation's facilities delivers less than the required quantity of electricity in a given contract year or is otherwise in default under its PPA, the Corporation may have to pay a penalty to the relevant power purchaser, which could adversely affect its revenues and profitability.

Equipment Failure or Unexpected Operations and Maintenance Activity

The Corporation's facilities are subject to the risk of equipment failure resulting from the deterioration of the asset from use or age, latent defect and design or operator error, among other things. To the extent that a facility's equipment requires longer than forecast downtimes for maintenance and repair, or suffers power generation disruptions for other reasons, the Corporation's business, operating results, financial condition or prospects could be adversely affected.

Interest Rate Fluctuations and Refinancing Risk

Interest rate fluctuations are of particular concern to a capital-intensive industry such as electricity generation. The Corporation faces interest rate and debt refinancing risk in respect of floating-rate bank credit facilities used for construction and long-term financings. The Corporation's ability to refinance debt on favourable terms is dependent on debt capital market conditions, which are inherently variable and difficult to predict.

Financial Leverage and Restrictive Covenants Governing Current and Future Indebtedness

The Corporation's operations and those of its subsidiaries are subject to contractual restrictions contained in the instruments governing any of their current and future indebtedness. The degree to which the Corporation and its subsidiaries are leveraged could have important consequences to shareholders, including: (i) the Corporation's and its subsidiaries' ability to obtain additional financing for working capital, capital expenditures, acquisitions or other project developments in the future may be limited; (ii) a significant portion of the Corporation's and its subsidiaries' cash flows from operations may be dedicated to the payment of the principal of and interest on their indebtedness, thereby reducing funds available for future operations; (iii) some of the Corporation's and its subsidiaries' borrowings may carry variable interest rates, which exposes the Corporation and its subsidiaries to the risk of increasing interest rates; and (iv) the Corporation and its subsidiaries may be more vulnerable to economic downturns and be limited in their ability to withstand competitive pressures.

The Corporation and its subsidiaries are subject to operating and financial restrictions through covenants in certain loan and security agreements. These restrictions prohibit or limit the Corporation's and its subsidiaries' ability to, among other things, incur additional debt, provide guarantees for indebtedness, create liens, dispose of assets, liquidate, dissolve, amalgamate, consolidate or effect any corporate or capital reorganization, make distributions or pay dividends, issue any equity interests and create subsidiaries. These restrictions may limit the Corporation's and its subsidiaries' ability to obtain additional financing, withstand downturns in the Corporation's and its subsidiaries' business and take advantage of business opportunities. Moreover, the Corporation and its subsidiaries may be required to seek additional debt financing on terms that include more restrictive covenants, require repayment on an accelerated schedule, or impose other obligations that limit the Corporation's or its subsidiaries' ability to grow the business, acquire assets or take other actions the Corporation or its subsidiaries might otherwise consider appropriate or desirable.

Possibility That the Corporation May Not Declare or Pay a Dividend

Holders of Common Shares, Series A Preferred Shares and Series C Preferred Shares do not have a right to dividends on such shares unless such dividends are declared by the Board of Directors. The declaration of dividends is at the discretion of the Board of Directors even if the Corporation has sufficient funds, net of its liabilities, to pay such dividends.

The Corporation may not declare or pay a dividend if the Corporation’s cash available for distribution is not sufficient or if there are reasonable grounds to believe that (i) the Corporation is, or would after the dividend payment be, unable to pay its liabilities as they become due; or (ii) the realizable value of the Corporation's assets would thereby be less than the aggregate of its liabilities and stated capital of its outstanding shares.

Ability to Secure New Power Purchase Agreements or Renew Any Power Purchase Agreement

Securing new PPAs, which is a key component of the Corporation's growth strategy, is a risk factor in light of the competitive environment environment in which the Corporation operates. The Corporation expects to continue to enter into PPAs for the sale of its power, which PPAs are mainly obtained through participation in competitive requests for proposals. During these processes, the Corporation faces competitors ranging from large utilities to small independent power producers, some of which have significantly greater financial and other resources than the Corporation. There is no assurance that the Corporation will be selected as power supplier following any particular request for proposals in the future or that existing PPAs will be renewed or will be renewed on equivalent terms and conditions upon the expiry of their respective terms.

CRITICAL ACCOUNTING ESTIMATES

The preparation of financial statements in conformity with IFRS requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. During the reporting period, management made a number of estimates and assumptions pertaining primarily to the fair value calculation of the assets acquired and liabilities assumed in business acquisitions, impairment of assets, useful lives and recoverability of property, plant and equipment, intangible assets and project development costs, deferred income taxes, asset retirement obligations, as well as the fair value of financial assets and liabilities including derivatives. These estimates and assumptions are based on current market conditions, management's planned course of action and assumptions about future business and economic conditions. Changes in the underlying assumptions and estimates could have a material impact on the reported amounts. These estimates are reviewed periodically. If adjustments prove necessary, they are recognized in earnings in the period in which they are made. Changes made during the year ended December 31, 2014, are described in the "Accounting Changes" section. Other significant accounting policies are listed in Note 3 of the Corporation's audited consolidated financial statements for the year ended December 31, 2014.

ACCOUNTING CHANGES

New IFRS affecting the reported financial performance and financial position in the current year

IFRIC 21 - Levies

In May 2013, the International Accounting Standards Board (”IASB”) issued IFRIC 21 – Levies (“IFRIC 21”), an interpretation of IAS 37 – Provisions, Contingent Liabilities and Contingent Assets (“IAS 37”), on the accounting for levies imposed by governments. IAS 37 sets out criteria for the recognition of a liability, one of which is the requirement for the entity to have a present obligation as a result of a past event (“obligating event”). IFRIC 21 clarifies that the obligating event that gives rise to a liability to pay a levy is the activity described in the relevant legislation that triggers the payment of the levy. This standard has been adopted and applied in these financial statements. The application of this standard has not had any material impact on the amounts reported for the current year.

IFRS 9 - Financial Instruments

On October 1, 2014, the Corporation early adopted IFRS 9 (2013), Financial Instruments ("IFRS 9 (2013)"). This standard establishes principles for the financial reporting classification and measurement of financial assets and financial liabilities. This standard also incorporates a new hedging model which aligns hedge accounting more closely with risk management. This new model does not fundamentally change the types of hedging relationships or the requirement to measure and recognize hedge ineffectiveness; however, it will provide more hedging strategies to be used for risk management to qualify for hedge accounting and introduce more judgment in assessing the effectiveness of a hedging relationship. This new standard also increases required disclosures about an entity’s risk management strategy, cash flows from hedging activities and the impact of hedge accounting on the consolidated financial statements.

IFRS 9 (2013) uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 (2013) is based on how an entity manages its financial instruments and the contractual cash flow characteristics of the financial asset. Most of the requirements in IAS 39 for classification and measurement of financial liabilities were carried forward in IFRS 9 (2013).

The adoption of IFRS 9 (2013) did not result in any measurement adjustments to the Corporation’s financial assets and financial liabilities. The Corporation has reviewed its significant accounting policies for financial instruments and hedging relationships to align them with IFRS 9 (2013).

The following summarizes the classification and measurement changes for the Corporation’s non-derivative financial assets and as a result of the adoption of IFRS 9 (2013).

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

	Category under IAS 39	Category under IFRS 9
Cash and cash equivalents	Loans and receivables	Amortized cost
Restricted cash and short-term investment	Loans and receivables	Amortized cost
Accounts receivable	Loans and receivables	Amortized cost
Reserve accounts	Loans and receivables	Amortized cost
Cash and cash equivalents	Loans and receivables	Amortized cost
Short term investment and government-backed	Held-to-maturity	Amortized cost
Government-backed securities	Held-to-maturity	Amortized cost
Loans to related parties	Loans and receivables	Amortized cost

All non-derivative financial liabilities classified as other financial liability under IAS 39 are now classified as amortized cost.

Derivative financial instruments were classified as held for trading under IAS 39 and are now classified at fair value.

At the date of transition, the Corporation did not use hedge accounting for its derivative financial instruments.

New and revised IFRS issued but not yet effective

IFRS 15 - Revenue From Contracts With Customers

In May 2014, IASB issued IFRS 15– Revenue from contracts with customers (“IFRS 15”). This standard replaces IAS 11 construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the construction of real estate, IFRIC 18 Transfers of assets from customers, and SIC-31 Revenue Barter transactions involving advertising services. IFRS 15 applies to all contracts with customers except those that are within the scope of other IFRSs. IFRS 15 is effective for annual periods commencing on or after January 1, 2017, with early adoption permitted. The Corporation is evaluating the impact this standard is expected to have on its consolidated financial statements.

IFRS 11 - Joint Arrangement

IFRS 11 was amended in May 2014 to add new guidance on how to account for the acquisition of an interest in a joint operation that constitutes a business. The amendments are effective for annual periods beginning on or after January 1, 2016. Early adoption is permitted.The Corporation is evaluating the impact the amendments are expected to have on its consolidated financial statements.

IFRS 9 - Financial Instruments (2014)

In July 2014, the IASB issued the complete IFRS 9 (2014), Financial Instruments ("IFRS 9 (2014)"). IFRS 9 (2014) differs in some regards from IFRS 9 (2013) which the Corporation early adopted effective October 1, 2014. IFRS 9 (2014) includes updated guidance on the classification and measurement of financial assets. The final standard also amends the impairment model by introducing a new expected credit loss model for calculating impairment. The mandatory effective date of IFRS 9 (2014) is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted. The Corporation is currently assessing the impact of the adoption of this standard on its consolidated financial statements.

SUBSEQUENT EVENTS

Term Conversion of the Kwoiek Creek Project-Level Debt

On February 13, 2015, the non-recourse construction loan for the Kwoiek Creek hydroelectric facility was converted into a term loan, to be amortized over a 36-year period ending in 2052. The loan bears interest at a fixed rate of 5.08%.

Term Conversion of the Northwest Stave River Project-Level Debt

Also on February 13, 2015, the non-recourse construction loan for the Northwest Stave River hydroelectric facility was converted into a term loan, to be amortized over a 35-year period ending in 2053. The loan bears interest at a fixed rate of 5.30%.

Responsibility for Financial Reporting

The consolidated financial statements of Innergex Renewable Energy Inc. (the “Corporation”) accompanying this annual report and all of the information herein concerning the Corporation are the responsibility of Management.

These consolidated financial statements were prepared by Management in accordance with **International Financial Reporting Standards (“IFRS”)** by applying the detailed accounting policies set out in the notes to the consolidated financial statements. Management is of the opinion that the consolidated financial statements were prepared based on reasonable and material criteria and using justifiable and reasonable estimates. The Corporation's financial information, presented elsewhere in the annual report, is consistent with what is presented in the consolidated financial statements.

Management maintains efficient and high-quality internal accounting and management control systems while ensuring that costs are reasonable. These systems provide assurance that the financial information is relevant, accurate and reliable, and that the Corporation's assets are correctly accounted for and adequately protected.

The Board of Directors of the Corporation is responsible for ensuring that Management fulfils its financial reporting responsibilities. In addition, the Board of Directors is ultimately responsible for reviewing and approving the Corporation's consolidated financial statements. The Board of Directors fulfils this responsibility through its Audit Committee.

The Audit Committee is appointed by the Board of Directors and all of its members are external non-related Directors.

The Audit Committee meets with Management and the independent auditor for the purposes of discussing internal controls relating to the financial reporting process, audit of financial information and other financial issues, and to make sure that each party is properly fulfilling its responsibilities. In addition, the Audit Committee reviews the annual report, the consolidated financial statements and the independent auditor's report. The Audit Committee submits its finding to the Board of Directors for review and for approval of the consolidated financial statements prior to their presentation to the shareholders. The Audit Committee also determines whether to retain the services of independent auditor and to renew their mandate, which is subject to Board review and shareholders' approval.

These consolidated financial statements were approved by the Corporation's Board of Directors. The Corporation's consolidated financial statements were audited by its independent auditor, Deloitte LLP, in accordance with **Canadian generally accepted auditing standards** and on the shareholders' behalf. Deloitte LLP enjoy full and unrestricted access to the Audit Committee.

[s] Michel Letellier
Michel Letellier, MBA
President
and Chief Executive Officer

[s] Jean Perron
Jean Perron, CPA, CA
Chief Financial Officer and
Senior Vice President

Innergex Renewable Energy Inc.

Longueuil, Canada, February 24, 2015

INDEPENDENT AUDITOR'S REPORT

To the Shareholders of
Innergex Renewable Energy Inc.

We have audited the accompanying consolidated financial statements of Innergex Renewable Energy Inc., which comprise the consolidated statements of financial position as at December 31, 2014 and December 31, 2013 and the consolidated statements of earnings, consolidated statements of comprehensive income (loss), consolidated statements of changes in shareholders' equity and consolidated statements of cash flows for the years then ended, and a summary of significant accounting policies and other explanatory information.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with International Financial Reporting Standards, and for such internal control as management determines is necessary to enable the preparation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditor's Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with Canadian generally accepted auditing standards. Those standards require that we comply with ethical requirements and plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor's judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the entity's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the entity's internal control. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained in our audits is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of Innergex Renewable Energy Inc. as at December 31, 2014 and December 31, 2013, and its financial performance and its cash flows for the years then ended in accordance with International Financial Reporting Standards.

Deloitte LLP[1]

Montreal, Quebec
February 24, 2015

1 CPA auditor, CA, public accountancy permit No. A109248

CONSOLIDATED STATEMENTS OF EARNINGS

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

	Notes	Year ended December 31 2014	2013
Revenues		241,834	198,259
Expenses			
Operating	6	41,512	33,947
General and administrative		15,064	11,194
Prospective projects		5,696	4,202
Earnings before finance costs, income taxes, depreciation, amortization, other net expenses (revenues), share of loss (earnings) of joint ventures and unrealized net loss (gain) on derivative financial instruments		179,562	148,916
Finance costs	7	86,537	65,158
Other net expenses (revenues)	8	7,797	(392)
Earnings before income taxes, depreciation, amortization, share of loss (earnings) of joint ventures and unrealized net loss (gain) on derivative financial instruments		85,228	84,150
Depreciation	6, 18	53,145	48,674
Amortization	6, 19	20,947	20,486
Share of loss (earnings) of joint ventures	9	701	(6,053)
Unrealized net loss (gain) on derivative financial instruments	10	121,685	(45,249)
(Loss) earnings before income taxes		(111,250)	66,292
(Recovery of) income tax expense			
Current	11	3,014	2,618
Deferred	11	(29,886)	18,243
		(26,872)	20,861
Net (loss) earnings		(84,378)	45,431
Net (loss) earnings attributable to:			
Owners of the parent		(54,853)	48,170
Non-controlling interests		(29,525)	(2,739)
		(84,378)	45,431
Weighted average number of common shares outstanding (in 000s)	12	98,341	94,694
Basic net (loss) earnings per share ($)	12	(0.63)	0.43
Diluted weighted average number of common shares outstanding (in 000s)	12	98,551	94,780
Diluted net (loss) earnings per share ($)	12	(0.63)	0.43

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

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

	Notes	Year ended December 31 2014	2013
Net (loss) earnings		(84,378)	45,431
Items of comprehensive (loss) income that will be subsequently reclassified to earnings:	27		
Foreign exchange gain on translation of self-sustaining foreign subsidiaries		642	356
Related deferred tax		(85)	(46)
Foreign exchange (loss) on the designated portion of the US dollar denominated debt used as hedge on the investment in self-sustaining foreign subsidiaries		(648)	(352)
Related deferred tax		85	45
Change in fair value of hedging instruments		(343)	—
Related deferred tax		90	—
Other comprehensive (loss) income		(259)	3
Total comprehensive (loss) income		(84,637)	45,434
Total comprehensive (loss) income attributable to:			
Owners of the parent		(55,112)	48,173
Non-controlling interests		(29,525)	(2,739)
		(84,637)	45,434

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at	Notes	December 31, 2014	December 31, 2013
Assets			
Current assets			
Cash and cash equivalents		54,609	34,267
Restricted cash and short-term investments	15	85,807	49,745
Accounts receivable	16	35,271	19,799
Reserve accounts	17	651	1,771
Income tax receivable	11	93	80
Derivative financial instruments	10	2,948	7,563
Loans to related parties	31	—	6,798
Prepaid and others		5,269	5,085
		184,648	125,108
Reserve accounts	17	40,684	45,791
Property, plant and equipment	18	1,895,789	1,583,417
Intangible assets	19	487,312	466,093
Project development costs	20	61,020	81,643
Investments in joint ventures	9	14,536	24,639
Derivative financial instruments	10	3,968	7,066
Deferred tax assets	11	14,025	1,804
Goodwill	21	8,269	8,269
Other long-term assets		5,764	33,244
		2,716,015	2,377,074

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF FINANCIAL POSITION

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

As at	Notes	December 31, 2014	December 31, 2013
Liabilities			
Current liabilities			
Dividends payable to shareholders		16,882	15,651
Accounts payable and other payables	22	45,607	48,258
Income tax liabilities	11	1,408	2,216
Derivative financial instruments	10	104,095	12,915
Current portion of long-term debt	23	33,799	26,649
Current portion of other liabilities	24	244	362
		202,035	106,051
Construction holdbacks		10,818	1,347
Derivative financial instruments	10	48,669	26,081
Accrual for acquisition of long-term assets		25,339	9,855
Long-term debt	23	1,610,800	1,313,718
Other liabilities	24	13,808	10,567
Liability portion of convertible debentures	25	80,018	79,831
Deferred tax liabilities	11	162,303	163,689
		2,153,790	1,711,139
Shareholders' equity			
Common share capital	26 a)	62,224	10,374
Contributed surplus from reduction of capital on common shares	26 b)	784,482	784,482
Preferred shares	26 c)	131,069	131,069
Share-based payment	26 d)	2,050	1,806
Equity portion of convertible debentures	25	1,340	1,340
Deficit		(466,336)	(344,809)
Accumulated other comprehensive (loss) income	27	(15)	244
Equity attributable to owners		514,814	584,506
Non-controlling interests	29.2	47,411	81,429
Total shareholders' equity		562,225	665,935
		2,716,015	2,377,074

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

	Equity attributable to owners										
For the year ended December 31, 2014	Number of common shares (In 000s)	Common shares capital account	Contributed surplus from reduction of capital on common shares	Preferred shares	Share-based payment	Equity portion of convertible debentures	Deficit	Accumulated other comprehensive (loss) income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2014	95,655	10,374	784,482	131,069	1,806	1,340	(344,809)	244	584,506	81,429	665,935
Net loss							(54,853)		(54,853)	(29,525)	(84,378)
Other items of comprehensive loss								(259)	(259)		(259)
Total comprehensive loss	—	—	—	—	—	—	(54,853)	(259)	(55,112)	(29,525)	(84,637)
Common shares issued on June 20, 2014 : private placement (Note 5.1)	4,027	41,720							41,720		41,720
Issuance fees (Net of $22 of deferred income taxes)		(60)							(60)		(60)
Common shares issued through dividend reinvestment plan	990	10,190							10,190		10,190
Share-based payment					244				244		244
Distributions to non-controlling interests (Note 31)									—	(6,798)	(6,798)
Investments from non-controlling interests (Note 29.2)									—	2,305	2,305
Dividends declared on common shares							(59,549)		(59,549)		(59,549)
Dividends declared on preferred shares							(7,125)		(7,125)		(7,125)
Balance December 31, 2014	100,672	62,224	784,482	131,069	2,050	1,340	(466,336)	(15)	514,814	47,411	562,225

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

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

	Equity attributable to owners										
For the year ended December 31, 2013	Number of common shares (In 000s)	Common shares capital account	Contributed surplus from reduction of capital on common shares	Preferred shares	Share-based payment	Equity portion of convertible debentures	Deficit	Accumulated other comprehensive income	Total	Non-controlling interests	Total shareholders' equity
Balance January 1, 2013	93,660	120,500	656,281	131,069	1,511	1,340	(330,621)	241	580,321	107,611	687,932
Net earnings (loss)							48,170		48,170	(2,739)	45,431
Other items of comprehensive income								3	3		3
Total comprehensive income	—	—	—	—	—	—	48,170	3	48,173	(2,739)	45,434
Common shares issued through dividend reinvestment plan	1,995	18,075							18,075		18,075
Reduction of capital on common shares		(128,201)	128,201						—		—
Share-based payment					295				295		295
Business acquisitions									—	1	1
Distributions to non-controlling interests									—	(23,444)	(23,444)
Dividends declared on common shares							(54,967)		(54,967)		(54,967)
Dividends declared on preferred shares							(7,391)		(7,391)		(7,391)
Balance December 31, 2013	95,655	10,374	784,482	131,069	1,806	1,340	(344,809)	244	584,506	81,429	665,935

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

		Year ended December 31	
		2014	2013
	Notes		
Operating activities			
Net (loss) earnings		(84,378)	45,431
Items not affecting cash:			
Depreciation	18	53,145	48,674
Amortization	19	20,947	20,486
Share of loss (earnings) of joint ventures	9	701	(6,053)
Unrealized net loss (gain) on derivative financial instruments	10	121,685	(45,249)
Inflation compensation interest	7	6,699	1,892
Amortization of financing fees	7	895	902
Amortization of revaluation of long-term debt and convertible debentures	7	1,016	1,955
Accretion expenses on other liabilities	7	621	546
Share-based payment		244	295
Deferred income taxes		(29,886)	18,243
Effect of exchange rate fluctuations		701	398
Write-off of project development costs		—	222
Others		180	(86)
Interest on long-term debt and convertible debentures	7	76,523	59,823
Interest paid		(74,474)	(59,741)
Loss on contingent considerations		—	(19)
Distributions received from joint ventures		7,136	3,272
Current income tax expense		3,014	2,618
Net income taxes paid		(3,886)	(1,606)
		100,883	92,003
Changes in non-cash operating working capital items	28	(13,218)	30,283
		87,665	122,286
Financing activities			
Dividends paid on common shares		(48,127)	(36,602)
Dividends paid on preferred shares		(7,125)	(6,673)
Increase of long-term debt		379,901	186,627
Repayment of long-term debt		(120,590)	(145,321)
Payment of deferred financing costs		(2,580)	(3,066)
Payment of other liabilities	24	(361)	—
Payment of issuance cost of common and preferred shares		(82)	(353)
		201,036	(5,388)

The accompanying notes are an integral part of these audited consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOWS

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

	Notes	Year ended December 31 2014	2013
Investing activities			
Cash acquired on business acquisitions	5	—	1,885
Business acquisitions	5	(38,368)	(28,577)
(Increase) decrease of restricted cash and short-term investments		(36,062)	38,066
Loans to related parties	31	—	(6,798)
Net funds withdrawn from the reserve accounts	17	6,538	527
Additions to property, plant and equipment		(205,460)	(103,680)
Additions to intangible assets		—	(27)
Additions to project development costs		(24,955)	(27,799)
Withdrawals from (Investments in) joint ventures		2,259	(2,923)
Investment from non-controlling interest	29.2	5	—
Reductions (additions) to other long-term assets		27,480	(2,962)
Proceeds from disposal of property, plant and equipment		166	76
		(268,397)	(132,212)
Effects of exchange rate changes on cash and cash equivalents		38	85
Net increase (decrease) in cash and cash equivalents		20,342	(15,229)
Cash and cash equivalents, beginning of year		34,267	49,496
Cash and cash equivalents, end of year		54,609	34,267
Cash and cash equivalents is comprised of:			
Cash		32,920	23,518
Short-term investments		21,689	10,749
		54,609	34,267

Additional information is presented in Note 28.

