ATLANTIC POWER CORP
Form 10-K
February 28, 2019
Table of Contents

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.

Table of Contents

TABLE OF CONTENTS

i

Table of Contents

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.

Table of Contents

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;

Table of Contents

- 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.

Table of Contents

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

Table of Contents

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

Table of Contents

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.

Table of Contents

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

Table of Contents

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 2023
Georgia	Biomass	55	100.00	%	55	Georgia Power	September 2032
Illinois	Natural Gas	177	100.00	%	100	Merchant	N/A
					77	Equistar Chemicals, LP (3)	December 2034
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 2020 (6)
New York	Hydro	60	100.00	%	60	Niagara Mohawk Power Corporation	December 2027 (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

Table of Contents

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.

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.

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.

Table of Contents

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;

Table of Contents

· 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

Table of Contents

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

Table of Contents

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_2eq") 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

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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."

Table of Contents

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;

Table of Contents

· 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 Pennslyvania 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

Table of Contents

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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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

Table of Contents

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

Table of Contents

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.

Table of Contents

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

Table of Contents

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

Table of Contents

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 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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

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.

Table of Contents

	Year Ended December 31,				
(in millions of U.S. dollars, except as otherwise stated)	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.

Table of Contents

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;

Table of Contents

- 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.

Table of Contents

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

Table of Contents

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

Table of Contents

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	

Table of Contents

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;

Table of Contents

- 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.

Table of Contents

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.

Table of Contents

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) %

Table of Contents

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

Table of Contents

- 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

Table of Contents

· 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

Table of Contents

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.

Table of Contents

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.

Table of Contents

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 %

Table of Contents

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.

Table of Contents

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.

Table of Contents

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 December 31,		
	2018	2017	Change
Net cash provided by operating activities	$ 137.5	$ 169.2	$ (31.7)
Net cash used in investing activities	(17.0)	(4.3)	(12.7)
Net cash used in financing activities	(135.0)	(178.9)	43.9

Operating Activities

Cash flow from our projects may vary from year to year based on working capital requirements and the operating performance of the projects, as well as changes in prices under PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, and the transition to merchant or re contracted pricing following the expiration of PPAs. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

For the year ended December 31, 2018, the net decrease in cash flows provided by operating activities of $31.7 million was primarily the result of the following:

· Contract expirations – the expiration of the enhanced dispatch contracts at our North Bay and Kapuskasing projects on December 31, 2017, as well as operations ceasing at our San Diego projects in February 2018, had an approximate $72 million impact on cash flows from operations;

Table of Contents

- OEFC Settlement – we received approximately $26.6 million related to our settlement with the OEFC for the year December 31, 2017 and did not receive any payments in 2018; and

- Major maintenance – a planned major maintenance outage at our Manchief project had a $5.5 million impact on cash flows from operations. Additionally, costs incurred to prepare our Tunis project for commercial operations had a $3.3 million impact on cash flows from operations.

These decreases were partially offset by increases in net cash provided by operating activities that were primarily the result of the following:

- Working capital – changes in working capital resulted in a $39.3 million increase in cash flows from operating activities primarily due to a $20.6 million decrease in working capital at our Kapuskasing, North Bay and San Diego projects, which were not in operation at December 31, 2018 but were under contract in 2017;

- Interest expense – our interest payments were $30.7 million lower than the comparable 2017 period due to lower interest rates and outstanding principal on our senior secured credit facility, the repayment of the Epsilon Power Partners term facility, in full, in the second quarter of 2018 and the repayment of Piedmont's project-level debt, in full, in the fourth quarter of 2017; and

- Distributions from unconsolidated affiliates – we received $14.3 million in higher distributions from our unconsolidated affiliates, primarily at our Orlando ($6.6 million increase), Chambers ($5.5 million increase) and Frederickson ($2.0 million increase) projects.

Investing Activities

For the year ended December 31, 2018, the net increase in cash flows used in investing activities of $12.7 million was primarily the result of the following:

- Acquisition of Koma Kulshan – we paid $12.8 million, net of cash received, to acquire an additional 0.25% ownership of Koma Kulshan in the second quarter of 2018 and the remaining 50% of Koma Kulshan in the third quarter of 2018; and

- Deposit for acquisition – we made a $2.6 million down payment for the acquisition of two biomass plants in South Carolina, which is expected to close late in the third quarter or in the fourth quarter of 2019; and

- Proceeds from sale of equity investment – in 2017, we received $1.0 million from the sale of our 17.7% equity interest in Selkirk Cogen L.P.

