ATLANTIC POWER CORP
Form 10-K
February 28, 2019
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018
OR
TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission file number 001-34691

ATLANTIC POWER CORPORATION

(Exact Name of Registrant as Specified in its Charter)

| | |
|---|---|
| British Columbia, Canada | 55-0886410 |
| (State of Incorporation) | (I.R.S. Employer Identification No.) |
| 3 Allied Drive, Suite 155 | |
| Dedham, MA | 02026 |
| (Address of Principal Executive Offices) | (Zip Code) |

(617) 977-2400

(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

| Title of Each Class | Name of Each Exchange on Which Registered |
|---|---|
| Common Shares, no par value per share, and the associated Rights to Purchase Common Shares | The New York Stock Exchange |

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes No

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes No

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated filer," "smaller reporting company," and "emerging growth company" in Rule 12b-2 of the Exchange Act.

Large Accelerated Filer Accelerated Filer Non-Accelerated Filer Smaller reporting company Emerging growth company

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act.

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes No

As of June 30, 2018, the aggregate market value of the voting and nonvoting common equity held by non-affiliates of the registrant was $239.3 million based upon the last reported sale price on the New York Stock Exchange. For purposes of the foregoing calculation only, all directors and executive officers of the registrant have been deemed affiliates.

As of February 27, 2019, 109,686,626 of the registrant's Common Shares were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2019 Annual Meeting of Shareholders, to be filed not later than 120 days after the end of the registrant's fiscal year, are incorporated by reference into Items 10 through 14 of Part III of this Annual Report on Form 10-K.

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PART I

As used herein, the terms “Atlantic Power,” the “Company,” “we,” “our,” and “us” refer to Atlantic Power Corporation, togeth with those entities owned or controlled by Atlantic Power Corporation, unless the context indicates otherwise. All references to “Cdn$” and “Canadian dollars” are to the lawful currency of Canada and references to “$,” “US$” and “U.S. dollars” are to the lawful currency of the United States. All dollar amounts herein are in U.S. dollars, unless otherwise indicated.

CAUTIONARY STATEMENT REGARDING FORWARD LOOKING INFORMATION

Certain statements in this Annual Report on Form 10 K constitute “forward looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995 and Canadian securities laws. Forward looking statements generally can be identified by the use of forward looking terminology such as “outlook,” “objective,” “may,” “will,” “expect,” “intend,” “estimate,” “anticipate,” “believe,” “should,” “plans,” “continue,” or similar expressions suggesting future outcomes events. Examples of such statements in this Annual Report on Form 10 K include, but are not limited to, statements with respect to the following:

- our ability to generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities;
- the outcome or impact of our business strategy to increase our intrinsic value on a per-share basis through disciplined management of our balance sheet and cost structure and investment of our discretionary cash in a combination of organic and external growth projects, acquisitions, and repurchases of debt and equity securities;
- our ability to renew or enter into new power purchase agreements (“PPAs”) on favorable terms or at all after the expiration of our current agreements;
- our ability to meet the financial covenants under our Credit Facilities (as defined herein) and other indebtedness;
- our ability to ensure that our plants operate safely and effectively;
- expectations regarding maintenance and capital expenditures; and
- the impact of legislative, regulatory, competitive and technological changes.

Such forward looking statements reflect our current expectations regarding future events and operating performance and speak only as of the date of this Annual Report on Form 10 K. Such forward looking statements are based on a number of assumptions which may prove to be incorrect, including, but not limited to the assumption that the projects will operate and perform in accordance with our expectations. Many of these risks and uncertainties can affect our actual results and could cause our actual results to differ materially from those expressed or implied in any forward looking statement made by us or on our behalf.

Forward looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. In addition, a number of factors could cause actual results to differ materially from the results discussed in the forward looking statements, including, but not limited to, the factors included in the filings Atlantic Power makes from time to time with the SEC and the risk factors described under "Item 1A. Risk Factors" in this Annual Report on Form 10 K. Our business is both highly competitive and subject to various risks.

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These risks include, without limitation:

- the expiration or termination of power purchase agreements and our ability to renew or enter into new PPAs on favorable terms or at all;
- our ability to service our debt obligations or generate sufficient cash flow to pay preferred dividends;
- our ability to access liquidity for the ongoing operation of our business and the execution of our business plan or any potential options, which may involve one or more of the use of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately placed bank or institutional non recourse operating level debt;
- our indebtedness and financing arrangements and the terms, covenants and restrictions included in our Credit Facilities;
- exchange rate fluctuations;
- the impact of downgrades in our credit rating or the credit rating of our outstanding debt securities, and changes in our creditworthiness;
- unstable capital and credit markets;
- the dependence of our projects on their electricity and thermal energy customers;
- exposure of certain of our projects to fluctuations in the price of electricity or natural gas;
- the dependence of our projects on third party suppliers;
- projects not operating according to plan;
- the effects of weather, which affects demand for electricity and fuel as well as operating conditions;
- U.S., Canadian and/or global economic conditions and uncertainty;
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risks beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events;

- the adequacy of our insurance coverage;
- the impact of significant energy, environmental and other regulations on our projects;
- the impact of impairment of goodwill, long lived assets or equity method investments;
- the impact of failure to fully comply with Section 404 of the Sarbanes-Oxley Act of 2002;
- increased competition, including for acquisitions;
- our limited control over the operation of certain minority owned projects;
- transfer restrictions on our equity interests in certain projects;
- risks inherent in the use of derivative instruments;

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- labor disruptions;

- the impact of hostile cyber intrusions;

- the impact of our failure to comply with the U.S. Foreign Corrupt Practices Act and/or Canadian Corruption of Foreign Public Officials Act; and

- our ability to retain, motivate and recruit executives and other key employees.

Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include, without limitation, third-party projections of regional fuel and electric capacity and energy prices based on assumptions about future economic conditions and courses of action, the general conditions of the markets in which the Company operates, revenues, internal and external growth opportunities, the Company's ability to sell assets at favorable prices or at all and general financial market and interest rate conditions. Although the forward-looking statements contained in this Annual Report on Form 10-K are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. Certain statements included in this Annual Report on Form 10-K may be considered "financial outlook" for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this Annual Report on Form 10-K. These forward-looking statements are made as of the date of this Annual Report on Form 10-K and, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

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ITEM 1. BUSINESS

GENERAL

Atlantic Power is an independent power producer that owns power generation assets in nine states in the United States and two provinces in Canada. Our power generation projects, which are diversified by geography, fuel type, dispatch profile and offtaker, sell electricity to utilities and other large customers predominantly under long term PPAs, which seek to minimize exposure to changes in commodity prices. As of December 31, 2018, our portfolio consisted of seventeen projects operating or under contract with an aggregate electric generating capacity of approximately 1,598 megawatts ("MW") on a gross ownership basis and approximately 1,252 MW on a net ownership basis. Fourteen of the projects are majority owned by the Company. Two of our Ontario projects totaling 80 MW on a gross and net ownership basis have not operated since the expiration of their contracts on December 31, 2017. In early February 2018, our three plants in San Diego, totaling 112 MW on a gross and net ownership basis, ceased operations and will be decommissioned, as discussed in Our Organization and Segments.

The following charts show, based on generation capacity in MW, the diversification of our portfolio by segment and fuel type for our projects currently in operation:

We sell the majority of the capacity and energy from our power generation projects under PPAs to a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from June 30, 2019 to March 31, 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. Sales of electricity are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

We directly operate and maintain the majority of our power generation projects. We also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including Heorot Power Management LLC ("Heorot") and Purenergy LLC ("Purenergy"). Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

HISTORY OF OUR COMPANY

Atlantic Power Corporation is a corporation continued under the laws of British Columbia, Canada, which was incorporated in 2004. We used the proceeds from our initial public offering on the Toronto Stock Exchange ("TSX") in

November 2004 to acquire a 58% interest in Atlantic Power Holdings, LLC (which we refer to herein as “Atlantic Holdings”) from two private equity funds managed by ArcLight Capital Partners, LLC (“ArcLight”) and from Caithness Energy, LLC (“Caithness”). Until December 31, 2009, we were externally managed under an agreement with Atlantic Power Management, LLC, an affiliate of ArcLight, when we agreed to pay ArcLight an aggregate of $15 million to terminate its management agreement with us. In connection with the termination of the management agreement, we

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hired all of the then current employees of Atlantic Power Management and entered into employment agreements with its three officers.

At the time of our initial public offering, our publicly traded security was an Income Participating Security (“IPS”), which was comprised of one common share and a subordinated note. In November 2009, our shareholders approved a conversion from the IPS structure to a traditional common share structure in which each IPS was exchanged for one new common share and each old common share that did not form a part of an IPS was exchanged for approximately 0.44 of a new common share. Our common shares trade on the TSX under the symbol “ATP”. On July 23, 2010, we also began trading on the New York Stock Exchange (“NYSE”) under the symbol “AT”.

On November 5, 2011, we directly and indirectly acquired all of the issued and outstanding limited partnership units of Capital Power Income L.P., which was renamed Atlantic Power Limited Partnership on February 1, 2012 (the “Partnership”). The Partnership’s portfolio consisted of 19 wholly owned power generation assets located in both Canada and the United States, a 50.15% interest in a power generation asset in the state of Washington, and a 14.3% common ownership interest in Primary Energy Recycling Holdings, LLC which was later sold in 2012. At the acquisition date, the transaction increased the net generating capacity of our projects by 143% from 871 MW to approximately 2,116 MW.

On June 26, 2015, we sold our 100% ownership interest in Meadow Creek Project Company, LLC (“Meadow Creek”), 99% ownership in Canadian Hills Wind, LLC (“Canadian Hills”), 50% ownership interest in Rockland Wind Farm, LLC (“Rockland”), 27.6% ownership interest in Idaho Wind Partners 1, LLC (“Idaho Wind”) and 12.5% ownership interest in Goshen Phase II, LLC (“Goshen”) (collectively, the “Wind Projects”), totaling 521 MW net ownership to TerraForm AP Acquisition Holdings, LLC (“TerraForm”), an affiliate of SunEdison, Inc.

## OUR BUSINESS STRATEGY

### General

Our business strategy is to increase the intrinsic value of the Company on a per-share basis. An important element of that strategy is strengthening our balance sheet and financial flexibility by continuing to reduce our debt and interest costs significantly. We also continue to evaluate our overhead and operating costs for further cost savings opportunities. We use our depth of operational and commercial experience to enhance the operating, contractual and financial performance of our current portfolio of projects, and to extend or renew expiring PPAs for our projects when it is economically feasible to do so. In allocating discretionary capital we are guided by the price-to-value relationship and the impact on intrinsic value per share. We rank the various potential uses – organic growth, external investments and acquisitions, and repurchases of our debt and equity securities – on that basis. With respect to organic growth, we have made optimization investments (to improve efficiency or reliability or increase capacity) in our existing projects that have produced cash returns higher than those currently available externally. We may undertake additional investments to repower certain facilities in conjunction with extensions of existing PPAs, if the returns are attractive. We believe that we have a highly disciplined and opportunistic approach to external growth, with a focus on out-of-favor assets. We will use discretionary cash for repurchases of our debt and equity securities only when the price-to-value level is compelling.

Extending PPAs following their expiration

PPAs in our portfolio have expiration dates ranging from June 30, 2019 to March 31, 2037. We plan for PPA expirations by evaluating various options in the market. New arrangements may involve responses to utility solicitations for capacity and energy, direct negotiations with the original purchasing utility for PPA extensions, approaches by the projects to likely bilateral counterparties, including traditional PPAs, tolling agreements with creditworthy energy trading firms or the use of derivatives to lock in value. The current market for PPAs is challenging. When a PPA expires or is terminated, it is possible that the price received by the project for power under subsequent arrangements, if any, may be reduced and in some cases, significantly. We do not assume that revenues or operating margins under existing PPAs will necessarily be sustained after PPA expirations, since most original PPAs included capacity payments related to return of and return on original capital invested, and counterparties or evolving regional electricity markets may or may not provide similar payments under new or extended PPAs. Our projects may not be able to secure a new agreement

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and could be exposed to selling power at spot market prices. It is possible that subsequent PPAs or the spot markets may not be available at prices that permit the operation of the project on a profitable basis, which may result in our decision to mothball or retire the project. For the status of description of some of our PPAs and related renegotiations, see Item 1A. "Risk Factors—Risk Related to Our Business and Our Projects—The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations and financial condition."

Organic growth

We plan to continue to enhance the operational and financial performance of our projects by improving their operating efficiencies, output, reliability and operation and maintenance costs through investments to upgrade or enhance existing equipment or plant configurations. We also seek to optimize commercial arrangements such as PPAs, fuel supply and transportation contracts, steam sales agreements, operations and maintenance agreements and hedging arrangements. To the extent we achieve PPA extensions or new contracts on economically feasible terms, and we have sufficient cash flow or are able to obtain financing, we may expand or repower existing projects, or develop new long-term contracted plants with industrial customers.

External Growth & Acquisitions

We pursue external growth opportunities consistent with our strategy to maximize the intrinsic value of the Company on a per-share basis. Our acquisition strategy is focused on power generation assets in operation in the United States and Canada, targeting out-of-favor assets with a compelling price-to-value relationship. We may also pursue the greenfield development of new power generation projects when a favorable risk/reward balance exists.

OUR COMPETITIVE STRENGTHS

We have the following competitive strengths:

- Diversified projects. Our power generation projects in operation or under contract have an aggregate gross electric generation capacity of approximately 1,598 MW, and our net ownership interest in these projects is approximately 1,252 MW at December 31, 2018. These projects are diversified by fuel type, electricity and steam customers, technologies, project operators and geography. The majority are located in the U.S. Eastern, Mid Atlantic and Midwest regions, and the province of British Columbia.

- Experienced management team. Our management team has a depth of experience in commercial power operations and maintenance, project development, asset management, mergers and acquisitions, capital raising and management and financial controls.

- Stability of project cash flow. Many of our power generation projects currently in operation have been in operation for more than ten years. Cash flows from each project are generally supported by PPAs with investment grade utilities and other creditworthy counterparties. We aim to stabilize operating margins through a combination of a project's PPAs, fuel supply agreements and/or commodity hedges, when possible.

- Strong in house operations and asset management teams. We manage the operations of fourteen of our seventeen operating power generation projects, which represent approximately 62% of our portfolio's total net generating capacity. The remaining three generation projects are operated by third parties, which are recognized leaders in the independent power business.

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## ASSET MANAGEMENT

Our asset management strategy is to manage our physical assets and commercial relationships to increase shareholder value. We proactively seek scale opportunities and to establish best practices that result in EBITDA and cash flow growth across all of our seventeen operating plants. Our asset management group works to ensure that our projects receive appropriate preventative and corrective maintenance and incur capital expenditures to provide for their safety, efficiency, availability, flexibility, longevity, and growth in EBITDA contribution. We also proactively look for opportunities to optimize power purchase, fuel supply, long term service and other agreements to deliver strong and predictable financial performance. The teams at each of the businesses have extensive experience in managing, operating and maintaining the assets.

For operations and maintenance services at the three projects in our portfolio which we do not operate, we partner with experienced operators in the independent power business. Examples of our third party operators include Heorot and Purenergy, which are experienced, well regarded energy infrastructure management services companies. In addition, employees of Atlantic Power with significant experience managing similar assets are involved in all significant decisions with the objective of proactively identifying value creating opportunities such as contract renewals or restructurings, asset level refinancings, add on acquisitions, divestitures and participation at partnership meetings and calls.

## OUR ORGANIZATION AND SEGMENTS

The following tables outline by segment our portfolio of power generating assets in operation as of December 31, 2018, including our interest in each facility. We believe our portfolio is well diversified in terms of electricity and steam customers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region.

We have four reportable segments: East U.S., West U.S., Canada and Un Allocated Corporate. The segment classified as Un Allocated Corporate includes activities that support the executive and administrative offices, capital structure and costs of being a public registrant. These costs are not allocated to the operating segments when determining segment profit or loss.

The sections below provide descriptions of our projects as they are aligned in our segment reporting structure for financial reporting purposes.

### East U.S. Segment

Our East U.S. segment accounted for 56.2%, 33.7% and 35.7% of consolidated revenue in 2018, 2017 and 2016, respectively, and total net generation capacity of 531 MW at December 31, 2018. Niagara Mohawk Power Corporation accounted for 15.1% of total consolidated revenues and 26.8% of total revenues from the East U.S. segment for the year ended December 31, 2018.

The table below provides the revenue and project income for the East U.S. segment. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations—Project Income (Loss) by Segment for additional details on our project income (loss).

| | East U.S. Segment | |
|---|---|---|
| | Revenue ($ in millions) | Project income (loss) ($ in millions) |
| 2018 | $ 158.7 | $ 70.9 |
| 2017 | 152.5 | (17.0) |
| 2016 | 134.5 | 31.2 |

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Set forth below is a list of our East U.S. projects in operation at December 31, 2018:

| Location | Fuel | Gross MW | Economic Interest | | Net MW | Primary Electric Purchasers | Power Contract Expiry |
|---|---|---|---|---|---|---|---|
| Florida | Natural Gas | 129 | 50.00 | % | 65 | Progress Energy Florida | December 202 |
| Georgia | Biomass | 55 | 100.00 | % | 55 | Georgia Power | September 203 |
| Illinois | Natural Gas | 177 | 100.00 | % | 100 | Merchant | N/A |
| | | | | | 77 | Equistar Chemicals, LP (3) | December 203 |
| Michigan | Biomass | 40 | 100.00 | % | 40 | Consumers Energy | June 2028 |
| New Jersey | Coal | 262 | 40.00 | % | 89 | Atlantic City Electric (5) | March 2024 |
| | | | | | 16 | Chemours Co. | March 2024 |
| New Jersey | Natural Gas | 29 | 100.00 | % | 29 | Merck & Co., Inc. | September 202 (6) |
| New York | Hydro | 60 | 100.00 | % | 60 | Niagara Mohawk Power Corporation | December 202 (7) |

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

(2) Equistar has an option to purchase Morris that is exercisable in December 2020 and in December 2027.

(3) Equistar has the right under the PPA to take up to 77 MW, but on average has taken approximately 50 MW.

(4) Represents the credit rating of LyondellBasell, the parent company of Equistar Chemicals, as Equistar is not rated.

(5) The base PPA with Atlantic City Electric ("ACE") makes up the majority of the revenue from the 89 Net MW. For sales of energy and capacity not purchased by ACE under the base PPA and sold to the spot market, profits are shared with ACE under a separate power sales agreement.

(6) Merck has a one-year extension option that, if exercised, would extend the PPA expiration date to September 30, 2021.

(7) The Curtis Palmer PPA expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. From January 6, 1995 through December 31, 2018, the facility has generated 7,651 GWh under its PPA. Based on cumulative generation to date, we expect the PPA to expire prior to December 2027.

West U.S. Segment

Our West U.S. segment accounted for 15.5%, 25.4% and 24.9% of consolidated revenue in 2018, 2017 and 2016, respectively, and total net generation capacity of 487 MW at December 31, 2018. Power Service Company of Colorado accounted for 7.0% of total consolidated revenues and 45.7% of total revenues from the West U.S. segment for the year ended December 31, 2018.

The table below provides the revenue and project income (loss) for the West U.S. segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations—Project Income (Loss) by Segment for additional details on our project income (loss).

| | West U.S. Segment | |
|---|---|---|
| | Revenue ($ in millions) | Project income (loss) ($ in millions) |
| 2018 | $ 43.8 | $ 0.9 |
| 2017 | 108.9 | (72.0) |
| 2016 | 101.3 | 11.8 |

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Set forth below is a list of our West U.S. projects in operation at December 31, 2018:

| Location | Fuel | Gross MW | Economic Interest | | Net MW | Primary Electric Purchasers | Power Contract Expiry |
|---|---|---|---|---|---|---|---|
| California | Natural Gas | 49 | 100.00 | % | 49 | Southern California Edison | May 2020 (1) |
| Colorado | Natural Gas | 300 | 100.00 | % | 300 | Public Service Company of Colorado | April 2022 |
| Washington | Natural Gas | 250 | 50.15 | % | 50 | Benton Co. PUD | August 2022 |
| | | | | | 45 | Grays Harbor PUD | August 2022 |
| | | | | | 30 | Franklin Co. PUD | August 2022 |
| Washington | Hydro | 13 | 100.00 | % | 13 | Puget Sound Energy | March 2037 |

(1) Oxnard’s steam sales agreement expires in February 2020.

(2) Public Service Company of Colorado has an option to purchase Manchief that is exercisable in May 2020 and in May 2021.

(3) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

In August 2018, we terminated discussions with the Navy regarding site control for Naval Station, Naval Training Center (‘NTC”) and North Island. We are proceeding with plans to decommission all three sites in 2019, which is a requirement of our land use agreements with the Navy. Pending a determination with the Navy regarding the scope of work and receipt of bids from contractors, the final cost of the decommissioning may exceed our asset retirement obligation of $5.0 million.

Canada Segment

Our Canada segment accounted for 27.9%, 39.1% and 40.7% of consolidated revenue in 2018, 2017 and 2016, respectively, and total net generation capacity for operational projects of 237 MW at December 31, 2018. British Columbia Hydro and Power Authority (“BC Hydro”) accounted for 12.5% of total consolidated revenues and 44.0% of total revenues from the Canada segment for the year ended December 31, 2018.