The accompanying notes are an integral part of these audited consolidated financial statements.

DESCRIPTION OF BUSINESS

Innergex Renewable Energy Inc. (the "Corporation") was incorporated under the *Canada Business Corporation Act* on October 25, 2002. The Corporation is a developer, owner and operator of renewable power-generating facilities, essentially focused on the hydroelectric, wind power and solar photovoltaic sectors. The head office of the Corporation is located at 1111, St-Charles Street West, East Tower, Suite 1255, Longueuil, Qc, J4K 5G4, Canada.

These consolidated financial statements were approved by the Board of Directors on February 24, 2015.

These consolidated financial statements have been prepared in accordance with the accounting policies described in Note 3.

1. BASIS OF PRESENTATION AND STATEMENT OF COMPLIANCE

These consolidated financial statements have been prepared using accounting policies consistent with International Financial Reporting Standards ("IFRS").

The consolidated financial statements have been prepared on a historical cost basis, except for certain financial instruments that are measured at fair values as described in the significant accounting policies. Historical cost is generally based on the fair value of the consideration given in exchange for assets.

2. APPLICATION OF NEW AND REVISED IFRS

2.1 New IFRSs affecting the reported financial performance and financial position in the current year

IFRIC 21 - Levies

In May 2013, the International Accounting Standards Board ("IASB") issued IFRIC 21 – Levies ("IFRIC 21"), an interpretation of IAS 37 – Provisions, Contingent Liabilities and Contingent Assets ("IAS 37"), on the accounting for levies imposed by governments. IAS 37 sets out criteria for the recognition of a liability, one of which is the requirement for the entity to have a present obligation as a result of a past event ("obligating event"). IFRIC 21 clarifies that the obligating event that gives rise to a liability to pay a levy is the activity described in the relevant legislation that triggers the payment of the levy. This standard has been adopted and applied in these financial statements. The application of this standard has not had any material impact on the amounts reported for the current year.

IFRS 9- Financial instruments

On October 1, 2014, the Corporation early adopted IFRS 9 (2013), Financial Instruments ("IFRS 9 (2013)"). This standard establishes principles for the financial reporting classification and measurement of financial assets and financial liabilities. This standard also incorporates a new hedging model which aligns hedge accounting more closely with risk management. This new model does not fundamentally change the types of hedging relationships or the requirement to measure and recognize hedge ineffectiveness; however, it will provide more hedging strategies to be used for risk management to qualify for hedge accounting and introduce more judgment in assessing the effectiveness of a hedging relationship. This new standard also increases required disclosures about an entity's risk management strategy, cash flows from hedging activities and the impact of hedge accounting on the consolidated financial statements.

IFRS 9 (2013) uses a single approach to determine whether a financial asset is measured at amortized cost or fair value, replacing the multiple rules in IAS 39. The approach in IFRS 9 (2013) is based on how an entity manages its financial instruments and the contractual cash flow characteristics of the financial asset. Most of the requirements in IAS 39 for classification and measurement of financial liabilities were carried forward in IFRS 9 (2013).

The adoption of IFRS 9 (2013) did not result in any measurement adjustments to the Corporation's financial assets and financial liabilities. The Corporation has reviewed its significant accounting policies for financial instruments and hedging relationships to align them with IFRS 9 (2013).

The following summarizes the classification and measurement changes for the Corporation's non-derivative financial assets and as a result of the adoption of IFRS 9 (2013).

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

	Category under IAS 39	Category under IFRS 9
Cash and cash equivalents	Loans and receivables	Amortized cost
Restricted cash and short-term investments	Loans and receivables	Amortized cost
Accounts receivable	Loans and receivables	Amortized cost
Reserve accounts		
Cash and cash equivalents	Loans and receivables	Amortized cost
Short term investment	Held-to-maturity	Amortized cost
Government-backed securities	Held-to-maturity	Amortized cost
Loans to related parties	Loans and receivables	Amortized cost

All non-derivative financial liabilities classified as other financial liability under IAS 39 are now classified as amortized cost.

Derivative financial instruments were classified as held for trading under IAS 39 and are now classified at fair value.

At the date of transition, the Corporation did not use hedge accounting for its derivative financial instruments.

2.2 New and revised IFRS issued but not yet effective

IFRS 15- Revenue from contracts with customers

In May 2014, IASB issued IFRS 15– Revenue from contracts with customers ("IFRS 15"). This standard replaces IAS 11 construction Contracts, IAS 18 Revenue, IFRIC 13 Customer Loyalty Programmes, IFRIC 15 Agreements for the construction of real estate, IFRIC 18 Transfers of assets from customers, and SIC-31 Revenue Barter transactions involving advertising services. IFRS 15 applies to all contracts with customers except those that are within the scope of other IFRSs. IFRS 15 is effective for annual periods commencing on or after January 1, 2017, with early adoption permitted. The Corporation is evaluating the impact this standard is expected to have on its consolidated financial statements.

IFRS 11- Joint arrangement

IFRS 11 was amended in May 2014 to add new guidance on how to account for the acquisition of an interest in a joint operation that constitutes a business. The amendments are effective for annual periods beginning on or after January 1, 2016. Early adoption is permitted.The Corporation is evaluating the impact the amendments are expected to have on its consolidated financial statements.

IFRS 9 - Financial Instruments (2014)

In July 2014, the IASB issued the complete IFRS 9 (2014), Financial Instruments ("IFRS 9 (2014)"). IFRS 9 (2014) differs in some regards from IFRS 9 (2013) which the Corporation early adopted effective October 1, 2014. IFRS 9 (2014) includes updated guidance on the classification and measurement of financial assets. The final standard also amends the impairment model by introducing a new expected credit loss model for calculating impairment. The mandatory effective date of IFRS 9 (2014) is for annual periods beginning on or after January 1, 2018 and must be applied retrospectively with some exemptions. Early adoption is permitted. The Corporation is currently assessing the impact of the adoption of this standard on its consolidated financial statements.

3. SIGNIFICANT ACCOUNTING POLICIES

Principles of consolidation

The consolidated financial statements include the accounts of the Corporation, and the subsidiaries that it controls. Control exists where the Corporation has the power over the subsidiary, where the Corporation is exposed or has rights to variable returns from its involvement with the subsidiary and where the Corporation has the ability to use its power to affect its returns. Subsidiaries are consolidated from the effective date of acquisition up to the effective date of disposal or loss of control.

Investments in joint ventures

A joint venture is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the net assets of the joint arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

The results and assets and liabilities of joint ventures are incorporated in these consolidated financial statements using the equity method of accounting. Under the equity method, an investment in a joint venture is initially recognized in the consolidated statement of financial position at cost and adjusted thereafter to recognize the Corporation's share of the profit or loss and other comprehensive income of the joint venture. When the Corporation's share of losses of a joint venture exceeds the Corporation's interest in that joint venture (which includes any long-term interest that, in substance, forms part of the Corporation's net investment in the joint venture), the Corporation discontinues recognizing its share of further losses. Additional losses are recognized only to the extent that the Corporation has incurred legal or constructive obligations or made payments on behalf of the joint venture.

An investment is accounted for using the equity method from the date on which the investee becomes a joint venture. On acquisition of the investment in a joint venture, any excess of the cost of the investment over the Corporation's share of the net fair value of the identifiable assets and liabilities of the investee is recognized as goodwill, which is included within the carrying amount of the investment. Any excess of the Corporation's share of the net fair value of the identifiable assets and liabilities over the cost of the investment, after reassessment, is recognized immediately in earnings or loss.

The requirements of IAS 39 are applied to determine whether it is necessary to recognize any impairment loss with respect to the Corporation's investment in a joint venture. When necessary, the entire carrying amount of the investment (including goodwill) is tested for impairment in accordance with IAS 36 Impairment of Assets as a single asset by comparing its recoverable amount (higher of value in use and fair value less costs to sell) with its carrying amount. Any impairment loss recognized forms part of the carrying amount of the investment. Any reversal of the impairment loss is recognized in accordance with IAS 36 to the extent that the recoverable amount of the investment subsequently increases.

The Corporation discontinues the use of the equity method from the date when the investment ceases to be a joint venture. When the Corporation retains an interest in the former joint venture and the retained interest is a financial asset, the Corporation measures the retained interest at fair value at that date and the fair value is regarded as its fair value on initial recognition in accordance with IFRS 9. The difference between the carrying amount of the joint venture at the date the equity method was discontinued, and the fair value of any retained interest and any proceeds from disposing of a part interest in the joint venture is included in the determination of the gain or loss on disposal of the joint venture. In addition, the Corporation accounts for all amounts previously recognized in other comprehensive income in relation to that joint venture on the same basis as would be required if that joint venture had directly disposed of the related assets or liabilities. Therefore, if a gain or loss previously recognized in other comprehensive income by that joint venture would be reclassified to profit or loss on the disposal of the related assets or liabilities, the Corporation reclassifies the gain or loss from equity to profit or loss (as a reclassification adjustment) when the equity method is discontinued.

Investments in joint operations

A joint operation is a joint arrangement whereby the parties that have joint control of the arrangement have rights to the assets, and obligations for the liabilities, relating to the arrangement. Joint control is the contractually agreed sharing of control of an arrangement, which exists only when decisions about the relevant activities require unanimous consent of the parties sharing control.

When the Corporation undertakes its activities under joint operations, the Corporation as a joint operator recognizes in relation to its interest in a joint operation:

- its assets, including its share of any assets held jointly;
- its liabilities, including its share of any liabilities incurred jointly;
- its revenue form the sale of its share of the output arising from the joint operation;
- its share of the revenue from the sale of the output by the joint operation; and
- its expenses, including its share of any expenses incurred jointly.

The Corporation accounts for the assets, liabilities, revenues and expenses relating to its interest in a joint operation in accordance with IFRSs applicable to the particular assets, liabilities, revenues and expenses.

When the Corporation transacts with a joint operation in which a group entity is a joint operator (such as a sale or contribution of assets), the Corporation is considered conducting the transaction with other parties to the joint operation and profits and losses resulting from the transactions are recognized in the Corporation's consolidated financial statements only to the extent of the other parties' interests in the joint operation.

When the Corporation transacts with a joint operation in which a group entity is a joint operator (such as a purchase of assets), the Corporation does not recognize its share of the gains and losses until it resells those assets to a third party.

Business combinations

Acquisitions of subsidiaries and businesses are accounted for using the acquisition method. The cost of the acquisition is measured at the aggregate of the fair values, at the acquisition date, of assets given, liabilities incurred or assumed, and equity instruments issued by the Corporation in exchange for control of the acquiree. Acquisition-related costs are recognized in the consolidated statement of earnings as incurred. Where appropriate, the cost of acquisition includes any asset or liability resulting from a contingent consideration arrangement, measured at its acquisition-date fair value. Subsequent changes in such fair values are adjusted against the cost of acquisition when they qualify as measurement period adjustments. All other subsequent changes in the fair value of contingent consideration classified as an asset or liability are accounted for in accordance with the relevant IFRS and reflected through net earnings. Changes in the fair value of contingent consideration classified as equity are not recognized.

Cash and cash equivalents

Cash and cash equivalents include cash on hand, bank balances and short-term investments with original maturities of three months or less, net of bank overdrafts whenever they are an integral part of the Corporation's cash management process.

Restricted cash and short-term investments

The Corporation holds restricted cash and short-term investments as required under some of its project financings.

The restricted cash accounts and short-term investments are currently invested in cash or in short-term investments having maturities of three months or less.

The availability of funds in the restricted cash and short-term investments accounts are restricted by credit agreements.

Reserve accounts

The Corporation holds two types of reserve accounts designed to help ensure its stability. The first is the hydrology/wind reserve established at the start of commercial operations of a facility to compensate for the variability of cash flows related to fluctuations in hydrology or wind conditions or other unpredictable events. The amounts in the reserve are expected to vary from quarter to quarter according to the seasonality of cash flows. The second is the major maintenance reserve established in order to prefund any major plant repairs that may be required to maintain the Corporation's generating capacity.

The reserve accounts are currently invested in cash or in short-term investments having maturities of three months or less as well as in Government-backed securities.

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

The availability of funds in the reserve accounts may be restricted by credit agreements.

Property, plant and equipment

Property, plant and equipment are comprised mainly of hydroelectric facilities, wind farm facilities and a solar facility that are either in operation or under construction. They are recorded at cost less accumulated depreciation and accumulated impairment losses if any.

Property, plant and equipment are depreciated using the straight-line method over the lesser of (i) the estimated useful lives of the assets or (ii) the period for which the Corporation owns the rights to the assets. Improvements that increase or extend the service life or capacity of an asset are capitalized. Maintenance and repair costs are expensed as incurred. Property, plant and equipment are not depreciated until they are ready for their intended use.

The estimated useful lives, residual values and depreciation methods are reviewed at the end of each reporting period, with the effect of any changes in estimate accounted for on a prospective basis.

An item of property, plant and equipment is derecognized upon disposal or when no future economic benefits are expected to arise from the continued use of the asset. Any gain or loss arising on the disposal or retirement of an item of property, plant and equipment is determined as the difference between the sale proceeds and the carrying amount of the asset and is recognized in earnings.

Borrowing costs directly attributable to the acquisition, construction or production of qualifying assets, which are assets that necessarily take a substantial period of time to get ready for their intended use or sale, are added to the cost of those assets, until such time as the assets are substantially ready for their intended use or sale. The total costs of those assets, including the addition of borrowing costs, shall not exceed the recoverable amount of the assets.

Investment income earned on the temporary investment of specific borrowings pending their expenditure on qualifying assets is deducted from the borrowing costs eligible for capitalization.

All other borrowing costs are recognized in earnings in the period in which they are incurred.

The useful life used to calculate depreciation is as follows:

Type of property, plant and equipment	Ending years of depreciation period	Useful life for the depreciation period
Hydroelectric facilities	2019 to 2088	15 to 75 years
Wind farm facilities	2021 to 2037	15 to 25 years
Solar facility	2032 to 2037	20 to 25 years
Other equipments	2015 to 2019	3 to 10 years

Leases

Leases where the lessor retains substantially all the risks and rewards of ownership are classified as operating leases. Payments made under operating leases (net of any incentives received from the lessor) are charged to income on a straight line basis over the term of the leases.

Intangible assets

Intangible assets consist of various permits, licenses and agreements. Intangibles assets are amortized using the straight-line method over a period ending on the maturity date of the permits, licenses or agreements of each facility. The estimated useful life reflects the Power Purchase Agreement's ("PPA") renewable rights periods, since it is the Corporation's intention to exercice its option to renew its PPAs. They are recorded at cost less accumulated amortization and accumulated impairment losses. Amortization starts when the related facility becomes ready for its intended use.

Intangible assets related to facilities under construction are not amortized until the related facilities are ready for their intended use. Intangible assets also include the cost of extended warranties for wind farm equipments; these costs are amortized over the warranty period.

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

The estimated useful life and amortization method are reviewed at the end of each reporting period, with the effect of any changes in estimate being accounted for on a prospective basis.

The useful life used to calculate amortization is as follows:

Intangible assets related to:	Ending years of amortization period	Useful life for the amortization period
Hydroelectric facilities	2016 to 2088	4 to 75 years
Wind farm facilities	2026 to 2028	19 to 20 years
Solar facility	2032	20 years
Extended warranties for wind turbines	2016	2 to 3 years

Project development costs

Project development costs represent costs incurred for the acquisition of prospective projects and for the development of hydroelectric, wind farm and solar sites. They are recorded at cost less impairment losses. Development phase starts when a public announcement is made by a utility that a prospective project has been selected to be awarded a power purchase agreement. These costs are transferred to property, plant and equipment or intangible assets when construction starts. Current costs for prospective projects are expensed as incurred and costs of a project under development are written off in the year if the project is abandoned. Borrowing costs directly attributable to the acquisition or development are capitalized as project development costs.

Impairment of property, plant and equipment , intangible assets and project development costs other than goodwill

At the end of each reporting period, the Corporation reviews the carrying amounts of its property, plant and equipment, intangible assets and project development costs to determine whether there is any indication that those assets have suffered an impairment loss. If any such indication exists, the recoverable amount of the asset is estimated in order to determine the extent of the impairment loss (if any). Where it is not possible to estimate the recoverable amount of an individual asset, the Corporation estimates the recoverable amount of the cash-generating unit to which the asset belongs. Where a reasonable and consistent basis of allocation can be identified, corporate assets are also allocated to individual cash-generating units, or otherwise they are allocated to the smallest group of cash-generating units for which a reasonable and consistent allocation basis can be identified.

Intangible assets not yet available for use are tested for impairment at least annually, and whenever there is an indication that the asset may be impaired.

Recoverable amount is the greater of fair value less costs to sell and value in use. In assessing value in use, the estimated future cash flows are discounted to their present value using a pre-tax discount rate that reflects current market assessments of the time value of money and the risks specific to the asset for which the estimates of future cash flows have not been adjusted.

If the recoverable amount of an asset (or cash-generating unit) is estimated to be less than its carrying amount, the carrying amount of the asset (or cash-generating unit) is reduced to its recoverable amount. An impairment loss is recognized immediately in earnings.

Where an impairment loss subsequently reverses, the carrying amount of the asset (or a cash-generating unit) is increased to the revised estimate of its recoverable amount, so that the increased carrying amount does not exceed the carrying amount that would have been determined had no impairment loss been recognized for the asset (or cash-generating unit) in prior years. A reversal of an impairment loss is recognized immediately in earnings.

Goodwill

Goodwill is measured as the excess of the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree and the fair value of the acquirer's previously held equity interest in the acquiree (if any) over the net of the amount of the identifiable assets acquired and the liabilities assumed at the date of acquisition. If, after reassessment, the net amount of the identifiable assets acquired and liabilities assumed exceeds the sum of the consideration transferred, the amount of any non-controlling interests in the acquiree and the fair value of the acquirer's previously held interest in the acquiree (if any), the excess is recognized immediately in earnings as a bargain purchase gain.