These increases were partially offset by the following:

· Purchases of PP&E – investments in capitalized plant additions were $3.5 million lower than 2017.

Financing Activities

For the year ended December 31, 2018, the net decrease in cash flows used in financing activities of $43.9 million was primarily the result of the following:

· Convertible debenture redemptions – we paid $88.1 million to redeem and cancel the Series C Debentures, in full, and the Series D Debentures, in part, with proceeds from the issuance of the Series E Debentures;

Table of Contents

- Common share repurchases – we paid $16.6 million in 2018 to repurchase and cancel common shares as compared to $0.2 million in 2017;

- Preferred share repurchases – we paid $8.0 million in 2018 to repurchase and cancel preferred shares as compared to $3.1 million in 2017; and

- Deferred financing costs – we incurred $5.1 million of deferred financing costs related to the issuance of the Series E Debentures in 2018.

These decreases were partially offset by the following:

- Convertible debenture issuance – we received $92.2 million from the issuance of the Series E Debentures; and

- Corporate and project-level debt repayments – we made $65.6 million of lower principal payments than 2017 primarily due to the $54.6 million payment to retire Piedmont's non-recourse project-level debt in 2017.

2017 compared to 2016

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

	Year ended December 31, 2017	2016	Change
Net cash provided by operating activities	$ 169.2	$ 112.3	$ 56.9
Net cash used in investing activities	(4.3)	(2.4)	(1.9)
Net cash used in financing activities	(178.9)	(98.6)	(80.3)

Operating Activities

Cash flow from our projects may vary from year to year based on working capital requirements and the operating performance of the projects, as well as changes in prices under PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, and the transition to merchant or re contracted pricing following the expiration of PPAs. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

For the year ended December 31, 2017, the net increase in cash flows provided by operating activities of $56.9 million was primarily the result of the following:

· OEFC Settlement – we received approximately $26.6 million related to our settlement with the OEFC for the year December 31, 2017;

· Impact of lower fuel costs and enhanced dispatch contracts in Ontario – we recorded $33.9 million of higher gross margin at North Bay, Kapuskasing and Nipigon as a result of the expiration of unfavorable gas purchase agreements in December 2016, as well as operating under the enhanced dispatch contracts in 2017;

· Operations and maintenance – we incurred $17.4 million of lower operations and maintenance costs, as a result of decreased maintenance expense at Morris and Williams Lake, which underwent outages in 2016, and at North Bay and Kapuskasing, which did not operate during 2017 due to the terms of their enhanced dispatch contracts; and

- Hydrological conditions at Curtis Palmer – higher water flows at our Curtis Palmer project had a $13.3 million impact on cash flows from operations.

These increases were partially offset by a decrease in net cash provided by operating activities that was primarily the result of the following:

- Working capital – changes in working capital resulted in a $24.3 million decrease in cash flows from operating activities as compared to 2016 primarily due to $10.5 million of timing in revenue receipts at our Kapuskasing, Nipigon and North Bay and $3.4 million decrease in prepaids, supplies and other assets;

- Hydrological conditions and maintenance outage at Mamquam – lower water flows and a forced outage at our Mamquam project had a $3.2 million impact on cash flows from operations; and

- Waste heat – lower waste heat at our Calstock project had a $2.6 million negative impact on cash flows from operations.

Investing Activities

For the year ended December 31, 2017, the net increase in cash flows used in investing activities of $1.9 million was primarily the result of the following:

- Reimbursement of construction costs – we received a reimbursement of $4.8 million in capitalized costs from the customer for a construction project at Morris in 2016.

These increases were partially offset by the following:

- Purchases of PP&E – investments in capitalized plant additions were $1.9 million lower than 2016; and

- Proceeds from sale of equity investment – we received $1.0 million from the sale of our 17.7% equity interest in Selkirk Cogen L.P.

Financing Activities

For the year ended December 31, 2017, the net increase in cash flows used in financing activities of $80.6 million was primarily the result of the following:

· The Credit Facilities – we received $231.1 million of net proceeds from issuance of the senior secured term loan in 2016 after repayment of the previous term loan;

· Corporate and project-level debt repayments – we made $69.4 million of higher principal payments than 2016 primarily due to the $54.6 million retirement of Piedmont's non-recourse project-level debt, as well as higher principal payments on our Term Loan; and

· Preferred share repurchases – we paid $3.1 million in 2017 to repurchase and cancel preferred shares.