The table below provides the revenue and project income (loss) for the Canada segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations—Project Income (Loss) by Segment for additional details on our project income (loss).

| | Canada Segment | |
|---|---|---|
| | Revenue ($ in millions) | Project income (loss) ($ in millions) |
| 2018 | $ 78.9 | $ 17.0 |
| 2017 | 168.6 | 38.8 |
| 2016 | 162.5 | (35.7) |

Set forth below is a list of our Canada projects in operation or under contract at December 31, 2018:

| Location | Fuel | Gross MW | Economic Interest | | Net MW | Primary Electric Purchasers | Power Contract Expiry |
|---|---|---|---|---|---|---|---|
| British Columbia | Hydro | 50 | 100.00 | % | 50 | BC Hydro | September 2027 |
| British Columbia | Hydro | 6 | 100.00 | % | 6 | BC Hydro | August 2022 |
| British Columbia | Biomass | 66 | 100.00 | % | 66 | BC Hydro | June 2019 |
| Ontario | Biomass | 35 | 100.00 | % | 35 | Ontario Electricity Financial Corporation | June 2020 |
| Ontario | Natural Gas | 40 | 100.00 | % | 40 | Independent Electricity System Operator | December 2022 |
| Ontario | Natural Gas | 37 | 100.00 | % | 37 | Independent Electricity System Operator | October 2033 |

(1) BC Hydro has an option to purchase Mamquam that is exercisable in November 2021 and every five-year anniversary thereafter.

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General

Historically, the North American electricity industry was characterized by vertically integrated monopolies. During the late 1980s, several jurisdictions began a process of restructuring by moving away from vertically integrated monopolies toward more competitive market models. Rapid growth in electricity demand, environmental concerns, increasing electricity rates, technological advances and other concerns prompted government policies to encourage the supply of electricity from independent power producers. More recently, the North American electricity industry has become more diversified but faces the challenges of declining reserve margins and energy prices and uncertainty resulting from environmental regulations.

According to the North American Electric Reliability Corporation's ("NERC") 2018 Long Term Reliability Assessment ("LTRA"), published in December 2018, the 10-year forecast compound annual growth rate of the peak summer and winter electricity demand has leveled off, but remains historically low. The LTRA reference case shows a compound annual growth rate of 0.6% for both the summer and winter seasons. This growth rate is consistent with the 2017 LTRA. However, the projected growth rate was 1.5% just a decade earlier. These growth rates are expected to continue to decline due to the increase in energy efficiency and conservation programs as well as the continued growth of distributed solar and other storage sources.

Despite recent and projected low demand growth, regions where we operate are projected to have reserve margin shortfalls or reserve margins that are lower than NERC's reference reserve margin level. According to the LTRA, the North American electric power system is undergoing a significant transformation with ongoing retirements of fossil-fired and nuclear capacity as well as growth in natural gas, wind, and solar resources. This shift is caused by several drivers, such as existing and proposed federal, state, and provincial environmental regulations as well as low natural gas prices, in addition to the ongoing integration of both distributed and utility-scale renewable resources. Natural gas-fired generation surpassed coal as the predominant fuel source for electric generation and is the leading fuel type for capacity additions.

Non utility power generation

The electric power industry is one of the largest industries in the United States, generating annualized retail electricity sales of approximately $370 billion through November 2018, based on information published by the Energy Information Administration, an increase from $359 billion during the same period of 2017. A significant portion of the power produced in the United States and Canada is generated by non utility generators. According to the Energy Information Administration, independent power producers represented approximately 40% of total net generation in 2018. Independent power producers sell the electricity that they generate to electric utilities and other load serving entities (such as municipalities and electric cooperatives) by way of bilateral contracts or open power exchanges. The electric utilities and other load serving entities, in turn, generally sell this electricity to industrial, commercial and residential customers. In the independent power generation sector, electricity is generated from a number of energy sources, including natural gas, coal, water, waste products such as biomass (e.g., wood, wood waste, agricultural waste), landfill gas, geothermal, solar and wind. All of our plants are non utility electric generating facilities in the North American electrical power generation industry.

## Competition

The power generation industry is characterized by intense competition, and we compete with utilities, industrial companies, yieldcos and other independent power producers. Historically low crude and natural gas prices as well as decreased rates of demand growth have contributed to reduced capacity and energy prices and increasing competition among generators to obtain power sales agreements. We also compete for acquisition and joint venture opportunities with numerous private equity, infrastructure and pension funds, Canadian and U.S. independent power firms, utility non regulated subsidiaries and other strategic and financial players.

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## REGULATORY MATTERS

### Overview

Our facilities and operations are subject to laws and regulations that govern, among other things, transactions by and with purchasers of power, including utility companies, the development and construction of generation facilities, the ownership and operations of generation facilities, access to transmission, and the geographical location, zoning, land use and operation aspects of our facilities and properties, including environmental matters.

In the United States, the power generation and sale aspects of our projects are primarily regulated by the Federal Energy Regulation Commission ("FERC"), although most of our projects benefit from the special provisions accorded to Qualifying Facilities ("QFs") or Exempt Wholesale Generators ("EWGs").

In Canada, electricity generation is subject primarily to provincial regulation. Our projects in British Columbia are therefore subject to different regulatory regimes from our projects in Ontario.

### Generating projects

#### United States

Nine of our power generating projects are QFs under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"), and FERC regulations. A QF falls into one or both of two primary classes, both of which would facilitate one of PURPA's goals to more efficiently use fossil fuels to generate electricity than typical utility plants. The first class of QFs includes energy producers that generate power using renewable energy sources such as wind, solar, geothermal, hydro, biomass or waste fuels. The second class of QFs includes cogeneration facilities, which must meet specific fossil fuel efficiency requirements by producing both electricity and steam versus electricity only.

The generating projects with QF status are currently party to a PPA with a utility or have been granted authority to charge market-based rates or are exempt from FERC rate-making authority. The FERC has granted eight of the projects the authority to charge market-based rates based primarily on a finding that the projects lack market power. The projects with QF status are also exempt from state regulation respecting the rates of electric utilities and the financial or organizational regulation of electric utilities. However, state regulators may review the prudency of utilities entering into PPAs with QFs and the siting of the generation facilities. The majority of our generation is sold by QFs under PPAs that required approval by state authorities.

PURPA, as initially implemented by the FERC, generally required that vertically integrated electric utilities purchase power from QFs at their avoided costs. The Energy Policy Act of 2005 (the "EP Act of 2005"), however, established new limits on PURPA's requirement that electric utilities buy electricity from QFs to certain markets that lack competitive characteristics. The projects with EWG status are also exempt from state regulation respecting the rates of electric utilities.

Notwithstanding their status as QFs and EWGs, our projects remain subject to various aspects of FERC regulation, including those relating to power marketer status and to oversight of mergers, acquisitions and investments relating to utilities under the Federal Power Act, as amended by the EP Act of 2005. Eight of our projects are also subject to reliability standards developed and enforced by NERC. NERC is a not-for-profit regulatory authority whose mission is to assure the reliability and security of the bulk power system in North America.

Pursuant to its authority, NERC has issued, and the FERC has approved, a series of mandatory reliability standards. Users, owners and operators of the bulk power system can be penalized significantly for failing to comply with the FERC-approved reliability standards. We have designated our Manager of Operational and Regulatory Compliance to oversee compliance with reliability standards and an outside law firm specializing in this area advises us on FERC and NERC compliance, including annual compliance training for relevant employees.

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British Columbia, Canada

The vast majority of British Columbia's power is generated or procured by BC Hydro, which is one of the largest electric utilities in Canada. BC Hydro is owned by the Province of British Columbia and is regulated by the British Columbia Utilities Commission (the "BCUC"), which is governed by the Utilities Commission Act (British Columbia) (the "UCA"). The BCUC is also responsible for the regulation of British Columbia's public energy utilities including publicly owned and investor-owned utilities (i.e., independent power producers).

BC Hydro is generally required to acquire all new power (beyond what it already generates from existing BC Hydro plants) from independent power producers.

All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by the BCUC. In making its determination, the BCUC will examine whether the contract is in the public interest. The BCUC may hold a hearing in this regard. Furthermore, the BCUC may make rules governing conditions to be contained in agreements entered into by public utilities for electricity.

Pursuant to the UCA, the BCUC has adopted the standards developed by the NERC and the Western Electricity Coordinating Council ("WECC") in respect to all generators of electricity in British Columbia, including independent power producers. As a practical matter, the BCUC appointed WECC as Administrator to assist the BCUC in carrying out the registration of parties and compliance monitoring.

The Clean Energy Act (the "Clean Energy Act"), which became law in 2010, sets out British Columbia's energy objectives. The Clean Energy Act states, among other things, that British Columbia aims to accelerate and expand the development of clean and renewable energy sources in British Columbia to, among other things, promote economic development and job creation and continue to work toward the reduction of greenhouse gas emissions. The legislation also explicitly states that British Columbia will encourage the use of waste heat, biogas and biomass to reduce waste. Clean Energy Production in B.C.: An inter-Agency Guidebook for Project Development, which was released by the Provincial government in 2016, is consistent with the Clean Energy Act, favors clean and renewable energy sources such as waterpower, windpower and ocean energy generation. Pursuant to the Clean Energy Act, BC Hydro is required to submit a report to the BCUC every five years outlining how it intends to meet these objectives and provide updates on its progress to date.

Other provincial regulators in British Columbia having authority over independent power producers include the British Columbia Safety Authority, the Ministry of Environment and Climate Change Strategy, and the Integrated Land Management Bureau.

Ontario, Canada

In Ontario, the Ontario Energy Board ("OEB") is an administrative tribunal with overall responsibility for the regulation and supervision of the natural gas and electricity industries in Ontario and with the authority to grant or renew, and set the terms for, licenses with respect to electricity generation facilities, including our projects.

No person is permitted to own or operate large or medium-scale electricity generation facilities in Ontario without a license from the OEB.

The OEB's general functions include:

- Determination of the rates charged for regulated services in the electricity sector;
- Licensing of market participants;
- Inspections, particularly with respect to compelling production of records and information;
- Market monitoring and reporting, including on anti-competitive practice;

· Consumer advocacy; and
· Enforcement and compliance.

The OEB has the authority effectively to modify licenses by adopting “codes” that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the OEB can result in fines. While the OEB provides reports to the Ontario Minister of Energy, it generally operates independently from the government. However, the Minister may issue policy directives (with Cabinet approval) concerning general policy and the objectives to be pursued by the OEB, and the OEB is required to implement such policy directives.

A number of other regulators and quasi-governmental entities play a role in electricity regulation in Ontario, including the Independent Electricity System Operator (“IESO”), Hydro One, the Electrical Safety Authority (“ESA”) and the Ontario Electricity Financial Corporation (“OEFC”).

In 1998, the Legislative Assembly of Ontario passed the Energy Competition Act of 1998, which authorized the establishment of a market in electricity, and reorganized Ontario Hydro into five companies: Ontario Power Generation (“OPG”), the Ontario Hydro Services Company (later renamed Hydro One), the Independent Electricity Market Operator (later renamed the IESO), the ESA, and OEFC. The two commercial companies, Ontario Power Generation and Hydro One, were intended to eventually operate as private businesses rather than as crown corporations. In the fall of 2015, the Province sold off 15% of Hydro One in an IPO with an additional 38% sold through December 31, 2017. In January of 2018, the Province sold a further 2.4% of the company’s outstanding common shares to 129 First Nations of Ontario. The Province now owns approximately 48.9% of the company’s common shares, including the 1.5% owned by Ontario Power Generation, a company wholly-owned by the Province.

The IESO is responsible for administering the wholesale electricity market and controlling Ontario’s transmission grid. The IESO is a non-profit corporation whose directors are appointed by the government of Ontario. The IESO’s “Market Rules” form the regulatory framework for the operation of Ontario’s transmission grid and electricity market. The Market Rules require, among other things, that generators meet certain equipment and performance standards and certain system reliability obligations. The IESO may enforce the Market Rules by imposing financial penalties. The IESO may also terminate, suspend or restrict participatory rights.

In November 2006, the IESO entered into a memorandum of understanding with NERC, in which it recognized NERC as the “electricity reliability organization” in Ontario. In addition, the IESO has also entered into a similar MOU with both the Northeast Power Coordinating Council (the “NPCC”) and NERC. The IESO is accountable to NERC and NPCC for compliance with NERC and NPCC reliability standards. Although the IESO may impose Ontario-specific reliability standards, such standards must be consistent with, and at least as stringent as, NERC’s and NPCC’s standards. Effective July 1, 2016, the IESO changed the definition of what generating facilities are considered part of the Bulk Electric System (“BES”). Any new facility grouped into the BES, which includes all Ontario sites except Kapuskasing, will have to comply with all NERC reliability standards in effect in Ontario. As of January 1, 2015, the IESO is responsible for procuring new electricity generation. As a result, the IESO enters into electricity generation contracts with electricity generators in Ontario from time to time. The IESO also administers the Ontario Reliability Compliance Program, working with various market participants to ensure they understand and adhere to their obligations.

Although the Green Energy Act became law in Ontario in 2009 for renewable electricity generation technologies, including via a feed-in tariff program, this statute was repealed as of January 1, 2019 with the introduction and proclamation of the Green Energy Repeal Act, 2018. This Act amended provisions of the Electricity Act, 1998, as well as the Environmental Protection Act, and the Planning Act, among others. In particular, amendments to the Environmental Protection Act now provide that, absent a demonstrated demand for the electricity which would be generated by a given renewable energy project, the provincial government is empowered to prohibit the issuance or renewal of energy approvals for any such project. Amendments to the Planning Act now stipulate that there is no appeal route in respect of any refusal or failure to adopt an amendment authorizing a renewable energy undertaking, except by the Minister. Further amendments provide that there is now no appeal route in respect of all or any part of an application for amendment to a by-law if the amendment proposes to permit a renewable energy undertaking, except by the Minister. The provincial government has stated that the repeal of the Green Energy Act will empower individual

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municipalities to make planning decisions related to the development of new energy projects. In July of 2018, the provincial government cancelled hundreds of renewable energy contracts in the province. In the related Minister's Directive, the Minister noted that the IESO's recent system planning work "indicates that Ontario's current contracted and rate regulated electricity resources are sufficient to satisfy or exceed forecasted provincial needs for the near term and that there are other means of meeting future energy supply and capacity needs at materially lower costs than long-term contracts that lock in the prices paid for these resources."

In January 2019, the provincial government initiated a consultation process in order to consider the merits of shifting to a single annual natural gas rate which will include both delivery-related and commodity-related rates.

Carbon emissions

United States – regional and state

In the United States, during the past several years government actions addressing carbon emissions have occurred primarily at the regional and state levels. Beginning in 2009, the Regional Greenhouse Gas Initiative ("RGGI") was established by certain Northeast and Mid-Atlantic states as the first cap-and-trade program in the United States for CO2 emissions. CO2 allowances are now a tradable commodity in the RGGI states. The nine states currently participating in RGGI have varied implementation plans and schedules. RGGI implemented a new, reduced CO2 cap in 2014, with further reductions of 2.5% each year from 2015 to 2020. On January 29, 2018, the governor of New Jersey signed an executive order directing the state's Department of Environmental Protection and the Board of Public Utilities to take all necessary regulatory and administrative measures to ensure New Jersey's timely return to full participation in RGGI. We have project interests in two RGGI states, New York and New Jersey. New York provides cost mitigation for independent power projects with certain types of power contracts. New Jersey, pending final legislation, is also expected to provide similar cost mitigation. California's cap-and-trade program governing greenhouse gas emissions became effective for the electricity sector on January 1, 2013. California, along with British Columbia and Quebec, is part of the Western Climate Initiative, which supports the implementation of state and provincial greenhouse gas emissions trading programs. Other states and regions in the United States have considered similar regulations, and it is possible that federal climate legislation will be established in the future.

In 2006, the State of California passed legislation initiating two programs to control/reduce the creation of greenhouse gases. The two laws are more commonly known as AB 32 (the Global Warming Solutions Act) and SB 1368. In 2016, California enacted SB 32, which expanded the requirements of AB 32. Under AB 32 and SB 32, the California Air Resources Board (the "CARB") is required to adopt a greenhouse gas emissions cap on all major sources (not limited to the electric sector) to achieve goals of reaching (i) 1990 greenhouse gas emissions levels by the year 2020, (ii) 40% below 1990 levels by 2030, and (iii) 80% below 1990 emissions levels by 2050. Under the CARB regulations that took effect on January 1, 2013, electricity generators and certain other facilities are now subject to an allowance for greenhouse gas emissions, with allowances allocated by both formulas set by the CARB and auctions.

SB 1368 added the requirement that the California Energy Commission, in consultation with the California Public Utilities Commission (the "CPUC") and the CARB, establish greenhouse gas emission performance standards and implement regulations for PPAs with a term of five or more years entered into prospectively by publicly owned electric utilities. The legislation directs the California Energy Commission to establish the performance standard as one not exceeding the rate of greenhouse gas emitted per megawatt hour ("MWh") associated with combined-cycle, gas turbine baseload generation.

United States – Federal

Over the past several years, the U.S. Environmental Protection Agency (the "EPA") has taken a number of actions respecting $CO_2$ emissions. The EPA's actions include its December 2009 finding of "endangerment" to public health and welfare from greenhouse gases, its issuance in September 2009 of the Final Mandatory Reporting of Greenhouse Gases Rule which required large sources, including power plants, to monitor and report greenhouse gas emissions to the EPA annually beginning in 2011, and its issuance in May 2010 of its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, which under a phased-in approach requires large industrial

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facilities, including power plants, to obtain permits to emit, and to use best available control technology to curb emissions of, greenhouse gases. In addition, in August 2015, the EPA issued its final rule regulating carbon emissions from existing electric generating units, which is referred to as the Clean Power Plan (the “CPP”). As a result of judicial challenge, however, the CPP has not been implemented, and more recently the Trump Administration has pursued efforts to revoke it. In October 2017, the EPA issued a proposed rule to repeal the CPP for existing power plants; in August 2018, the EPA issued its proposed Affordable Clean Energy Rule, which would establish emissions guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants; and in December 2018, the EPA issued a proposed rule to considerably ease the greenhouse gas standards for new power plants. Any such rulemaking activities could take years to complete, and are likely to draw legal challenges. At this time, we cannot predict the outcome of the current legal challenges to the CPP or any legal challenges to future administrative actions.

Canada - Federal

In Canada, the federal government has implemented greenhouse gas reporting regulations and are developing additional programs to address greenhouse gas emissions. Under the 2004 federal Greenhouse Gas Emissions Reporting Program (“GHGRP”), all facilities which emit 50,000 tonnes or more of carbon dioxide equivalent (“$CO_2$eq”) per year are required to submit reports on their emissions to Environment Canada.

On October 3, 2016, the Government of Canada announced its proposed pan-Canadian approach for the pricing of carbon pollu January 15, 2018, the Government of Canada released the draft Greenhouse Gas Pollution Pricing Act, setting out the mechanics to be used to backstop the federal government’s pan-Canadian approach to carbon pricing in provinces that have not implemented, by January 1, 2019, a carbon pricing system that the federal government has determined complies with its carbon pricing requirements. It also included a proposed design of rules to enhance market liquidity. In May 2018, the federal Government published “Carbon pricing: compliance options under the federal output-based pricing system,” a document that describes the proposed rules, and on June 21, 2018 the Greenhouse Gas Pollution Pricing Act went into effect. Since that time the federal government has published, on October 31, 2018, SOR/2018-212, 213 and 214 (the “GHGPPA SOR”), to amend Schedule 1 to the Greenhouse Gas Pollution Pricing Act, to establish criteria respecting facilities and persons, and to issue the greenhouse gas emissions information production order.

Alberta, British Columbia and Québec already have compliant carbon pricing systems in place and are not expected to be subject to the federal backstop regime. Although at the beginning of 2017, Ontario had implemented a compliant cap and trade system, there was a change in the provincial government as a result of the election held in June 2018. The newly elected Ontario government cancelled the cap and trade regulation and prohibited all trading of emission allowances, effective as of July 3, 2018, and on October 31, 2018 formally repealed the cap-and- trade legislation. As a result, our Ontario operations are now subject to the federal backstop regime. Under the federal GHGPPA SOR, large industrial emitters, such as our operations in Tunis and Nipigon, are subject to the federal output-based pricing system (“OBPS”)` provided for in Part 2 of the Greenhouse Gas Pollution Pricing Act. The federal backstop regime imposes a minimum Cdn$20/tonne of CO2e (“tCO2e”) carbon price beginning on January 1, 2019, increasing by Cdn$10 increments each following year to 2022.

The validity of the federal backstop regime is being challenged on constitutional grounds by Ontario and Saskatchewan, and Ontario also is working on its own output-based performance standards for large emitters (which appear likely to be similar to and potentially compatible with the federal OBPS). The details of both the federal OBPS and the Ontario output-based performance standards had not been settled at the beginning of 2019, notwithstanding that they are to be effective from and after January 1, 2019. The federal government issued a "Notice of intent to make regulations under part 2 of the Greenhouse Gas Pollution Pricing Act" on December 20, 2018, and subsequently, on January 9, 2019, issued "The Complete Text for Proposal for the Output-Based Pricing System Regulations" for public comment (which are due by February 15, 2019). The implications of the federal OBPS for our operations in Tunis and Nipigon is discussed below (in the section on Canada – Ontario).

Canada – British Columbia

The Government of British Columbia has enacted a number of significant pieces of climate action legislation

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that frame British Columbia’s approach to reducing greenhouse gas emissions with the goal of supporting its participation in the emerging low-carbon economy.