For purposes of impairment testing, goodwill is allocated to each of the Corporation's cash-generating unit (or groups of cash-generating units) that is expected to benefit from the synergies of the combination.

A cash-generating unit to which goodwill has been allocated is tested for impairment annually, or more frequently when there is indication that the unit may be impaired. If the recoverable amount of the cash-generating unit is less than its carrying amount, the impairment loss is allocated first to reduce the goodwill of the unit. Any impairment loss for goodwill is recognized in earnings. An impairment loss recognized for goodwill is not reversed in subsequent periods.

Other long-term assets

Other long-term assets include security deposits under various agreements and long-term receivables.

Accrual for acquisition of long-term assets

The accrual for acquisition of long-term assets is defined as long-term debt commitments that have been secured and that will be drawn upon to finance the Corporation's projects currently under development or construction.

Provisions and asset retirement obligations

A provision is a liability of uncertain timing or amount. Provisions are recognized when the Corporation has a present obligation (legal or constructive) as a result of a past event, it is probable that the Corporation will be required to settle the obligation, and a reliable estimate can be made of the amount of the obligation. A legal obligation can arise through a contract, legislation, or other operation of law. A constructive obligation arises from an entity's actions whereby, through an established pattern of past practice, published policies or a sufficiently specific current statement, the entity has indicated it will accept certain responsibilities and has thus created a valid expectation that it will discharge those responsibilities. The amount recognized as a provision is the best estimate, at each period end, of the expenditures required to settle the present obligation considering the risks and uncertainties associated with the obligation. Where expenditures are expected to be incurred in the future, the obligation is measured at its present value using a current market-based, risk adjusted interest rate.

Asset retirement obligations are recorded as liabilities when those obligations are incurred and are measured as the present value , if a reasonable estimate of the expected costs to settle the liability can be determined, discounted at a current pre-tax rate specific to the liability. In subsequent years, the liability is adjusted for changes resulting from the passage of time and revisions to either the timing or the amount of the original estimate of the undiscounted cash flows. The accretion of the liability to its fair value as a result of the passage of time is charged to earnings while changes resulting from the revisions to either the timing, the amount of the original estimate of the undiscounted cash flows or a change of the discount rate are accounted for as part of the carrying amount of the related long-lived asset.The carrying amount of the asset retirement obligations is reviewed quarterly to reflect current estimates and changes in the discount rate.

Financial instruments

The Corporation initially recognizes financial assets on the trade date at which the Corporation becomes a party to the contractual provisions of the instrument.

Financial assets are initially measured at fair value. If the financial asset is not subsequently accounted for at fair value through profit or loss, then the initial measurement includes transaction costs that are directly attributable to the asset’s acquisition or origination. On initial recognition, the Corporation classifies its financial assets as subsequently measured at either amortized cost or fair value, depending on its business model for managing the financial assets and the contractual cash flow characteristics of the financial assets.

(i) Financial assets measured at amortized cost
A financial asset is subsequently measured at amortized cost, using the effective interest method and net of any impairment loss, if:
- The asset is held within a business model whose objective is to hold assets in order to collect contractual cash flows; and
- The contractual terms of the financial asset give rise, on specified dates, to cash flows that are solely payments of principal and/or interest.

The Corporation currently classifies its Cash and cash equivalents, restricted cash and short-term investments, accounts receivable, reserve accounts, and loans to related parties as assets measured at amortized cost.

(ii) Financial assets measured at fair value
These assets are measured at fair value and changes therein, including any interest or dividend income, are recognized in profit or loss.
However, for investments in equity instruments that are not held for trading, the Corporation may elect at initial recognition to present gains and losses in other comprehensive income. For such investments measured at fair value through other comprehensive income, gains and losses are never reclassified to profit or loss, and no impairment is recognized in profit or loss. Dividends earned from such investments are recognized in profit or loss, unless the dividend clearly represents a repayment of part of the cost of the investment.

The Corporation currently classifies its derivative financial instruments as financial assets measured at fair value.

The Corporation derecognizes a financial asset when the contractual rights to the cash flows from the asset expire, or it transfers the rights to receive the contractual cash flows on the financial asset in a transaction in which substantially all the risks and rewards of ownership of the financial asset are transferred.

Financial liabilities are classified into the following categories.

(i) Financial liabilities measured at amortized cost
The Corporation classifies non-derivatives financial liabilities as measured at amortized cost. Non-derivative financial liabilities are initially recognized at fair value less any directly attributable transaction costs. Subsequent to initial recognition, these liabilities are measured at amortized cost using the effective interest method.

(ii) Financial liabilities measured at fair value
Financial liabilities at fair value are initially recognized at fair value and are re-measured at each reporting date with any changes therein recognized in net earnings. The Corporation currently classifies its derivative financial instruments as a financial liability measured at fair value.

The Corporation derecognizes a financial liability when its contractual obligations are discharged, cancelled or expired.

Financial assets and liabilities are offset and the net amount presented in the consolidated statement of financial position when, and only when, the Corporation has a legal right to offset the amounts and intends either to settle on a net basis or to realize the asset and settle the liability simultaneously.

Financial instruments are classified in fair value hierarchy levels as follows:
Level 1 valuation based on quoted prices (unadjusted) in active markets for identical assets or liabilities;
Level 2 valuation techniques based on inputs other than quoted prices included in Level 1 that are observable for the asset or liability, either directly (i.e. as prices) or indirectly (i.e. derived from prices);
Level 3 valuation techniques using inputs for the asset or liability that are not based on observable market data (unobservable inputs).

The fair value hierarchy requires the use of observable market inputs whenever such inputs exist. A financial instrument is classified to the lowest level of the hierarchy for which a significant input has been considered in measuring fair value. The Corporation recognizes transfers between levels of the fair value hierarchy at the end of the reporting period during which the change has occurred.

The Corporation did not disclose the fair value of its Cash and cash equivalents, restricted cash and short-term investments, accounts receivable, loans to related parties because their carrying amounts are reasonable approximation of fair values.

Fair value of reserve account investments, which are level 1 under the fair value hierarchy, is presented in note 17.

Financial assets or liabilities measured at fair value are derivative financial instruments which are level 3 for PPAs inflation provision and embedded derivative and level 2 for interest rate swap, bond forward contracts and foreign exchange forwards contracts.

Impairment of financial assets

The Corporation assesses at the end of each reporting period whether there is objective evidence that a financial asset or group of financial assets is impaired. Evidence of impairment may include indications that the debtors or a group of debtors is experiencing significant financial difficulty, default or delinquency in interest or principal payments, the probability that they will enter bankruptcy or other financial reorganization, and where observable data indicates that there is a measurable decrease in the estimated future cash flows, such as changes in arrears or economic conditions that correlate with defaults. Impairment losses are recorded in other net expenses (revenues) if applicable.

If, in a subsequent period, the amount of the impairment loss decreases and the decrease can be related objectively to an event occurring after the impairment was recognized (such as an improvement in the debtor's credit rating), the reversal of the previously recognized impairment loss is recognized in the consolidated statement of earnings and comprehensive income.

Hedging relationships

The Corporation enters into derivative financial instruments to hedge its market risk exposures. On initial designation of new hedges, since October 1, 2014, the Corporation formally documents the relationship between the hedging instruments and hedged items, including the risk management objectives and strategy in undertaking the hedge transaction, together with the methods that will be used to assess the effectiveness of the hedging relationship. The Corporation makes an assessment, both at the inception of the hedge relationship as well as on an ongoing basis, whether the hedging instruments are expected to be effective in offsetting the changes in the fair value or cash flows of the respective hedged items during the period for which the hedge is designated.

For a cash flow hedge of a forecasted transaction, the transaction should be highly probable to occur and should present an exposure to variations in cash flows that could ultimately affect reported net earnings.

Derivatives are recognized initially at fair value, and attributable transaction costs are recognized in net earnings as incurred. Subsequent to initial recognition, derivatives are measured at fair value, and changes therein are accounted for as described below.

Cash flow hedges

When a derivative is designated as the hedging instrument in a hedge of the variability in cash flows attributable to a particular risk associated with a recognized asset or liability or a highly probable forecasted transaction that could affect net earnings, the effective portion of changes in the fair value of the derivative is recognized in other comprehensive income and presented in accumulated other comprehensive income as part of equity. The amount recognized in other comprehensive income is removed and included in net earnings under the same line item in the consolidated statement of earnings as the hedged item, in the same period that the hedged cash flows affect net earnings. Any ineffective portion of changes in the fair value of the derivative is recognized immediately in net earnings. If the hedging instrument no longer meets the criteria for hedge accounting, expires or is sold, terminated or exercised, then hedge accounting is discontinued prospectively. The cumulative gain or loss previously recognized in other comprehensive income remains in accumulated other comprehensive income until the forecasted transaction affects profit or loss. If the forecasted transaction is no longer expected to occur, then the balance in accumulated other comprehensive income is recognized immediately in net earnings.

Net investment in foreign operation hedges

The Corporation applies hedge accounting to foreign currency differences arising between the functional currency of the foreign operation and Corporation's functional currency (Canadian dollars).

Foreign currency differences arising on the retranslation of a financial liability designated as a hedge of a net investment in a foreign operation are recognized in other comprehensive income to the extent that the hedge is effective, and are presented within equity in the accumulated other comprehensive income. Any ineffective portion of changes in the hedging instruments is recognized directly in net earnings. When the hedged part of a net investment is disposed of, the relevant amount in the accumulated other comprehensive income is transferred to the statement of earnings as part of the profit or loss on disposal.

Embedded derivatives

Embedded derivatives are separated from the host contract and accounted for separately if the economic characteristics and risks of the host contract and the embedded derivative are not closely related, a separate instrument with the same terms as the embedded derivative would meet the definition of a derivative, and the combined instrument is not measured at fair value through profit or loss.

Non-controlling interests

Non-controlling interests in the net assets of consolidated subsidiaries are identified separately from the Corporation's equity therein. The interest of non-controlling shareholders may be initially measured either at fair value or at the non-controlling interest's proportionate share in the recognized amounts of the acquiree's identifiable net assets. The choice of measurement basis is made on an acquisition by acquisition basis. Subsequent to acquisition, non-controlling interests consist of the amount attributed to such interests at initial recognition and the non-controlling interest's share of changes in equity since the date of the acquisition.

Revenue recognition

Revenues are recognized, on an accrual basis, upon delivery of electricity at rates provided for under the PPAs entered into with the purchasing utilities or upon compensations from insurance or suppliers for loss of revenues when it is virtually certain that the claim will be received.

Government assistance

Government assistance in the form of subsidies or refundable investment tax credits are recorded in the consolidated financial statements when there is reasonable assurance that the Corporation complied with all conditions necessary to obtain the assistance.

The Corporation is entitled to subsidies under the EcoEnergy program. The subsidies are equal to 1¢ per KWh produced at the Ashlu Creek, Fitzsimmons Creek, Douglas Creek, Fire Creek, Stokke Creek, Tipella Creek, Lamont Creek, Upper Stave River, Magpie Limited Partneship and Umbata Falls hydro facilities and at the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms for the first 10 years following commissioning of each facility. As per the electricity purchase agreements, the Corporation must transfer 75% of the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms subsidies to Hydro-Québec. Gross EcoEnergy subsidies of $13,886 ($12,463 in 2013) are included in the revenues and the 75% payable to Hydro-Québec for the Carleton, Baie-des-Sables and L'Anse-à-Valleau wind farms are included in the operating expenses.

The Corporation incurs renewable energy development expenditures, which are eligible for refundable investment tax credits. The recorded investment tax credits are based on management's estimates of amounts expected to be recovered and are subject to an audit by the taxation authorities. Investment tax credits for renewable energy development expenditures are reflected as a reduction in the cost of the assets or expenses to which they relate.

Share-based payment

The Corporation measures equity-settled stock option awards using the fair value method. Expense is measured at the grant date at the fair value of the award and is recognized over the vesting period based on the Corporation's estimate of the number of options that will eventually vest. Each equity-settled stock option award that vests in installments is accounted for as a separate award with its own distinct fair value measurement. The fair value of options is amortized to earnings over the vesting period with an offset to share-based payment in equity. For options that are forfeited before vesting, the compensation expense that had previously been recognized and the offset to share-based payment in equity are reversed. When options are exercised, the corresponding share-based payment in equity and the proceeds received by the Corporation are credited to share capital.

Foreign currency translation

The Corporation and its subsidiaries each determine their functional currency based on the currency of the primary economic environment in which they operate. The Corporation's functional currency is the Canadian dollar. Transactions denominated in a currency other than the functional currency of an entity are translated at the exchange rate in effect on the transaction date. The resulting exchange gains and losses are included in each entity's net earnings in the period in which they arise.

The Corporation's foreign operations are translated to the Corporation's presentation currency, which is the Canadian dollar, for inclusion in the consolidated financial statements. Foreign denominated monetary and non-monetary assets and liabilities of foreign operations are translated at exchange rates in effect at the end of the reporting period and revenue and expenses are translated at exchange rate in effect on the transaction date. The resulting translation gains and losses are included in other comprehensive income (loss) with the cumulative gain or loss reported in accumulated other comprehensive income. Amounts previously recognized in accumulated other comprehensive income are recognized in earnings when there is a reduction in the net investment.

The Corporation designates a portion of its U.S. dollar-denominated debt to hedge its investment in its U.S. functional currency foreign operations. Translation gains or losses on the portion of the debt designated as a hedge are included in other comprehensive income with the cumulative gain or loss reported in accumulated other comprehensive income. The gain or loss relating to the portion of the debt in excess of the investment in the foreign subsidiaries is recognized immediately in earnings. Gains and losses on the hedging instrument relating to the effective portion of the hedge accumulated in the foreign currency translation reserve are reclassified to earnings in the same way as exchange differences relating to the foreign operations. The Corporation formally documents this hedge. On a quarterly basis, the Corporation reviews the hedge to ensure that it effectively offsets the translation gains or losses arising from its investment in its U.S. functional currency foreign operation.

Income taxes

Current tax and deferred tax are recognized in earnings except to the extent that it relates to a business combination, or to items recognized directly in equity or in other comprehensive income (loss).

Current tax is the expected tax on the taxable income or loss for the year, using tax rates enacted or substantively enacted at the reporting date, and any adjustment to tax payable in respect of previous years.

Deferred tax is recognized in respect of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for taxation purposes. Deferred tax is measured at the tax rates that are expected to be applied to temporary differences when they reverse, based on the laws that have been enacted or substantively enacted at the reporting date.

Deferred tax is not recognized in respect of subsidiaries for the temporary differences between the carrying amounts of the investments and the tax basis, unless such differences are expected to reverse in the foreseeable future.

Deferred tax assets are recognized to the extent that it is probable that taxable profits will be available against which the deductible temporary differences can be utilized.

Earnings (loss) per share

Basic earnings (loss) per share are computed by dividing net earnings available to common shareholders by the weighted average number of shares outstanding during the year.

The Corporation uses the treasury stock method for calculating diluted earnings (loss) per share. Diluted earnings (loss) per share are computed similarly to basic earnings (loss) per share except that the weighted average shares outstanding are increased to include additional shares from the assumed conversion of convertible debentures and the exercise of stock options, if dilutive. The number of additional shares is calculated by assuming that convertible debentures were converted and that outstanding stock options were exercised and that the proceeds from such exercises were used to acquire shares at the average market price during the year.

4. CRITICAL ACCOUNTING JUDGEMENTS AND KEY SOURCES OF ESTIMATION UNCERTAINTY

Significant estimates and assumptions

The preparation of financial statements in conformity with IFRS requires management to make estimates and assumptions. These estimates and assumptions affect the reported amounts of assets and liabilities and disclosures of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting period. Actual results could differ from these estimates. During the reporting period, management made a number of estimates and assumptions pertaining primarily to the fair value calculation of the assets acquired and liabilities assumed in business acquisitions, impairment of assets, useful lives and recoverability of property, plant and equipment, intangible assets and project development costs, deferred income taxes, asset retirement obligations, as well as the fair value of financial assets and liabilities including derivatives. These estimates and assumptions are based on current market conditions, management's planned course of action and assumptions about future business and economic conditions. Changes in the underlying assumptions and estimates could have a material impact on the reported amounts. These estimates are reviewed periodically. If adjustments prove necessary, they are recognized in earnings in the period in which they are made.

Critical judgments and estimates

Fair Value of Financial Instruments

Certain financial instruments, such as derivative financial instruments, are carried in the consolidated statements of financial position at fair value, with changes in fair value reflected in earnings. Fair values of some financial instruments are estimated by using valuation techniques using several assumptions such as interest rate, credit spread and risk.

Useful Lives of Property, Plant and Equipment and Intangible assets

Property, plant and equipment and intangible assets represent a significant proportion of the Corporation's total assets. The Corporation reviews estimates of the useful lives of property, plant and equipment and Intangible assets on an annual basis and adjust depreciation on a prospective basis, if necessary.

Goodwill Impairment

The Corporation makes a number of estimates when calculating the recoverable amount of goodwill using discounted future cash flows or other valuation methods. These estimates include the assumed growth rates for future cash flows, the numbers of years used in the cash flow model, and the discount rate.

Impairment of Property, plant and equipment, Intangible assets and Project development costs

The Corporation makes a number of estimates when calculating fair value using discounted future cash flows or other valuation methods. These estimates include the assumed growth rates for future cash flows, the number of years used in the cash flow model, and the discount rate.

Business acquisition fair value

The Corporation makes a number of estimates when allocating fair values to the assets and liabilities acquired in a business acquisition. Fair values are estimated by using valuation techniques using several assumptions such as production, earnings and expenses, interest rate and discount rate.

Structured entity

Based on the contractual arrangements between the Corporation and the other partner, the Corporation concluded that it has control over Kwoiek Creek Resources L.P and Mesgi'g Ugju's'n (MU) Wind Farm L.P.

Asset retirement obligations

The Corporation makes a number of estimates when calculating fair value of the amount of obligation using discounted rate. The obligation is measured at its present value using a current market-based, risk adjusted interest rate.

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

Hedging

The Corporation makes an assessment, both at the inception of the hedge relationship as well as on an ongoing basis, whether the hedging instruments are expected to be effective in offsetting the changes in the fair value or cash flows of the respective hedged items during the period for which the hedge is designated.

Income Taxes

The calculation of income taxes requires judgment in interpreting tax rules and regulations. The Corporation's tax filings are also subject to audits, the outcome of which could change the amount of current and deferred tax assets and liabilities. The Corporation believes that it has sufficient amounts accrued for outstanding tax matters based on the information that currently is available. Deferred tax assets and liabilities require management's judgment in determining the amounts to be recognized. In particular, judgment is required when assessing the timing of reversal of temporary differences to which future income tax rates are applied. Further, the amount of deferred tax assets, which is limited to the amount that is probable to be realized, is estimated with consideration given to the timing, sources and amounts of future taxable profit.

5. BUSINESS ACQUISITIONS

5.1 Acquisition of assets of Sainte-Marguerite-1

On June 20, 2014, the Corporation and the Desjardins Group Pension Plan ("Desjardins") finalized the acquisition of the Sainte-Marguerite-1 ("SM-1") run-of-river hydroelectric facility located in Quebec, Canada. The final purchase price of the SM-1 facility was $80,088 plus assumption of $37,455 in non-recourse, project-level debt carrying an effective fixed interest rate of 3.30% and maturing in 2025 (see note 23).

The final purchase price of $80,088, was paid as follows: $38,368 in cash (including hodlback of $467) and $41,720 by the issuance of preferred units of Innergex Sainte-Marguerite, S.E.C. (“SM-1 LP”) which the seller immediately transferred to the Corporation in exchange for 4,027,051 newly issued common shares of the Corporation at a price of $10.36 per common share. As a result, the Corporation now holds the preferred units of SM-1 LP that carry a preferred distribution rate of 10.5% until January 1, 2024 and 11.3% thereafter.

The final purchase price has been calculated as follows:

Cash	38,368
Shares issued	41,720
Total purchase price	80,088

The Corporation and Desjardins respectively own 50.01% and 49.99% of the common units of SM-1 LP. Concurrent with the acquisition of the SM-1 facility, Desjardins subscribed to a debenture issued by SM-1 LP for total proceeds of $40,901. This debenture carries an interest rate of 8.0%, has no predetermined repayment schedule and matures in 2064.

Upon closing of the acquisition, the seller used a portion of the cash proceeds to repay to the Corporation the $25,000 deposit it received in July 2012, plus accrued interest income of $3,464. This deposit and accrued interests were accounted in other long-term assets prior to their repayment.

All power generated from the facility is sold to Hydro-Québec under Power Purchase Agreements expiring in 2017 and 2027.