These increases were partially offset by the following:

· Convertible debenture repayments – we paid $188.5 million to redeem and cancel convertible debentures in 2016;

Table of Contents

- Deferred financing costs – we incurred $16.2 million of deferred financing costs related to the refinancing of the senior secured credit facilities in 2016; and

- Common share repurchases – we paid $0.2 million in 2017 to repurchase and cancel common shares as compared to $19.5 million in 2016.

Liquidity and Capital Resources

	December 31, 2018	December 31, 2017
Cash and cash equivalents	$ 68.3	$ 78.7
Restricted cash	2.1	6.2
Total	70.4	84.9
Revolving credit facility availability	123.1	119.5
Total liquidity	$ 193.5	$ 204.4

Our primary source of liquidity is distributions from our projects and availability under our Revolving Credit Facility. Our liquidity depends in part on our ability to successfully enter into new PPAs at projects when PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from June 30, 2019 to March 31, 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. As a result, this may reduce the cash received from project distributions and the cash available for further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash. See "Risk Factors—Risks Related to Our Structure—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing external growth opportunities or fund our operations."

Moreover, on January 29, 2018, we closed the Series E Debentures Offering of Cdn$100 million aggregate principal amount of Series E Debentures. We also granted the underwriters the option to purchase up to an additional Cdn$15 million aggregate principal amount of Series E Debentures at any time up to 30 days after the date of closing of the Series E Debentures offering to cover over-allotments. The underwriters exercised that option, for the full Cdn$15 million aggregate principal amount, on February 2, 2018. On the initial closing date, we received net proceeds from the Series E Debentures offering, after deducting the underwriting fee and expenses, of approximately Cdn$94.7 million. We received an additional Cdn$14.4 million of net proceeds from the exercise of the over-allotment option. On March 2, 2018, we redeemed all of the $42.5 million remaining principal amount of Series C Debentures with the use of a portion of the proceeds from the Series E Debentures Offering. On March 3, 2018, we redeemed Cdn$56.2 million principal amount of the Series D Debentures with the remaining proceeds from the Series E Debentures Offering.

We expect to reinvest approximately $24.3 million in our portfolio in the form of project capital expenditures and maintenance expenses in 2019. Such investments are generally paid at the project level. See "—Capital and Maintenance

Expenditures." We also expect to pay the remaining $10.4 million of the purchase price for two biomass plants in South Carolina when the transaction closes (expected to be) late in the third quarter or the fourth quarter of 2019. The Company plans to use its liquidity to redeem the remaining Cdn$24.7 million of 6.00% Series D Debentures ($18.1 million equivalent) at or before their December 2019 maturity date. Other than these items, we do not expect any other material or unusual requirements for cash outflow in 2019 for capital expenditures or other required investments. We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due for at least the next 12 months from February 27, 2019.

Table of Contents

Repurchases of Securities

On December 31, 2018, we commenced a new NCIB for each of our Series D and Series E Debentures, our common shares and for each series of the preferred shares of APPEL, our wholly-owned subsidiary. Under the NCIBs, our broker may purchase up to 10% of the public float of our convertible debentures and common shares and up to 10% of the public float of APPEL's preferred shares, determined as of December 17, 2018, up to the following limits:

	Maturity Date	Interest Rates	Limit on Purchase (Principal Amount) Total Limit
Convertible Debenture	December 2019	6.00 %	Cdn$ 2,473,800
Convertible Debenture	January 2025	6.00 %	Cdn$ 11,500,000

	Limit on Purchase (Number of Shares) Total Limit (1)
Common Shares	10,623,464
Series 1 Preferred Shares	427,500
Series 2 Preferred Shares	233,109
Series 3 Preferred Shares	148,311

(1) Represented 10% of the public float for the Common Shares and 10% of the public float for the Preferred Shares.

The NCIBs commenced on December 31, 2018 and will expire on December 30, 2019 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the NCIBs. In certain circumstances, we may be required to suspend the NCIBs under applicable law. From December 31, 2018 through February 27, 2019, we purchased the maximum limit of 427,500 shares of Series 1 Preferred Shares, 27,777 of Series 2 Preferred Shares and the maximum limit of 148,311 Series 3 Preferred Shares at a total cost of Cdn$9.2 million. During the same period, we also repurchased and cancelled 44,390 common shares.

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.