One key piece of legislation is the Greenhouse Gas Reduction Targets Act, which was re-enacted in November 2018 as the Climate Change Accountability Act (British Columbia) (“CCAA”), which sets legislated targets for the reduction of greenhouse gas emissions in British Columbia. Using 2007 as a base year, CCAA (along with related Ministerial Orders) requires that emissions must be reduced by a minimum of 40% by 2030, 60% by 2040 and 80% by 2050. Also required in connection with CCAA are (from 2020 onward) British Columbia Greenhouse Gas Inventory Reports (reports are prepared in even-numbered years and tables are updated in odd-numbered years), Community Energy and Emissions Inventory Reports (prepared every two years) and Carbon Neutral Action Reports (prepared annually), all of which are designed to provide scientific, comparable and consistent reporting of greenhouse gas sources.

Other related, key pieces of legislation include the Carbon Tax Act (“CTA”) and the Greenhouse Gas Industrial Reporting and Control Act (“GGIRCA”). CTA operates to put a price on greenhouse gas emissions, providing an incentive for sustainable choices and practices by producers of greenhouse gases. GGIRCA came into force on January 1, 2016 and combined several pieces of British Columbia's existing greenhouse gas legislation into a single legislative framework. It includes the ability to set a greenhouse gas emissions intensity benchmark for regulated industries and enables the benchmark to be met through flexible options, such as purchasing offsets or paying a set price per tonne of greenhouse gas emissions that would be dedicated to a technology fund. Three regulations necessary to implement GGIRCA also came into force on January 1, 2016: the Greenhouse Gas Emission Reporting Regulation (“GGERR”), the Greenhouse Gas Emission Administrative Penalties and Appeals Regulation (“GGEAPAR”) and the Greenhouse Gas Emission Control Regulation (“GGECR”). GGERR establishes compliance reporting requirements and ensures that industrial operations that emit more than 10,000 carbon dioxide equivalent tonnes per year report their greenhouse gas pollution each year. GGEAPAR establishes the process for when, how much, and under what conditions administrative penalties may be levied for non-compliance with GGIRCA or the regulations made under GGIRCA. GGECR establishes the BC Carbon Registry and sets criteria for developing emission offsets issued by the provincial government. GGECR also establishes the price for funded units issued under GGIRCA that would go towards a technology fund. Regulated operations will purchase offsets from the market or funded units from government to meet emission limits. Funded unit revenue that goes to a technology fund will also support the development of clean technologies with significant potential to reduce British Columbia's emissions over the long term.

Canada - Ontario

In a news release issued on June 15, 2018, Ontario Premier-designate Doug Ford announced that the first act of his newly formed government would be to cancel Ontario’s cap and trade program (under the Climate Change Mitigation and Low-carbon Economy Act, 2016). Effective as of July 3, 2018, the Ontario government cancelled the cap and trade regulation and prohibited all trading of emissions allowances, and on October 31, 2018 formally repealed the Ontario cap-and-trade legislation. Bill 4: Cap and Trade Cancellation Act, 2018 (the legislation which repealed the former cap-and-trade regime) retired or cancelled outstanding emissions allowances and strictly limited the ability of those holding emissions allowances to bring claims seeking to recover for any damages suffered as a result.

Under the previous cap-and-trade regime, facilities in Ontario with annual greenhouse gas emissions of 25,000 tonnes or more were generally required by law to participate in the regime by obtaining emissions allowances. However, facilities which primarily generate electricity using natural gas from a local distributor were excluded from the requirement to obtain emission allowances and instead participated in the program through the payment of the carbon price charged by the local natural gas distributor on the natural gas delivered after the end of 2016. As a result, our operations in Ontario were not holding emissions allowances when the Ontario cap and trade program was cancelled and were not adversely affected by the cancellation of that regime.

As a result of the cancellation of the Ontario cap-and-trade regime, from January 1, 2019 our operations in Nipigon and Tunis are subject to the federal OBPS and potentially also to the Ontario output-based performance standard (both of which remain to be fully detailed). Under the federal "Notice Establishing Criteria Respecting

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Facilities and Persons and Publishing Measures: SOR/2018-213," any facility which emitted more than 50kt of CO2e during any of the 2014, 2015, 2016 or 2017 calendar years, and which carries out, as its primary activity, the generation of electricity using fossil fuels, is a covered facility and subject to the OBPS. Since the Nipigon and Tunis projects are each generating electricity using natural gas and each reported emissions in excess of 50kt of CO2e for one of the 2014, 2015, 2016 or 2017 calendar years (119,248 tonnes for 2014 in the case of Tunis and 115,725 tonnes for 2016 in the case of Nipigon), each is considered a covered facility and subject to the federal OBPS.

Assuming that the federal OBPS regulations remain as set out in the January 9, 2019 proposal (discussed in the section on Canada - Federal), the Tunis and Nipigon projects will be required to either pay an excess emissions charge or remit compliance units as prescribed by the federal backstop regime for each tonne of CO2e emissions in excess of 370 tonnes of CO2e / GWh of electricity generated by such operations and will receive free emissions allowances if the emissions fall below that measure. The details of arrangements for the possible recovery of these potential additional costs from the IESO will depend on the terms of the applicable PPA.

Renewable Energy

More than half of the U.S. states and most Canadian provinces have set mandates requiring the achievement of certain levels of renewable energy production and/or energy efficiency during target timeframes. This includes generation from wind, solar and biomass, and/or renewable fuel mandates. For example, in 2011, California enacted a law requiring retail sellers of electricity to deliver 33% of their customers' electricity requirements from renewable resources, as defined in the statute, by 2020. In 2015, California enacted SB 350, which increases the amount of electricity from renewable resources that California retail sellers must deliver after 2020 to 40% of retail sales by December 2024, 45% of retail sales by December 2027, and 50% of retail sales by December 2030. In order to meet $CO_2$ reduction goals, changes in the generation fuel mix are forecasted to include a reduction in existing coal resources, higher reliance on natural gas and renewable energy resources and an increase in demand-side resources. Investments in new or upgraded transmission lines will be required to move increasing renewable generation from more remote locations to load centers.

In December 2015, 195 countries participating in the United Nations Framework Convention on Climate Change ("UNFCC"), at its 21st Conference of the Parties meeting ("COP21") held in Paris, adopted a new global agreement on the reduction of climate change (the "Paris Agreement"). The Paris Agreement became effective in November 2016, after it had been ratified by a sufficient number of countries. The Paris Agreement sets a goal of holding the increase in global average temperature to well below 2 degrees Celsius and pursuing efforts to limit the increase to 1.5 degrees Celsius, to be achieved by aiming to reach a global peaking of greenhouse gas emissions as soon as possible. The Paris Agreement consists of two elements: a legally binding commitment by each participating country to set an emissions reduction target, referred to as "nationally determined contributions" or "NDCs," with a review of the NDCs that could lead to updates and enhancements every five years (Article 4) and a transparency commitment requiring participating countries to disclose in full their progress (Article 13). As decided at the 24th Conference of the Parties meeting in December 2020, countries are expected to submit updated NDCs in 2020. Accordingly, the Paris Agreement may result in additional regulations to reduce carbon emissions in coming years.

Canada ratified the Paris Agreement, and submitted an NDC that included a 2030 target of 30% below 2005 levels. The United States also submitted an NDC, which called for reducing its net greenhouse gas emissions by 26-28% below 2005 levels by 2025. However, the Trump Administration has announced the planned withdrawal of the U.S. from the Paris Agreement. In light of the legislative, judicial and executive factors influencing regulatory action, significant uncertainty exists as to how greenhouse gas restrictions in the U.S. will impact our facilities in the future.

## EMPLOYEES

As of February 27, 2019, we had 230 employees, 166 in the United States and 64 in Canada. Of our Canadian employees, 44 are covered by collective bargaining agreements, which will expire on December 19, 2020 and December 31, 2020. During 2018, we did not experience any labor stoppages or labor disputes at any of our facilities.

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AVAILABLE INFORMATION

We make available, free of charge, on our website, www.atlanticpower.com, our Annual Report on Form 10 K, Quarterly Reports on Form 10 Q, Current Reports on Form 8 K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Additionally, we make available on our website and the System for Electronic Document Analysis and Retrieval at www.sedar.com, our Canadian securities filings. The public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. We are not a foreign private issuer, as defined in Rule 3b 4 under the Exchange Act.

Information contained on our website or that can be accessed through our website is not incorporated into and does not constitute a part of this Annual Report on Form 10 K. We have included our website address only as an inactive textual reference and do not intend it to be an active link to our website.

ITEM 1A. RISK FACTORS

This section highlights specific risks that could affect our Company. You should carefully consider each of the following risks and all of the other information set forth in this Annual Report on Form 10 K. Based on the information currently known to us, we believe the following information identifies the most significant risk factors affecting our Company. However, the risks and uncertainties described below are not the only ones related to our business and are not necessarily listed in the order of their importance. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business, results of operations or financial condition.

If any of the following risks and uncertainties develops into actual events or if the circumstances described in the risks and uncertainties occur or continue to occur, these events or circumstances could have a material adverse effect on our business, results of operations or financial condition. These events could also have a negative effect on the trading price of our securities.

Risks Related to Our Structure

We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities

We continue to focus on executing our business plan, including the objectives of enhancing the value of our existing assets through discretionary capital investments and commercial activities, delevering our balance sheet to improve our cost of capital and ability to compete for new investments, improving our cost structure and reducing overhead. However, we may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities.

Our ability to make required payments under our outstanding indebtedness, as well as meeting the greater of the requirements of the 50% cash sweep or the targeted debt balance, or to prepay or redeem any such indebtedness, will depend on our financial and operating performance, including our ability to generate cash flow from operations in the future. As a result, we may be required to refinance such indebtedness and/or obtain third party financing in order to repay, redeem or refinance such indebtedness when it comes due. There can be no assurance that our business will generate sufficient cash flow from operations or that future borrowings or refinancing opportunities will be available to us at an acceptable cost, in amounts sufficient, or at all, to enable us to service our debt obligations or to repay or redeem any such indebtedness at maturity, particularly because of our high levels of debt and the debt incurrence restrictions imposed by the various agreements governing our indebtedness. Steps taken to refinance our indebtedness or obtain other third party financing, if any, may not be successful and may not permit us to meet our scheduled debt service obligations, which could have a material adverse effect on our liquidity and financial condition.

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In addition, a payout of a significant portion of our cash flow to service our debt, including pursuant to the mandatory amortization feature of the Credit Facilities, or to pay dividends on our preferred shares, may result in us not retaining a sufficient amount of cash to finance growth and reinvestment opportunities, including on our preferred shares through the acquisition of additional projects, to the extent any such acquisitions are otherwise available to us. As a result, we may have to forego growth and reinvestment opportunities that would otherwise be desirable, if we do not find alternative sources of financing for such opportunities. In addition, even if we are able to find alternative sources of financing for such opportunities, we may be precluded from pursuing an otherwise attractive acquisition or investment if the projected short term cash flow from the acquisition or investment is not adequate to service the capital raised to fund such acquisition or investment. This could also limit our flexibility in planning for, or reacting to, changes in our business and industry, placing us at a competitive disadvantage compared to our competitors. We cannot provide any assurance that we will be able to identify, finance or close any transactions associated with any such growth or reinvestment opportunities on acceptable terms or timing, or at all.

Further, if we are unable to generate sufficient cash flow from operations, our ability to support our liquidity needs, including, but not limited to, servicing our debt obligations, including pursuant to the mandatory amortization feature of the Credit Facilities, or financing internal or external growth opportunities, will depend on our ability to access the credit and capital markets, neither of which may be available to us on acceptable terms, or at all. Further, access to the credit and capital markets and the cost and availability of credit may be adversely affected by factors beyond our control, including turmoil in the financial services industry, volatility in securities trading markets and general economic conditions. We cannot provide any assurance that we will be able to access the credit or capital markets on acceptable terms or timing, or at all.

Our Credit Facilities contain certain terms, covenants and restrictions that could impact our available cash flow and restrict our ability to make acquisitions or investments or issue additional indebtedness

Our Credit Facilities contain certain terms, covenants and restrictions, including a mandatory amortization feature and customary prepayment provisions. Such terms, covenants and restrictions may impact our available cash flow and limit our ability to retain sufficient amounts of cash to service our debt obligations or finance internal or external growth opportunities. Our Credit Facilities are a primary source of our liquidity. See "Management's Discussion and Analysis of Financial Condition and Results of Operations—Liquidity and Capital Resources."

The covenants under the Credit Facilities include a requirement that APLP Holdings Limited Partnership ("APLP Holdings") and its subsidiaries maintain certain leverage and interest coverage ratios (each, as defined in the credit agreement governing the Credit Facilities (the "Credit Agreement")). The Credit Facilities also contain customary restrictions and limitations on the Partnership's and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case, subject to customary carve outs and exceptions and various thresholds. Any such limitations could restrict our ability to, among other things, make acquisitions or investments or issue additional indebtedness.

Discontinuation, reform or replacement of LIBOR, or uncertainty related to the potential for any of the foregoing, may adversely affect us

The U.K. Financial Conduct Authority announced in 2017 that LIBOR could be effectively discontinued after 2021. In addition, other regulators have suggested reforming or replacing other benchmark rates. The discontinuation, reform or replacement of LIBOR or any other benchmark rates may have an unpredictable impact on contractual mechanics in the credit markets or cause disruption to the broader financial markets. Uncertainty as to the nature of such potential discontinuation, reform or replacement may negatively impact the volatility of LIBOR rates, liquidity, our access to funding required to operate our business, or the trading market for our existing Credit Facilities.

Under our existing Credit Facilities, if LIBOR becomes unavailable or if LIBOR ceases to accurately reflect the costs to the lenders, we may be required to pay interest under an alternative base rate which could cause the amount of interest payable on the term loan to be materially different than expected. We may choose in the future to pursue an amendment to our existing Credit Facilities to provide for a transition mechanism or other reference rate in anticipation of LIBOR's discontinuation, but we can give no assurance that we will be able to reach agreement with our lenders on any such amendment.

Our indebtedness and financing arrangements, and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make preferred dividend payments, acquisitions or investments or issue additional indebtedness we otherwise would seek to do

The degree to which we are leveraged on a consolidated basis could have important consequences for our shareholders and other stakeholders, including:

- our ability in the future to obtain additional financing for, among other things, the repayment or redemption of indebtedness and other debt service obligations and investment in internal and external growth opportunities, including the acquisition of additional projects, to the extent any such acquisitions are otherwise available to us, or other purposes;

- our ability to refinance indebtedness on terms acceptable to us or at all;

- our ability to satisfy debt service and other obligations;

- our vulnerability to general adverse industry conditions and economic conditions, including but not limited to adverse changes in foreign exchange rates and commodity prices;

- the availability of cash flow to fund other corporate purposes and grow our business;

- our flexibility in planning for, or reacting to, changes in our business and the industry; and

- our competitive position relative to our competitors that are not as highly leveraged.

As of December 31, 2018, our consolidated debt represented approximately 79% of our total capitalization, comprised of debt and balance sheet equity.

The agreements governing our indebtedness limit, but do not prohibit, the incurrence of additional indebtedness. Our current or future borrowings could increase the level of financial risk to us and, to the extent that the interest rates are not fixed and rise, or that borrowings are refinanced at higher rates, our available cash flow and results of operations could be adversely affected. Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 96% of our debt, including our share of the project level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

As of December 31, 2018, we had (i) no amount outstanding and $76.9 million issued in letters of credit under our revolving credit facility, (ii) $102.4 million of outstanding convertible debentures, and (iii) $625.0 million of outstanding Term Loan, Medium term Notes and non recourse project level debt.

In addition, some of our projects currently have non recourse term loans or other financing arrangements in place with various lenders. These financing arrangements are typically secured by all of the project assets and contracts as well as our equity interests in the project. The terms of these financing arrangements generally impose many covenants and obligations on the part of the borrower. For example, some of these agreements contain requirements to maintain specified historical, and in some cases, prospective debt service coverage ratios before cash may be distributed from the relevant project to us, which would adversely affect our available cash flow. We have, in the past, failed to meet the cash flow coverage ratio tests at certain of our projects, which restricted those projects from making cash distributions. Although all of our projects with non-recourse loans are currently meeting their debt service requirements, we cannot provide any assurances that our projects will generate enough future cash flow to meet any applicable ratio tests in order to be able to make distributions to us.

In many cases, an uncured default by any party under key project agreements (such as a PPA or a fuel supply agreement) will also constitute a default under the project's term loan or other financing arrangement. Failure to comply with the terms of these term loans or other financing arrangements, or events of default thereunder, may prevent cash distributions by the particular project(s) to us and may entitle the lenders to demand repayment and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition. In addition, failure to comply with the terms, restrictions or obligations of any of our revolving credit facility, convertible debentures or Credit Facilities, or the preferred shares of the Partnership, or any other financing arrangements, borrowings or indebtedness, or events of default thereunder, may entitle the lenders to demand repayment, accelerate related debt as well as any other debt to which a cross default or cross acceleration provision applies and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition. In addition, if and for as long as we have failed to declare, or are in arrears on the payment of, dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares, the Partnership will not make any distributions on its limited partnership units. Additionally, if our lenders under our indebtedness demand payment, we may not, at that time, have sufficient cash and cash flows from operating activities to repay such indebtedness.

Our failure to refinance or repay any indebtedness when due could constitute a default under such indebtedness and restrict our ability to take certain actions, including paying dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares. In addition, any covenant breach or event of default could harm our credit rating and our ability to obtain additional financing on acceptable terms or at all. The occurrence of any of these events could have a material adverse effect on our business, results of operations, financial condition and liquidity.

Paying dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares could also be restricted if we fail to meet the targeted debt balances of the Credit Facilities, even though failing to do so would not result in an event of default.

Exchange rate volatility may affect our available cash flow and results of operations

Our dividend payments on our preferred shares and our interest payments on some of our corporate level long term debt and convertible debentures are denominated in Canadian dollars. Conversely, some of our projects' revenues and expenses are denominated in U.S. dollars. Our Canadian dollar-denominated debt instruments are revalued at each balance sheet date based on the U.S. dollar to Canadian dollar foreign exchange rate at the balance sheet date, with changes in the value of the debt recorded in the consolidated statements of operations. The U.S. dollar to Canadian dollar foreign exchange rate has been volatile in recent years, which in turn creates volatility in our results due to the revaluation of our Canadian dollar denominated debt. Although we currently generate sufficient revenues in Canadian dollars to fund our Canadian dollar obligations, future exchange rate volatility or changes to our Canadian dollar revenues could expose us to currency exchange rate risks, against which we do not typically hedge. Any arrangements to mitigate this exchange rate risk may not be sufficient to fully protect against this risk. If hedging transactions do not fully protect against this risk, changes in the currency exchange rate between U.S. and Canadian dollars could adversely affect our available cash flow and results of operations.

A downgrade in our credit rating or in the credit rating of our outstanding debt securities, or any deterioration in credit quality, could negatively affect our ability to access capital and our ability to hedge, and could trigger termination rights under certain contracts

A downgrade in our credit rating, a downgrade in the credit rating of our outstanding debt securities, or any deterioration in credit quality could adversely affect our ability to renew existing, or obtain access to new, credit facilities and could increase the cost of such facilities, restrict access to our revolving credit facility and/or trigger termination rights or enhanced disclosure requirements under certain contracts to which we are a party. Any downgrade of our corporate credit rating could also cause counterparties to require us to post letters of credit or other additional collateral, make cash prepayments, or obtain a guarantee agreement, all of which would expose us to additional costs and/or could adversely affect our ability to comply with covenants or other obligations under any of our revolving credit facility, convertible debentures or unsecured notes or any other financing arrangements, borrowings or indebtedness (or could constitute an event of default under any such financing arrangements, borrowings or indebtedness that we may be

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unable to cure), any of which could have a material adverse effect on our business, results of operations and financial condition.

Changes in our creditworthiness may affect the value of our common shares

Changes to our perceived creditworthiness and ability to meet our required covenants on an ongoing basis may affect the market price or value and the liquidity of our common shares.

The future issuance of additional common shares could dilute existing shareholders

From time to time, we may decide to issue additional common shares, redeem outstanding debt for common shares, repay outstanding principal amounts under existing debt by issuing common shares, or issue equity-related securities such as convertible debt. We may also, from time to time, decide to issue common shares to meet strategic objectives or in connection with acquiring assets or pursuing broader strategic options. The issuance of additional common shares may have a dilutive effect on shareholders and may adversely impact the price of our common shares.

Volatile capital and credit markets may adversely affect our ability to raise capital on favorable terms and may adversely affect our business, results of operations, financial condition and cash flows

Disruptions in the capital and credit markets in the United States, Canada or abroad can adversely affect our ability to access the capital markets. Our access to funds under our credit facility is dependent on the ability of the banks that are parties to the facility to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. Longer term disruptions in the capital and credit markets as a result of turmoil in the financial services industry, volatility in securities trading markets and general economic conditions could result in an inability to support our liquidity needs, including, but not limited to, the service of our debt obligations or financing of internal or external growth opportunities. See "—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities."

Our ability to arrange for financing on a recourse or non recourse basis and the costs of such capital are dependent on numerous factors, some of which are beyond our control, including:

· general industry, economic and capital market conditions;

· the availability of bank credit;

· investor confidence;

· our financial condition, performance and prospects as well as companies in our industry or similar financial circumstances; and

· changes in tax and securities laws which are conducive to raising capital.

Should future access to capital not be available to us, either as a result of market conditions or our financial condition, we may not be able to service our debt obligations or finance internal or external growth opportunities, any of which would adversely affect our business, results of operations and financial condition.