Additional cash flows generated from the assets acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. The acquisition of the SM-1 facility added an additional installed capacity of approximately 30.5 MW to the Corporation's portfolio of operational hydroelectric facilities.

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

The following table reflects the preliminary purchase price allocation:

Reserve account	259
Property, plant and equipment	115,470
Intangible assets	18,807
Current liabilities	(506)
Long-term debt	(37,455)
Deferred tax liabilities	(16,487)
Net assets acquired	80,088

The purchase price allocation remains subject to the completion of the valuation of the property, plant and equipment, intangible assets, deferred tax liabilities and consequential adjustments.

The transaction costs relating to this acquisition have been expensed as transaction costs of the business combination in accordance with IFRS 3.

If the acquisition had taken place on January 1, 2014, the consolidated revenues and net loss for the year ended December 31, 2014 would have been $247,129 and $83,892.

The amounts of revenues and net loss of SM-1 LP since June 20, 2014 included in the consolidated statement of earnings are $4,821 and $2,763 respectively for the 195 days ended December 31, 2014.

5.2 Acquisition of Magpie Limited Partnership

On July 25, 2013, the Corporation finalized the acquisition of 99.999% of the common units of the Magpie run-of-river hydroelectric facility located in Québec (the "Magpie Acquisition"). The Minganie Regional County Municipality holds 30% of the voting units as well as a convertible debenture and a non-interest bearing debenture. The convertible debenture entitles the municipality to a 30% interest in the facility upon conversion of the debenture at or before January 1, 2025. The Corporation has paid cash the purchase price of $28,577.

All power generated from the facility is sold to Hydro-Québec under a PPA expiring in 2032.

Additional cash flows generated from the assets acquired are expected to further increase the Corporation's liquidity and flexibility to fund the development of future projects. The acquisition of the Magpie facility added an additional installed capacity of approximately 40.6 MW to the Corporation's portfolio of operational hydroelectric facilities.

The following table reflects the final purchase price allocation:

Cash and cash equivalents	1,885
Accounts receivable	1,321
Prepaid and others	52
Reserve account	422
Property, plant and equipment	74,460
Intangible assets	30,413
Current liabilities	(1,203)
Long-term debt	(66,024)
Other long-term liabilities	(2,428)
Deferred tax liabilities	(10,320)
Non-controlling interests	(1)
Net assets acquired	28,577

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

The transaction costs relating to this acquisition have been expensed as transaction costs of the business combination in accordance with IFRS 3.

If the acquisition had taken place on January 1, 2013, the consolidated revenues and net earnings for the year ended December 31, 2013 would have been $203,323 and $45,786.

The amounts of revenues and net earnings of Magpie Limited Partnership since July 25, 2013 included in the consolidated statement of earnings are $5,489 and $1,835 respectively for the 160 days ended December 31, 2013.

5.3 Acquisition of Brown Miller Power L.P.

The valuation of the acquisition of Brown Miller Power L.P. has been finalized during the year 2013. The following table reflects the final purchase price allocation:

	Preliminary purchase price allocation	Subsequent Adjustments	Final purchase price allocation
Accounts receivable	429	—	429
Prepaid and others	153	—	153
Property, plant and equipment	64,391	(14,732)	49,659
Intangible assets	13,436	14,732	28,168
Current liabilities	(9)	—	(9)
Deferred tax liabilities	(9,765)	—	(9,765)
	68,635	—	68,635

6. OPERATING EXPENSES

	Year ended December 31	
	2014	2013
Salaries	3,607	2,851
Insurance	2,400	2,119
Operation and maintenance	18,210	16,367
Property taxes and royalties	17,295	12,610
	41,512	33,947

Depreciation and amortization recorded in the consolidated statements of earnings are mainly related to operating expenses incurred to generate revenues.

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

7. FINANCE COSTS

	Year ended December 31	
	2014	2013
Interest on long-term debt and on convertible debentures	76,523	59,823
Inflation compensation interest	6,699	1,892
Amortization of financing fees	895	902
Amortization of revaluation of long-term debt and convertible debentures	1,016	1,955
Accretion expenses on other liabilities	621	546
Others	783	40
	86,537	65,158

8. OTHER NET EXPENSES (REVENUES)

	Year ended December 31	
	2014	2013
Transaction costs	521	609
Realized loss on derivative financial instruments	8,366	3,259
Realized loss on foreign exchange	589	369
Gain on contingent considerations	—	(19)
Other net revenues	(2,045)	(2,832)
Loan impairment	366	—
Write-off of project development costs	—	222
Settlement of claims received in relation with an acquisition	—	(2,000)
	7,797	(392)

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

9. INVESTMENTS IN JOINT VENTURES

9.1 Details of material joint ventures

Details of the Corporation's material joint ventures at the end of the reporting period are as follows:

Name of joint venture	Principal activity	Place of creation and principal place of operation	Proportion of ownership interest and voting rights held by the Corporation	
			December 31, 2014	December 31, 2013
Umbata Falls, L.P.	Own and operate an hydroelectric facility	Ontario	49%	49%
Viger-Denonville, L.P.	Own and operate a wind farm	Québec	50%	50%

The joint ventures are accounted for using the equity method in these consolidated financial statements.

Summarized financial information in respect of the Corporation's material joint ventures is set out below. The summarized financial information below represents amounts shown in the joint venture's financial statements prepared in accordance with IFRSs.

Umbata Falls, L.P.

Summary Statements of Earnings and Comprehensive (loss) Income

	Year ended December 31	
	2014	2013
Revenues	10,754	12,073
Operating, general and administrative expenses	859	746
	9,895	11,327
Finance costs	2,443	2,501
Other net revenues	(38)	(34)
Depreciation and amortization	4,015	4,024
Unrealized net loss (gain) on derivative financial instruments	3,844	(4,694)
Net (loss) earnings and comprehensive (loss) income	(369)	9,530

Summary Statements of Financial Position

As at	December 31, 2014	December 31, 2013
Cash and cash equivalents	2,350	1,738
Other current assets	1,879	1,947
Current assets	4,229	3,685
Non-current assets	72,116	75,864
Accounts payable and other payables	217	133
Other current liabilities	46,607	47,839
Current liabilities	46,824	47,972
Non-current liabilities	5,749	1,852
Shareholder's equity	23,772	29,725

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

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	December 31, 2014	December 31, 2013
Net assets of the joint venture	23,772	29,725
Proportion of the Corporation's ownership interest in the joint venture	49%	49%
Carrying amount of the Corporation's interest in the joint venture	11,648	14,565

Umbata Falls, L.P. 's Debt

The loan consists of a five-year term loan, amortized over a 25-year period starting in July 2009. The term loan bears interest at BA rate plus an applicable margin for an all-in rate of 2.59%. The term loan is repayable in quarterly instalments.The July 2014 term maturity of the Umbata Falls loan, which is included in the current liabilities, has been extended to March 31, 2015. Umbata Falls, L.P. expects to refinance the outstanding balance before the extended date.

The lender also agreed to make available a letter of credit facility in a principal amount not exceeding $500. As at December 31, 2014, an amount of $470 has been used to secure two letters of credit. This debt is secured by all of Umbata Falls LP's assets with a carrying value of approximately $76,300.

Umbata Falls, L.P. entered into an amortizing interest rate swap of $51,000, maturing in 2034 and bearing an interest rate of 3.98%.

Viger-Denonville, L.P.

Summary Statements of Earnings and Comprehensive (loss) Income

	Year ended December 31	
	2014	2013
Revenues	11,081	1,295
Operating, general and administrative expenses	1,818	131
	9,263	1,164
Finance costs	3,570	231
Other net revenues	(69)	(3,720)
Depreciation and amortization	2,933	369
Unrealized net loss on derivative financial instruments	3,838	1,517
Net (loss) earnings and comprehensive (loss) income	(1,009)	2,767

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

Summary Statements of Financial Position

As at	December 31, 2014	December 31, 2013
Cash and cash equivalents	4,996	1,787
Other current assets	964	7,434
Current assets	5,960	9,221
Non-current assets	62,452	63,940
Accounts payable and other payables	520	183
Other current liabilities	3,482	8,017
Current liabilities	4,002	8,200
Non-current liabilities	58,588	44,813
Shareholder's equity	5,822	20,148

Reconciliation of the above summarized financial information to the carrying amount of the interest in the joint venture recognized in the consolidated financial statements:

As at	December 31, 2014	December 31, 2013
Net assets of the joint venture	5,822	20,148
Proportion of the Corporation's ownership interest in the joint venture	50%	50%
Carrying amount of the Corporation's interest in the joint venture	2,911	10,074

Viger-Denonville, L.P. 's Debt

The loan consists of a 18-year term loan, amortized over an 18-year period starting in June 2014. The term loan carries a floating interest rate equal to the banker's acceptance rate plus an applicable margin for an all-in rate of 3.90%. The principal repayments are variable and set to $2,518 for 2015. The lenders also agreed to make available a letter of credit facility in an amount not to exceed $984. As at December 31, 2014, an amount of $984 has been used to secure one letter of credit. These loans are secured by Viger-Denonville, L.P's assets with a carrying value of approximately $68,400.

Viger-Denonville, L.P. entered into an amortizing interest rate swap of $58,520, maturing in 2031 and bearing an interest rate of 3.40%.

9.2 Commitments of joint ventures

As at December 31, 2014, the Corporation's share of the expected schedule of commitment payments for Umbata Falls, L.P. and Viger-Denonville, L.P. is as follows:

Years of	Hydroelectric Generation	Wind Power Generation	Total
2015	23,283	3,009	26,292
2016	563	3,018	3,581
2017	459	3,013	3,472
2018	409	3,009	3,418
2019	367	2,941	3,308
Thereafter	1,667	34,390	36,057
Total	26,748	49,380	76,128

Umbata Falls, L.P.

25 years after the beginning of the operations, the partnership will be dissolved. Upon the dissolution of the partnership, the property and assets of the partnership shall be transferred to the other partner for no consideration.

Viger-Denonville, L.P.

Parc Eolien Communautaire Viger-Denonville LP entered into royalties and other commitments related to amounts to set aside for the dismantling of wind farm components, commitments to surrounding municipalities and the operation of the wind farms.

10. DERIVATIVE FINANCIAL INSTRUMENTS

The Corporation holds interest rate swap contracts and bond forwards contracts ("Interest hedging instruments") that enable it to hedge its exposure to the floating interest rates payable on the portion of its long-term debt. The counterparties to the contracts are major financial institutions; the Corporation does not anticipate any payment defaults on their part. The estimated impact of an increase in swap rates curve of 0.1% would decrease the negative fair value of these financial instruments by $14,570. Conversely, a decrease in swap rates curve of 0.1% would result in an increase of $14,866 of the negative fair value of these financial instruments.

The Corporation records embedded derivatives separately from the host contracts:

- The inflation embedded derivative relates to provisions establishing minimum inflation rate at 3% of the selling prices provided for under some of the PPAs entered into with Hydro-Québec. The Corporation does not anticipate any payment defaults from the counterparty. The fair value of these financial instruments is evaluated using revenue estimates based on long-term production averages estimated for each facility. It varies based on the difference between the 3% minimum inflation rate and the long-term inflation rate, which is estimated at 2% as at December 31, 2014 over the remaining terms of these agreements, discounted at a rate of 2.20%. The expected impact of a 0.1% increase in the long-term inflation rate would reduce the fair value of these financial instruments by $529; a 0.1% decrease in the long-term inflation rate would increase the fair value of these financial instruments by $527.

- The foreign exchange embedded derivative adjusts the price of an equipment purchase for exchange rate fluctuations between the Euro and the Canadian dollar. The equipment purchase price varies based on the change in the exchange rate for a notional amount of 78,400 Euros. The expected impact of a 10% increase in the Euro relative to the Canadian dollar would create a loss in earnings of $9,800; a 10% decrease in the Euro relative to the Canadian dollars would create a gain in earnings of $9,800. However, this embedded derivative is economically hedged with a foreign exchange forward contract with the same notional amount. Gains or losses on the embedded derivative caused by a change in the exchange rate between the Euro and the Canadian dollar are offset by gains or losses associated with the foreign exchange forward contract.

The classification of the fair value hierarchy of all the financial assets and liabilities remained the same during 2014.

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

Financial assets (liabilities)	Foreign exchange embedded derivative (Level 3)	Foreign exchange forwards (Level 2)	Interests hedging instruments (Level 2)	Inflation provisions (Level 3)	Total
As at January 1, 2014	—	—	(31,015)	6,648	(24,367)
Embedded derivative in equipment purchases contract	547	—	—	—	547
Variation in fair value of derivative financial instruments	995	(1,228)	(128,543)	(1,275)	(130,051)
Settlements	—	—	8,366	—	8,366
Recognized in statement of earnings	995	(1,228)	(120,177)	(1,275)	(121,685)
Variation in fair value of derivative financial instruments recognized in other comprehensive income	—	—	(343)	—	(343)
As at December 31,2014	1,542	(1,228)	(151,535)	5,373	(145,848)

Financial assets (liabilities)	Interests hedging instruments (Level 2)	Inflation provisions (Level 3)	Total
As at January 1, 2013	(78,007)	8,391	(69,616)
Variation in fair value of derivative financial instruments	43,733	(1,743)	41,990
Settlements	3,259	—	3,259
Unrealized net gain (loss) on derivative financial instruments	46,992	(1,743)	45,249
As at December 31, 2013	(31,015)	6,648	(24,367)

Reported in the consolidated financial statements:

As at	December 31, 2014	December 31, 2013
Current assets – derivative financial instruments	2,948	7,563
Long-term asset – derivative financial instruments	3,968	7,066
Current liability – derivative financial instruments	(104,095)	(12,915)
Long-term liability – derivative financial instruments	(48,669)	(26,081)
	(145,848)	(24,367)

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

Interest rate risk

The terms of the contracts reducing the Corporation's risk of interest rate fluctuations are as follows:

Contract	Maturity	Early termination option	Notional Amounts December 31, 2014	Notional Amounts December 31, 2013
Contracts for which hedge accounting is not used				
Bond forwards, from 2.74% to 3.32% (3.04% to 3.27% in 2013)	2015	None	535,000	340,000
Interest rate swaps, from 3.96% to 4.09%	2015	None	15,000	15,000
Interest rate swap, 4.27%	2016	None	3,000	3,000
Interest rate swaps, 4.27% to 4.41%	2018	None	82,600	82,600
Interest rate swaps, 2.94% to 4.93%, amortizing	2026	None	49,718	52,539
Interest rate swaps, from 3.35% to 3.60%, amortizing	2027	None	37,506	39,807
Interest rate swap, 3.74%, amortizing	2030	None	93,511	97,723
Interest rate swap, 4.22%, amortizing	2030	2016	27,485	28,803
Interest rate swap, 4.25%, amortizing	2031	2016	43,360	45,417
Interest rate swap, 4.61%, amortizing	2035	2025	100,463	102,818
Interest rate swap, 2.85%, amortizing	2041	2016	19,313	19,591
			1,006,956	827,298
Contract for which hedge accounting is used				
Interest rate swaps from 2.30% to 2.33%	2024	2019	40,000	—
			1,046,956	827,298

The Corporation entered into hedge agreements to mitigate the risk of fluctuations in the interest rates on its long-term debt. Rates on contracts represent the interest rate, excluding the applicable margin on the debt.

Foreign exchange risk

The terms of the contract reducing the Corporation's foreign exchange risk is as follows:

Contract	Maturity	Early termination option	Notional Amounts December 31, 2014	Notional Amounts December 31, 2013
Contract for which hedge accounting is not used				
Foreign exchange forwards, CAD1.43/Euro	2015	None	78,400	—

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

As at December 31, 2014, the following items were designated as cash-flow hedging instruments to mitigate the interest rate risk:

	Nominal amount of the hedging instrument	Carrying amount of the hedging instrument		Line item in the statement of financial position where the hedging instrument is located	Changes in fair value used for calculating hedge ineffectiveness for 2014
		Assets	Liabilities		
Cash-flow hedges:					
Interest rate risk					
Interest rate swaps	40,000	—	(424)	Derivative financial instruments (short term and long term)	(424)

The following table summarizes the Corporation's hedged items as at December 31, 2014:

	Changes in fair value used for calculating hedge ineffectiveness for 2014	Cash flow hedge reserve	Foreign currency translation reserve
Cash-flow hedge:			
Interest rate risk			
Interest rate swap	343	343	—
Hedge of net investment in a foreign operation:			
Foreign exchange risk			
Libor advances	648	—	648

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

The following table summarizes the impact of hedge ineffectiveness and hedging gains or losses as at December 31, 2014:

	Changes in fair value of the hedging instrument recognized in other comprehensive income	Hedge ineffectiveness recognized in profit or loss	Line item in profit or loss that includes the hedge ineffectiveness	Amount reclassified from the cash flow hedge reserve to profit or loss	Amount reclassified from the foreign currency translation reserve to profit or loss	Line item affected in profit or loss resulting from the reclassification
Cash-flow hedge:						
Interest rate risk						
Interest rate swap	343	83	unrealized net loss (gain) on derivative financial instruments	—	—	—
Hedge of net investment in a foreign operation:						
Foreign exchange risk						
Libor advances	648	—	—	—	—	—

The sources of hedge ineffectiveness are related to the variation of the credit risk of each parties of the hedge.

11. INCOME TAXES

a. Income tax recognized in profit or loss

	December 31, 2014	December 31, 2013
Current tax		
Current tax expense in respect of the current year	3,079	2,639
Adjustments recognized in the current year in relation to the current tax expense of prior years	(65)	(21)
	3,014	2,618
Deferred tax		
(Recovery) deferred tax expense recognized in the current year	(29,280)	16,003
(Decrease) increase in deferred income tax rates	(198)	1,226
Adjustments recognized in the current year in relation to the deferred tax of prior years	(408)	1,014
	(29,886)	18,243
Total (recovery of) income tax expense recognized in the current year	(26,872)	20,861

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

The total (recovery of) income tax expense for the year can be reconciled to the accounting (loss) profit as follows:

	December 31, 2014	December 31, 2013
(Loss) earnings before income taxes	(111,250)	66,292
Canadian statutory income tax rate	26.6%	26.5%
(Recovery of) income tax expense calculated at the statutory rate	(29,593)	17,567
Items affecting the statutory rate:		
Non-deductible expenses	547	473
Effect of previously unrecognized and unused tax losses and temporary differences used in the year	(1,663)	(520)
Income taxable at a different rate than the Canadian statutory tax rate	537	—
(Decrease) increase in deferred income tax rates	(198)	1,226
Increase in taxable temporary differences in relation to investments in subsidiaries and in joint ventures	623	1,262
Tax on dividends on preferred shares	212	171
Adjustments recognized in the current year in relation to the current tax of prior years	(65)	(21)
Adjustments recognized in the current year in relation to the deferred tax of prior years	(408)	1,014
Adjustments related to changes in legislation	—	(1,260)
Income tax on loss allocated to minority interests on non-taxable entities	3,116	943
Others	20	6
(Recovery of) income tax recognized in profit or loss	(26,872)	20,861

The tax rate used for 2014 and 2013 reconciliations above is the average combined corporate tax rate payable by corporate entities in Canada on taxable profits under federal and provincials' tax laws. The increase of the tax rate is due to internal reorganization and the acquisition of a project located in Quebec.

b. Income tax recognized in other comprehensive income

	December 31, 2014	December 31, 2013
Deferred tax		
Arising on income and expenses recognized in other comprehensive income:		
Translation of self-sustaining foreign subsidiaries	85	46
Designated portion of the US dollar denominated debt used as a hedge on the investments in self-sustaining foreign subsidiaries	(85)	(45)
Change in fair value of hedging instruments recognized in other comprehensive income	(90)	—
Total income tax recognized directly in other comprehensive income	(90)	1

c. Income tax recognized directly in equity

	December 31, 2014	December 31, 2013
Deferred tax		
Arising on transactions with owners:		
Share issue expenses deductible over 5 years	(22)	—
Total income tax recognized directly in equity	(22)	—

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

d. Current tax assets and liabilities

	December 31, 2014	December 31, 2013
Current tax assets		
Tax refund receivable	93	80
Current tax liabilities		
Income tax payable	1,408	2,216

e. Deferred tax balances

The following is the analysis of deferred tax assets (liabilities) presented in the consolidated statements of financial position:

	December 31, 2014	December 31, 2013
Deferred tax assets	14,025	1,804
Deferred tax liabilities	(162,303)	(163,689)
	(148,278)	(161,885)

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

	As at January 1, 2014	Recognized in statement of earnings	Recognized in other comprehensive income	Recognized in business acquisition	Transfert of project development costs to property, plant and equipment and intangibles	Recognized directly in equity	Net exchange differences	As at December 31, 2014
Deferred tax assets (liabilities) in relation to:								
Property, plant and equipment	(86,445)	1,984	—	(16,698)	(8,567)	—	54	(109,672)
Intangible assets	(93,555)	3,693	—	(1,545)	(6,126)	—	(42)	(97,575)
Project development costs	(12,716)	(11,456)	—	—	14,693	—	—	(9,479)
Investments into subsidiaries and in joint ventures	(672)	(56)	(85)	—	—	—	—	(813)
Non-repatriated income from foreign subsidiaries	(681)	(174)	—	—	—	—	—	(855)
Derivative financial instruments	14,772	32,630	90	—	—	—	—	47,492
Long-term debt	(5,675)	(130)	—	1,756	—	—	—	(4,049)
Convertible debentures	(175)	49	—	—	—	—	—	(126)
Other liabilities	649	(68)	—	—	—	—	—	581
Financing fees	1,198	(1,938)	—	—	—	22	—	(718)
Share-based payment	405	205	—	—	—	—	—	610
	(182,895)	24,739	5	(16,487)	—	22	12	(174,604)
					—			
Tax losses	21,010	5,147	85	—	—	—	84	26,326
	(161,885)	29,886	90	(16,487)	—	22	96	(148,278)

As at December 31, 2014, the Corporation, its subsidiaries and joint ventures have non-capital losses totaling approximately $94,000 that may be applied against future taxable income. These non-capital losses expire gradually between 2027 and 2034.