Corporate Debt Service Obligations

The following table summarizes the maturities of our corporate debt at December 31, 2018:

	Maturity Date	Interest Rates		Remaining Principal Repayments	2019	2020	2021	2022	2023	Therea
Senior secured term loan facility(1)	April 2023	4.17 %	- 5.09 %	$ 450.0	$ 65.0	$ 105.0	$ 80.0	$ 75.0	$ 125.0	$ —
MTNs	June 2036	5.95 %		153.9	—	—	—	—	—	153
Convertible Debenture	December 2019	6.00 %		18.1	18.1	—	—	—	—	—
Convertible Debenture	January 2025	6.00 %		84.3	—	—	—	—	—	84.3
Total Corporate Debt				$ 706.3	$ 83.1	$ 105.0	$ 80.0	$ 75.0	$ 125.0	$ 238

(1) The Credit Facility contains a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of APLP Holdings Limited Partnership (“APLP Holdings”) and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP

Table of Contents

Holdings and its subsidiaries, debt service on the Credit Facilities and the 5.95% Medium Term Notes due June 23, 2036 (“MTNs”), letters of credit costs to meet the requirements of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Note that failing to meet the mandatory amortization requirements is not an event of default, but could result in APLP Holdings being unable to make distributions to Atlantic Power Corporation and Atlantic Power Preferred Equity Limited being unable to pay dividends to its shareholders. The amortization profile in the table above is based on principal payments according to the targeted principal amount described in (ii) above.

Credit Facilities

On April 13, 2016, APLP Holdings Limited Partnership (“APLP Holdings”), our wholly-owned subsidiary, entered into new Senior Secured Credit Facilities, comprising $700 million in aggregate principal amount of Senior Secured Term Loan facilities (the “Term Loans”) and $200 million in aggregate principal amount of senior secured credit facilities (the “Revolver” and together with the Term Loans, the “Credit Facilities”). At December 31, 2018, $450.0 million of the Term Loans is outstanding and letters of credit in an aggregate face amount of $76.9 million are issued (but not drawn) pursuant to the revolving commitments under the Revolver and used (i) to fund a debt service reserve in an amount equivalent to six months of debt service, and (ii) to support contractual credit support obligations of APLP Holdings and its subsidiaries and of certain other affiliates of the Company.

Borrowings under Credit Facilities are available in U.S. dollars and Canadian dollars and, at inception, bore interest at a rate equal to the Adjusted Eurodollar Rate, the Base Rate or the Canadian Prime Rate as applicable, plus an applicable margin between 4.00% and 5.00% that varied depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. In April 2017, the repricing of the Credit Facilities became effective reducing the interest rate margin on the term loan and revolver by 0.75% to LIBOR plus 4.25%. In October 2017, a second repricing reduced the interest rate margin on the Credit Facilities by another 0.75% to LIBOR plus 3.50%. In April 2018, a third repricing reduced the interest rate margin on the Credit Facilities by an additional 0.50% to LIBOR plus 3.00% and in October 2018, a fourth repricing reduced the interest rate margin on the Credit Facilities by 0.25% to LIBOR plus 2.75%. The LIBOR floor remains at 1.00%. We also extended the maturity date of the Revolver by one year through April 2022. The Term Loans mature in April 2023.

The Term Loans include a 3% original issue discount. Letters of credit are available to be issued under the Revolver until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. In addition to paying interest on outstanding principal under the Credit Facilities, APLP Holdings is required to pay a commitment fee of 0.75% times the unused commitments under the Revolver.

The Credit Facilities are secured by a pledge of the equity interests in APLP Holdings and certain of its subsidiaries, guaranties from certain of the subsidiaries of APLP Holdings (the "Subsidiary Guarantors"), a downstream guarantee from the Company, a limited recourse guaranty from Atlantic Power GP II, Inc., the entity that holds all of the equity interest in APLP Holdings, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of APLP Holdings and its subsidiaries (subject to certain exceptions), and certain other assets. The Credit Facilities also have the benefit of a debt service reserve account, which is required to be funded and maintained at the debt service reserve requirement, equal to six months of debt service. The reserve requirement is maintained utilizing a letter of credit. APLP, a wholly-owned, indirect subsidiary of the Company, is a party to an existing indenture governing its Cdn$210 million aggregate principal amount MTNs that prohibits APLP (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, APLP Holdings has granted an equal and ratable security interest in the collateral package securing the Credit Facilities in favor of the trustee under the indenture governing the MTNs for the benefit of the holders of the MTNs.