We have guaranteed the performance of some of our subsidiaries, which may result in substantial costs in the event of non performance

We have issued certain guarantees of the performance of some of our subsidiaries in certain situations, which obligates us to perform in the event that the subsidiaries do not perform. In the event of non performance by the subsidiaries, we could incur substantial cost to fulfill our obligations under these guarantees. Such performance guarantees could have a material impact on our business, results of operations, financial condition and cash flows. See Notes 12, 20 and 23 to the consolidated financial statements for information on our guarantee obligations.

We have anti takeover protections that may discourage, delay or prevent a change in control that could benefit our shareholders.

The Business Corporations Act (British Columbia) (the “BCBCA”) and our Articles of Continuance contain provisions that could make it more difficult for a third party to acquire us without the consent of our Board of Directors (“Board”). These provisions include:

· As a notice of meeting is required to include certain particulars in the case where a shareholder meeting is being requisitioned by shareholders, our Board must be given advance notice regarding special business that is to be brought by such requisitioning shareholders before the shareholder meeting. For special business, advance notice describing the special business to be discussed at the meeting must be provided and that notice must include any documents to be approved or ratified as an addendum or state that such document will be available for inspection at our records office or other reasonably accessible location;

· Under the BCBCA, shareholders may make proposals for matters to be considered at the annual general meeting of shareholders, provided that such shareholders represent at least 1% of the voting shares of a company or such shares have a fair market value of at least Cdn$2,000. Such proposals must be sent to us in advance of any proposed meeting by delivering a timely written notice in proper form to our registered office. The notice must include information on the business the shareholder intends to bring before the meeting. These provisions could have the effect of delaying until the next shareholder meeting shareholder actions that are favored by the holders of a majority of our outstanding voting securities; and

· Casual vacancies on our Board can be approved prior to the next annual meeting of shareholders by the directors of our Board of Directors.

If we experience a change of control, unless we elect to make a voluntary prepayment of the term loan under the Credit Facilities, the Partnership will be required to offer each electing lender a prepayment of such lender’s term loans under the Credit Facilities at a price equal to 101% of par. Additionally, a change in control will permit holders of our convertible debentures to require that we purchase the debentures upon the conditions set forth in the respective indenture governing the debentures, which may discourage, delay or prevent a change of control or the acquisition of a substantial block of our common shares. In addition, some of our PPAs or other commercial agreements may contain change of control provisions.

We have a shareholder rights plan in place that may delay or prevent a change of control or the acquisition of a substantial block of our common shares and may make any future unsolicited acquisition attempt more difficult.

Under the rights plan:

- The rights will generally become exercisable if a person or group acquires 20% or more of Atlantic Power's outstanding common shares (unless such transaction is a "permitted bid" or a transaction to which the application of the shareholders rights plan has been waived pursuant to the terms of the plan) and thus becomes an "acquiring person." A "permitted bid" is an offer pursuant to which, among other things, such person or group agrees to hold the offer open to all shareholders for a period longer than the statutorily required period;

- Each right, when exercisable, will entitle the holder, other than the "acquiring person," to acquire shares of Atlantic Power's common shares at a significant discount to the then prevailing market price; and

- As a result, the rights plan may cause substantial dilution to a person or group that becomes an "acquiring person" and may discourage or delay a merger or acquisition that shareholders may consider favorable, including transactions in which shareholders might otherwise receive a premium for their shares.

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Our common shares may not continue to be qualified investments under Canadian tax laws

There can be no assurance that our common shares will continue to be qualified investments under relevant Canadian tax laws for trusts governed by registered retirement savings plans, registered retirement income funds, deferred profit sharing plans, registered education savings plans, registered disability savings plans and tax free savings accounts. Canadian tax laws impose penalties for the acquisition or holding of non qualified or ineligible investments.

We are subject to Canadian tax

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes, and dividends paid by us are generally subject to Canadian withholding tax if paid to a shareholder that is not a resident of Canada. We hold promissory notes from our U.S. holding companies (the “Intercompany Notes”) and are required to include, in computing our taxable income, interest on the Intercompany Notes.

Canadian federal income tax laws and policies could be changed in a manner which adversely affects holders of our common shares

There can be no assurance that Canadian federal income tax laws and Canada Revenue Agency administrative policies respecting the Canadian federal income tax consequences generally applicable to us, to our subsidiaries, or to a U.S. or Canadian holder of common shares will not be changed in a manner which adversely affects holders of our common shares.

Our current structure may be subject to additional U.S. federal income tax liability

Under our current structure, our subsidiaries that are incorporated in the United States are subject to U.S. federal income tax on their income at regular corporate rates (currently as high as 21%, plus state and local taxes), and two of our U.S. holding companies will claim interest deductions with respect to the Intercompany Notes in computing their income for U.S. federal income tax purposes. To the extent any interest expense under the Intercompany Notes is disallowed or is otherwise not deductible, the U.S. federal income tax liability of our U.S. holding companies will increase, which could affect the after tax cash available to distribute to us.

We received advice from our U.S. tax counsel at the time of the issuance, based on certain representations by us and our U.S. holding companies and determinations made by our independent advisors, as applicable, that the

Intercompany Notes should be treated as debt for U.S. federal income tax purposes. However, it is possible that the Internal Revenue Service (the “IRS”) could successfully challenge these positions and assert that any of these arrangements should be treated as equity rather than debt for U.S. federal income tax purposes or that the interest on such arrangements is otherwise not deductible. In this case, the otherwise deductible interest would be treated as non deductible distributions and, in the case of the Intercompany Notes, may be subject to U.S. withholding tax to the extent our respective U.S. holding company had current or accumulated earnings and profits. The determination of debt or equity treatment for U.S. federal income tax purposes is based on an analysis of the facts and circumstances. There is no clear statutory definition of debt for U.S. federal income tax purposes, and its characterization is governed by principles developed in case law, which analyze numerous factors that are intended to identify the nature of the purported creditor’s interest in the borrower.

Not all courts have applied this analysis in the same manner, and some courts have placed more emphasis on certain factors than other courts have. To the extent it were ultimately determined that our interest expense on the Intercompany Notes were disallowed, our U.S. federal income tax liability for the applicable open tax years would materially increase, which could materially affect the after tax cash available to us to distribute. Alternatively, the IRS could argue that the interest on the Intercompany Notes exceeded or exceeds an arm’s length rate, in which case only the portion of the interest expense that does not exceed an arm’s length rate may be deductible and the remainder may be subject to U.S. withholding tax to the extent our U.S. holding companies had current or accumulated earnings and profits. We have received advice from independent advisors that the interest rate on these debt instruments was and is, as applicable, commercially reasonable under the circumstances, but the advice is not binding on the IRS.

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Furthermore, our U.S. holding companies' deductions attributable to the interest expense on the Intercompany Notes may be limited by the amount by which each U.S. holding company's net interest expense (the interest paid by each U.S. holding company on all debt, including the Intercompany Notes, less its interest income) exceeds 30% of its adjusted taxable income (generally, U.S. federal taxable income before net interest expense, net operating loss carryovers, and, for tax years beginning before January 1, 2022, depreciation and amortization). Any disallowed interest expense may currently be carried forward to future years. In addition, if our U.S. holding companies do not make regular interest payments as required under these debt agreements, other limitations on the deductibility of interest under U.S. federal income tax laws could apply to defer and/or eliminate all or a portion of the interest deduction that our U.S. holding companies would otherwise be entitled to.

In addition, recently enacted U.S. tax legislation made significant changes to the U.S. federal income tax rules applicable to our activities in the United States. Although the tax legislation enacted on December 22, 2017 reduced the federal corporate income tax rate from 35% to 21%, it also added additional limitations on deductions attributable to interest expense (discussed in the preceding paragraph) and introduced "base erosion" rules that may effectively limit the tax deductibility of certain payments made by U.S. entities to non-U.S. affiliates. We evaluated the full effect of this legislation on our business and operations and believe that the interest expense limitation and base erosion and anti-abuse tax will not have a material impact on cash taxes in future tax years.

Our U.S. holding companies have existing net operating loss carryforwards that we can utilize to offset future taxable income. Some of these loss carryforwards are subject to an annual limitation on their use. Although we expect these losses will be available to us as a future benefit, in the event that they are successfully challenged by the IRS or subject to additional future limitations, including, but not limited to, as a result of implementation of any of the potential options we are considering, our ability to realize these benefits may be limited. Although not expected, a reduction in our net operating losses, or additional limitations on our ability to use such losses, may result in a material increase in our future income tax liability.

Atlantic Power Preferred Equity Ltd. is subject to Canadian tax, as is Atlantic Power's income from the Partnership

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes. See "Risks Related to Our Structure—We are subject to Canadian tax." We are required to include in computing our taxable income any income earned by the Partnership. In addition, Atlantic Power Preferred Equity Ltd., a subsidiary of the Partnership, is also a Canadian corporation and is generally subject to Canadian federal, provincial and other taxes. Atlantic Power Preferred Equity Ltd. is liable to pay its applicable Canadian taxes.

Risks Related to Our Business and Our Projects

The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations and financial condition

Power generated by our projects, in most cases, is sold under PPAs that expire at various times. Currently, our PPAs are scheduled to expire between June 30, 2019 and March 31, 2037. See Item 1. Business—Our Organization and Segments for details about our projects' PPAs and related expiration dates. In addition, these PPAs may be subject to termination prior to expiration in certain circumstances, including default by the project. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all; the price received by the project for power under subsequent arrangements may be reduced significantly, or there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA at the project. It is possible that subsequent PPAs may not be available at prices that permit the operation of the project on a profitable basis. When the affected project temporarily or permanently ceases operations, or when we have an expectation that we will be unable to renew or renegotiate the PPA, the value of the project may be impaired such that we would be required to record an impairment loss under applicable accounting rules. See "—Impairment of goodwill or long lived assets could have a material adverse effect on our business, results of operations and financial condition."

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Nine of our projects, representing 57% of our operating net MW and 51% of our 2018 Project Adjusted EBITDA, have PPAs or other contractual arrangements that will expire within the next five years. These projects are Williams Lake (2019), Oxnard (2020), Calstock (2020), Kenilworth (2020), Manchief (2022), Frederickson (2022), Moresby Lake (2022), Nipigon (2022) and Orlando (2023).

Our projects depend on their electricity and thermal energy customers and there is no assurance that these customers will perform their obligations or make required payments

Each of our projects relies on one or more PPAs, steam sales agreements or other agreements with one or more utilities or other customers for a substantial portion of its revenue. At times, we rely on a single customer or a limited number of customers to purchase all or a significant portion of a project's output. In 2018, the largest customers of our power generation projects, including projects recorded under the equity method of accounting, are Niagara Mohawk Power Corporation, Equistar Chemicals L. P., BC Hydro, Georgia Power Company and IESO, which account for approximately 15.1%, 12.6%, 12.5%, 10.9% and 10.8%, respectively, of the consolidated revenue of our projects. If a customer stops purchasing output from our power generation projects or purchases less power than anticipated, such customer may be difficult to replace, if at all. Further concentration of our customers would increase our dependence on any one customer. Our cash flows and results of operations, including the amount of cash available to make payments on our indebtedness, are highly dependent upon customers under such agreements fulfilling their contractual obligations. There is no assurance that these customers will perform their contractual obligations or make required payments.

Further, our customers generally have investment grade credit ratings, as measured by Standard & Poor's. Customers that have assigned ratings at the top end of the range have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the bottom end of the range have the weakest capacity. Agency ratings are subject to change, and there can be no assurance that a ratings agency will continue to rate the customers, and/or maintain their current ratings. A security rating may be subject to revision or withdrawal at any time by the rating agency, and each rating should be evaluated independently of any other rating. We cannot predict the effect that a change in the ratings of the customers will have on their liquidity or their ability to pay their debts or other obligations.

Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating margin of these projects and on our business, results of operations and financial condition

PPAs that are based on spot market pricing for some or all of their output will be exposed to fluctuations in the wholesale price of electricity. In addition, as PPAs expire or terminate, the relevant project will be required to either negotiate a new PPA or sell into the electricity wholesale market, in which case the prices for electricity will depend on market conditions at the time, which may not be favorable. The open market wholesale prices for electricity are very volatile. Long and short term power prices may fluctuate substantially due to other factors outside of our control, including:

- changes in generation capacity in the electricity markets, including the addition of new supplies of power from existing competitors or new market entrants as a result of the development of new generation facilities, expansion or retirement of existing facilities or additional transmission capacity;

- electric supply disruptions, including plant outages and transmission disruptions;

- fuel transportation capacity constraints;

- weather conditions;

- changes in the demand for power or in patterns of power usage;

- development of new fuels and new technologies for the production or storage of power;

- development of new technologies for the production of natural gas;

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· availability of competitively priced renewable fuel sources;

· available supplies of natural gas, crude oil and refined products, and coal;

· interest rate and foreign exchange rate fluctuation;

· availability and price of emission credits;

· geopolitical concerns affecting global supply of oil and natural gas;

· general economic conditions which impact energy consumption in areas where we operate; and

· power market, fuel market and environmental regulation and legislation.

The market price for electricity is affected by changes in demand for electricity. Factors such as economic slowdown, worse than expected economic conditions, milder than normal weather, the growth of energy efficiency and efforts aimed at energy conservation, among others, could reduce energy demand or significantly slow the growth in demand for electricity, thereby reducing the market price for electricity. A reduction in demand could contribute to conditions that no longer support the continued operation of certain power generation projects, which could adversely affect our results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs, among others.

Both our Chambers and Morris projects are contracted but have some exposure to market prices for power. At Chambers, plant capacity is sold forward pursuant to the power purchase agreement with our utility customer but the project is economically dispatched, which impacts variable operating margins. For example, during periods of low demand and low spot electricity prices, the project is dispatched less, which reduces the project's operating margin. In addition, the utility customer has the right to sell a portion of the output into the spot market if it is economical to do so, and the Chambers project shares in the profit from these sales. This also adds some variability to the project's financial results.

At Morris, a portion of the capacity is contracted with the industrial customer through 2034. The remaining capacity has been sold forward into the Pennsylvania New Jersey Maryland ("PJM") capacity market through annual auctions covering the period through May 2022. The capacity revenues from these auctions generally represent the majority of the operating margin of the uncontracted portion of the project. Energy associated with the capacity sold forward into the PJM market is generally dispatched by PJM when economic to do so or when needed for other reasons. The project can also offer ancillary services to the grid. The sale of energy and ancillary services from the uncontracted portion of the project is not at a fixed price or margin and therefore can add variability to the project's financial results.

Our projects depend on third party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects

The amount of energy generated at the projects is highly dependent on suppliers under certain fuel supply agreements fulfilling their contractual obligations. The loss of significant fuel supply agreements or an inability or failure by any supplier to meet its contractual commitments may adversely affect our results.

Upon the expiration or termination of existing fuel supply agreements, we or our project operators will have to renegotiate these agreements or may need to source fuel from other suppliers. We may not be able to renegotiate these agreements or enter into new agreements on similar terms. There can be no assurance as to availability of the supply or pricing of fuel under new arrangements, and it can be very difficult to accurately predict the future prices of fuel. If our suppliers are unable to perform their contractual obligations or we are unable to renegotiate our fuel supply agreements, we may seek to meet our fuel requirements by purchasing fuel at market prices, exposing us to market price volatility

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and the risk that fuel and transportation may not be available during certain periods at any price. Changes in market prices for natural gas, biomass, coal and oil may result from the following:

· weather conditions;

· seasonality;

· demand for energy commodities and general economic conditions;

· availability and price of emission credits;

· additional generating capacity;

· disruption or other constraints or inefficiencies of electricity, gas or coal transmission or transportation;

· availability and levels of storage and inventory for fuel stocks;

· natural gas, crude oil, refined products and coal production levels;

· changes in market liquidity;

· governmental regulation and legislation; and

· our creditworthiness and liquidity, and the willingness of fuel suppliers/transporters to do business with us.

Revenues earned by our projects may be affected by the availability, or lack of availability, of a stable supply of fuel at reasonable or predictable prices. The price we can obtain for the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel or delivery costs. To the extent possible, our projects attempt to match fuel cost setting mechanisms in supply agreements to energy payment formulas in the PPA and to provide for indexing or pass through of fuel costs to customers. In cases where there is no pass through of fuel costs, we often attempt to mitigate the market price risk of changing commodity costs through the use of hedging strategies. To the extent that costs are not matched well to PPA energy payments, pass-through of fuel costs is not allowed or hedging strategies are unsuccessful, increases in fuel costs may adversely affect our results of operation. This may have a material adverse effect on our business, results of operations and financial condition.

Our projects may not operate as planned

The ability of our projects to meet availability requirements and generate the required amount of power to be sold to customers under the PPAs are primary determinants of the amount of cash that will be distributed from the projects to us, and that will in turn be available for debt service obligations, investments in internal or external growth opportunities or funding of our operations. There is a risk of equipment failure due to wear and tear, more frequent and/or larger than forecasted downtimes for equipment maintenance and repair, unexpected construction delays, latent defect, design error or operator error, or force majeure events, among other things, which could adversely affect revenues and cash flow. Additionally, older equipment, even if maintained in accordance with good practices, is subject to operational failure, including events that are beyond our control, and may require unplanned expenditures to operate efficiently. Unplanned outages of generation facilities, including extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operation and maintenance expenses and may reduce our revenues or require us to incur significant costs as a result of obtaining replacement power from third parties in the open market to satisfy our obligations.

In general, our power generation projects transmit electric power to the transmission grid for purchase under the PPAs through a single step up transformer. As a result, the transformer represents a single point of vulnerability and may exhibit no abnormal behavior in advance of a catastrophic failure that could cause a temporary shutdown of the facility until a replacement transformer can be found or manufactured. To the extent that we suffer disruptions of plant

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availability and power generation due to transformer failures or for any other reason, there could be a material adverse effect on our business, results of operations and financial condition and the amount of available cash flow may be adversely affected.

We provide letters of credit under our $200 million Revolving Credit Facility for contractual credit support at some of our projects. If the projects fail to perform under the related project level agreements, the letters of credit could be drawn and we would be required to reimburse our senior lenders for the amounts drawn.

The effects of weather and climate change may adversely impact our business, results of operations and financial condition

Our operations are affected by weather conditions, which directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Conversely, moderate temperatures in winter or summer decrease heating or cooling electricity and gas demand and revenues. To the extent that weather is warmer in the summer or colder in the winter than assumed, we may require greater resources to meet our contractual commitments. These conditions, which cannot be accurately predicted, may have an adverse effect on our business, results of operations and financial condition by causing us to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

To the extent climate change contributes to the frequency or intensity of weather-related events, our operations and planning process could be impacted, which may adversely impact our business, results of operations and financial condition.

Revenues from hydropower projects are highly dependent on precipitation and associated weather conditions and in the absence of such suitable conditions, our hydropower projects may not meet anticipated production levels, which could adversely affect our forecasted revenues

We own interests in four hydropower projects, which are subject to substantial resource risks. The energy and revenues generated at a hydro energy project are highly dependent on precipitation patterns, which are variable and difficult to predict for any given year. We base our investment decisions with respect to each hydro energy project on the historical stream flow records for the area. However, actual climatic conditions in any given year may not meet the historical averages, which would impair our ability to meet anticipated production levels, which could adversely affect our forecasted revenues.

U.S., Canadian and/or global economic conditions and uncertainty could adversely affect our business, results of operations and financial condition

Our business may be affected by changes in U.S., Canadian and/or global economic conditions, including inflation, deflation, interest rates, availability of capital, consumer spending rates and the effects of governmental initiatives to manage economic conditions. Uncertainty about global economic conditions may cause consumers to alter behaviors that may directly or indirectly reduce energy spending, which could have a material adverse effect on demand for our product. Volatility in the financial markets and the deterioration of national and global economic conditions may have a material adverse effect on our business, results of operations and financial condition.

Financial markets can also be, and have been in the past, affected by concerns over U.S. fiscal policy, federal deficit and related budget and tax issues. These concerns continue to raise discussions relating to the stability of the long term sovereign credit rating of the United States. Any actions taken by the U.S. federal government regarding the federal deficit or any action taken or threatened by ratings agencies, could significantly impact the global and U.S. economies and financial markets. Any such economic downturn could have a material adverse effect on our business, results of operations and financial condition.

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Risks that are beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events could have a material adverse effect on our business, results of operations, ability to raise capital and financial condition

Man made events, such as acts of terror and governmental responses to acts of terror, could adversely affect general economic conditions, which could have a material impact on our business, results of operations and financial condition. Strategic targets, such as energy related facilities, may be at greater risk of future terrorist activities than other domestic targets. Our projects may be targets of terrorist activities, as well as events occurring in response to or in connection with them, that could cause environmental repercussions and/or result in full or partial disruption of the ability of the projects to generate and/or transmit electricity. Any such environmental repercussions or other disruption could result in a decline in energy consumption and significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our business, results of operations and financial condition.

Our projects could also be impacted by natural disasters, such as earthquakes, floods, lightning activity, hurricanes, tropical storms, winter storms, tornadoes, wind, seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive or otherwise disrupt our operations or compromise the physical or cyber security of our facilities, which could result in increased costs and could adversely affect our ability to manage our business effectively. We maintain standard insurance against catastrophic losses, which are subject to deductibles, limits and exclusions; however, our insurance coverage may not be sufficient to cover all of our losses. Additionally, future significant weather related events, natural disasters and other similar events that have an adverse effect on the economy could have a material adverse effect on our business, results of operations, ability to raise capital and financial condition.