The Corporation and its subsidiaries recorded capital losses totaling approximately $3,000 that may be applied against capital gains in future years.

The Corporation recognized a deferred tax asset on non-capital and capital losses because it is probable that sufficient taxable profit and taxable capital gains will be available from hydroelectric, solar and wind projects currently in operation or that will be in the near future.

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

	As at January 1, 2013	Recognized in statement of earnings	Recognized in other comprehensiv e income	Recognized in business acquisition	Transfert of project development costs to property, plant and equipment and intangibles and other reclassifications	Net exchange differences	As at December 31, 2013
Deferred tax assets (liabilities) in relation to:							
Property, plant and equipment	(67,345)	(10,904)	—	(5,729)	(2,542)	75	(86,445)
Intangible assets	(81,738)	308	—	(7,748)	(4,343)	(34)	(93,555)
Project development costs	(24,529)	5,141	—	—	6,672	—	(12,716)
Investments into subsidiaries and in joint ventures	(420)	(206)	(46)	—	—	—	(672)
Non-repatriated income from foreign subsidiaries	(513)	(168)	—	—	—	—	(681)
Derivative financial instruments	26,396	(11,624)	—	—	—	—	14,772
Long-term debt	(8,554)	358	—	2,521	—	—	(5,675)
Convertible debentures	(217)	42	—	—	—	—	(175)
Other liabilities	—	13	—	636		—	649
Financing fees	3,085	(1,887)	—	—	—	—	1,198
Share-based payment	—	192	—	—	213	—	405
	(153,835)	(18,735)	(46)	(10,320)	—	41	(182,895)
					—		
Tax losses	20,416	492	45	—	—	57	21,010
	(133,419)	(18,243)	(1)	(10,320)	—	98	(161,885)

f. Unrecognized deductible temporary differences, unused tax losses and unused tax credits

	December 31, 2014	December 31, 2013
Tax losses - revenue in nature	3,525	8,079
Tax losses- capital in nature	—	569
Transaction costs	2,162	2,842
	5,687	11,490

The unrecognized tax losses-revenue in nature will expire gradually between 2029 and 2033.

12. EARNINGS PER SHARE

The net (loss) earnings per share are computed as follows:

	Year ended December 31	
	2014	2013
Net (loss) earnings attributable to owners of the parent	(54,853)	48,170
Dividends declared on preferred shares	(7,125)	(7,391)
Net (loss) earnings available to common shareholders	(61,978)	40,779
Weighted average number of common shares (in 000s)	98,341	94,694
Basic net (loss) earnings per share ($)	(0.63)	0.43
Weighted average number of common shares (in 000s)	98,341	94,694
Effect of dilutive elements on common shares (in 000s) (a)	210	86
Diluted weighted average number of common shares (in 000s)	98,551	94,780
Diluted net (loss) earnings per share ($) (b)	(0.63)	0.43

a. During the year ended December 31, 2014, 1,640,000 of 3,470,684 stock options (2,013,420 of 3,073,684 for the year ended December 31, 2013) and 7,558,684 shares which can be issued on conversion of convertible debentures (7,558,684 for the year ended December 31, 2013) were excluded from the calculation of diluted weighted average number of shares outstanding as the exercise price was above the average market price of common shares.

b. During the year ended December 31, 2014, 1,830,684 of 3,470,684 stock options were excluded from the calculation of diluted net loss per shares as it was anti-dilutive due to a net loss available to common shareholders.

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

13. KEY MANAGEMENT PERSONNEL COMPENSATION

The following are the expenses that the Corporation recognized for its key management personnel. The members of the Board of Directors as well as the President and all the Vice-Presidents are key management personnel of the Corporation.

	Year ended December 31	
	2014	2013
Salaries and short-term benefits	4,525	3,940
Attendance fees for members of the Board of Directors	567	566
Termination benefits	—	39
Performance share plan	694	678
Share-based payment	244	295
	6,030	5,518

14. EMPLOYEE BENEFITS

The expenses that the Corporation recognized for its employee benefits is composed of salaries and short-term benefits. The expenses were included in the following categories:

	Year ended December 31	
	2014	2013
Operating expenses	3,607	2,851
General and administrative	8,534	7,919
Prospective projects expenses	2,542	1,631
Transaction costs	281	609
Capitalized in Property, plant and equipment	4,377	2,769
Capitalized in Project development costs	1,873	2,552
	21,214	18,331

15. RESTRICTED CASH AND SHORT-TERM INVESTMENTS

As at	December 31, 2014	December 31, 2013
Restricted cash accounts	7,387	19,975
Restricted proceeds account	71,678	23,115
Debt service payment accounts	6,742	6,655
	85,807	49,745

As part of the Kwoiek Creek LP , Northwest Stave LP and Tretheway LP credit agreements, the Corporation maintains restricted cash accounts and restricted proceeds accounts. The balance of the loans proceeds are held in restricted proceeds account managed by the lenders and amounts are transferred from time to time into the restricted cash accounts to finance the construction of the projects. The restricted cash accounts are used to pay the current construction costs of the projects and to hold the construction holdbacks amounts that will be released at the end of the construction of the respective projects.

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

In relation with the six run-of-river hydroelectric facilities at Harrison Hydro L.P. (the "Harrison Operating Facilities"), the Corporation maintains debt service payment accounts. The debt service payment accounts require a monthly transfer equal to one-sixth of the next semi-annual bond payments and a monthly transfer equal to one-third of the next quarterly bond payment required on the outstanding junior bonds. Senior and junior loan payments are taken from this account on their due dates.

16. ACCOUNTS RECEIVABLE

As at	December 31, 2014	December 31, 2013
Trade	27,983	14,787
Commodity taxes	4,421	1,595
Investment tax credits	1,538	1,898
Others	1,329	1,519
	35,271	19,799

Substantially all of the Corporation's trade receivables relate to electricity sold to public utilities including Hydro-Québec, British Columbia Hydro, Hydro One Inc. and its affiliates and Idaho Power Company. Hydro-Québec currently holds a credit rating of A+ from Standard & Poor's (S&P). British Columbia Hydro and Power Authority currently holds a credit rating of AAA from S&P. The Ministry of Energy of the Province of Ontario has stated that the Province of Ontario, which currently holds a credit rating of AA- from S&P, will honor Hydro One Inc. and its affiliates obligations under the PPAs to which it is a party. Hydro One Inc. and its affiliates currently holds a credit rating of A+ from S&P. Idaho Power Company currently has a credit rating of BBB from S&P.

Commodity taxes and investment tax credits are receivable from the federal or provincial governments, following the development and construction of projects.

The Corporation did not record any allowance for doubtful accounts since, based on its experience, there is a low risk of bad debts. The Corporation does not hold any specific guarantees for its accounts receivable. All accounts receivable are current.

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

17. RESERVE ACCOUNTS

	Hydrology / wind power reserve	Major maintenance reserve	December 31, 2014 Total
Reserves – As at January 1, 2014	43,972	3,590	47,562
Reserve acquired on business acquisition (Note 5.1)	—	259	259
Net withdrawals from the reserves	(6,485)	(53)	(6,538)
Impact of foreign exchange fluctuations	60	(8)	52
Reserves – end of year	37,547	3,788	41,335
Less:			
Current portion	(651)	—	(651)
Long-term portion	36,896	3,788	40,684

	Hydrology / wind power reserve	Major maintenance reserve	December 31, 2013 Total
Reserves – As at January 1, 2013	45,291	2,325	47,616
Reserve acquired on business acquisition (Note 5.2)	—	422	422
Net (withdrawals from) investments in the reserves	(1,362)	835	(527)
Impact of foreign exchange fluctuations	43	8	51
Reserves – end of year	43,972	3,590	47,562
Less:			
Current portion	(1,771)	—	(1,771)
Long-term portion	42,201	3,590	45,791

During the year, the amounts held in the hydrology/wind power reserve generated investment income of $400 ($395 in 2013).

During the year, the amounts held in the major maintenance reserve generated investment income of $36 ($27 in 2013).

Reserve account investments	Maturity	Fair value	Net carrying value
Government-backed securities	2015	724	724
Short-term investments	2015	9,032	9,032
Cash and cash equivalents	—	31,579	31,579
		41,335	41,335

The fair value of the government-backed securities is determined by referring directly to the published active market prices. Short-term investments are held at major financial institutions. The Corporation recorded no impairment of these financial instruments since the counterparties have high credit ratings.

The availability of $39,018 ($42,797 in 2013) in the reserve accounts is restricted by credit agreements.

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

18. PROPERTY, PLANT AND EQUIPMENT

	Land	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Other equipments	Total
Cost							
As at January 1, 2014	2,141	1,063,065	370,729	124,205	201,742	7,473	1,769,355
Additions	161	7,463	501	—	222,555	1,150	231,830
Business acquisition (Note 5.1)	230	115,240	—	—	—	—	115,470
Transfer of assets upon commissioning	—	154,175	—	—	(154,175)	—	—
Transfer from projects under development	—	—	—	—	17,279	—	17,279
Dispositions	—	(298)	—	—	—	(185)	(483)
Other changes	—	(28)	876	39	—	(82)	805
Net foreign exchange differences	9	512	—	—	—	11	532
As at December 31, 2014	2,541	1,340,129	372,106	124,244	287,401	8,367	2,134,788
Accumulated depreciation							
As at January 1, 2014	—	(107,529)	(64,772)	(9,915)	—	(3,722)	(185,938)
Depreciation	—	(28,015)	(17,736)	(5,951)	—	(1,443)	(53,145)
Dispositions	—	30	—	—	—	151	181
Other changes	—	10	(20)	—	—	87	77
Net foreign exchange differences	—	(166)	—	—	—	(8)	(174)
As at December 31, 2014	—	(135,670)	(82,528)	(15,866)	—	(4,935)	(238,999)
Carrying amount as at December 31, 2014	2,541	1,204,459	289,578	108,378	287,401	3,432	1,895,789

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

Additions in the current year include $5,647 of capitalized financing costs ($13,359 for the year ended December 31, 2013) incurred prior to their intended use.

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 term credit facility are capitalized for the portion of the financing actually used for a specific property, plant and equipment.

The cost of facilities were reduced by investment tax credits of $1,408 ($1,161 as at December 31, 2013).

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

	Land	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Other equipments	Total
Cost							
As at January 1, 2013	2,105	920,368	370,819	124,133	140,901	6,127	1,564,453
Additions	30	6,945	1,213	100	87,926	1,453	97,667
Business acquisitions (Notes 5.2 and 5.3)	—	59,606	—	—	—	122	59,728
Transfer of assets upon commissioning	—	75,177	—	—	(75,177)	—	—
Transfer from projects under development	—	—	—	—	47,565	32	47,597
Dispositions	—	—	(99)	—	—	(240)	(339)
Other changes	—	605	(1,204)	(28)	527	(29)	(129)
Net foreign exchange differences	6	364	—	—	—	8	378
As at December 31, 2013	2,141	1,063,065	370,729	124,205	201,742	7,473	1,769,355
Accumulated depreciation							
As at January 1, 2013	—	(83,609)	(47,255)	(3,965)	—	(2,512)	(137,341)
Depreciation	—	(23,815)	(17,517)	(5,950)	—	(1,392)	(48,674)
Dispositions	—	—	—	—	—	156	156
Other changes	—	2	—	—	—	29	31
Net foreign exchange differences	—	(107)	—	—	—	(3)	(110)
As at December 31, 2013	—	(107,529)	(64,772)	(9,915)	—	(3,722)	(185,938)
Net value as at December 31, 2013	2,141	955,536	305,957	114,290	201,742	3,751	1,583,417

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

19. INTANGIBLE ASSETS

	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Total
Cost					
As at January 1, 2014	478,619	81,582	9,538	12,115	581,854
Business acquisition (Note 5.1)	18,807	—	—	—	18,807
Transfer of assets upon commissioning	4	—	—	(4)	—
Transfer from projects under development	—	—	—	23,240	23,240
Other changes	—	(5,766)	—	—	(5,766)
Net exchange differences	190	—	—	—	190
As at December 31, 2014	497,620	75,816	9,538	35,351	618,325
Accumulated amortization					
As at January 1, 2014	(90,526)	(24,460)	(775)	—	(115,761)
Amortization	(15,498)	(4,876)	(477)	(96)	(20,947)
Other changes	—	5,766	—	—	5,766
Net exchange differences	(71)	—	—	—	(71)
As at December 31, 2014	(106,095)	(23,570)	(1,252)	(96)	(131,013)
Net value as at December 31, 2014	391,525	52,246	8,286	35,255	487,312

	Hydroelectric facilities	Wind farm facilities	Solar facility	Facilities under construction	Total
Cost					
As at January 1, 2013	426,334	81,582	9,538	7,195	524,649
Business acquisitions (Note 5.2 and 5.3)	45,145	—	—	—	45,145
Transfer of assets upon commissioning	7,000	—	—	(7,000)	—
Transfer from projects under development	—	—	—	12,111	12,111
Other changes	5	—	—	(191)	(186)
Net exchange differences	135	—	—	—	135
As at December 31, 2013	478,619	81,582	9,538	12,115	581,854
Accumulated amortization					
As at January 1, 2013	(74,924)	(20,003)	(298)	—	(95,225)
Amortization	(15,552)	(4,457)	(477)	—	(20,486)
Other changes	(5)	—	—	—	(5)
Net exchange differences	(45)	—	—	—	(45)
As at December 31, 2013	(90,526)	(24,460)	(775)	—	(115,761)
Net value as at December 31, 2013	388,093	57,122	8,763	12,115	466,093

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

20. PROJECT DEVELOPMENT COSTS

	December 31, 2014	December 31, 2013
Cost		
Beginning of year	81,643	103,529
Additions	20,443	38,044
Transfer to property, plant and equipment	(17,279)	(47,597)
Transfer to intangible assets	(23,240)	(12,111)
Write-off of project development costs	—	(222)
Other changes	(547)	—
End of year	61,020	81,643

For the years ended December 31, 2014 and 2013, the Corporation conducted annual project development costs impairment tests. Based on the result of these tests, no impairment charge was required.

The recoverable amount of the project development costs is determined based on a value in use calculation which uses cash flow projections based on comparatives projects financial budgets approved by management covering a period extending between 40 and 75 years and a pre-tax discount rate of 6.50% (7.84% to 9.00% in 2013).

Assumptions used to determine the recoverable amount of assets are the following:

- The discount rate is a weighted average between the consolidated cost of debt and the consolidated cost of equity to which a risk premium is added for each project.
- A cash-generating unit is an individual hydroelectric facility.
- The future expected cash flows are based on comparative projects budgets of each cash-generating unit. The budgets have been built using long-term averages of water flows. These long-term averages approximate actual results.
- The number of projects and the timing of projects to be developed.

Additions in the current year include $235 of capitalized interests ($622 in 2013).

21. GOODWILL

Allocation of goodwill to each cash-generating unit is as follows:

As at	December 31, 2014	December 31, 2013
St-Paulin	935	935
Portneuf	4,166	4,166
Chaudière	3,168	3,168
Total Goodwill	8,269	8,269

For the years ended December 31, 2014 and 2013, the Corporation conducted annual goodwill impairment tests. Based on the result of these tests, no impairment charge was required.

The recoverable amount of each cash-generating unit is determined based on a value in use calculation which uses cash flow projections based on financial budgets approved by management covering a period extending to the lesser of 50 years or the period for which the Corporation owns its rights on the site and a pre-tax discount rate of 5.54% (6.84% in 2013).

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

Assumptions used to determine the recoverable amount of assets are the following:

- The discount rate is a weighted average between the consolidated cost of debt and the consolidated cost of equity to which a risk premium is added for each cash-generating unit.
- A cash-generating unit is an individual hydroelectric facility.
- The future expected cash flows are based on the budgets before debt service and income tax of each cash-generating unit. The budgets have been built using long-term averages of water flows. These long-term averages approximate actual results.

22. ACCOUNTS PAYABLE AND OTHER PAYABLES

As at	December 31, 2014	December 31, 2013
Trade and other payables	30,058	32,750
Current portion of construction holdbacks	6,143	7,129
Interest payable	7,019	6,548
Commodity taxes	2,387	1,831
	45,607	48,258

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

23. LONG-TERM DEBT

As at	December 31, 2014	December 31, 2013
Revolving credit term facility (a)		
Prime rate advances renewable until 2019 (rate of 3.85%, 3.60% in 2013)	20	20
Bankers' acceptances renewable until 2019 (rate of 3.06%, rate of 2.57% in 2013)	321,880	170,480
LIBOR advances, US$13,900 renewable until 2019 (rate of 2.04%, 1.54% in 2013)	16,125	14,784
Term loans		
Harrison Operating Facilities, non-interest bearing term loans from partners maturing in April 2015 (b)	1,750	—
Hydro-Windsor, 8.25% fixed rate term loan maturing in 2016 (c)	2,145	3,186
Fitzsimmons Creek, floating-rate term loan maturing in 2016 (2.42%, 2.37% in 2013) (d)	21,430	21,791
Magpie, 2.33% fixed rate bridge loan maturing in 2017(e)	850	1,156
Magpie, 5.30% fixed rate debenture maturing in 2017(e)	1,094	1,399
Montagne-Sèche, floating-rate term loan maturing in 2021 (rate of 3.05%, 3.72% in 2013) (f)	27,485	28,803
Rutherford Creek, 6.88% fixed rate term loan maturing in 2024 (g)	42,677	45,757
Magpie, 6.16% fixed rate convertible debenture convertible in 2025 (e)	5,262	5,497
Ashlu Creek, floating-rate term loan maturing in 2025 (rate of 2.96%, 2.81% in 2013) (h)	96,695	98,822
Sainte-Marguerite, 3.30% fixed rate term loan maturing in 2025 (i)	35,899	—
L'Anse-à-Valleau, floating-rate term loan maturing in 2026 (rate of 2.50%, 2.32% in 2013) (j)	38,716	41,188
Carleton, floating-rate term loan maturing in 2027 (rate of 3.46%, 3.28% in 2013) (k)	48,997	51,712
Stardale, floating-rate term loan maturing in 2030 (rate of 3.55%, 3.47% in 2013) (l)	101,643	106,220
Magpie, 4.37% fixed rate term loan maturing in 2031 (e)	54,452	56,566
Kwoiek Creek, 5.08% fixed rate construction loan maturing in 2052 (m)	168,500	168,500
Northwest Stave River, 5.30% fixed rate construction loan maturing in 2053 (n)	71,972	71,972
Kwoiek Creek, 10.07% fixed rate maturing in 2054 (m)	3,662	3,662
Tretheway, 4.99% fixed rate construction loan (o)	92,916	—
Sainte-Marguerite, 8.00% fixed rate debenture maturing in 2064 (i)	42,401	—
Other loans with various maturities and interest rates	136	116
Bonds		
Harrison Operating Facilities, senior real return bond maturing in 2049 (rate of 3.95%, 3.97% in 2013) (p) (s)	225,014	223,049
Harrison Operating Facilities, 6.61% senior fixed rate bond maturing in 2049 (q) (s)	209,485	211,681
Harrison Operating Facilities, junior real return bond maturing in 2049 (rate of 5.02%, 5.04% in 2013) (r) (s)	27,820	27,031
	1,659,026	1,353,392
Deferred financing costs	(14,427)	(13,025)
	1,644,599	1,340,367
Current portion of long-term debt	(33,799)	(26,649)
Long-term portion	1,610,800	1,313,718

a. Revolving term credit facility

On November 6, 2014 the Corporation executed an amending agreement to extend its revolving term credit facility from 2018 to 2019, as well as to temporarily increase its borrowing capacity by $50,000 until June 30, 2015, from $425,000 to $475,000. These modifications provides greater financing flexibility until the Corporation closes the four project-level financings that remain to be put in place.