Table of Contents

The Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The negative covenants include a requirement that APLP Holdings and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 5.50:1.00 at December 2017 to 4.25:1.00 from June 30, 2020, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 3.00:1.00 at December 31, 2017 to 4.00:1.00 from June 30, 2022. In addition, the Credit Agreement includes customary restrictions and limitations on APLP Holdings' 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 certain exceptions and other customary carve-outs and various thresholds. Specifically, APLP Holdings may be restricted from making dividend payments or other distributions to Atlantic Power Corporation, and APLP and its subsidiaries may be prohibited from making dividends or distributions to Atlantic Power Preferred Equity Limited shareholders in the event of a covenant default or if APLP Holdings fails to achieve a target principal amount on the new term loan that declines quarterly based on a predetermined specified schedule.

Under the Credit Agreement, if a Change of Control (as defined in the Credit Agreement) occurs, unless APLP Holdings elects to make a voluntary prepayment of the term loans under the Credit Facilities, it 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. In addition, in the event that APLP Holdings elects to repay, prepay, refinance or replace all or any portion of the term loan facilities within six months from the repricing date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid, refinanced or replaced.

The Credit Agreement also contains a mandatory amortization feature and other mandatory prepayment provisions, including prepayments:

from the proceeds of asset sales (except from the sale proceeds of certain excluded projects), insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and

with respect to excess cash flows, to be determined by using the greater of (i) 50% of the cash flow of APLP Holdings and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP Holdings and its subsidiaries, debt service on the Credit Facilities and the MTNs, funding of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Failure to achieve the specified target principal amount for any quarter does not constitute a default by APLP Holdings.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of APLP Holdings and its subsidiaries, bankruptcy, material judgments rendered against APLP Holdings or certain of its subsidiaries, certain ERISA or regulatory events, a Change of Control of APLP Holdings (solely with respect to the Revolver), or defaults under certain guaranties and collateral documents securing the Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

Project Level Debt Service Obligations

Project level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The following table summarizes the maturities of project level debt. The amounts represent our

Table of Contents

share of the non recourse project level debt balances at December 31, 2018. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. All project level debt is non recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. See Note 12, Long term debt. 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.

Non Recourse Debt

The range of interest rates presented represents the rates in effect at December 31, 2018. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

	Maturity Date	Range of Interest Rates	Total Remaining Principal Repayments	2019	2020	2021	2022	2023	Thereafter
Consolidated Projects:									
Cadillac	August 2025	6.10 % - 6.34 %	$ 21.0	$ 3.1	$ 3.1	$ 2.7	$ 3.3	$ 3.3	$ 5.5
Total Consolidated Projects			21.0	3.1	3.1	2.7	3.3	3.3	5.5
Equity Method Projects:									
Chambers(1)	December 2019 and 2023	4.50 % - 5.00 %	42.9	5.2	7.8	8.8	10.1	10.1	0.9
Total Equity Method Projects			42.9	5.2	7.8	8.8	10.1	10.1	0.9
Total Project-Level Debt			$ 63.9	$ 8.3	$ 10.9	$ 11.5	$ 13.4	$ 13.4	$ 6.4

(1) In June 2014, Chambers refinanced its project debt and issued (i) Series A (tax exempt) Bonds due December 2023, of which our proportionate share is $41.3 million, and (ii) Series B (taxable) Bonds due December 2019, of which our proportionate share is $1.6 million. The above table does not include our $4.2 million proportionate share of issuance premiums.

Preferred shares issued by a subsidiary company

In 2007, a subsidiary acquired in our acquisition of the Partnership issued 5.0 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Shares") priced at Cdn$25.00 per share. Cumulative dividends are payable on a quarterly basis at the annual rate of Cdn$1.2125 per share. Beginning on June 30, 2012, the Series 1 Shares were redeemable by the subsidiary company at Cdn$26.00 per share, declining by Cdn$0.25 each year to Cdn$25.00 per share on or after June 30, 2016, plus, in each case, an amount equal to all accrued and unpaid dividends thereon.

In 2009, a subsidiary company acquired in our acquisition of the Partnership issued 4.0 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the "Series 2 Shares") priced at Cdn$25.00 per share. The Series 2 Shares pay fixed cumulative dividends of Cdn$1.75 per share per annum, as and when declared, for the initial five year period ending December 31, 2014. The dividend rate was reset on December 31, 2014 and will reset every five years thereafter at a rate equal to the sum of the then five year Government of Canada bond yield and 4.18%. On December 31, 2014 and on December 31 every five years thereafter, the Series 2 Shares were and will be redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all declared and unpaid dividends thereon to, but excluding the date fixed for redemption. The holders of the Series 2 Shares had and will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the "Series 3 Shares") of the subsidiary, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the subsidiary, at a rate equal to the sum of the then 90 day Government of Canada Treasury bill rate and 4.18%. On December 31, 2014, 1,661,906 of Series 2 shares were converted to Series 3 shares.