Our business faces significant operating hazards, natural disaster risks and other hazards such as fire and explosions and insurance may not be sufficient to cover all losses

Our business involves significant operating hazards related to the generation of electricity, including hazards related to acquiring, transporting and unloading fuel, operating large pieces of rotating equipment, structural collapse, machinery failure, and delivering electricity to transmission and distribution systems. In addition, we are exposed to natural disaster risks and other hazards such as fire and explosions. These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, disruption of communication systems and technology, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being subject to various litigation matters, including regulatory and administrative proceedings, asserting claims for substantial damages, including for environmental cleanup costs, personal injury and property damage and fines and/or penalties. While we believe that the projects maintain an amount of insurance coverage that is adequate and similar to what would be maintained by a prudent owner/operator of similar facilities, and are subject to deductibles, limits and exclusions which are customary or reasonable given the cost of procuring insurance, current operating conditions and insurance market conditions, there can be no assurance that such insurance will continue to be offered on an economically feasible basis, nor that all events that could give rise to a loss or liability are insurable or insured, nor that the amounts of insurance will at all times be sufficient to cover each and every loss or claim that may occur involving our assets or operations of our projects. Any losses in excess of those covered by insurance, which may include a significant judgment against any project or project operator, the loss of a significant permit or other approval or the imposition of a significant fine or penalty, could have a material adverse effect on our business, results of operations, financial condition and future prospects.

Our operations are subject to the provisions of various energy laws and regulations

Our business is subject to extensive Canadian and U.S. federal, state, provincial and local laws and regulations. Compliance with the requirements under these various regimes may cause us to incur significant additional costs, and failure to comply with such requirements could result in the shutdown of the non complying facility, the imposition of liens, fines and/or civil or criminal liability.

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Generally, in the United States, our projects are subject to regulation by the FERC regarding the terms and conditions of wholesale service and rates, as well as by state regulators regarding the prudency of utilities entering into PPAs entered into by QF projects and the siting of the generation facilities. The majority of our generation is sold by QF projects under PPAs that required approval by state authorities.

The EP Act of 2005 also limited the requirement that electric utilities buy electricity from QFs in certain markets that have certain competitive characteristics, potentially making it more difficult for our current and future projects to negotiate favorable PPAs with these utilities.

If any project were to lose its status as a QF, it would lose its ability to make sales to utilities on favorable terms. Such project may no longer be entitled to exemption from provisions of the Public Utility Holding Company Act of 2005 or from certain provisions of the Federal Power Act and state law and regulations. Loss of QF status could also trigger defaults under covenants to maintain that status in the PPAs and project level debt agreements, and if not cured within allowed cure periods, could result in termination of agreements, penalties or acceleration of indebtedness under such agreements. In such event, our business, results of operations and financial condition could be negatively impacted.

Notwithstanding their status as QFs and EWGs, our facilities remain subject to numerous FERC regulations, including those relating to power marketer status, approval of mergers, acquisitions and investments relating to utilities, and mandatory reliability rules and regulations delegated to NERC. Any violation of these rules and regulations could subject us to significant fines and penalties and negatively impact our business, results of operations and financial condition.

The EP Act of 2005 and other federal and state programs also may provide incentives for various forms of electric generation technologies, which may subsidize our competitors. The U.S. regulatory environment has undergone significant changes in the last several years due to state and federal policies affecting wholesale competition and the creation of incentives for the addition of large amounts of new renewable energy generation and, in some cases, transmission. These changes are ongoing and we cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on our business. In addition, in some of these markets, interested parties have proposed material market design changes, including the elimination of a single clearing price mechanism as well as proposals to re regulate the markets. Other proposals to re regulate may be made and legislative or other attention to the electric power market restructuring process may delay or reverse the deregulation process. If competitive restructuring of the electric power markets is reversed, discontinued, or delayed, or new law or other future regulatory developments are introduced, our business, results of operations and financial condition could be negatively impacted.

Generally, in Canada, our projects are subject to energy regulation primarily by the relevant provincial authorities. In addition, our projects are subject to Canada’s corporate, commercial and other laws of general application to businesses. Our projects require licenses, permits and approvals which can be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain, comply with and renew, as required, all necessary licenses, permits and approvals for these facilities. If we cannot comply with and renew as required all applicable licenses, permits and approvals, our business, results of operations and financial condition could be adversely affected.

The introductions of new laws, or other future regulatory developments, may have a material adverse impact on our business, operations or financial condition.

Risks with respect to the two Canadian provinces where we currently have projects are addressed further below.

British Columbia

The Government of British Columbia has a number of specific statutes and regulations that govern the generation, transmission and distribution of electricity within British Columbia. Our projects in that province are subject to these laws. These statutes can be changed by act of the provincial legislature and the regulations may be changed by the provincial cabinet. Such changes could have a material effect on our projects.

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The Utilities Commission Act governs the BCUC, which is responsible for the regulation of British Columbia's public energy utilities, which include publicly owned and investor owned utilities (i.e., independent power producers). All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by the BCUC as being "in the public interest." The BCUC may hold a hearing in this regard. Furthermore, the BCUC may make rules governing conditions to be contained in agreements entered into by public utilities for electricity. Consequently, power procurement is controlled by the BCUC and, as a result, our potential contracts with BC Hydro may be subject to terms that adversely affect us.

The Clean Energy Act sets out British Columbia's energy objectives, one of which is the generation of at least 93% of the electricity in British Columbia from clean or renewable resources. BC Hydro is required to submit for review and approval every five years to the Government of British Columbia resource plans outlining how it will meet these objectives. BC Hydro is generally required to acquire all new power (beyond what it already generates from existing BC Hydro plants) from independent power producers. Two of our three British Columbia projects currently sell all of their electricity to BC Hydro, and the third project sells substantially all of its electricity to BC Hydro. Therefore, changes to BC Hydro's energy procurement policies and financial difficulties of or regulatory intervention in respect of BC Hydro and/or the province's energy objectives could impact the market for electricity generated by our British Columbia projects, although BC Hydro is currently limited by regulation to undertaking efficiency improvements at its existing facilities and undertaking development of new generation facilities/projects only with BCUC approval. There is a risk that the regulatory regime could adversely affect the amount of power that BC Hydro purchases from our projects and the competitive environment or the price at which BC Hydro is willing to purchase power from our British Columbia projects.

Ontario

The government of Ontario has a number of specific statutes and regulations that govern our projects in that province. The statutes can be changed by act of the provincial legislature and the regulations may be changed by the provincial cabinet. Such changes could have a material effect on our projects.

In Ontario, the OEB is an administrative tribunal with authority to grant or renew, and set the terms for, licenses with respect to electricity generation facilities, including our projects. No person is permitted to own or operate a large or medium scale electricity generation facility in Ontario without a license from the OEB. Although all of our Ontario projects are currently licensed, the OEB has the authority to effectively modify the licenses by adopting "codes" that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the OEB can result in fines.

Although the OEB provides reports to the Ontario Minister of Energy, it generally operates independently from the government. However, the Minister may issue policy directives (with Cabinet approval) concerning general policy and the objectives to be pursued by the OEB, and the OEB is required to implement such policy directives. Thus, the OEB's regulation of our projects is subject to potential political interference, to a degree.

A number of other regulators and quasi governmental entities play a role, including the IESO, Hydro One, the ESA and OEFC. All these agencies may affect our projects.

As discussed above, in 2018, the Ontario provincial government cancelled hundreds of renewable energy projects which had previously received approval, and has introduced or amended legislation which will have an impact on the development of new renewable energy projects.

Noncompliance with federal reliability standards may subject us and our projects to penalties

Many of our operations are subject to the regulations of NERC, a self regulatory non governmental organization which has statutory responsibility to regulate bulk power system users and generation and transmission owners and operators. NERC groups the users, owners, and operators of the bulk power system into 17 categories, known as functional entities—e.g., Generator Owner, Generator Operator, Purchasing Selling Entity, etc.—according to

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the tasks they perform. The NERC Compliance Registry lists the entities responsible for complying with federal mandatory reliability standards and the FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity found to be in noncompliance. Violations may be discovered or identified through self certification, compliance audits, spot checking, self reporting, compliance investigations by NERC (or a regional reliability organization) and the FERC, periodic data submissions, exception reporting, and complaints. The penalty that could be imposed for violating the requirements of the standards is a function of the Violation Risk Factor. Penalties for the most severe violations can reach as high as $1 million per violation, per day, and our projects could be exposed to these penalties if violations occur, which could have a material adverse effect on our business, results of operations and financial condition.

Our projects are subject to significant environmental and other regulations

Our projects are subject to numerous and significant federal, state, provincial and local laws, including statutes, regulations, by laws, guidelines, policies, directives and other requirements governing or relating to, among other things: air emissions; discharges into water; ash disposal; the storage, handling, use, transportation and distribution of dangerous goods and hazardous, residual and other regulated materials, such as chemicals; the prevention of releases of hazardous materials into the environment; the prevention, presence and remediation of hazardous materials in soil and groundwater, both on and off site; land use and zoning matters; and workers' health and safety matters. Our facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, penalties and property damage. As such, the operation of our projects carries an inherent risk of environmental, health and safety liabilities (including potential civil actions, compliance or remediation orders, fines and other penalties), and may result in the projects being involved from time to time in administrative and judicial proceedings relating to such matters. We have implemented environmental, health and safety management programs designed to regularly improve environmental, health and safety performance, but there is no guarantee that such programs will fully and effectively eliminate the inherent risk of environmental, health and safety liabilities related to the operation of our projects.

Environmental laws and regulations have generally become more stringent over the long term; however, more recently the Trump Administration has taken numerous actions to reduce U.S. federal regulatory burdens, particularly for coal-fired power plants. In the United States, the Clean Air Act and related regulations and programs of the Environmental Protection Agency extensively regulate the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds by power plants. The EPA's Cross-State Air Pollution Rule ("CSAPR"), issued in 2011 and updated in 2017, requires 27 states and the District of Columbia to curb emissions of sulfur dioxide and nitrogen oxides from power plants through participation in a cap and trade system or more aggressive state-by-state emissions limits. Other stringent EPA air emission regulations include updates to national ambient air quality standards for sulfur dioxide, issued in 2010; for fine particulate matter, issued in 2012; and for ozone, issued in 2015. However, in December 2018 the EPA proposed revising the findings that supported its 2011 mercury and air toxics emissions standards for power plants ("MATS"). In July 2018, the Trump Administration issued the first in a planned series of two final rules to significantly roll back the EPA's regulations governing disposal of coal ash in landfills and impoundments. The Trump Administration also has been pursuing other initiatives that would revoke existing environmental requirements, largely focused on coal mining and coal-fired power plants. We continue to assess the impact of these changes on our business.

Similar increasingly stringent environmental regulations also apply to our projects in British Columbia and Ontario.

Significant costs may be incurred for either capital expenditures or the purchase of allowances under any or all of these programs to keep the projects compliant with environmental laws and regulations. Some of our projects' PPAs do not allow for the pass-through of emissions allowance or emission reduction capital expenditure costs. If it is not economical to make those expenditures, it may be necessary to retire or mothball facilities, or restrict or modify our operations to comply with more stringent standards.

Our projects have obtained environmental permits and other approvals that are required for their operations. Compliance with applicable environmental laws, regulations, permits and approvals and material future changes to them could materially impact our businesses. Although we believe the operations of the projects are currently in material

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compliance with applicable environmental laws, licenses, permits and other authorizations required for the operation of the projects, and although there are environmental monitoring and reporting systems in place with respect to all the projects, there is no guarantee that more stringent laws will not be imposed, that there will not be more stringent enforcement of applicable laws or that such systems may not fail, which may result in material expenditures. Failure by the projects to comply with any environmental, health or safety requirements, or increases in the cost of such compliance, including as a result of unanticipated liabilities or expenditures for investigation, assessment, remediation or prevention, could result in additional expense, capital expenditures, restrictions and delays in the projects' activities, the extent of which cannot be predicted and which could have a material adverse effect on our business, results of operations and financial condition.

If additional regulatory requirements are imposed on energy companies mandating limitations on greenhouse gas emissions or requiring efficiency improvements, such requirements may result in compliance costs that alone or in combination could make some of our projects uneconomical to maintain or operate

The EPA, other regulatory agencies, environmental advocacy groups and other organizations are focusing considerable attention on greenhouse gas emissions from power generation facilities and their potential role in climate change. See "Item 1. Business—Industry Regulation—Carbon Emissions."

There are also potential impacts on our natural gas businesses as legislation or regulations may require greenhouse gas emission reductions from the natural gas sector, which could affect demand for natural gas. Additionally, greenhouse gas requirements could result in increased demand for energy conservation and renewable products, as well as increase competition surrounding such innovation. Additionally, our reputation could be damaged due to public perception surrounding greenhouse gas emissions at our power generation projects. Any such negative public perception could ultimately result in a decreased demand for electric power generation or distribution. Several regions of the United States and Canada have moved forward with greenhouse gas emission regulation.

Concerning our projects in British Columbia, regulatory restrictions stemming from GGIRCA, CCAA, and financial commitments arising in connection with the requirements under the CTA, could affect our ability to operate our projects in British Columbia and affect our profitability. Concerning our projects in Ontario, the federal OBPS, from the beginning of 2019, may have increased the cost of generating electricity using natural gas and the price of the electricity produced by our natural gas-powered projects in the Province. In addition, on December 15, 2016, the IESO entered into an electricity trade agreement with Hydro-Québec under which the IESO will purchase a total of 14 terawatt hours (TWh) of electricity from Hydro-Québec over a seven-year period from 2017 to 2023. The News Release issued by the Government of Ontario regarding this agreement stated that "Ontario will reduce the cost to its consumers by $70 million compared to its previous plan by importing 2 TWh of hydroelectric power each year from Québec to replace the use of natural gas." We anticipate that the increasing carbon price and other initiatives to reduce greenhouse gas emissions associated with the generation of electricity in the Province could affect our ability to operate our projects in Ontario and affect our profitability, but note that there will be a federal election in Canada in 2019 and that the future of the current federal carbon pricing regime for GHG emissions is now uncertain.

All of our subject generating facilities have complied on a timely basis with the new EPA and Ontario greenhouse gas reporting requirements. Compliance with greenhouse gas emission reduction requirements may require increasing the energy efficiency of equipment at our natural gas projects, purchase of allowances and/or offsets, fuel switching, and/or retirement of high emitting projects and potential replacement with lower-emitting projects. The cost of compliance with greenhouse gas emission legislation and/or regulation is subject to significant uncertainties due to the outcome of several interrelated assumptions and variables, including timing of the implementation of rules, required levels of reductions, allocation requirements of the new rules, the maturation and commercialization of carbon capture and storage technology, the selected compliance alternatives and in the United States the actions taken by the Trump Administration to revoke Obama era climate regulations. We cannot estimate the aggregate effect of such requirements on our business, results of operations, financial condition or our customers. However, such expenditures, if material, could make our generation facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect our business, results of operations and financial condition.

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Impairment of goodwill, long lived assets or equity method investments could have a material adverse effect on our results of operations and financial condition

As of December 31, 2018, we had $21.3 million of goodwill, which represented approximately 2% of our total assets on our consolidated balance sheets. Goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if an event or change in circumstance occurs that would more likely than not reduce the fair value of a reporting unit below its carrying value. We could be required to, and have in the past, evaluated the potential impairment of goodwill outside of the required annual evaluation process if we experience situations, including but not limited to, sustained declines in market capitalization, deterioration in general economic conditions or our operating or regulatory environment, increased competitive environment, an increase in fuel costs (particularly when we are unable to pass-through the impact to customers), significant changes in forecasted market prices for power, negative or declining cash flows, loss of a key contract or customer (particularly when we are unable to replace it on equally favorable terms), or our inability to renew certain of our PPAs following their expiration or termination. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. Additionally, goodwill may be impaired if any acquisitions we make do not perform as expected.

Long lived assets are initially recorded at acquisition cost and are amortized or depreciated over their estimated useful lives. Long lived assets are evaluated for impairment only when impairment indicators are present, whereas goodwill is evaluated for impairment on an annual basis or more frequently if potential impairment indicators are present. Otherwise, the recoverability assessment of long lived assets is similar to the potential impairment evaluation of goodwill particularly as it relates to the identification of potential impairment indicators, and making estimates and assumptions to determine fair value, as described above.

We have recorded $0, $187.2 million and $85.9 million of goodwill, long-lived asset and equity method investment impairments for the years ended December 31, 2018, 2017 and 2016, respectively. See Note 9 to the consolidated financial statements included in this Annual Report on Form 10 K.

Failure to fully comply with Section 404 of the Sarbanes-Oxley Act of 2002 could negatively affect our business, market confidence in our reported financial information, and the price of our common stock.

We continue to document, test, and monitor our internal controls over financial reporting in order to satisfy all of the requirements of Section 404 of the Sarbanes-Oxley Act of 2002; however, we cannot be assured that our disclosure controls and procedures and our internal control over financial reporting will prove to be completely adequate in the future. Failure to fully comply with Section 404 of the Sarbanes-Oxley Act of 2002 could negatively affect our business, market confidence in our reported financial information, and the price of our common stock.

Increasing competition could adversely affect our performance and the performance of our projects

The power generation industry is characterized by intense competition and our projects encounter competition from utilities, industrial companies and other independent power producers, in particular with respect to uncontracted output. In recent years, there has been increasing competition among generators for PPAs, and this has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins.

Further, changes and developments in technology, including fuel cells, microturbines, solar cells and other emerging technologies related to energy generation, distribution and consumption, may facilitate the entrance of new competitors, increase the supply of electricity, and reduce the cost of methods of producing power that we do not currently use or lower the price of or demand for energy. If these technologies became cost-competitive, we could face increasing competition and the value of our generating facilities could be reduced.

In addition, we continue to confront significant competition for acquisition and investment opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments on attractive terms, if at all. Increasing competition among participants in the power generation industry may adversely affect our performance and the performance of our projects. Further, a payout of a significant portion of our cash flow to service our debt may result in us not retaining a sufficient amount of cash to finance acquisition or investment opportunities and

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make other capital and operating expenditures. See "—Risk Related to Our Structure—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities."

We have limited control over management decisions at certain projects

Three of our projects are not wholly owned by us or we have contracted for their operations and maintenance, and in some cases we have limited control over the operation of the projects. Although we generally prefer to acquire projects where we have control, we may make acquisitions in non control situations to the extent that we consider it advantageous to do so and consistent with regulatory requirements and restrictions, including the Investment Company Act of 1940. Third party operators operate three of our projects. As such, we must rely on the technical and management expertise of these third party operators, although typically we negotiate to obtain positions on a management or operating committee if we do not own 100% of a project. To the extent that such third party operators do not fulfill their obligations to manage the operations of the projects or are not effective in doing so, our cash flow may be adversely affected. The approval of third party operators also may be required for us to receive distributions of funds from projects or to transfer our interest in projects. Our inability to control fully certain projects could have an adverse effect on our business, results of operations and financial condition.

We may face significant competition for acquisitions and may not be able to finance or otherwise pursue, execute or successfully integrate acquisitions or new business initiatives

We may be unable to identify attractive acquisition candidates in the power industry in the future, and we may not be able to make acquisitions on an accretive basis or at all, or be sure that such acquisitions, if any, will be successfully integrated into our existing operations. In addition, a payout of a significant portion of our cash flow to service our debt obligations, may result in us not retaining a sufficient amount of cash to finance any acquisition or other growth opportunities, to the extent any such acquisition or other opportunities are available to us. As a result, we may have to forego such opportunities, even if they would otherwise be necessary or desirable, if we do not find alternative sources of financing for such opportunities to make cash available to us. In addition, even if we are able to find alternative sources of financing for such opportunities, we may be precluded from pursuing an otherwise attractive acquisition or investment if the projected short term cash flow from the acquisition or investment is not adequate to service the capital raised to fund such acquisition or investment. This could limit our flexibility in planning for, or reacting to, changes in our business and industry, placing us at a competitive disadvantage compared to our competitors.

Although electricity demand is expected to grow, such growth is projected to occur at a slow rate. While the North American power industry is continuing to undergo consolidation and may present attractive investment opportunities, the demand for and the value of power generation assets is likely to be impacted by future regulatory policies as the industry continues to transition. This consolidation and transition may present attractive acquisition opportunities, but we are likely to confront significant competition for those opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments.

Any acquisition, investment or new business initiative may involve potential risks, including an increase in indebtedness, the inability to successfully integrate operations, the potential disruption of our ongoing business, the diversion of management's attention from other business concerns, inadequate return on capital and the possibility that we pay more than the acquired company or interest is worth. There may also be liabilities that we fail to discover, or are unable to discover, in our due diligence prior to the consummation of an acquisition or prior to launching an initiative or entering a market. We may not be indemnified for some or all of these liabilities in an acquisition transaction.

Our equity interests in certain projects may be subject to transfer restrictions

The partnership or other agreements governing some of the projects may limit a partner's ability to sell its interest. Specifically, these agreements may prohibit any sale, pledge, transfer, assignment or other conveyance of the interest in a project without the consent of the other partners. In some cases, other partners may have rights of first offer or rights of first refusal in the event of a proposed sale or transfer of our interest. These restrictions may limit or prevent us from managing our interests in these projects in the manner we see fit, and may have an adverse effect on our ability

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to sell our interests in these projects at the prices we desire. See "—Risks Related to Our Structure—We cannot provide any assurance regarding the outcome or impact on our business of any potential options we are considering."