As at December 31, 2014, the Bankers' Acceptances ("BA") rate advances and prime rate advances totaling $321,900 along with a LIBOR rate advance of $16,125 (US$13,900) were due under this facility. An amount of $31,145 has been used to secure letters of credit. Thus, the unused and available position of the facility was $105,830. The carrying value of assets of the Corporation and subsidiaries given as securities under this facility totals approximately $803,300.

b. Harrison Operating Facilities, term loans

On April 21, 2014, the partners of the Corporation in the Harrison Project loaned money to Harrison Operating Facilities. The loans are non-interest bearing. The partner's loans made to Harrison Operating Facilities amount to $1,750.

c. Hydro-Windsor

The loan consists of a 20-year term loan starting in December 1996 amortized over a 20-year period maturing in December 2016. The loan is repayable by monthly blended payments of principal and interest totaling $105. The principal repayments for 2015 are set to $1,078. The loan is secured by Hydro-Windsor LP's assets, with a carrying value of approximately $10,400.

d. Fitzsimmons Creek

The loan consists of a five-year term loan, amortized over a 30-year period starting in December 2011. The loan advances bear interest at BA rate plus an applicable margin. The principal repayments are variable and are set to $295 for 2015.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $150. As at December 31, 2014, an amount of $150 has been used to secure two letters of credit. This debt is secured by Fitzsimmons Creek Hydro LP's assets with a carrying value of approximately $25,600

e. Magpie

As part of the Magpie Acquisition, the Corporation assumed a $1,188 bridge loan, bearing interest at 6.06%, repayable in monthly blended payments of principal and interest totaling $27 and maturing on August 1, 2017. The bridge loan was accounted for at its fair market value of $1,281 on the Magpie Acquisition for an effective rate of 2.33%.

As part of the Magpie Acquisition, the Corporation assumed a $2,000 debenture, bearing no interest and repayable in yearly installments of $400 and maturing on December 31, 2017. The debenture was accounted for at its fair market value of $1,778 on the Magpie Acquisition for an effective rate of 5.30%.

As part of the Magpie Acquisition, the Corporation assumed a $3,000 convertible debenture, bearing interest at 15.50%, maturing in 2025. The convertible debenture was accounted for at its fair market value of $5,545 on the Magpie Acquisition for an effective rate of 6.16%. The convertible debenture entitles the municipality to a 30% interest in the facility upon conversion of the debenture on or before January 1, 2025. Early conversion is at the discretion of the Corporation.

As part of the Magpie Acquisition, the Corporation assumed a $49,251 term loan, bearing interest at 6.36%, repayable in monthly blended payments of principal and interest totaling $379 and maturing on December 1, 2031. The term loan was accounted for at its fair market value of $57,420 on the Magpie Acquisition for an effective rate of 4.37%.

The loans are repayable in monthly instalments. The principal repayments for the term loan are variable and are set at $1,593 for 2015; the principal repayments for the bridge loan are set at $288 for 2015 .The bridge loan and the term loan are secured by Magpie LP's assets with a carrying value of approximately $103,800.

f. Montagne-Sèche

In May 2014, the Corporation has renegotiated the loan to extend the maturity to June 2021. As at December 31, 2014, the loan bears interest at BA rate plus an applicable margin. The principal repayments are variable and set to $1,422 for 2015.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $445. As at December 31, 2014, an amount of $267 has been used to secure one letter of credit. The loan is secured by Innergex Montagne-Sèche, LP's assets with a carrying value of approximately $39,000.

g. Rutherford Creek

The loan consists of a 20-year fixed rate term loan starting in July 2004 amortized over a 12-year period effective July 1, 2012. This debt is repayable by monthly blended payments of principal and interest totaling $511. The principal repayments for 2015 are set to $3,299. The loan is secured by Rutherford Creek Power Limited Partnership's assets, with a carrying value of approximately $86,000.

h. Ashlu Creek

The loan consists of a 15-year term loan, amortized over a 25-year period starting in September 2010. The loan bears interest at BA rate plus an applicable margin. The term loan is repayable in quarterly installments. The principal repayments are variable and are set to $2,506 for 2015.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $3,000. As at December 31, 2014 an amount of $1,595 has been used to secure one letter of credit. The loan is secured by Ashlu Creek hydroelectric facility's assets with a carrying value of approximately $172,400.

i. Sainte-Marguerite

As part of the Sainte-Marguerite Acquisition, the Corporation assumed a $30,796 term loan, bearing interest at 7.40%, repayable in monthly blended payments of principal and interest totaling $360, increasing over the years and maturing in 2025. The principal repayments for 2015 are set to $2,308. The term loan was accounted for at its fair market value of $37,455 for an effective rate of 3.30%. The loan is secured by Sainte-Marguerite LP's assets with a carrying value of approximately $140,500.

Concurrent with the acquisition of the Sainte-Marguerite facility, a debenture was issue by Sainte-Marguerite LP to Desjardins Group Pension Plan for total proceeds of $40,901. In December 2014, an additional $1,500 was subscribed to the debenture issued by Sainte-Marguerite LP for a total amount of $42,401. This debenture carries an interest rate of 8.00%, has no predetermined repayment schedule and matures in 2064.

j. L'Anse-à-Valleau

The loan consists of an 18.5-year term loan starting in December 2007 and amortized over an 18.5-year period. The loan bears interests at BA rate plus an applicable margin. The term loan is repayable in quarterly installments. The principal repayments are variable and are set at $2,625 for 2015.

The lenders also agreed to make available a credit facility of $1,200 in order to secure letters of credit. As at December 31, 2014, an amount of $423 has been used to secure one letter of credit. The loan is secured by Innergex AAV, LP's assets with a carrying value of approximately $60,700.

k. Carleton

On June 26, 2013, the Corporation closed a $52,800 non-recourse term loan to refinance its ownership portion of the Carleton wind farm. The loan consists of a 14-year term loan, amortized over a 14-year period which starts on June 26, 2013. The term loan bears interest at BA rate plus an applicable margin. The term loan is repayable in quarterly installments. The principal repayments are variable and are set at $3,176 for the 2015.

This debt is secured by all Innergex CAR, LP's assets with a carrying value of approximately $77,900.

l. Stardale

The loan consists of an 18-year term loan starting in September 2012 and amortized over an 18-year period. The term loan is repayable in quarterly installments. The principal repayments are variable and set to $4,781 for 2015. The loan bears interest at the BA rate plus an applicable credit margin.

The lenders also agreed to make available a letter of credit facility in an amount not to exceed $5,600. As at December 31, 2014, an amount of $5,600 has been used to secure two letters of credit. The loan is secured by Stardale L.P.'s assets with a carrying value of approximately $120,800.

m. Kwoiek Creek

The $168,500 construction term loan carries a fixed interest rate of 5.08%; it was converted into a term loan in February 2015 and the principal will be amortized over a 36-year period, ending in 2052. The loan is secured by Kwoiek Creek Resources L.P.'s assets with a carrying value of approximately $182,700.

The partner of the Corporation in the Kwoiek Creek Project made a loan to Kwoiek Creek Resources Limited Partnership's. As per the agreements related to the project, both partners can participate in the financing of the project. The loans bear interests at a rate 10.07%. The partner's loan made to Kwoiek Creek Resources Limited Partnership amounts to $3,662. The Corporation's loan made to Kwoiek Creek Resources Limited Partnership, which was eliminated in the financial statement consolidation process, amounts to $56,732 as at December 31, 2014.

n. Northwest Stave River

On May 23, 2013, the Corporation closed a $71,972 non-recourse construction and term project financing for the Northwest Stave River hydroelectric project. The construction loan carries a fixed interest rate of 5.30%; It was converted into a term loan in February 2015 and the principal will be amortized over a 35-year period ending in 2053. The loan is secured by Northwest Stave River L.P.'s assets with a carrying value of approximately $87,800.

o. Tretheway

On September 30, 2014, the Corporation closed a $92,916 non-recourse construction and term project financing for the Tretheway Creek run-of-river hydroelectric project. The construction loan is carrying a fixed interest rate of 4.99%; upon the start of the project’s commercial operation, it will convert into a 40-year term loan and the principal will begin to be amortized over a 35-year period, starting in the sixth year. As of December 31, 2014, $92,916 has been drawn on this loan. The loan is secured by Tretheway L.P.'s assets with a carrying value of approximately $133,300.

p. Harrison Operating Facilities, Senior Real Return bond

The Harrison Operating Facilities Senior Real Return bond bears interest at 2.96% adjusted by an inflation ratio as well as an inflation compensation interest factor. Both inflation adjustments are based on the All-items Consumer Price Index for Canada (“CPI”), not seasonally adjusted. Payments on this bond are due semi-annually and the bond matures in June 2049. Semi-annual payments are $5,790 before CPI adjustment ($6,527 including CPI adjustment in 2014). In December 2031, the payment amount decreases to $4,481 before CPI adjustment where it remains until maturity. For 2015, the principal repayments are set to $5,527. The bond is secured by the Harrison Operating Facilities.

q. Harrison Operating Facilities, Senior Fixed Rate bond

The Harrison Operating Facilities Senior Fixed Rate bond bears interest at 6.61%. Payments on this bond are due semi-annually with the bond maturing in September 2049. Semi-annual payments amount to $8,072. In September 2031 the payment amount decreases to $6,724 where it remains until maturity. For 2015, the principal repayments are set to $3,103. The bond is secured by the Harrison Operating Facilities.

r. Harrison Operating Facilities, Junior Real Return bond

The Harrison Operating Facilities Junior Real Return Rate bond bears interest at 4.27% adjusted by an inflation ratio as well as an inflation compensation interest factor. Both inflation adjustments are based on the CPI, not seasonally adjusted. Payments on this bond are due quarterly and the bond matures in September 2049. Quarterly interests payments amount to $291 before CPI adjustment ($328 including CPI adjustment in 2014).

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

In June 2017 the payment amount increases to $389 before CPI adjustment where it remains until maturity. Principal repayment does not commence until June 2017. The bond is secured by the Harrison Operating Facilities.

s. Summary of Harrison Operating Facilities

The bonds are secured by the Harrison Operating Facilities. The carrying value of the property and assets of the Harrison Operating Facilities totals approximately $671,800.

	Senior Real Return Bond	Senior Fixed Rate Bond	Junior Real Return Bond	Total
Balance – January 1, 2014	223,049	211,681	27,031	461,761
Inflation compensation interest	5,991	—	708	6,699
Principal repayment	(5,342)	(2,937)	—	(8,279)
Amortization of revaluation	1,316	741	81	2,138
Balance – December 31, 2014	225,014	209,485	27,820	462,319

The increase in inflation compensation interest is a result of the CPI rate change over the reference period.

Principal repayments

The principal repayments for the next years, excluding the revaluations, will be as follows:

	Principal repayments	Amortization of revaluation	Long-term debt
2015	34,170	(371)	33,799
2016	52,974	(490)	52,484
2017	35,682	(594)	35,088
2018	37,624	(686)	36,938
2019	375,797	(787)	375,010
Thereafter	1,167,643	(41,936)	1,125,707
	1,703,890	(44,864)	1,659,026

24. OTHER LIABILITIES

Other liabilities, including amounts shown in current liabilities, consist of contingent considerations, asset retirement obligations and interests payable on SM-1 LP debenture relating to the Corporation's facilities.

	Contingent considerations	Asset retirement obligations	Interests payable on SM-1 LP debenture	Total
As at January 1, 2014	5,464	5,465	—	10,929
Interest expense included in finance cost	—	—	1,766	1,766
Accretion expense included in finance cost	355	266	—	621
Revisions in estimated cash flows	—	1,097	—	1,097
Payment of contingent considerations	(361)	—	—	(361)
As at December 31, 2014	5,458	6,828	1,766	14,052
Current portion of other liabilities	(244)	—	—	(244)
Long-term portion of other liabilities	5,214	6,828	1,766	13,808

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

	Contingent considerations	Asset retirement obligations	Total
As at January 1, 2013	2,775	6,095	8,870
Liability assumed as part of the business acquisition (note 5.2)	2,428	—	2,428
Accretion expense included in finance cost	280	266	546
Gain on contingent considerations	(19)	—	(19)
Revision in estimated cash flows	—	(896)	(896)
As at December 31, 2013	5,464	5,465	10,929
Current portion of other liabilities	(362)	—	(362)
Long-term portion of other liabilities	5,102	5,465	10,567

a. Contingent considerations

An acquisition realized in 2011 provides for the potential payment of additional amounts to the vendors over a period commencing on the acquisition date and ending on the 40th anniversary of the last project under development to achieve commercial operation (or to April 4, 2061 if earlier). The deferred payments are effectively intended to provide for a potential sharing of the value created if the projects perform better than the Corporation's expectations and would result in incremental accretion to the Corporation, net of these payments. The maximum aggregate amount of all deferred payments under this acquisition is limited to a present value amount of $35,000 as at the acquisition date.

In connection with another acquisition, the Corporation agreed to pay contingent considerations based upon future events for a period of three years after April 20, 2011. In 2014, there was no contingent consideration to be paid in connection with this acquisition.

In connection with the Magpie Acquisition, the Corporation assumed an obligation to pay contingent consideration to the Minganie Regional County Municipality until the convertible debenture issued by Magpie L.P. is converted. Upon conversion, the Minganie Regional County Municipality will be entitled to a participation of 30% in Magpie L.P.

b. Asset retirement obligations

Asset retirement obligations primarily arise from obligations to retire wind farms and solar facility upon expiry of the site leases. The wind farm facilities and solar facility were constructed on sites held under leases expiring 25 years after the signing date. The Corporation estimates that the undiscounted value of the payments required for settling the obligations over a 25-year period will be as follows:

Year of expected payments	
2031	2,592
2032	2,466
2033	2,748
2036	1,542
2037	6,243
	15,591

The cash flows were discounted at rates between 3.86% to 4.39% as at December 31, 2014 (4.81% to 5.30% in 2013) to determine the obligations.

c. Interests payable on SM-1 LP debenture

In connection with the acquisition of the SM-1 facility, Desjardins subscribed to a debenture issued by SM-1 LP for total proceeds of approximately $40,901. In December 2014, an additionnal $1,500 was subscribed to the debenture issued by SM-1 LP for a total amount of $42,401. This debenture carries an interest rate of 8.00%, has no predetermined repayment schedule and matures in 2064. Unpaid interests are compounded and are recorded in other long term liabilities.

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

25. CONVERTIBLE DEBENTURES

The convertible debentures bear interest at an annual rate of 5.75% and will mature on April 30, 2017. Interest is payable semi-annually on April 30 and October 31 of each year. Each convertible debenture is convertible into common shares of the Corporation at the option of the holder at any time prior to the earlier of April 30, 2017 and the redemption date specified by the Corporation. The conversion price is $10.65 per common share (the “Conversion Price”), being a conversion rate of approximately 93.8967 common shares per each thousand of dollars of principal amount of convertible debentures. Holders converting their convertible debentures will receive accrued and unpaid interest thereon for the period from the last interest payment date on their convertible debentures to the date of conversion.

Since April 30, 2013, and prior to April 30, 2015, the convertible debentures may be redeemed by the Corporation. Such redemption would be done, provided that the trading price of the common shares on the Toronto Stock Exchange is not less than 125% of the Conversion Price. On or after April 30, 2015 and prior to April 30, 2017, the convertible debentures may be redeemed at the option of the Corporation at a price equal to their principal amount. Subject to required regulatory approval, the Corporation may, at its option, elect to satisfy its obligation to pay the principal amount of the convertible debentures on redemption or at maturity, in whole or in part, through the issuance of freely tradable common shares upon prior notice, by delivering that number of common shares obtained by dividing the principal amount of the convertible debentures by 95% of the current market price. Any accrued or unpaid interest will be paid in cash.

The convertible debentures are subordinated to all other indebtedness of the Corporation.

The liability portion is being accreted such that the liability at maturity will equal the face value less prior conversions if any.

	December 31, 2014	December 31, 2013
Liability portion of convertible debentures, at fixed rate, 5.75% (effective rate of 6.09%), maturing on April 30, 2017, with a face value of $80,500	80,018	79,831
Equity portion of convertible debentures	1,340	1,340

26. SHAREHOLDERS' CAPITAL

Authorized

The authorized capital of the Corporation consists of an unlimited number of common shares and an unlimited number of preferred shares, non-voting, retractable and redeemable. This includes up to 3,400,000 Cumulative Rate Reset Preferred Shares, Series A (the "Series A Preferred Shares"), up to 3,400,000 Cumulative Floating Rate Preferred Shares, Series B (the "Series B Preferred Shares") and up to 2,000,000 Cumulative Redeemable Fixed Rate Preferred Shares, Series C (the "Series C Preferred Shares").

a) Common shares

Details of common shares issued are shown in the Consolidated Statements of Changes in Shareholders' Equity.

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

Special resolutions 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 were adopted on May 14, 2013. This resulted in a decrease of the shareholders' capital account and an equivalent increase of the contributed surplus from reduction of capital on common shares account.

c) Preferred shares

Series A Preferred Shares

On September 14, 2010, the Corporation issued a total of 3,400,000 Series A Preferred Shares at $25.00 per share for aggregate gross proceeds of $85,000. For the initial five-year period to, but excluding January 15, 2016 (the "Initial Fixed Rate Period"), the holders of Series A Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board of Directors. The dividends will be payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to $1.25 per share.

For each five-year period after the Initial Fixed Rate Period (each a "Subsequent Fixed Rate Period"), the holders of the Series A Preferred Shares will be entitled to receive fixed cumulative preferential cash dividends, as and when declared by the Board of Directors. The dividends will be payable quarterly in an annual amount per Series A Preferred Share, equal to the sum of the yield on a Government of Canada bond with a term to maturity of five years on the applicable fixed rate calculation date, plus 2.79%, applicable to such Subsequent Fixed Rate Period multiplied by $25.00.

Each holder of Series A Preferred Shares will have the right, at its option, to convert all or any of its Series A Preferred Shares into the Series B Preferred Shares of the Corporation on the basis of one Series B Preferred Share for each Series A Preferred Share converted, subject to certain conditions, on January 15, 2016 and on January 15 every five years thereafter. The holders of Series B Preferred Shares will be entitled to receive floating rate cumulative preferential cash dividends, as and when declared by the Board of Directors. The dividends will be payable quarterly in an annual amount per Series B Preferred Share equal to the Treasury Bills rate for the preceding quarterly period, plus 2.79%, per annum determined on the 30th day prior to the first day of the applicable quarterly floating rate period multiplied by $25.00.

The Series A Preferred Shares and the Series B Preferred Shares will not be redeemable by the Corporation prior to January 15, 2016.

Series C Preferred Shares

On December 11, 2012, the Corporation issued a total of 2,000,000 Series C Preferred Shares at $25.00 per share for aggregate gross proceeds of $50,000.

Holders of the Series C Preferred Shares will be entitled to receive, fixed cumulative preferential cash dividends as and when declared by the Corporation's Board of Directors. The dividends will be payable quarterly on the 15th day of January, April, July and October in each year at an annual rate equal to $1.4375 per share.

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

The Series C Preferred Shares will not be redeemable by the Corporation prior to January 15, 2018. The Series C Preferred Shares do not have a fixed maturity date and are not redeemable at the option of the holders.

d) Share-based payment

Stock option and performance share plans

The Corporation has a stock option plan and performance share plan. The share-based payments expense is accounted under fair value method. In accordance with this method, the stock options and the performance shares are measured at the fair value of the equity instruments at the date of grant.

The Corporation has a stock option plan providing for the granting of options by the Board of Directors to employees, officers, directors and certain consultants of the Corporation and its subsidiaries to purchase common shares. Options granted under the stock option plan will have an exercise price of not less than the market price of the common shares at the date of grant of the option, calculated as the volume weighted average trading price of the common shares on the Toronto Stock Exchange for the five trading days immediately preceding the date of grant.

The maximum number of common shares of the Corporation available for issuance pursuant to options granted under the stock option plan is 4,064,123. Any common shares subject to an option that expires or terminates without having been fully exercised may be subject to a further option. The number of common shares issuable to non-executive directors of the Corporation under the stock option plan cannot at any time exceed 1% of the issued and outstanding common shares.