Our projects are exposed to risks inherent in the use of derivative instruments

We and our projects may use derivative instruments, including futures, forwards, options and swaps, to manage commodity and financial market risks. These activities, though intended to mitigate price volatility, expose us to other risks. In the future, the project operators could recognize financial losses on these arrangements, including as a result of volatility in the market values of the underlying commodities, if a counterparty fails to perform under a contract or upon the failure or insolvency of a financial intermediary, exchange or clearinghouse used to enter, execute or clear the transactions. If actively quoted market prices and pricing information from external sources are not available, the valuation of these contracts would involve judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Most of these contracts are recorded at fair value with changes in fair value recorded currently in the statement of operations, resulting in significant volatility in our income (loss) (as calculated in accordance with GAAP) that does not significantly affect current period cash flows or the underlying risk management purpose of the derivative instruments. As a result, we may be unable to accurately predict the impact that our risk management decisions may have on our quarterly and annual income (loss) (as calculated in accordance with GAAP).

If the values of these financial contracts change in a manner that we do not anticipate, or if a counterparty fails to perform under a contract, it could harm our business, results of operations, financial condition and cash flows. We have executed natural gas swaps to reduce our risks to changes in the market price of natural gas, which is the fuel consumed at many of our projects. Due to decreases in natural gas prices, we have incurred losses on these natural gas swaps. We execute these swaps only for the purpose of managing risks and not for speculative trading.

We do not typically hedge the entire exposure of our operations against commodity price volatility. To the extent we do not hedge against commodity price volatility, our business, results of operations and financial condition may be improved or diminished based upon movement in commodity prices.

Certain employees are subject to collective bargaining

A number of our plant employees, at one plant in British Columbia and at two plants in Ontario, are subject to collective bargaining agreements. These agreements expire periodically and we may not be able to renew them without a labor disruption or without agreeing to significant increases in labor costs. Strikes, work stoppages or the inability to negotiate future collective bargaining agreements on favorable terms could have a material adverse effect on our business, results of operations and financial condition.

Our Pension Plan may require additional future contributions

Certain of our employees in Canada are participants in a defined benefit pension plan that we sponsor. The additional amount of future contributions to our defined benefit plan will depend upon asset returns and a number of other factors and, as a result, the amounts we will be required to contribute in the future may vary. Cash contributions to the plan will reduce the cash available for our business.

Hostile cyber intrusions could severely impair our operations, lead to the disclosure of confidential information, damage our reputation and otherwise have an adverse effect on our business, results of operations and financial condition

From time to time, we, like others in our industry, are subject to cyber intrusions in which customer data and proprietary business information is targeted. A cyber intrusion is considered to be any adverse event that threatens the confidentiality, integrity or availability of our information resources. More specifically, a cyber intrusion is an intentional attack or an unintentional event that can include gaining unauthorized access to systems to disrupt operations, corrupt data, steal confidential information, and impact our ability to make collections or otherwise impact our

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operations. We are dependent on various information technologies throughout our company and our projects to carry out multiple business activities. Further, the computer systems that run our facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. and/or Canadian bulk power system or our operations could view our computer systems, software or networks as attractive targets for cyber attack. In addition, our business requires that we collect and maintain confidential employee and shareholder information, which is subject to the risk of electronic theft or loss.

A successful cyber attack, such as unauthorized access, malicious software or other violations on the systems that control generation and transmission at our projects could severely disrupt business operations, diminish competitive advantages through reputation damages and increase operational costs. The breach of certain business systems could affect our ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. For these reasons, a significant cyber incident could materially and adversely affect our business, results of operations and financial condition.

Failure to comply with the U.S. Foreign Corrupt Practices Act and/or the Canadian Corruption of Foreign Public Officials Act could subject us to, among other things, penalties and legal expenses that could harm our reputation and have a material adverse effect on our business, results of operations and financial condition

We are subject to anti corruption laws and regulations including the U.S. Foreign Corrupt Practices Act ("FCPA") and the Canadian Corruption of Foreign Public Officials Act (the "CFPOA"), which generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or keeping business and/or other benefits. In addition, the FCPA imposes accounting standards and requirements on U.S. publicly traded corporations and their foreign affiliates, which are intended to prevent the diversion of corporate funds to the payment of bribes and other improper payments, and to prevent the establishment of "off books" slush funds from which improper payments can be made (similar provisions have been proposed to be added to the CFPOA). The Securities and Exchange Commission has increased its enforcement of the FCPA during the past several years. In recent years, enforcement of the CFPOA in Canada has also increased and can be attributed, in part, to the establishment of the Royal Canadian Mounted Police's International Anti Corruption Unit in 2008. Although we have implemented policies and procedures designed to ensure that we, our employees and other intermediaries comply with the FCPA and/or the CFPOA, there is no assurance that such policies or procedures will work effectively all of the time or protect us against liability under the FCPA and/or the CFPOA for actions taken by our employees and other intermediaries with respect to our business or any businesses that we may acquire. If we are not in compliance with the FCPA and/or the CFPOA, we may be subject to criminal penalties pursuant to the CFPOA and/or criminal and civil penalties and other remedial measures pursuant to the FCPA, including changes or enhancements to our procedures, policies and control, as well as potential personnel change and disciplinary actions, which could have an adverse impact on our business, results of operations and financial condition.

Our success depends in part on our ability to retain, motivate and recruit executives and other key employees, and failure to do so could negatively affect us

Our success depends in part on our ability to retain, recruit and motivate key employees who have experience in our industry. Experienced employees in the power industry are in high demand and competition for their talents can be intense. Further, an aging work force in the power industry necessitates recruiting, retaining and developing the next generation of leadership. A failure to attract and retain executives and other key employees with specialized knowledge in power generation could have an adverse impact on our business, results of operations and financial condition because of the difficulty of promptly finding qualified replacements. See "—Risks Related to our Structure—Our recent management changes may impact our business plan."

## ITEM 1B.  UNRESOLVED STAFF COMMENTS

None.

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## ITEM 2.  PROPERTIES

We have included descriptions of the locations and general character of our principal physical operating properties, including an identification of the segments that use such properties, in “Item 1. Business,” which is incorporated herein by reference. A significant portion of our equity interests in the entities owning these properties is pledged as collateral under our Credit Facilities or under non recourse operating level debt arrangements.

Our principal executive office is located at 3 Allied Drive Suite 155, Dedham, Massachusetts under a lease that expires in 2024.

## ITEM 3.  LEGAL PROCEEDINGS

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of December 31, 2018.

## ITEM 4.  MINE SAFETY DISCLOSURES

Not applicable.

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PART II

## ITEM 5. MARKET FOR REGISTRANT’S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

### Purchases of Equity Securities by the Issuer and Affiliated Purchasers

### Share Repurchase Program

On December 31, 2018, we commenced a new Normal Course Issuer Bid (“NCIB”) for each of our Series D and Series E Debentures, our common shares and for each series of the preferred shares of Atlantic Power Preferred Equity Ltd. (“APPEL”), our wholly-owned subsidiary. The NCIBs expire on December 30, 2019 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the new NCIBs. Under the NCIB, we may purchase up to a total of 10,623,464 common shares based on 10% of our public float as of December 17, 2018 and we are limited to daily purchases of 10,300 common shares per day with certain exceptions including block purchases and purchases on other approved exchanges. All purchases made under the NCIBs will be made through the facilities of the TSX or other Canadian designated exchanges and published marketplaces and in accordance with the rules of the TSX at market prices prevailing at the time of purchase. Common share purchases under the NCIBs may also be made on the New York Stock Exchange in compliance with rule 10b-18 under the U.S. Securities Exchange Act of 1934, as amended, or other designated exchanges and published marketplaces in the U.S. in accordance with applicable regulatory requirements. The ability to make certain purchases through the facilities of the NYSE is subject to regulatory approval. As of December 31, 2018, we have not made any repurchases under the new NCIBs.

This new NCIB replaced the prior NCIB that expired on December 28, 2018. Through December 31, 2018, we repurchased and cancelled approximately 7.8 million common shares at a cost of $16.6 million. The following table provides purchases of common equity securities by the Issuer and Affiliated Purchasers for the period of October 1, 2018 through December 31, 2018:

| | Total Number of | Average Price Paid | Total Number of Shares as Part of a Publicly Announced | Dollar Value of Maximum Number of Shares to be Purchased Under |
|---|---|---|---|---|

| Purchase Period | Shares Purchased | Per Share | Purchase Plan | the Plan | |
|---|---|---|---|---|---|
| 10/1/2018 - 10/31/2018 | 291,327 | $ 2.15 | 291,327 | | |
| 11/1/2018 - 11/30/2018 | 668,532 | $ 2.15 | 668,532 | | |
| 12/1/2018 - 12/31/2018 | 1,076,904 | $ 2.14 | 1,076,904 | $ 0 | (1) |
| Total | 2,036,763 | | 2,036,763 | | |

(1) This plan expired on December 28, 2018.

The Board authorization permits the Company to repurchase common and preferred shares and convertible debentures. Therefore, in addition to the current NCIBs, from time to time we may repurchase our securities, including our common shares, our convertible debentures and our APPEL preferred shares through open market purchases, including pursuant to one or more “Rule 10b5-1 plans” pursuant to such provision under the United States Securities Exchange Act of 1934, as amended, NCIBs, issuer self tender or substantial issuer bids, or in privately negotiated transactions. There can be no assurances as to the amount, timing or prices of repurchases, which may vary based on market conditions, other market opportunities and other factors. Any share repurchases outside of previously authorized NCIBs would be effected after taking into account our then current cash position and then anticipated cash obligations or business opportunities.

Market Information and Holders

Our common shares trade on the NYSE under the symbol “AT” and on the TSX under the symbol “ATP”. The number of common shares outstanding was 109,686,626 on February 27, 2019.

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Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2018 regarding our Long Term Incentive Plan. For the description of our Long Term Incentive Plan, see Note 17, Equity Compensation Plans to the consolidated financial statements.

| | Number of securities to be issued upon exercise of outstanding options, warrants and rights(1)(2) (a) | Weighted-average exercise price of outstanding options, warrants and rights (b) | Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))(1)(2) (c) |
|---|---|---|---|
| Equity compensation plans approved by security holders | 2,634,801 | $ — | — |
| Equity compensation plans not approved by security holders | 359,936 | — | 179,968 |
| Total | 2,994,737 | $ — | 179,968 |

(1) Number of securities to be issued upon exercise of outstanding awards and number of securities remaining available for future issuance reflects expected redemption of award one third in cash and two thirds in common shares. Specifically, the number of securities to be issued upon exercise of outstanding awards reflects two-thirds of the number of outstanding notional shares. See Item 15. "Exhibits and Financial Statements Schedule"—Note 2(u), Equity compensation plans.

(2) The maximum aggregate number of common shares that may be issued under our Long Term Incentive Plan upon redemption of notional shares is 6,000,000 and the maximum aggregate number of common shares that may be issued under our Transition Equity Grant Participation Agreement upon redemption of notional shares is 600,000. See Item 15. "Exhibits and Financial Statements Schedule"—Note 2(u), Equity compensation plans.

Performance Graph

The performance graph below compares the cumulative total shareholder return on our common shares for the period December 31, 2013, through December 31, 2018, with the cumulative total return of the Standard & Poor's 500 Composite Stock Price Index, or S&P 500, and the Standard & Poor's TSX Composite, or S&P/TSX. Our common shares trade on the NYSE under the symbol "AT" and the TSX under the symbol "ATP".

The performance graph shown below is being furnished and compares each period assuming that a $100 investment was made on December 31, 2013, in each of our common shares, the stocks included in the S&P 500 and the stocks included in the S&P/TSX, and that all dividends were reinvested.

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Comparison of Cumulative Total Return

| | Dec-2013 | Dec-2014 | Dec-2015 | Dec-2016 | Dec-2017 | Dec-2018 |
|---|---|---|---|---|---|---|
| AT | $ 100.00 | $ 84.90 | $ 64.13 | $ 81.39 | $ 76.51 | $ 70.65 |
| S&P | 100.00 | 113.69 | 115.07 | 127.03 | 148.86 | 144.48 |
| S&P / TSX | 100.00 | 107.42 | 107.42 | 112.23 | 119.00 | 105.15 |

## ITEM 6.  SELECTED FINANCIAL DATA

The following table sets forth our selected historical consolidated financial information for each of the periods indicated. The annual historical information for each of the years in the three year period ended December 31, 2018 has been derived from our audited consolidated financial statements included elsewhere in this Annual Report on Form 10 K.

You should read the following selected consolidated financial data along with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our consolidated financial statements and the accompanying notes, which describe the impact of material acquisitions and dispositions that occurred in the three year period ended December 31, 2018.

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| (in millions of U.S. dollars, except as otherwise stated) | Year Ended December 31, 2018(a) | 2017(a) | 2016(a) | 2015(a)(b) | 2014(a)(b)(c)(d |
|---|---|---|---|---|---|
| Project revenue | $ 282.3 | $ 431.0 | $ 399.2 | $ 420.2 | $ 489.9 |
| Project income (loss) | 88.2 | (47.4) | 10.1 | (41.4) | (38.9) |
| Income (loss) from continuing operations | 37.2 | (93.0) | (113.9) | (84.1) | (153.2) |
| Income (loss) from discontinued operations, net of tax | — | — | — | 19.5 | (29.0) |
| Net income (loss) attributable to Atlantic Power Corporation | 36.8 | (98.6) | (122.4) | (62.4) | (177.4) |
| Basic earnings (loss) per share | | | | | |
| Earnings (loss) per share from continuing operations attributable to Atlantic Power Corporation | $ 0.33 | $ (0.86) | $ (1.02) | $ (0.76) | $ (1.37) |
| Earnings (loss) per share from discontinued operations, net of tax | — | — | — | 0.25 | (0.10) |
| Net income (loss) attributable to Atlantic Power Corporation | $ 0.33 | $ (0.86) | $ (1.02) | $ (0.51) | $ (1.47) |
| Diluted earnings (loss) per share attributable to Atlantic Power Corporation (e) | $ 0.29 | $ (0.86) | $ (1.02) | $ (0.51) | $ (1.47) |
| Dividend declared per common share | $ — | $ — | $ — | $ 0.09 | $ 0.29 |
| Total assets | $ 1,024.5 | $ 1,158.8 | $ 1,456.8 | $ 1,671.2 | $ 2,853.2 |
| Total long-term liabilities | $ 716.2 | $ 829.1 | $ 1,020.0 | $ 1,020.0 | $ 1,656.6 |

(a) Includes $0, $187.2 million, $85.9 million, $127.8 million and $106.6 million of goodwill, long lived asset and equity method investment impairments for the years end December 31, 2018, 2017, 2016, 2015 and 2014, respectively.

(b) Excludes the Wind Projects, which are classified as discontinued operations for the years ended December 31, 2015 and 2014.

(c) Excludes Greeley, which is classified as discontinued operations for the year ended December 31, 2014.

(d) The total assets exclude $62.8 million of deferred financing costs for the year ended December 31, 2014.

(e) Diluted earnings (loss) per share is computed including dilutive potential shares, which include those issuable upon conversion of convertible debentures and under our long-term incentive plan (“LTIP”). Please see the notes to our historical consolidated financial statements included elsewhere in this Form 10 K for information relating to the number of shares used in calculating basic and diluted earnings (loss) per share for the periods presented.

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## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following management's discussion and analysis of financial condition and results of operations should be read in conjunction with our audited consolidated financial statements included in this Annual Report on Form 10 K. All dollar amounts discussed below are in millions of U.S. dollars, unless otherwise stated. The financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP").

(in millions of U.S. dollars, except per share amounts)

The discussion and analysis below has been organized as follows:

1) Our Strategy, Overview of 2018 Results and Recent Events
2) Consolidated Overview and Results of Operations
3) Project Operating Performance
4) Supplementary Non-GAAP Financial Information
5) Liquidity and Capital Resources
6) Critical Accounting Policies

### Our Strategy, Overview of 2018 Results and Recent Events

We continue to be focused on the following priorities:

- Debt reduction: By significantly reducing our debt we believe that we have strengthened our balance sheet, improved our financial flexibility and credit profile and meaningfully reduced our cash interest payments. We expect to continue reducing debt over the next several years and improving our leverage ratio.
- Cost control: We have reduced our corporate overhead structure significantly and continue to seek opportunities to further lower it.
- PPA renewals: We seek to leverage the strength of our operations, fuel and technological diversity and location of our projects to renew or extend expiring PPAs where economically feasible, or make alternative arrangements in what continues to be challenging market conditions.
- Capital allocation: We plan to be rational in allocating our capital to balance risk and reward, evaluating competing uses such as organic growth, external investments or acquisitions and share repurchases with a goal of achieving returns that are accretive to our intrinsic value per share.
- Optimizing our fleet: By making capital investments in or efficiency improvements to our existing projects we are able to achieve cash returns that are higher than what is currently available in the external markets and at lower risk. We also have implemented various initiatives that we expect will ensure the continued safe and reliable operating performance of our projects while achieving modest cost savings.

- External growth: We take a creative, disciplined and value-oriented approach to external development or acquisitions, focusing on out-of-favor generation assets with an attractive price-to-value relationship.

In 2018, we continued to make progress in strengthening the Company. Our key achievements in the execution of our strategy during 2018 were:

- Debt reduction – During 2018, we made payments of $100.3 million to amortize our corporate and project-level debt. Additionally, we were able to reprice the Term Loan Facilities twice during 2018, lowering the rate from LIBOR plus 3.50% to LIBOR plus 2.75%. In 2017, we repriced these facilities twice from LIBOR plus 5.0% to LIBOR plus 3.50%. The multiple repricings of the term loan facility are expected to save (approximately) a cumulative $44 million of interest expense from repricing through maturity. We also reshaped our maturity profile by issuing Cdn$115 million of convertible debentures due in 2025 and using a portion of the proceeds to redeem the full $42.5 million of our Series C Debentures scheduled to mature in June 2019 and a partial redemption of Cdn$56.2 million of our Series D Debentures maturing in December 2019.

· Common and preferred share repurchases – We utilized $24.6 million of our discretionary capital to repurchase and cancel common ($16.6 million) and preferred ($8.0 million) shares during 2018 at prices that were attractive relative to our estimates of value.

· PPA renewals – In April 2018, a subsidiary of Merck & Co., Inc. exercised the first of its three successive one-year extension options under the PPA for Kenilworth. In January 2019, Merck exercised the second such option, extending the expiration date of our Kenilworth project's PPA from September 30, 2019 to September 30, 2020.

· Overhead cost reduction – We cut our corporate overhead expense from approximately $54 million in 2013 to $24 million for 2018, which represents a cumulative reduction from 2013 of approximately 57%. We have maintained our corporate overhead in the $23 million range for the past three years.

· External growth – We made our first external acquisition in over five years with the purchase in July 2018 of the remaining 50% interest in our Koma Kulshan project, which brought our ownership to 100%. We also signed an agreement to purchase two biomass facilities in South Carolina with an expected close late in the third quarter or in the fourth quarter of 2019.

· Investment in our fleet – During 2018 we invested $35.2 million in the portfolio in the form of project capital expenditures and maintenance expenses, seeking to maintain the safety and operating efficiency of our fleet.

Performance highlights

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2018 | 2017 | 2016 |
| Project revenue | $ 282.3 | $ 431.0 | $ 399.2 |
| Project income (loss) | $ 88.2 | $ (47.4) | $ 10.1 |
| Net income (loss) attributable to Atlantic Power Corporation | $ 36.8 | $ (98.6) | $ (122.4) |
| Earnings (loss) per share attributable to Atlantic Power Corporation—basic | $ 0.33 | $ (0.86) | $ (1.02) |
| Earnings (loss) per share attributable to Atlantic Power Corporation—diluted | 0.29 | (0.86) | (1.02) |
| Project Adjusted EBITDA(1) | $ 185.1 | $ 288.8 | $ 202.2 |

(1) See reconciliation and definition below under Supplementary Non GAAP Financial Information.

Revenue decreased from $431.0 million in the year ended December 31, 2017 to $282.3 million in the year ended December 31, 2018, a decrease of $148.7 million. The primary drivers of the increase are as follows:

- San Diego projects – the Naval Station, North Island and NTC projects ceased operations in February 2018. This resulted in a $69.0 million decrease in project revenue;

- Enhanced dispatch contracts – the enhanced dispatch contracts with the IESO for Kapuskasing and North Bay expired in December 2017, which resulted in a $54.4 million decrease in project revenue;

- OEFC settlement – we recorded $28.6 million of project revenue related to the OEFC settlement in the comparable 2017 period at our North Bay, Kapuskasing and Tunis projects, which did not recur in 2018;

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· Williams Lake – the project's energy purchase agreement extension became effective in April 2018, which provides lower pass-through of costs than the previous contract. The project also had lower dispatch than the comparable 2017 period. These factors resulted in a $10.7 million decrease in project revenue; and

· Koma Kulshan Acquisition – We recognized a $7.2 million gain for the year ended December 31, 2018 as a result of remeasuring our previous 50% equity interest in Koma Kulshan to fair value after acquiring the remaining 50% and consolidating the project.

These decreases in project revenue were partially offset by:

· Morris – there was a $7.4 million increase in revenue at our Morris project due to higher capacity prices, higher merchant dispatch and higher steam and ancillary services than 2017.

Consolidated project income was $88.2 million for the year ended December 31, 2018, an increase of $135.6 million from the prior year project loss of $47.4 million. The primary drivers of the increase are as follows:

· Impairment of goodwill, long-lived assets and equity investments – we recorded $187.1 million of impairments in 2017 and none in 2018;

· Fuel expense – fuel expense decreased from $106.3 million in 2017 to $73.1 million in 2018 primarily due to a $34.4 million decrease at the Naval Station, North Island and NTC projects, which ceased operations in February 2018;

· Depreciation and amortization expense – depreciation and amortization expense decreased by $29.4 million from 2017 primarily due to decreases of $16.3 million and $13.5 million at our Kapuskasing and North Bay projects, respectively, which were fully depreciated as of December 31, 2017 and a decrease of $7.7 million at our San Diego projects due to accelerated depreciation beginning in the third quarter of 2017. These decreases were partially offset by $12.5 million of increased amortization of the PPA intangible asset at our Nipigon project;

· Interest expense – project-level interest expense decreased by $15.7 million from $17.5 million in 2017 to $1.8 million in 2018 primarily due to the repayment of Piedmont's non-recourse project-level debt, in full, in 2017; and

· Equity in earnings of unconsolidated affiliates – project income increased $5.3 million at Orlando due to higher capacity revenue than 2017 and $6.5 million at Frederickson due to maintenance outages in 2017.