Options must be exercised during a period established by the Board of Directors, which may not be greater than 10 years after the date of grant. Options granted under the stock option plan vest in equal amounts on a yearly basis over a period of four to five years following the grant date.

	December 31, 2014		December 31, 2013	
	Number of options (000's)	Weighted average exercise price ($)	Number of options (000's)	Weighted average exercise price ($)
Outstanding - beginning of year	3,073	9.95	2,736	10.08
Granted during the year	397	10.96	397	9.13
Exercised during the year	—	—	—	—
Canceled during the year	—	—	(60)	10.15
Outstanding - end of year	3,470	10.07	3,073	9.95
Options exercisable - end of year	2,252	10.08	1,728	10.22

The following options were outstanding and exercisable as at December 31, 2014:

Year of granting	Number of options outstanding (000's)	Exercise price ($)	Number of options exercisable (000's)	Year of maturity
2007	846	11.00	846	2017
2011	770	9.88	578	2018
2012	397	10.70	198	2019
2010	663	8.75	531	2020
2013	397	9.13	99	2020
2014	397	10.96	—	2021
	3,470		2,252	

The Corporation applies the fair value method of accounting for options granted to senior management, which is estimated using the Black-Scholes option-pricing model. Share-based payments are expensed and a credit is made to the share-based payment account in the equity of the Corporation to account for the options granted. The following assumptions were used to estimate the fair value of the options issued to grantees during the year:

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

	December 31, 2014	December 31, 2013
Risk-free interest rate	1.52%	2.04%
Expected annual dividend per common share	$0.60	$0.58
Expected life of options	6 years	6 years
Expected volatility	15.84%	17.85%
Fair value of options granted	$0.57	$0.53

For the purpose of compensation expense, stock-based compensation is amortized to expenses on a straight-line basis over the vesting period of a maximum of five years. The weighted average contractual life of the outstanding stock options is five years. Expected volatility is estimated by considering historic average share price volatility.

e) Dividend Reinvestment Plan ("DRIP")

The Corporation implemented a DRIP for its shareholders. On May 13, 2014, the Corporation elected to grant a discount of 2.5% on the purchase price of shares issued to shareholders participating in the DRIP. The plan allow eligible common shareholders the opportunity to reinvest a portion or all of the dividends they receive to purchase additional common shares of the Corporation, without paying fees such as brokerage commissions and service charges. Shares will either be purchased on the open market or issued from treasury.

27. ACCUMULATED OTHER COMPREHENSIVE (LOSS) INCOME

	Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries	Foreign exchange (loss) gain on the designated portion of the US dollar denominated debt used as hedge on the investment in self-sustaining foreign subsidiaries	Net currency translation reserve	Cash flow hedge interest rate risk	Total
Balance beginning of year 2014	(148)	392	244	—	244
Exchange differences on translating foreign operations	642	—	642	—	642
Hedging (loss) gain of the reporting period	—	(648)	(648)	(395)	(1,043)
Amount reclassified into earnings as reclassification adjustment	—	—	—	52	52
Related deferred tax	(85)	85	—	90	90
Balance end of year 2014	409	(171)	238	(253)	(15)

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

	Foreign exchange gain (loss) on translation of self-sustaining foreign subsidiaries	Foreign exchange (loss) gain on the designated portion of the US dollar denominated debt used as hedge on the investment in self-sustaining foreign subsidiaries	Total
Balance beginning of year 2013	(458)	699	241
Exchange differences on translating foreign operations	356	—	356
Hedging gain or (loss) of the reporting period	—	(352)	(352)
Related deferred tax	(46)	45	(1)
Balance end of year 2013	(148)	392	244

28. ADDITIONAL INFORMATION TO THE CONSOLIDATED STATEMENTS OF CASH FLOWS

a. Changes in non-cash operating working capital items

	Year ended December 31	
	2014	2013
Accounts receivable and income tax receivable	(15,463)	31,951
Prepaid and others	(183)	(318)
Accounts payable and other payables and income tax liabilities	2,428	(1,350)
	(13,218)	30,283

b. Additional information

	Year ended December 31	
	2014	2013
Interest paid (including $4,238 capitalized interest ($13,268 in 2013))	78,712	73,009
Non-cash transactions		
in unpaid property, plant and equipment	25,919	(6,532)
in unpaid development costs	(6,812)	10,245
in unpaid intangible assets	—	(27)
in unpaid issuance costs of preferred shares	—	(353)
loans to related parties	(6,798)	(23,444)
variation in discounted rates in asset retirement obligations	1,097	(896)
in common shares issued through dividend reinvestment plan	(10,191)	(18,075)
acquisition of assets for a project under development in exchange of the increase of a non-controlling interest in a subsidiary	(2,300)	—

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

29. SUBSIDIARIES

29.1 General information of subsidiaries

Details of the Corporation's material subsidiaries at the end of the reporting period are set out below.

Name of subsidiaries	Principal activity	Place of creation and operation	Proportion of ownership interest and voting rights held by the Corporation	
			December 31, 2014	December 31, 2013
Harrison Hydro L.P. and its subsidiaries	Own and operate hydroelectric facilities	British Columbia	50.01%	50.01%
Creek Power Inc. and its subsidiaries	Develop, construct, own and operate hydroelectric facilities	British Columbia	66.67%	66.67%
Kwoiek Creek Resources L.P. [1]	Own and operate a hydroelectric facility	British Columbia	50.00%	50.00%
Ashlu Creek Investments L.P.	Own and operate a hydroelectric facility	British Columbia	100.00%	100.00%
Innergex L.P.	Own and operate hydroelectric facilities	Québec	100.00%	100.00%
Innergex GM, L.P.	Own and operate a wind farm facility	Québec	100.00%	100.00%
Innergex Sainte-Marguerite S.E.C.	Own and operate a hydroelectric facility	Québec	50.01%	—
Tretheway Creek Power L.P.	Construct, own and operate a hydroelectric facility	British Columbia	100.00%	100.00%
Stardale Solar L.P.	Own and operate a solar facility	Ontario	100.00%	100.00%

1. The Corporation owns more than 50% of the economic interest in Kwoiek Creek Resources L.P.

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

The Corporation has subsidiaries, the principal activities of which are summarized as follows:

Principal activity	Principal place of business	Number of subsidiaries	
		December 31, 2014	December 31, 2013
Own or operate hydroelectric facilities	Québec	9	7
	Ontario	4	4
	British Columbia	22	21
	United States	1	1
		36	33
Own or operate wind farm facilities	Québec	10	10
Own or operate a solar facility	Ontario	2	2
Develop or construct hydroelectric facilities	British Columbia	8	12
	Québec	2	—
		10	12
Holdings and others	Québec	6	9
	Ontario	4	3
	British Columbia	10	8
	United States	2	2
	Nova Scotia	2	2
		24	24
		82	81

29.2 Details of non-wholly-owned subsidiaries that have non-controlling interests

The table below shows details of non-wholly-owned subsidiaries of the Corporation:

Name of subsidiaries	Place of creation and operation	Proportion of ownership interests and voting rights held by non-controlling interests		(Loss) earnings allocated to non-controlling interests for the year ended		Accumulated non-controlling interests (deficit)	
		December 31, 2014	December 31, 2013	December 31, 2014	December 31, 2013	December 31, 2014	December 31, 2013
Harrison Hydro L.P. and its subsidiaries	British Columbia	49.99%	49.99%	(4,177)	(3,450)	76,984	87,959
Creek Power Inc. and its subsidiaries	British Columbia	33.33%	33.33%	(15,554)	761	(14,796)	758
Kwoiek Creek Resources, L.P. (1)	British Columbia	50.00%	50.00%	(852)	(6)	(7,986)	(7,134)
Mesgi'g Ugju's'n (MU) Wind Farm L.P. (1)	Québec	50.00%	—	(7,559)	—	(5,259)	—
Innergex Sainte-Marguerite, S.E.C. (2)	Québec	49.99%	—	(1,381)	—	(1,376)	—
Others	Various	Various	Various	(2)	(44)	(156)	(154)
				(29,525)	(2,739)	47,411	81,429

1.The Corporation owns more than 50% of the economic interest in the subsidiary.
2.Period of 195 days.

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

Summarized financial information in respect of each of the Corporation's subsidiaries that has material non-controlling interests is set out below. The summarized financial information below represents amounts before intragroup eliminations.

Harrison Hydro L.P. and its subsidiaries

As at	December 31, 2014	December 31, 2013
Summary Statements of Financial Position		
Current assets	31,079	30,143
Non-current assets	646,421	662,749
Current liabilities	19,582	13,925
Non-current liabilities	462,609	460,511
Equity attributable to owners	118,325	130,497
Non-controlling interests	76,984	87,959

	Year ended December 31	
	2014	2013
Summary Statements of Earnings and Comprehensive Loss		
Revenues	49,671	47,196
Expenses	59,215	55,397
Net loss and comprehensive loss	(9,544)	(8,201)
Net loss and comprehensive loss attributable to:		
Owners of the parent	(5,367)	(4,751)
Non-controlling interests	(4,177)	(3,450)
	(9,544)	(8,201)
Distributions to non-controlling interests	6,798	23,444
Summary Statements of Cash Flows		
Net cash inflow from operating activities	12,799	13,908
Net cash outflow from financing activities	(4,779)	(7,877)
Net cash inflow (outflow) from investing activities	1,534	(9,751)
Net increase (decrease) in cash and cash equivalents	9,554	(3,720)

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

Creek Power Inc. and its subsidiaries

As at	December 31, 2014	December 31, 2013
Summary Statements of Financial Position		
Current assets	8,707	6,593
Non-current assets	218,832	67,349
Current liabilities	78,882	13,547
Non-current liabilities	204,384	69,534
Deficit attributable to owners	(40,931)	(9,897)
Non-controlling interest (deficit)	(14,796)	758

	Year ended December 31	
	2014	2013
Summary Statements of Earnings and Comprehensive (loss) Income		
Revenues	3,053	2,346
Expenses	49,641	15
Net (loss) earnings and comprehensive (loss) income	(46,588)	2,331
Net (loss) earnings and comprehensive (loss) income attributable to:		
Owners of the parent	(31,034)	1,570
Non-controlling interest	(15,554)	761
	(46,588)	2,331
Summary Statements of Cash Flows		
Net cash (outflow) inflow from operating activities	(969)	731
Net cash inflow from financing activities	122,986	19,485
Net cash outflow from investing activities	(116,624)	(20,661)
Net increase (decrease) in cash and cash equivalents	5,393	(445)

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

Kwoiek Creek Resources L.P.

As at	December 31, 2014	December 31, 2013
Summary Statements of Financial Position		
Current assets	28,098	34,019
Non-current assets	177,749	177,928
Current liabilities	8,362	23,694
Non-current liabilities	213,399	202,901
Deficit attributable to owners	(7,928)	(7,514)
Non-controlling interest deficit	(7,986)	(7,134)

	Year ended December 31	
	2014	2013
Summary Statements of Earnings and Comprehensive Income (loss)		
Revenues	17,969	7
Expenses	19,235	—
Net (loss) earnings and comprehensive (loss) income	(1,266)	7
Net (loss) earnings and comprehensive (loss) income attributable to:		
Owners of the parent	(414)	13
Non-controlling interest	(852)	(6)
	(1,266)	7
Summary Statements of Cash Flows		
Net cash inflow (outflow) from operating activities	2,255	(4,499)
Net cash (outflow) inflow from financing activities	(98)	3,391
Net cash outflow from investing activities	(2,986)	(3,012)
Net decrease in cash and cash equivalents	(829)	(4,120)

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

Mesgi'g Ugju's'n (MU) Wind Farm L.P.

The Mi'gmaq partner invested an amount of $2,300 in preferred units of the Mesgi'g Ugju's'n (MU) Wind farm L.P. This is reflected in the non-controlling interest account.

As at	December 31, 2014
Summary Statement of Financial Position	
Current assets	4,907
Non-current assets	11,807
Current liabilities	21,688
Non-current liabilities	1,140
Deficit attributable to owners	(855)
Non-controlling interest deficit	(5,259)

	Period of 285 days ended December 31, 2014
Summary Statement of Loss and Comprehensive loss	
Revenues	—
Expenses	17,064
Net loss and comprehensive loss	(17,064)
Net loss and comprehensive loss attributable to:	
Owners of the parent	(9,505)
Non-controlling interest	(7,559)
	(17,064)
Summary Statement of Cash Flows	
Net cash inflow from operating activities	278
Net cash inflow from financing activities	7,451
Net cash outflow from investing activities	(4,708)
Net increase in cash and cash equivalents	3,021

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

Innergex Sainte-Marguerite, S.E.C. ("SM-1 LP")

Desjardins has invested an amount of $5 in participating units of SM-1 LP. This is reflected in the non-controlling interest account.

As at	December 31, 2014
Summary Statement of Financial Position	
Current assets	2,286
Non-current assets	138,217
Current liabilities	6,283
Non-current liabilities	120,485
Equity attributable to owners	15,111
Non-controlling interest deficit	(1,376)

	Period of 195 days ended December 31, 2014
Summary Statement of Loss and Comprehensive loss	
Revenues	4,821
Expenses	7,584
Net loss and comprehensive loss	(2,763)
Net loss and comprehensive loss attributable to:	
Owners of the parent	(1,382)
Non-controlling interest	(1,381)
	(2,763)
Summary Statement of Cash Flows	
Net cash outflow from operating activities	(233)
Net cash inflow from financing activities	43,366
Net cash outflow from investing activities	(42,260)
Net increase in cash and cash equivalents	873

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

29.3 Financial support to structured entity

Kwoiek Creek Resources L.P

Based on the contractual arrangements between the Corporation and the other partner, the Corporation concluded that it has control over Kwoiek Creek Resources L.P.

The Corporation is responsible for financing approximately 20% of the capital costs and has loaned such amount or invested in preferred units of Kwoiek Creek Resources L.P.

Kwoiek Creek Resources Inc., the other partner, can participate for an amount up to $3,662 of subordinated debt.

The Corporation invested a total of $56,732 in preferred units of Kwoiek Creek Resources L.P. This investment provides the Corporation with revenues under the form of preferred distributions.

Interests or distributions on the aggregate subordinated debt and preferred units will subsequently be payable annually subject to the availability of gross revenues. The interests or distributions on preferred units are payable before making any distributions on the common units.

Mesgi'g Ugju's'n (MU) Wind Farm L.P

Based on the contractual arrangements between the Corporation and the other partner signed during the first quarter of 2014, the Corporation concluded that it has control over Mesgi'g Ugju's'n (MU) Wind Farm L.P.

The Corporation is responsible for financing equity required by the project. Mi'gmawei Mawiomi Resources L.P., the other partner, can participate in the financing of the equity for an amount up to a maximum of $10,000.

The Corporation invested a total of $8,650 in Mesgi'g Ugju's'n (MU) Wind Farm L.P. preferred units. This investment provides the Corporation with revenues in the form of preferred distributions. During the second quarter of the year 2014, the Mi'gmaq partner also invested an amount of $2,300 in preferred units of the Mesgi'g Ugju's'n (MU) Wind farm L.P.

Distributions on preferred units will subsequently be payable subject to the availability of gross revenues. The cumulated distributions on preferred units are payable before making any distributions on common units.

30. JOINT OPERATIONS

Name of entities	Principal activity	Place of creation and operation	Proportion of ownership interest and voting rights held by the Corporation	
			December 31, 2014	December 31, 2013
Innergex AAV, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex BDS, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex CAR, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex GM, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Innergex MS, L.P. (1)	own and operate a wind farm facility	Quebec	100%	100%
Others	operate wind farm facilities	Quebec	50%	38% to 50%

(1). Each of the Limited Partnership owns a 38% ownership interest in the assets, liabilities, revenues and expenses and 50% voting rights of the joint operations.

31. RELATED PARTY TRANSACTIONS

The Harrison Hydro L.P. distributed $13,600 in 2013. The funds were distributed in the form of non-interest bearing loans to the Corporation and its partners, which were presented as loans to partners as at December 31, 2013. On January 1, 2014, the $6,798 loans to partners were reimbursed directly from distributions from the Harrison Hydro L.P. and a corresponding decrease in non-controlling interests was recorded in 2014 with no impact to cash flows.

During 2013, loans were made to Viger-Denonville project until such time as the project-level financing was put in place or drawn. These loans bore interest at the same rate as the Corporation paid to its lenders on the revolving credit facility plus a margin. These loans were reimbursed prior to the end of 2013.

32. FINANCIAL INSTRUMENTS

a. Fair value disclosures

Fair value estimates are made at specific points in time using available information about the financial instrument in question. These estimates are subjective in nature and often cannot be determined precisely.

As at December 31, 2014, the Corporation determined that the carrying values of its current financial assets and liabilities approximated their fair values due to these instruments' short term maturity.

As at December 31, 2014 the Corporation determined that the carrying values of its short-term investments and government-backed securities included in reserve accounts approximated their fair values due to these instruments short-term maturity.

The carrying values of the floating rate long-term debts are approximately $64,782 lower than their estimated fair values based on the swap interest curve on December 31, 2014, increased by a risk premium ranging from 0.44% to 3.74% for a total ranging from 0.88% to 4.85%. The carrying values of the fixed-rate debts, the bonds and the debentures are approximately $78,263 lower than their estimated fair market values based on the swap interest curve on December 31, 2014, increased by a risk premium ranging from 0.44% to 4.85% for a total ranging from 1.81% to 6.83%.

b. Interest rate risk

The Corporation entered into hedge agreements to mitigate the risk of fluctuations in the interest rates on its long-term debt. The Corporation has entered into new bond forward contracts for a notional amount of $535,000 maturing in 2015 at a weighted average rate of 3.09%, to manage its risk on the projects of Upper Lillooet River, Boulder, Mesgi'g Ugju's'n and Big Silver.

The Corporation has entered into new interest rate swaps contracts for a notional amount of $40,000 maturing in 2024 at a weighted average rate of 2.31%, to manage its risk on the revolving term credit facility.

The interest hedging instruments and related risks are described in detail in Note 10.

c. Credit risk

Credit risk relates to the possibility that a loss may occur from a party's failure to comply with contractual requirements.

Cash and cash equivalents are mainly held at large Canadian financial institutions and, to a lesser degree, at major U.S. financial institutions.

The financial derivatives and related risks are described in detail in Note 10.

The Corporation's accounts receivable and related risks are described in detail in Note 16.

The reserve accounts and related risks are described in detail in Note 17.

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

d. Liquidity risk

Liquidity risk relates to the capacity of the Corporation to meet liabilities as they become due. Certain covenants of long-term borrowing contracts could prevent the Corporation from repatriating funds from certain subsidiaries.

Some interest rate hedging instruments have embedded early termination options that are exercisable only on their underlying debt's maturity date. The triggering of these options could pose a liquidity risk. Should the early termination option be triggered, a presumed realized loss would be offset by the savings realized on future interest expenses, as a negative swap value would be the result of an environment in which interest rates were lower than the rate embedded in the swap.

The Corporation has a negative working capital of $17,387 as at December 31, 2014 due to the $90,544 negative value of the bond forwards (positive working capital of $19,057 in 2013). The bond forwards are expected to be financed upon obtaining the project-level financings for Upper Lillooeet, Boulder, Big Silver and Mesgi'g Ugju's'n. If necessary, the Corporation can use its revolving credit term facility, as described in Note 23 a), of which $105,830 was available as at December 31, 2014 ($209,367 in 2013). In addition, in the event of lower revenue due to a decline in production or to a major equipment breakdown, the Corporation has available reserve accounts (as described in Note 17) and is covered by insurance plans. Accordingly, the Corporation believes its current working capital to be sufficiently covered to meet all of its needs.

The following table presents the maturities of the financial liabilities:

	Less than 3 months	Between 3 months and 1 year	Between 1 year and 5 years
Dividends payable to shareholders	16,882	—	
Accounts payable and other payables	36,474	9,133	
Income tax liabilities	295	1,113	
Current portion of derivative financial instruments	93,894	10,201	
Current portion of long-term debt	7,569	26,230	
Current portion of other liabilities	—	244	
Construction holdbacks			10,818
Derivative financial instruments			30,287
Accrual for acquisition of long-term assets			25,270
Long-term debt			499,519
Other liabilities			905
Liability portion of convertible debentures			80,018
Total	155,114	46,921	646,817

The maturities are determined based on the expected terms of the payments.

e. Market risk

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

The sale of electricity is made pursuant to long-term agreements where the offtakers are committed to take and pay for the total production, up to certain annual limits. The inflation clauses of the sale price of electricity are normally allowing the Corporation to cover its increase of variable operation expenses. The inflation clauses included in some of the electricity purchasing contracts with Hydro-Québec are limited to a maximum of 6% per year.

f. Foreign exchange risk

The foreign exchange risk relates to fluctuations in the U.S. dollar and Euro against the Canadian dollar.