These increases in project income were partially offset by a decrease in project income resulting from:

· Revenue – revenue decreased $148.7 million as discussed above.

A detailed discussion of project income (loss) by segment is provided in Consolidated Overview and Results of Operations below. The discussion of Project Adjusted EBITDA by segment begins on page 59.

Factors and trends that may influence our results

The primary components of our financial results are (i) the financial performance of our projects, (ii) unrealized gains and losses associated with derivative instruments, (iii) interest expense and foreign exchange impacts on corporate level debt, and (iv) impairment of goodwill, long lived assets and equity method investments. We have recorded net losses in four of the past five years, primarily as a result of non cash losses associated with items (ii), (iii) and (iv) above, which are described in more detail in the following paragraphs.

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Financial performance of our projects

The operating performance of our projects supports cash distributions that are made to us after all operating, maintenance, capital expenditures and debt service requirements are satisfied at the project level. Our projects are able to generate cash flows because they generally receive revenues from long term contracts that provide relatively stable cash flows. Risks to the stability of these distributions include the following:

· Power generated by our projects, in most cases, is sold under PPAs that expire at various times. Currently, our PPAs are scheduled to expire between June 30, 2019 and March 31, 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly, or there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA at the project. See "Risk Factors—Risks Related to Our Business and Our Projects—The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations and financial condition."

· Our PPAs are generally structured to minimize our risk to fluctuations in commodity prices by passing the cost of fuel through to the utility and its customers, but some of our projects do have exposure to market power and fuel prices. See Item 1A. "Risk Factors—Risks Related to Our Business and Our Projects—Our projects depend on third party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our hedging arrangements.

· Our most significant exposure to market power prices exists at the Chambers and Morris projects. At Chambers, plant capacity is sold forward pursuant to the power purchase agreement with our utility customer but the project is economically dispatched, which impacts variable operating margins. For example, during periods of low demand and low spot electricity prices, the project is dispatched less, which reduces the project's operating margin. In addition, the utility customer has the right to sell a portion of the output into the spot market if it is economical to do so, and the Chambers project shares in the profit from these sales. This also adds some variability to the project's financial results. At Morris, a portion of the capacity is contracted with the industrial customer through 2034. The remaining capacity has been sold forward into the PJM capacity market through annual auctions covering the period through May 2022. The capacity revenues from these auctions generally represent the majority of the operating margin of the uncontracted portion of the project. Energy associated with the capacity sold forward into the PJM market is generally dispatched by PJM when economic to do so or when needed for other reasons. The project can also offer ancillary services to the grid. The sale of energy and ancillary services from the uncontracted portion of the project is not at a fixed price or margin and therefore can add variability to the project's financial results. See Item 1A. "Risk Factors—Risks Related to Our Business and Our Projects—Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating margin of these projects and on our business, results of operations and financial condition."

· The performance of our projects is impacted by a variety of operational and other factors, including water and waste heat levels, planned and unplanned outages and maintenance requirements, delays in start up, sourcing of fuel from suppliers, among others. For additional details regarding the various operational and other risks that we face, see

"Risk Factors—Risks Related to Our Business and Our Projects."

- When revenue or fuel contracts at our projects expire, we may not be able to sell power or procure fuel under new arrangements that provide the same level or stability of project cash flows. If re contracted, the degree of the expected decline in cash flows from operations is subject to market conditions when we execute new PPAs for these projects and is difficult to estimate at this time. See Item 1A. "Risk Factors—Risks Related to Our Business and Our Projects—The expiration or termination of PPAs could have a material adverse impact on our business, results of operations and financial condition." These projects will

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be free of debt when their PPAs expire, which we expect to provide us with some flexibility to pursue the most economic type of contract without restrictions that might be imposed by project level debt.

- One of our projects has non recourse project level debt that can restrict the ability of the project to make cash distributions. The project level debt agreement contains a cash flow coverage ratio test that restricts the project's cash distributions if project cash flows do not exceed project level debt service requirements by a specified amount. Although this project is currently meeting its debt service requirements, we cannot provide any assurances that it will generate enough future cash flow to meet any applicable ratio tests and be able to make distributions to us. See "Liquidity and Capital Resources—Project level debt" and Item 1A. "Risk Factors—Risks Related to Our Structure—Our indebtedness and financing arrangements, and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make acquisitions or investments or issue additional indebtedness we otherwise would seek to do."

Non cash gains and losses on derivatives instruments

In the ordinary course of our business, we execute natural gas purchase agreements and natural gas swap contracts to manage our exposure to fluctuations in commodity prices, foreign currency forward contracts to manage our exposure to fluctuations in foreign exchange rates and interest rate swaps to manage our exposure to changes in interest rates on variable rate project level debt. Most of these contracts are recorded at fair value with changes in fair value recorded currently in earnings, resulting in significant volatility in our income that does not significantly affect current period cash flows or the underlying risk management purpose of the derivative instruments. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our derivative instruments.

Interest expense and other costs associated with debt

Interest expense relates to both non recourse project level debt and corporate level debt. A portion of our convertible debentures and long term corporate level debt are denominated in Canadian dollars. These debt instruments are revalued at each balance sheet date based on the U.S. dollar to Canadian dollar foreign exchange rate at the balance sheet date, with changes in the value of the debt recorded in the consolidated statements of operations. The U.S. dollar to Canadian dollar foreign exchange rate has been volatile in recent years, which in turn creates volatility in our results due to the revaluation of our Canadian dollar denominated debt.

Impairment

We test our long lived assets and goodwill for impairment at least annually, or more often if deemed appropriate based on the determination of management of the occurrence of certain trigger events under our impairment policy. We recorded $0, $187.1 million ($101.1 million at consolidated projects and $86.0 million at projects accounted for under the equity method of accounting) and $85.9 million of goodwill and long lived asset impairments for the years ended December 31, 2018, 2017 and 2016, respectively. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all. It is possible that subsequent PPAs may not be available at prices that permit the operation of the project on a profitable basis. When the affected project temporarily or permanently ceases operations, or when we have an expectation that we will be unable to renew or renegotiate the PPA, the value of the project may be impaired such that we would record an impairment loss. See “Critical Accounting Policies – Goodwill” for a discussion of the trends and factors that have resulted in the recorded goodwill and long-lived asset impairments.

Consolidated Overview and Results of Operations

We have four reportable segments: East U.S., West U.S., Canada and Un Allocated Corporate. The segment classified as Un Allocated Corporate includes activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects and intercompany eliminations. These costs

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are not allocated to the operating segments when determining segment profit or loss. Project income (loss) is the primary GAAP measure of our operating results and is discussed below by reportable segment.

2018 compared to 2017

The following tables and discussion summarize our consolidated results of operations and provide an analysis by reportable segment:

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 | 2017 | $ change | % change | |
| Project revenue: | | | | | |
| Energy sales | $ 130.9 | $ 148.9 | $ (18.0) | (12.1) | % |
| Energy capacity revenue | 97.9 | 105.8 | (7.9) | (7.5) | % |
| Other | 53.5 | 176.3 | (122.8) | (69.7) | % |
| | 282.3 | 431.0 | (148.7) | (34.5) | % |
| Project expenses: | | | | | |
| Fuel | 73.1 | 106.3 | (33.2) | (31.2) | % |
| Operations and maintenance | 85.0 | 87.8 | (2.8) | (3.2) | % |
| Depreciation and amortization | 83.7 | 113.1 | (29.4) | (26.0) | % |
| | 241.8 | 307.2 | (65.4) | (21.3) | % |
| Project other income (loss): | | | | | |
| Change in fair value of derivative instruments | 2.2 | 2.1 | 0.1 | 4.8 | % |
| Equity in earnings (loss) of unconsolidated affiliates | 43.2 | (54.8) | 98.0 | NM | |
| Interest, net | (1.8) | (17.5) | 15.7 | (89.7) | % |
| Impairment | — | (101.1) | 101.1 | (100.0) | % |
| Other income, net | 4.1 | 0.1 | 4.0 | NM | |
| | 47.7 | (171.2) | 218.9 | NM | |
| Project income (loss) | 88.2 | (47.4) | 135.6 | NM | |
| Administrative and other expenses: | | | | | |
| Administration | 23.9 | 23.6 | 0.3 | 1.3 | % |
| Interest expense, net | 52.7 | 64.2 | (11.5) | (17.9) | % |
| Foreign exchange (gain) loss | (22.8) | 16.3 | (39.1) | NM | |
| Other income, net | (3.0) | (0.4) | (2.6) | NM | |
| | 50.8 | 103.7 | (52.9) | (51.0) | % |
| Income (loss) from operations before income taxes | 37.4 | (151.1) | 188.5 | NM | |
| Income tax expense (benefit) | 0.2 | (58.1) | 58.3 | (100.3) | % |
| Net income (loss) | 37.2 | (93.0) | 130.2 | NM | |
| Net income attributable to preferred shares of a subsidiary company | 0.4 | 5.6 | (5.2) | (92.9) | % |
| Net income (loss) attributable to Atlantic Power Corporation | $ 36.8 | $ (98.6) | $ 135.4 | NM | |

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Project Income (Loss) by Segment

| | Year Ended December 31, 2018 | | | | |
|---|---|---|---|---|---|
| | East U.S. | West U.S. | Canada | Un-Allocated Corporate | Consolidated Total |
| Project revenue: | | | | | |
| Energy sales | $ 87.5 | $ 13.5 | $ 29.9 | $ — | $ 130.9 |
| Energy capacity revenue | 52.8 | 27.8 | 17.3 | — | 97.9 |
| Other | 18.4 | 2.5 | 31.7 | 0.9 | 53.5 |
| | 158.7 | 43.8 | 78.9 | 0.9 | 282.3 |
| Project expenses: | | | | | |
| Fuel | 49.1 | 10.9 | 13.1 | — | 73.1 |
| Operations and maintenance | 35.7 | 25.0 | 23.8 | 0.5 | 85.0 |
| Depreciation and amortization | 36.4 | 18.6 | 28.6 | 0.1 | 83.7 |
| | 121.2 | 54.5 | 65.5 | 0.6 | 241.8 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | (0.4) | — | 3.6 | (1.0) | 2.2 |
| Equity in earnings of unconsolidated affiliates | 35.7 | 7.5 | — | — | 43.2 |
| Interest expense, net | (1.9) | 0.1 | — | — | (1.8) |
| Impairment | — | — | — | — | — |
| Other income, net | — | 4.0 | — | 0.1 | 4.1 |
| | 33.4 | 11.6 | 3.6 | (0.9) | 47.7 |
| Project income (loss) | $ 70.9 | $ 0.9 | $ 17.0 | $ (0.6) | $ 88.2 |

| | Year Ended December 31, 2017 | | | | |
|---|---|---|---|---|---|
| | East U.S. | West U.S. | Canada | Un-Allocated Corporate | Consolidated Total |
| Project revenue: | | | | | |
| Energy sales | $ 87.3 | $ 33.0 | $ 28.6 | $ — | $ 148.9 |
| Energy capacity revenue | 49.4 | 45.6 | 10.8 | — | 105.8 |
| Other | 15.8 | 30.3 | 129.2 | 1.0 | 176.3 |
| | 152.5 | 108.9 | 168.6 | 1.0 | 431.0 |
| Project expenses: | | | | | |
| Fuel | 46.4 | 44.8 | 15.1 | — | 106.3 |
| Operations and maintenance | 34.5 | 26.0 | 27.6 | (0.3) | 87.8 |
| Depreciation and amortization | 35.2 | 25.6 | 51.9 | 0.4 | 113.1 |
| | 116.1 | 96.4 | 94.6 | 0.1 | 307.2 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | 6.3 | — | (6.1) | 1.9 | 2.1 |

| | | | | | |
|---|---|---|---|---|---|
| Equity in loss of unconsolidated affiliates | (27.6) | (27.2) | — | — | (54.8) |
| Interest expense, net | (17.4) | — | (0.1) | — | (17.5) |
| Impairment | (14.7) | (57.3) | (29.1) | — | (101.1) |
| Other income, net | — | — | 0.1 | — | 0.1 |
| | (53.4) | (84.5) | (35.2) | 1.9 | (171.2) |
| Project (loss) income | $ (17.0) | $ (72.0) | $ 38.8 | $ 2.8 | $ (47.4) |

East U.S.

Project income for 2018 increased $87.9 million from 2017 primarily due to:

· increased project income of $48.2 million and $11.6 million at Chambers and Selkirk, respectively, primarily due to impairments of our equity investments of $47.1 million and $10.6 million recorded for the year ended December 31, 2017, respectively;

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- increased project income of $11.5 million at Curtis Palmer due primarily to a $14.7 million goodwill impairment recorded in 2017, offset by a $3.2 million decrease in revenue from lower water flows than 2017;

- increased project income of $7.9 million at Piedmont primarily due to $7.1 million of lower interest expense and interest rate swap mark-to-market fair value adjustments resulting from the repayment of the project-level debt, in full, in 2017;

- increased project income of $5.7 million at Morris primarily due to higher energy and capacity revenues than 2017; and

- increased project income of $5.3 million at Orlando primarily due to higher generation and a higher capacity rate than 2017.

West U.S.

Project income for 2018 increased $72.9 million from 2017 primarily due to:

- decreased project loss of $16.5 million, $13.9 million and $7.5 million at Naval Station, North Island and NTC primarily due to $22.5 million, $21.2 million and $13.5 million long-lived asset impairments recorded in 2017, respectively. These projects ceased operations in February 2018;

- decreased project loss of $34.8 million at Frederickson primarily due to a $28.3 million impairment of our investment in the project recorded in 2017; and

- increased project income of $6.6 million at Koma Kulshan primarily due to a $7.2 million purchase accounting gain recognized from a step acquisition of the 50% remaining interest in Koma Kulshan in 2018.

These increases were partially offset by:

- decreased project income of $5.5 million at Manchief primarily due to a $7.4 million increase in maintenance expense from a turbine overhaul completed in 2018.

Canada

Project income for 2018 decreased $21.8 million from 2017 primarily due to:

- decreased project income of $21.0 million at North Bay primarily due to $37.2 million of revenue recorded related to the OEFC settlement and the expiration of the enhanced dispatch contract in the comparable period in 2017, partially offset by a $13.5 million decrease in depreciation expense;
- decreased project income of $20.4 million at Kapuskasing primarily due to $39.0 million of revenue recorded related to the OEFC settlement and the expiration of the enhanced dispatch contract in the comparable period in 2017, partially offset by a $16.3 million decrease in depreciation expense; and
- decreased project income of $9.4 million at Tunis primarily due to $6.8 million of revenue recorded related to the OEFC settlement in 2017 and a $3.3 million increase in maintenance expense in preparation of commencing operations in October 2018.

These decreases were partially offset by:

- increased project income of $27.4 million at Williams Lake primarily due to a $29.1 million long-lived asset impairment recorded in 2017 and a $6.7 million decrease in depreciation expense resulting from the long-lived asset impairment in 2017, partially offset by a $10.7 million decrease in project revenue due to the terms of the renewed energy purchase agreement extension that became effective in April 2018.

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Un Allocated Corporate

Total project loss increased $3.4 million from 2017 primarily due to a $2.9 million decrease in fair value of interest rate swap agreements and settlements of forward gas contracts.

Administrative and other expenses (income)

Administrative and other expenses (income) includes the income and expenses not attributable to our projects and are allocated to the Un allocated Corporate segment. These costs include the activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate tax. Significant non cash items that impact Administrative and other expenses (income), which are subject to potentially significant fluctuations, include the non cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar denominated obligations and the related deferred income tax expense (benefit) associated with these non cash items.

Administration

Administration expense did not change materially from 2017.

Interest, net

Interest expense decreased $11.5 million from $64.2 million in 2017 to $52.7 million in 2018 primarily due to lower outstanding debt balances than 2017, as well as a lower interest rate on our senior secured credit facility.

Foreign exchange (gain) loss

Foreign exchange gain increased by $39.1 million from a $16.3 million loss in 2017 to a $22.8 million gain in 2018 due to the revaluation of instruments denominated in Canadian dollars (primarily our MTNs and convertible debentures). The Canadian dollar depreciated 8.7% against the U.S. dollar from December 31, 2017 to December 31, 2018, as compared to a 6.6% increase in 2017. Additionally, our Canadian dollar obligations increased from 2017 as a result of the convertible debenture issuance in the first quarter of 2018.

Other income, net

Other income, net increased $2.6 million from 2017 primarily due to a $3.2 million unrealized gain recorded for the fair value of the conversion option of the Series E Debentures.

Income tax expense

Income tax expense for the year ended December 31, 2018 was $0.2 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 27%, was $10.1 million. The primary items impacting the tax rate for the twelve months ended December 31, 2018 were $0.5 million relating to withholding and state taxes and $0.7 million of other permanent differences. These items were offset by a net decrease to our valuation allowance of $6.7 million, consisting of $0.1 million of decreases in Canada due to utilization of net operating losses and $6.6 million decreases in the United States. Based on initiatives recently completed, we determined that sufficient deferred tax liabilities were likely to reverse in a timely manner against certain deferred tax assets, resulting in a reduction of the valuation allowance in the United States. In addition, the rate was further impacted by $3.3 million relating to changes in tax rates and $1.1 million related to capital loss on intercompany notes.

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2017 compared to 2016

The following tables and discussion summarize our consolidated results of operations and provides an analysis by reportable segment:

| | Year ended December 31, 2017 | 2016 | $ change | % change |
|---|---|---|---|---|
| Project revenue: | | | | |
| Energy sales | $ 148.9 | $ 184.2 | $ (35.3) | (19.2) % |
| Energy capacity revenue | 105.8 | 141.9 | (36.1) | (25.4) % |
| Other | 176.3 | 73.1 | 103.2 | NM |
| | 431.0 | 399.2 | 31.8 | 8.0 % |
| Project expenses: | | | | |
| Fuel | 106.3 | 149.5 | (43.2) | (28.9) % |
| Operations and maintenance | 87.8 | 105.2 | (17.4) | (16.5) % |
| Depreciation and amortization | 113.1 | 113.5 | (0.4) | (0.4) % |
| | 307.2 | 368.2 | (61.0) | (16.6) % |
| Project other expense: | | | | |
| Change in fair value of derivative instruments | 2.1 | 37.9 | (35.8) | (94.5) % |
| Equity in (loss) earnings of unconsolidated affiliates | (54.8) | 35.9 | (90.7) | NM |
| Interest expense, net | (17.5) | (9.2) | (8.3) | 90.2 % |
| Impairment | (101.1) | (85.9) | (15.2) | 17.7 % |
| Other income, net | 0.1 | 0.4 | (0.3) | (75.0) % |
| | (171.2) | (20.9) | (150.3) | NM |
| Project (loss) income | (47.4) | 10.1 | (57.5) | NM |
| Administrative and other expenses (income): | | | | |
| Administration | 23.6 | 22.6 | 1.0 | 4.4 % |
| Interest expense, net | 64.2 | 106.0 | (41.8) | (39.4) % |
| Foreign exchange loss | 16.3 | 13.9 | 2.4 | 17.3 % |
| Other income, net | (0.4) | (3.9) | 3.5 | (89.7) % |
| | 103.7 | 138.6 | (34.9) | (25.2) % |
| Loss from operations before income taxes | (151.1) | (128.5) | (22.6) | 17.6 % |
| Income tax benefit | (58.1) | (14.6) | (43.5) | NM |
| Net loss | (93.0) | (113.9) | 20.9 | (18.3) % |
| Net income attributable to preferred shares of a subsidiary company | 5.6 | 8.5 | (2.9) | (34.1) % |
| Net loss attributable to Atlantic Power Corporation | $ (98.6) | $ (122.4) | $ 23.8 | (19.4) % |

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Project Income (Loss) by Segment

| | Year Ended December 31, 2017 | | | | |
|---|---|---|---|---|---|
| | | | | Un-Allocated | Consolidated |
| | East U.S. | West U.S. | Canada | Corporate | Total |
| Project revenue: | | | | | |
| Energy sales | $ 87.3 | $ 33.0 | $ 28.6 | $ — | $ 148.9 |
| Energy capacity revenue | 49.4 | 45.6 | 10.8 | — | 105.8 |
| Other | 15.8 | 30.3 | 129.2 | 1.0 | 176.3 |
| | 152.5 | 108.9 | 168.6 | 1.0 | 431.0 |
| Project expenses: | | | | | |
| Fuel | 46.4 | 44.8 | 15.1 | — | 106.3 |
| Operations and maintenance | 34.5 | 26.0 | 27.6 | (0.3) | 87.8 |
| Depreciation and amortization | 35.2 | 25.6 | 51.9 | 0.4 | 113.1 |
| | 116.1 | 96.4 | 94.6 | 0.1 | 307.2 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | 6.3 | — | (6.1) | 1.9 | 2.1 |
| Equity in loss of unconsolidated affiliates | (27.6) | (27.2) | — | — | -54.8 |
| Interest expense, net | (17.4) | — | (0.1) | — | (17.5) |
| Impairment | (14.7) | (57.3) | (29.1) | — | (101.1) |
| Other income, net | — | — | 0.1 | — | 0.1 |
| | (53.4) | (84.5) | (35.2) | 1.9 | (171.2) |
| Project (loss) income | $ (17.0) | $ (72.0) | $ 38.8 | $ 2.8 | $ (47.4) |

| | Year Ended December 31, 2016 | | | | |
|---|---|---|---|---|---|
| | | | | Un-Allocated | Consolidated |
| | East U.S. | West U.S. | Canada | Corporate | Total |
| Project revenue: | | | | | |
| Energy sales | $ 70.1 | $ 31.9 | $ 82.2 | $ — | $ 184.2 |
| Energy capacity revenue | 49.0 | 45.6 | 47.3 | — | 141.9 |
| Other | 15.4 | 23.8 | 33.0 | 0.9 | 73.1 |
| | 134.5 | 101.3 | 162.5 | 0.9 | 399.2 |
| Project expenses: | | | | | |
| Fuel | 45.3 | 36.9 | 67.3 | — | 149.5 |
| Operations and maintenance | 41.3 | 26.4 | 36.4 | 1.1 | 105.2 |
| Depreciation and amortization | 34.4 | 29.1 | 49.5 | 0.5 | 113.5 |
| | 121.0 | 92.4 | 153.2 | 1.6 | 368.2 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | 9.2 | — | 25.5 | 3.2 | 37.9 |
| Equity in earnings of unconsolidated affiliates | 33.0 | 2.9 | — | — | 35.9 |
| Interest expense, net | (9.1) | — | — | (0.1) | (9.2) |

| | | | | | |
|---|---|---|---|---|---|
| Impairment | (15.4) | — | (70.5) | — | (85.9) |
| Other income, net | — | — | — | 0.4 | 0.4 |
| | 17.7 | 2.9 | (45.0) | 3.5 | (20.9) |
| Project income (loss) | $ 31.2 | $ 11.8 | $ (35.7) | $ 2.8 | $ 10.1 |

East U.S.

Project income for 2017 decreased $48.2 million from 2016 primarily due to:

· decreased project income of $48.1 million and $11.3 million at Chambers and Selkirk, respectively, primarily due to impairments of our equity investments of $47.1 million and $10.6 million recorded for the year ended December 31, 2017, respectively; and

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- decreased project income of $7.5 million at Orlando primarily due to an $11.9 million decrease in the fair value of natural gas swaps and lower revenue from decreased dispatch, partially offset by $6.8 million of lower fuel expense resulting from the settlement of favorable fuel swaps.

These decreases were partially offset by:

- increased project income of $13.8 million at Curtis Palmer due primarily to a $13.3 million increase in revenue from higher water flows than 2016; and

- increased project income of $5.0 million at Morris due primarily to $7.5 million of decreased maintenance expenses resulting from the overhaul of two gas turbines and one steam turbine during 2016 and $4.0 million higher revenues due to less maintenance outages than 2016. These increases were partially offset by $7.5 million of higher fuel expense.

West U.S.

Project income for 2017 decreased $83.8 million from 2016 primarily due to:

- decreased project income of $22.6 million, $21.0 million and $12.0 million at Naval Station, North Island and NTC primarily due to $22.5 million, $21.2 million and $13.5 million long-lived asset impairments recorded for the year ended December 31, 2017, respectively; and

- decreased project income of $30.1 million at Frederickson primarily due to a $28.3 million impairment of our investment in the project recorded for the year ended December 31, 2017.

Canada

Project income for 2017 increased $74.5 million from 2016 primarily due to:

- increased project income of $47.1 million at Mamquam due primarily to a $50.2 million goodwill impairment recorded for the year ended December 31, 2016, partially offset by a $2.8 million decrease in energy revenue due to lower water flows than 2016;

- increased project income of $26.6 million at North Bay due primarily to a $10.2 million goodwill and long-lived asset impairment recorded in the third quarter of 2016, $23.1 million of lower fuel expense in 2017 due to the expiration of an unfavorable fuel contract in December 2016, $3.7 million increase in revenue received due to the OEFC settlement and $2.3 million of lower maintenance expense. These increases were partially offset by a $13.6 million increased gain in the fair value of a fuel agreement accounted for as a derivative in 2016;

- increased project income of $24.8 million at Kapuskasing due primarily to $24.8 million of lower fuel expense in 2017 due to the expiration of an unfavorable fuel contract in December 2016, $8.9 million goodwill and long-lived asset impairment recorded in the third quarter of 2016 and $3.9 million of lower maintenance expense. These increases were partially offset by a $13.6 million gain in the fair value of a fuel agreement accounted for as a derivative in 2016; and

- increased project income of $6.1 million at Tunis due primarily to the collection of the OEFC settlement.

These increases were partially offset by:

- decreased project income of $27.0 million at Williams Lake primarily due to a $29.1 million long-lived asset impairment recorded for the year ended December 31, 2017; and

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- decreased project income of $3.2 million at Nipigon due primarily to a $4.4 million decrease in the fair value of fuel agreements accounted for as derivatives.

Un Allocated Corporate

Total project income for 2017 did not change materially from 2016.

Administrative and other expenses (income)

Administrative and other expenses (income) includes the income and expenses not attributable to our projects and are allocated to the Un allocated Corporate segment. These costs include the activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate tax. Significant non cash items that impact Administrative and other expenses (income), which are subject to potentially significant fluctuations, include the non cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar denominated obligations and the related deferred income tax expense (benefit) associated with these non cash items.

Administration

Administration expense increased $1.0 million from 2016 primarily due to a $0.6 million increase in employee compensation costs, $0.6 million of higher professional services costs and $0.2 million of lower rent expense.

Interest, net

Interest expense decreased $41.8 million from 2016 primarily due to $37.6 million of deferred financing cost write-offs resulting from the extinguishment of the Senior Secured Term Loan Facilities and the repurchase and cancellation of the Series A, B, and, in part, C convertible debentures during 2016 as well as lower outstanding debt balances and a lower interest rate on the senior secured credit facilities for the year ended December 31, 2017.

Foreign exchange loss

Foreign exchange loss increased $2.4 million from 2016 primarily due to a $1.4 million increase in unrealized loss in the revaluation of instruments denominated in Canadian dollars and $1.0 million of realized transaction losses. The U.S. dollar to Canadian dollar exchange rate was 1.25 and 1.34 at December 31, 2017 and 2016, respectively, a decrease of 6.6%. The average U.S. dollar to Canadian dollar exchange rate was 1.28 for the year ended December 31, 2017 and was 1.32 for the year ended December 31, 2016.

Other income, net

Other income, net decreased $3.5 million from the 2016 comparable period primarily due to a $3.7 million gain recorded on the purchase and cancellation of convertible debentures during 2016.

Income tax benefit

Income tax benefit for the year ended December 31, 2017 was $58.1 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $39.3 million. On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law making significant changes to the Internal Revenue Code. Changes include, but are not limited to, a corporate tax rate decrease from 35% to 21% effective for tax years beginning after December 31, 2017, new limitations on the deduction of net business interest expense, and a new base erosion and anti-abuse tax. After preliminary estimates based on guidance available as of the date of this filing, the interest expense limitation and base erosion and anti-abuse tax is not expected to have a material impact to cash taxes in future tax years. The primary item impacting the tax rate for the twelve months ended December 31, 2017 is the amount related to the remeasurement of deferred tax assets and liabilities, based on the rates at which they are expected to reverse in the future

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for $28.5 million. In addition, the rate was further impacted by $9.9 million related to goodwill impairment. These items were offset by $34.6 million related to a net decrease to our valuation allowances, consisting primarily of decreases of $34.1 million in the United States due to the remeasurement of deferred tax assets and a decrease of $0.5 million in Canada related to income. In addition, the rate was further impacted by $20.1 million relating to operating in higher tax rate jurisdictions, $2.4 million relating to foreign exchange and $0.1 million relating to other permanent differences.

Project Operating Performance

Two of the primary metrics we utilize to measure the operating performance of our projects are generation and availability. Generation measures the net output of our proportionate project ownership percentage in GWhs. Availability is calculated by dividing the total scheduled hours of a project less forced outage hours by the total hours in the period measured. The terms of our PPAs require our projects to maintain certain levels of availability. The majority of our projects were able to achieve substantially all of their respective capacity payments. The terms of our PPAs provide for certain levels of planned and unplanned outages. All references below are denominated in thousands of Net GWh.

| | Year ended December 31, | | | | | | |
|---|---|---|---|---|---|---|---|
| | | | | % change | | % change | |
| (in Net GWh) | 2018 | 2017 | 2016 | 2018 vs. 2017 | | 2017 vs. 2016 | |
| Segment | | | | | | | |
| East U.S. | 2,451.6 | 2,478.5 | 2,430.2 | (1.1) | % | 2.0 | % |
| West U.S. | 936.2 | 1,601.5 | 1,506.6 | (41.5) | % | 6.3 | % |
| Canada | 973.8 | 934.7 | 1,977.2 | 4.2 | % | (52.7) | % |
| Total | 4,361.6 | 5,014.7 | 5,914.0 | (13.0) | % | (15.2) | % |

Generation

Year ended December 31, 2018 compared with Year ended December 31, 2017

Aggregate power generation for 2018 decreased 13% from 2017 primarily due to:

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decreased generation in the West U.S. segment primarily due to a combined 741.7 net GWh decrease in generation at Naval Station, North Island and NTC, which ceased operations in February 2018, and a 111.3 net GWh decrease in generation at Frederickson due to milder weather than 2017, partially offset by a 188.4 net GWh increase in generation at Manchief due to higher dispatch than 2017; and

· decreased generation in the East U.S. segment primarily due to a 50.7 net GWh decrease in generation at Curtis Palmer due to lower water flows than 2017.

These decreases were partially offset by:

· increased generation in the Canada segment primarily due to an increase of 44.4 net GWh at Mamquam due to a 2017 maintenance outage and higher water flows than 2017.

Year ended December 31, 2017 compared with Year ended December 31, 2016

Aggregate power generation for 2017 decreased 15.2% from 2016 primarily due to:

· decreased generation in the Canada segment primarily due to a decrease of 928.6 net GWh on a combined basis at Kapuskasing, Nipigon and North Bay, due to their suspended operation status under the enhanced dispatch contracts.

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This decrease was partially offset by:

· increased generation in the East U.S. segment primarily due to a 107.6 net GWh increase in generation at Curtis Palmer due to higher water flows than the comparable period in 2016 and a 68.8 net GWh increase in generation at Morris due to a maintenance outage in 2016. These increases were partially offset by an 83.9 net GWh decrease in generation at Selkirk due to lower dispatch from low merchant power prices; and

· increased generation in the West U.S. segment primarily due to a 47.1 net GWh increase in generation at Frederickson, and a 34.6 net GWh increase in generation at Manchief due to higher dispatch than 2016.

Availability

| | Year ended December 31, | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | % change | | % change | |
| | 2018 | | 2017 | | 2016 | | 2018 vs. 2017 | | 2017 vs. 2016 | |
| Segment | | | | | | | | | | |
| East U.S. | 97.1 | % | 88.8 | % | 93.1 | % | 9.3 | % | (4.6) | % |
| West U.S. | 95.2 | % | 92.1 | % | 92.1 | % | 3.4 | % | — | % |
| Canada | 96.0 | % | 92.8 | % | 95.3 | % | 3.4 | % | (2.6) | % |
| Weighted average | 96.5 | % | 90.3 | % | 93.3 | % | 6.9 | % | (3.2) | % |

Year ended December 31, 2018 compared with Year ended December 31, 2017

Weighted average availability for 2018 increased to 96.5% from 90.3% in 2017 primarily due to:

· increased availability in the East U.S. segment primarily due to maintenance outages at Kenilworth and Orlando in 2017 and a shorter maintenance outage at Piedmont in 2018 than in 2017;

· increased availability in the West U.S. segment primarily due to maintenance outages at Frederickson in the comparable 2017 period, partially offset by decreased availability at Manchief due to a maintenance outage in the 2018 period; and

· increased availability in the Canada segment primarily due a maintenance outage at Mamquam in 2017.

Year ended December 31, 2017 compared with Year ended December 31, 2016

Weighted average availability for 2017 decreased to 90.3% from 93.3% in 2016 primarily due to:

- decreased availability in the East U.S. segment resulting from decreased availability at Kenilworth, which underwent a turbine overhaul in 2017, and decreased availability at Orlando due to a forced maintenance outage in 2017. These decreases were partially offset by increased availability at Morris, which underwent a planned maintenance outage in the third quarter of 2016;

- decreased availability in the West U.S. segment primarily due to a planned maintenance outage at Frederickson, offset by increased availability at NTC, which underwent an outage in 2016; and

- decreased availability in the Canada segment resulting from Williams Lake, primarily due to forced maintenance outages.

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Supplementary Non GAAP Financial Information

Project Adjusted EBITDA

The key measurement we use to evaluate the results of our business is Project Adjusted EBITDA. Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We believe that Project Adjusted EBITDA is a useful measure of financial results at our projects because it excludes non-cash impairment charges, gains or losses on the sale of assets and non-cash mark-to-market adjustments, all of which can affect year-to-year comparisons. Project Adjusted EBITDA is before corporate overhead expense. The most directly comparable GAAP measure to Project Adjusted EBITDA is Project (loss) income. A reconciliation of Net (loss) income to Project (loss) income and to Project Adjusted EBITDA is provided under "Project Adjusted EBITDA" below. Project Adjusted EBITDA for our equity investments in unconsolidated affiliates is presented on a proportionately consolidated basis in the table below.

| | Year ended December 31, | | | $ change | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 | 2017 |
| Net income (loss) | $ 37.2 | $ (93.0) | $ (113.9) | $ 130.2 | $ 20.9 |
| Income tax expense (benefit) | 0.2 | (58.1) | (14.6) | 58.3 | (43.5) |
| Income (loss) from operations before income taxes | 37.4 | (151.1) | (128.5) | 188.5 | (22.6) |
| Administration | 23.9 | 23.6 | 22.6 | 0.3 | 1.0 |
| Interest expense, net | 52.7 | 64.2 | 106.0 | (11.5) | (41.8) |
| Foreign exchange (gain) loss | (22.8) | 16.3 | 13.9 | (39.1) | 2.4 |
| Other income, net | (3.0) | (0.4) | (3.9) | (2.6) | 3.5 |
| Project income (loss) | $ 88.2 | $ (47.4) | $ 10.1 | $ 135.6 | $ (57.5) |
| Reconciliation to Project Adjusted EBITDA | | | | | |
| Depreciation and amortization | 99.7 | 133.2 | 133.5 | (33.5) | (0.3) |
| Interest expense, net | 3.4 | 19.2 | 10.9 | (15.8) | 8.3 |
| Change in the fair value of derivative instruments | (2.2) | (2.1) | (37.9) | (0.1) | 35.8 |
| Impairment | — | 187.1 | 85.9 | (187.1) | 101.2 |
| Other income, net | (4.0) | (1.2) | (0.3) | (2.8) | (0.9) |
| Project Adjusted EBITDA | $ 185.1 | $ 288.8 | $ 202.2 | $ (103.7) | $ 86.6 |
| Project Adjusted EBITDA by segment | | | | | |
| East U.S. | 120.8 | 112.5 | 92.4 | 8.3 | 20.1 |
| West U.S. | 21.9 | 49.1 | 51.2 | (27.2) | (2.1) |
| Canada | 41.9 | 125.8 | 58.8 | (83.9) | 67.0 |
| Un-Allocated Corporate | 0.5 | 1.4 | (0.2) | (0.9) | 1.6 |
| Total | $ 185.1 | $ 288.8 | $ 202.2 | $ (103.7) | $ 86.6 |

East U.S.

The following table summarizes Project Adjusted EBITDA for our East U.S. segment for the periods indicated:

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | % change 2018 vs. 2017 | % change 2017 vs. 2016 |
| East U.S. Project Adjusted EBITDA | $ 120.8 | $ 112.5 | $ 92.4 | 7 % | 22 % |

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Year ended December 31, 2018 compared with Year ended December 31, 2017

Project Adjusted EBITDA for 2018 increased $8.3 million or 7% from 2017 primarily due to increases in Project Adjusted EBITDA of:

- $7.4 million at Morris due to a higher capacity price, higher steam sales and ancillary revenue than 2017; and

- $2.8 million at Orlando due to higher availability and contractual capacity rates than 2017.

These increases were partially offset by a decrease in Project Adjusted EBITDA of:

- $2.8 million at Curtis Palmer primarily due to $3.2 million of decreased project revenues from lower water flows than 2017.

Year ended December 31, 2017 compared with Year ended December 31, 2016

Project Adjusted EBITDA for 2017 increased $20.1 million or 22% from 2016 primarily due to increases in Project Adjusted EBITDA of:

- $12.6 million at Curtis Palmer due to $13.3 million of increased revenues from higher water flows than 2016;

- $4.6 million at Orlando primarily due to lower fuel expense resulting from the settlements of favorable fuel swaps; and

- $4.0 million at Morris due to $7.5 million of decreased maintenance expenses and $4.0 million of higher revenues resulting from the overhaul of two gas turbines and one steam turbine during 2016. These increases were partially offset by $7.5 million higher fuel expense.

West U.S.

The following table summarizes Project Adjusted EBITDA for our West U.S. segment for the periods indicated:

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | | | | % change | % change |
| | 2018 | 2017 | 2016 | 2018 vs 2017 | 2017 vs 2016 |
| West U.S. | | | | | |
| Project Adjusted EBITDA | $ 21.9 | $ 49.1 | $ 51.2 | (55) % | (4) % |

Year ended December 31, 2018 compared with Year ended December 31, 2017

Project Adjusted EBITDA for 2018 decreased by $27.2 million or 55% from 2017 primarily due to decreases in Project Adjusted EBITDA of:

· $9.3 million, $9.0 million and $5.7 million at Naval Station, North Island and NTC, respectively, which ceased operations in February 2018; and

· $5.5 million at Manchief due to a $7.4 million increase in maintenance expense from a turbine overhaul, offset by a $1.8 million increase in project revenue due to higher dispatch.

These decreases were partially offset by an increase in Project Adjusted EBITDA of:

· $3.0 million at Frederickson due to lower planned maintenance expense than 2017.

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Year ended December 31, 2017 compared with Year ended December 31, 2016

Project Adjusted EBITDA for 2017 decreased by $2.1 million or 4% from 2016 primarily due to a decrease in Project Adjusted EBITDA of:

- $2.1 million at Frederickson primarily due to higher maintenance expense than 2016, partially offset by higher revenue.

Canada

The following table summarizes Project Adjusted EBITDA for our Canada segment for the periods indicated:

| | Year Ended December 31, | | | % change | % change |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | 2018 vs. 2017 | 2017 vs. 2016 |
| Canada Project Adjusted EBITDA | $ 41.9 | $ 125.8 | $ 58.8 | (67) % | 114 % |

Year ended December 31, 2018 compared with Year ended December 31, 2017

Project Adjusted EBITDA for 2018 decreased by $83.9 million or 67% from 2017 primarily due to decreases in Project Adjusted EBITDA of:

- $36.7 million and $34.5 million at Kapuskasing and North Bay, respectively, due to the expiration of the enhanced dispatch agreements in December 2017 and the OEFC settlement received in 2017;

- $9.0 million at Tunis due to $6.8 million of revenue recorded related to the OEFC settlement in 2017 and $3.0 million of higher maintenance expense incurred during 2018; and

·

$8.4 million at Williams Lake due to lower gross margin under the short-term contract extension that became effective in April 2018, partially offset by cost reductions.

These decreases were partially offset by increases in Project Adjusted EBITDA of:

· $3.3 million at Mamquam due to higher water flows and lower maintenance expense relative to 2017; and

· $2.3 million at Nipigon due to a contractual rate increase and lower payroll expense than 2017.

Year ended December 31, 2017 compared with Year ended December 31, 2016

Project Adjusted EBITDA for 2017 increased by $67.0 million from 2016 primarily due to increases in Project Adjusted EBITDA of:

· $60.6 million at Kapuskasing and North Bay primarily due to $21.8 million received from the OEFC settlement. These projects were not operational under the terms of their enhanced dispatch contracts during 2017. Additionally, each project had unfavorable fuel contracts that expired in 2016. As a result of these factors, gross margin increased $32.5 million and maintenance expense decreased $6.2 million in 2017;

· $6.8 million at Tunis primarily due to the collection of the OEFC settlement; and

· $2.8 million at Nipigon primarily due to $7.0 million of lower fuel expense due to non-operational status under the terms of its enhanced dispatch contract, partially offset by a $4.4 million decrease in the fair value of fuel swap agreements.

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These increases were partially offset by a decrease in Project Adjusted EBITDA of:

· $3.2 million at Mamquam, due to lower water flows than 2016 and forced outages in 2017.

Un allocated Corporate

The following table summarizes Project Adjusted EBITDA for our Un allocated Corporate segment for the periods indicated:

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2018 | 2017 | 2016 | % change 2018 vs. 2017 | % change 2017 vs. 2016 |
| Un-allocated Corporate Project Adjusted EBITDA | $ 0.5 | $ 1.4 | $ (0.2) | (64) % | NM |

Year ended December 31, 2018 compared with Year ended December 31, 2017

Project Adjusted EBITDA did not change materially from 2017.

Year ended December 31, 2017 compared with Year ended December 31, 2016

Project Adjusted EBITDA increased by $1.6 million from 2016 primarily due to lower administrative expenses related to reductions in the workforce.

Consolidated Cash Flow

2018 compared to 2017

The following table reflects the changes in cash flows for the periods indicated:

Year
ended