The Corporation has subsidiaries in the United States for which the revenues, net of the expenses incurred, are repatriated to Canada. A portion of the Corporation's debts is denominated in U.S. dollars. Repatriated funds that are not used to service the U.S. dollar-denominated debt are converted into Canadian dollars at the exchange rate in effect on the conversion date. The Corporation's net risk is estimated to be $19 for each 1% increase in the value of the Canadian dollar against the U.S. dollar. The Corporation uses a portion of its U.S. dollar-denominated debt to hedge its investment in its subsidiaries, as described in Note 10.

33. COMMITMENTS AND CONTINGENCIES

In addition to the commitments of the Joint Venture presented in note 9, the Corporation entered into the following transactions:

a. Power Purchase Agreements

Quebec facilities

Under PPAs with terms varying from 20 to 25 years and expiring between 2016 and 2034, Hydro-Québec agreed to purchase all of the electrical energy provided by the facilities and wind farms located in the Province of Quebec. Certain facilities have an agreed maximum quantity of electricity and a minimum quantity of electricity to deliver during each of the consecutive 12-month periods. All of the hydroelectric facilities, at the exception of Magpie facility, can renew their PPAs for identical periods.

Total revenues from Hydro-Québec amounted to $94,668 in 2014 ($86,927 in 2013), representing 39% of the Corporation's revenues (44% in 2013). The Corporation is economically dependent on Hydro-Québec given the size of its revenues.

British Columbia facilities

Under PPAs with terms varying from 20 to 40 years and expiring between 2016 and 2054, British Columbia Hydro and Power Authority agreed to purchase all of the electrical energy provided by the facilities located in the Province of British-Columbia.

Total revenues from British Columbia Hydro and Power Authority amounted to $107,195 in 2014 ($72,338 in 2013) representing 44% of the Corporation's revenues (36% in 2013). The Corporation is economically dependent on British Columbia Hydro and Power Authority given the size of its revenues.

Ontario facilities

Under PPAs with terms varying from 20 to 30 years and expiring between 2025 and 2032, Hydro One inc. and its affiliates agreed to purchase all of the electrical energy provided by the facilities located in Ontario.

Total revenues from the Ontario facilities amounted to $22,366 ($22,256 in 2013) representing 9% of the Corporation's revenues (11% in 2013).

Idaho facility

Under a PPAs with a 35-year term and expiring in 2030, Idaho Power Company agreed to purchase all of the electricity provided by Horseshoe Bend Hydroelectric Corporation.

Total revenues from Idaho Power Company amounted to $3,398 in 2014 ($3,013 in 2013), representing 1% of the Corporation's revenues (2% in 2013).

b. Other Commitments

Wind farm facilities

The Corporation and its subsidiaries entered into royalties and other commitments related to amounts to set aside for the dismantling of wind farm components, commitments to surrounding municipalities and the operation of the wind farms.

Subsidiaries and/or joint ventures are also committed under options on leases for projects under development.

Mesgi'g Ugju's'n (MU) Wind Farm L.P.

Mesgi'g Ugju's'n (MU) Wind Farm L.P. entered into various contracts for the construction of an hydroelectric power-generating facility.

Ashlu Creek facility

Pursuant to an agreement with Ashlu Creek Investments Limited Partnership, a First Nation is entitled to a royalty based on revenues of the Ashlu Creek Project since the beginning of operations. A First Nation is also entitled to an incremental share of gross revenues exceeding a yearly threshold of gross revenues set out in the agreement. The agreement also requires the assets of the Ashlu Creek Project to be transferred to a First Nation for a nominal price after 40 years of commercial operation.

Big Silver Creek facility

Big Silver Creek Power L.P. entered into several contracts for the construction of hydroelectric power-generating facility.

Boulder Creek facility

Boulder Creek LP entered into several contracts for the construction of hydroelectric power-generating facility.

Brown Miller facilities

Brown Miller Power L.P. has several royalties agreements based on a percentage of gross revenues or on production.

Glen Miller facility

Glen Miller Power, Limited Partnership entered into a 30-year lease agreement ending in December 2035 for the site that is in commercial operation. The lease has a 15-year extension option upon terms and conditions to be negotiated.

Glen Miller Power, Limited Partnership is committed to remit the facility to the lessor of the site, at the end of the lease agreement, for no consideration

Harrison Hydro L.P.

The ownership of Douglas Creek Project L.P. and Tipella Creek Project L.P. will be transferred to a First Nation on the 60^{th} anniversary of the commercial operation date for no financial consideration.

Harrison Hydro L.P. entered into an agreement with First Nations to pay annual royalties based on a percentage of the gross revenues starting after the date of commencement of commercial operations of the facilities. This percentage will increase every 20 years for the first 60 years. An additional royalty will be payable if the average price per megawatt hour is greater than an agreed amount.

Kwoiek Creek facility

Construction contracts

Kwoiek Creek Resources L.P. entered into various contracts for the construction of an hydroelectric power-generating facility.

Royalty agreement

Kwoiek Creek Resources L.P. entered into an agreement to pay to Kwoiek Creek Resources Inc. an annual royalty, which is based on a percentage of the gross revenues, less project costs, for the first 20 years after the date of commencement of commercial operations of the Kwoiek Creek Project and an increased royalty for the 20 years thereafter. For the first 20 years of the operating phase, the partnership will not pay any interest on its subordinated debt nor any distribution on the preferred units, which are owned by the Corporation or the other partner, unless the royalty has been paid.

Partnership agreement

40 years after the beginning of the operations, the Corporation's ownership will be transferred to the other partner. Subsequently, the Corporation will receive a royalty based on a percentage of the gross revenues less project costs.

Magpie facility

Magpie Limited Partnership has several royalties agreements based on gross revenues or on production.

North West Stave facility

North West Stave River Hydro LP, entered into an agreement to pay a First Nation an annual royalty based on a percentage of the gross revenues starting after the date of commencement of commercial operations of the North West Stave project. This percentage will increase every 20 years for the first 60 years. An additional royalty will be payable if the average price per megawatt hour is greater than an agreed amount.

Rutherford Creek facility

Rutherford L.P. agreed to make payments to the former owners, following the expiry of the Rutherford Creek PPA. This payment is based on the difference between the then selling price of electricity and the last selling price of electricity under the agreement, adjusted annually following the expiry of the agreement by 50% of the increase or decrease in the CPI over the previous 12 months. This amount will correspond to 35% of the gross revenues attributable to the difference for the 20-year period following the expiry of the power purchase agreement. It will accrue annually and be paid quarterly during the following year. After the 20-year period, that portion of the payment will correspond to 30% of the gross revenues attributable to the difference. This commitment is secured by the Rutherford L.P. facility but is subordinated to the $45,757 term loan described in Note 23 g).

Stardale Solar LP

Stardale Solar LP entered into a contract for the operations and maintenance of the solar farm.

Tretheway facility

Tretheway Creek Power L.P. entered into several contracts for the construction of a hydroelectric power-generating facility

Upper Lillooet facility

Upper Lillooet River LP entered into several contracts for the construction of hydroelectric power-generating facility.

Operating leases

The Corporation is engaged under long-term operating leases of premises which will expire between 2018 and 2020.

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

Summary of commitments

As at December 31, 2014, the expected schedule of commitment payments is as follows:

Year of expected payment	Hydroelectric Generation	Wind Power Generation	Solar Generation	Site Development	Total
2015	81,628	17,656	11,192	307,508	417,984
2016	98,888	17,666	11,123	231,511	359,188
2017	79,590	15,719	10,297	97,102	202,708
2018	80,035	15,429	10,019	11,162	116,645
2019	111,716	93,229	12,096	229,623	446,664
Thereafter	2,032,113	115,747	102,438	25,891	2,276,189
Total	2,483,970	275,446	157,165	902,797	3,819,378

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.

34. CAPITAL DISCLOSURES

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

The Corporation seeks to achieve its objectives by:

- Maintaining the generating capacity and enhancing the operation of its hydroelectric facilities, wind farms and solar farm; and
- Acquiring and developing new electricity-generating facilities.

The Corporation maintains its generating capacity by investing the necessary funds to maintain and continually upgrade its equipment. The Corporation also invests approximately $1,200 on an annual basis in major maintenance reserve in order to fund any major maintenance of hydroelectric facilities, wind farms or solar farm which may be required to preserve the Corporation's generating capacity.

The Corporation determines the amount of capital required, and its allocation between debt and equity, for the acquisition and development of new electricity-generating facilities by considering the specific characteristics of stability and growth of each facility. This determination is made in order to distribute a stable dividend while maintaining an acceptable level of indebtedness.

The Corporation has a hydrology/wind power reserve. This reserve could be used in the event that the net available cash for any given year is less than expected, due to normal changes in hydrology or wind conditions or other unpredictable factors.

The Corporation's capital is composed of long-term debt, convertible debentures and shareholders' equity. Total capital amounts to $2,286,842 at year end.

The Corporation uses equity primarily to finance the development of projects. The Corporation uses long-term debt to finance the construction of its facilities. The Corporation expects to finance 70% to 85% of its construction costs mostly through non-recourse long-term debt financing.

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

Future development and construction of new facilities,development of projects, expenses on prospective projects and other capital expenditures will be financed out of cash generated from the Corporation's operating facilities, borrowings and/or issuance of additional equity. To the extent that external sources of capital, including issuance of additional securities of the Corporation, become limited or unavailable, the Corporation's ability to make necessary capital investment to construct new or maintain existing project facilities will be impaired. There is no certainty that sufficient capital will be available on acceptable terms to fund further development or expansion.

Under the terms of the Revolving credit term facility described in Note 23 a), the Corporation needs to maintain, a leverage ratio and an interest coverage ratio. If the ratios are not met, the lender has the ability to recall the facility.

Regarding the respective non-recourse projects financing, some subsidiaries of the Corporation need to maintain minimum debt coverage ratios. If the ratios of a particular project financing are not met, the lenders could have the ability to recall the particular debt. Certain financial restrictive clauses could prevent the subsidiaries from making distributions to the Corporation.

All debt covenants are monitored on a regular basis by the Corporation. During the year, the Corporation and its subsidiaries met all the financial and non-financial conditions related to their credit agreements, with the exception of the Rutherford Creek facility, which made a distribution to the Corporation while it wasn't meeting one of its financial ratios. The amount was subsequently reimbursed and at no time constituted a default event.

The Corporation's capital management objectives, policies and procedures are to ensure the stability and sustainability of the dividend payable to its shareholders and the development or acquisition of power production facilities. The objectives were identical in prior years.

35. SEGMENT INFORMATION

Geographic segments

The Corporation owns interests in 25 hydroelectric facilities, six wind farms and one solar farm in Canada and one hydroelectric facility in the United States. For the year ended December 31, 2014, revenues generated by the Horseshoe Bend hydroelectric facility located in the United States totalled $3,398 ($3,013 in 2013), representing a contribution of 1.4% (1.5% in 2013) to the Corporation’s consolidated revenues for these periods.

Major Customers

A major customer is defined as an external customer whose transaction with the Corporation amount to 10% or more of the Corporation's annual revenues. The Corporation has identified two major customers. The sales of the Corporation to these major customers are the following:

		Year ended December 31	
Major customer	Segment	2014	2013
British Columbia Hydro and Power authority	Hydroelectric generation	107,195	72,338
Hydro-Québec	Hydroelectric and wind power generation	94,668	86,927
.		201,863	159,265

Operating segments

The Corporation has four operating segments: (a) hydroelectric generation (b) wind power generation (c) solar power generation and (d) site development.

Through its hydroelectric, wind power and solar power generation segments, the Corporation sells electricity produced by its hydroelectric, wind farm and solar facilities to publicly owned utilities or other creditworthy counterparties. Through its site development segment, it analyzes potential sites and develops hydroelectric, wind and solar facilities up to the commissioning stage.

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

The accounting policies for these segments are the same as those described in the significant accounting policies. The Corporation evaluates performance based on earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses (revenues), share of (earnings) loss of joint ventures and unrealized net (gain) loss on derivative financial instruments. The Corporation accounts for inter-segment and management sales at cost. Any transfers of assets from the site development segment to the hydroelectric, wind power generation or solar power generation segments are accounted for at cost.

The operations of the Corporation's operating segments are conducted by different teams, as each segment has different skill requirements.

Year ended December 31, 2014					
Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	171,029	53,971	16,834	—	241,834
Expenses:					
Operating	30,828	9,538	1,146	—	41,512
General and administrative	8,205	3,798	159	2,902	15,064
Prospective projects	—	—	—	5,696	5,696
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net expenses, share of loss of joint ventures and unrealized net loss on derivative financial instruments	131,996	40,635	15,529	(8,598)	179,562
Finance costs					86,537
Other net expenses					7,797
Earnings before income taxes, depreciation, amortization, share of loss of joint ventures and unrealized net loss on derivative financial instruments					85,228
Depreciation					53,145
Amortization					20,947
Share of loss of joint ventures					701
Unrealized net loss on derivative financial instruments					121,685
Loss before income taxes					(111,250)

As at December 31, 2014					
Goodwill	8,269	—	—	—	8,269
Total assets	1,752,495	352,723	120,957	489,840	2,716,015
Total liabilities	1,241,530	238,450	111,814	561,996	2,153,790
Acquisition of property, plant and equipment during the year	123,185	549	161	223,405	347,300

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

Year ended December 31, 2013 Operating segments	Hydroelectric generation	Wind power generation	Solar power generation	Site development	Total
Revenues	126,932	54,499	16,828	—	198,259
Expenses:					
Operating	22,849	9,939	1,159	—	33,947
General and administrative	7,373	2,140	317	1,364	11,194
Prospective projects	—	—	—	4,202	4,202
Earnings (loss) before finance costs, income taxes, depreciation, amortization, other net revenues, share of earnings of joint ventures and unrealized net gain on derivative financial instruments	96,710	42,420	15,352	(5,566)	148,916
Finance costs					65,158
Other net revenues					(392)
Earnings before income taxes, depreciation, amortization, share of earnings of joint ventures and unrealized net gain on derivative financial instruments					84,150
Depreciation					48,674
Amortization					20,486
Share of earnings of joint ventures					(6,053)
Unrealized net gain on derivative financial instruments					(45,249)
Earnings before income taxes					66,292

As at December 31, 2013					
Goodwill	8,269	—	—	—	8,269
Total assets	1,449,527	387,062	128,146	412,339	2,377,074
Total liabilities	949,570	248,594	116,085	396,890	1,711,139
Acquisition of property, plant and equipment during the year	66,581	1,213	100	89,501	157,395

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

36. SUBSEQUENT EVENTS

a. Dividends declared by the Board of Directors

Date of announcement	Record date	Payment date	Dividend per common share ($)	Dividend per Series A Preferred Share ($)	Dividend per Series C Preferred Share ($)
02/24/2015	03/31/2015	04/15/2015	0.1550	0.3125	0.359375

b. Term conversion of the Kwoiek Creek Project-Level Debt

On February 13, 2015, the non-recourse construction loan for the Kwoiek Creek hydroelectric facility was converted into a term loan, to be amortized over a 36-year period ending in 2052. The loan bears interest at a fixed rate of 5.08%.

c. Term conversion of the Northwest Stave Project-Level Debt

Also on February 13, 2015, the non-recourse construction loan for the Northwest Stave River hydroelectric facility was converted into a term loan, to be amortized over a 35-year period ending in 2053. The loan bears interest at a fixed rate of 5.30%.

INFORMATION FOR INVESTORS

STOCK EXCHANGE LISTING

Innergex Renewable Energy Inc.'s securities are listed on the Toronto Stock Exchange (TSX).

	TSX SYMBOL
Common shares	**INE**
Series A Preferred Shares	INE.PR.A
Series C Preferred Shares	INE.PR.C
Convertible debentures	INE.DB

Innergex Renewable Energy Inc. is a constituent of the following market indices:

- S&P/TSX Composite Index
- S&P/TSX Composite Dividend Index
- S&P/TSX Equity Income Index
- S&P/TSX Composite Low Volatility Index
- S&P/TSX SmallCap Index
- S&P/TSX Renewable Energy and Clean Technology Index.

SERIES A PREFERRED SHARES (TSX: INE.PR.A)

Innergex Renewable Energy Inc. currently has 3.4 million Series A Preferred Shares outstanding, with a nominal value of $25 and a fixed cumulative preferential annual cash dividend of $1.25 per share, payable quarterly on the 15th day of January, April, July, and October. Series A Preferred Shares are not redeemable by the Corporation prior to January 15, 2016.

SERIES C PREFERRED SHARES (TSX: INE.PR.C)

Innergex Renewable Energy Inc. currently has 2.0 million Series C Preferred Shares outstanding, with a nominal value of $25 and a fixed-rate cumulative preferential annual cash dividend of $1.4375 per share, payable quarterly on the 15th day of January, April, July, and October. Series C Preferred Shares are not redeemable by the Corporation prior to January 15, 2018.

CONVERTIBLE DEBENTURES (TSX: INE.DB)

Innergex Renewable Energy Inc. currently has convertible debentures outstanding for a total notional amount of $80.5 million, which bear interest at an annual rate of 5.75% and mature on April 30, 2017. Each convertible debenture is convertible into common shares of the Corporation at a price of $10.65 per share at the holder's option at any time prior to the earlier of April 30, 2017 and the redemption date specified by the Corporation. The convertible debentures are subordinated to all other indebtedness of the Corporation.

CREDIT RATINGS

	STANDARD & POOR'S
Innergex Renewable Energy Inc.	BBB-
Series A Preferred Shares	P-3
Series C Preferred Shares	P-3
Convertible debentures	–

TRANSFER AGENT AND REGISTRAR

For information concerning share certificates, dividend payments, a change of address, or electronic delivery of shareholder documents (such as quarterly and annual reports and proxy circulars), please contact the Corporation's transfer agent and registrar:

Computershare Investor Services Inc.

1500 University Street, Suite 700
Montreal, Quebec, Canada H3A 3S8
Phone: 1 800-564-6253 or 514 982-7555
Email: service@computershare.com
Website: computershare.com

DIVIDEND REINVESTMENT PLAN (DRIP)

Innergex Renewable Energy Inc. implemented a Dividend Reinvestment Plan for its common shareholders, which 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 Company's DRIP, please visit the Corporation's website at www.innergex.com or contact the DRIP administrator, Computershare Trust Company of Canada.

Please note that if you wish to enrol in the DRIP but own your shares indirectly through a broker or financial institution, you must contact this intermediary and ask them to enrol in the DRIP on your behalf.

INDEPENDENT AUDITOR

Deloitte LLP

COMMON SHARE DIVIDEND POLICY AND PAYMENT HISTORY

The Corporation intends to distribute an annual dividend of $0.62 per common share, payable quarterly[1]. The Corporation's dividend policy is determined by its Board of Directors and is based on the Corporation's results of operations, cash flows, financial condition, debt covenants, long-term growth prospects, solvency tests imposed under corporate law for the declaration of dividends, and other relevant factors.

PAYMENT HISTORY	2014	2013	2012
First Quarter	0.15 $	0.145 $	0.145 $
Second Quarter	0.15 $	0.145 $	0.145 $
Third Quarter	0.15 $	0.145 $	0.145 $
Fourth Quarter	0.15 $	0.145 $	0.145 $
	0.60 $	0.580 $	0.580 $

1 On February 24, 2015, the Board of Directors announced an increase in the annual dividend the Corporation intends to distribute to common shareholders of $0.02 to $0.62 per common share, payable quarterly.

STOCK CHART: JANUARY 1 - DECEMBER 31, 2014

52-WEEK HIGH/LOW: $11.54 - $9.64

ANNUAL SHAREHOLDERS' MEETING

The annual shareholders' meeting will be held:
On Wednesday, May 13, 2015, at 4:00 p.m. EDT
At the Hyatt Regency Montreal
1255 Jeanne-Mance, Montreal, Quebec H5B 1E5

Innergex Renewable Energy Inc.'s *Notice of Annual Meeting of Shareholders* and *Management Information Circular - Solicitation of Proxies* will be available no later than March 31, 2015, on the Investors page of our website. Hard copies will be available upon request.

INVESTOR RELATIONS

To obtain additional financial information, company updates, or recent news releases and investor presentations, please contact:

Marie-Josée Privyk, CFA, SIPC
Director – Communications and Sustainable Development
Tel.: 450 928-2550 ext. 222, mjprivyk@innergex.com

Or visit **www.innergex.com**

Ce document est disponible en français.
Pour la version numérique, visitez notre site Web à www.innergex.com.
Pour la version papier, communiquez avec nous à info@innergex.com.

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INNERGEX

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