The Series 1 Shares, the Series 2 Shares and the Series 3 Shares are fully and unconditionally guaranteed by us and by the Partnership on a subordinated basis as to: (i) the payment of dividends, as and when declared; (ii) the payment of amounts due on a redemption for cash; and (iii) the payment of amounts due on the liquidation, dissolution or winding up of the subsidiary company. If, and for so long as, the declaration or payment of dividends on the Series 1

Table of Contents

Shares, the Series 2 Shares or the Series 3 Shares is in arrears, the Partnership will not make any distributions on its limited partnership units and we will not pay any dividends on our common shares.

The subsidiary company paid aggregate dividends of $8.3 million and $8.7 million on Series 1 Shares, Series 2 Shares and Series 3 Shares for the years ended December 31, 2018 and 2017, respectively.

Capital and Maintenance Expenditures

Capital expenditures and maintenance expenses for the projects are generally paid at the project level using project cash flows and project reserves. Therefore, the distributions that we receive from the projects are made net of capital expenditures needed at the projects. The operating projects which we own consist of large capital assets that have established commercial operations. On going capital expenditures for assets of this nature are generally not significant because most major expenditures relate to planned repairs and maintenance and are expensed when incurred.

We expect to reinvest approximately $24.3 million in 2019 in our portfolio in the form of project capital expenditures and maintenance expenses. As explained above, these investments are generally paid at the project level. We believe one of the benefits of our diverse fleet is that plant overhauls and other major expenditures do not occur in the same year for each facility. Recognized industry guidelines and original equipment manufacturer recommendations provide a source of data to assess maintenance needs. In addition, we utilize predictive and risk based analysis to refine our expectations, prioritize our spending and balance the funding requirements necessary for these expenditures over time. Future capital expenditures and maintenance expenses may exceed the projected 2019 level as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

We invested approximately $35.2 million of project capital expenditures and maintenance expenses for the year ended December 31, 2018. In all cases, scheduled maintenance outages during the year ended December 31, 2018 occurred at such times that did not adversely impact the facilities' availability requirements under their respective PPAs.

Restricted Cash

At December 31, 2018, restricted cash totaled $2.1 million as compared to $6.2 million as of December 31, 2017.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations as of December 31, 2018:

	Payment Due by Period Less than 1 year	1-3 Years	3-5 Years	Thereafter	Total
Long-term debt including estimated interest(1)	$ 125.4	$ 251.1	$ 246.3	$ 368.4	$ 991.2
Operating leases	0.6	0.6	0.4	—	1.6
Operations and maintenance commitments	0.4	0.8	0.3	—	1.5
Fuel purchase and transportation obligations	7.5	8.4	5.1	—	21.0
Other liabilities	1.6	0.3	—	4.0	5.9
Total contractual obligations	$ 135.5	$ 261.2	$ 252.1	$ 372.4	$ 1,021.2

(1) Debt represents our proportionate share of project long term debt and corporate level debt. Project debt is non recourse to us and is generally amortized during the term of the respective revenue generating contracts of the projects. The range of interest rates on long term consolidated project debt at December 31, 2018 was 4.17% to 6.37%.

Guarantees

We and our subsidiaries entered into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchases and sale agreements, joint

Table of Contents

venture agreements, operation and maintenance agreements, fuel purchase and transportation agreements and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for certain tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

Off Balance Sheet Arrangements

As of December 31, 2018, we had no off balance sheet arrangements as defined in Item 303(a)(4) of Regulation S K.

Critical Accounting Policies and Estimates

Accounting standards require information be included in financial statements about the risks and uncertainties inherent in significant estimates, and the application of GAAP involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates, and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining the useful lives and recoverability of property, plant and equipment and PPAs, the recoverability of equity investments, the recoverability of goodwill, the recoverability of deferred tax assets, the fair value of our derivatives instruments, and fair values of acquired assets.

For a summary of our significant accounting policies, see Note 2 to the consolidated financial statements. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others; these policies are discussed below.

Long-lived asset impairment

Long lived assets, such as property, plant and equipment, and other intangible assets subject to depreciation and amortization, are reviewed for impairment annually or whenever events or changes in circumstances indicate that the carrying amount of an asset group may not be recoverable. Examples of such indicators include, among other factors, a significant decrease in the market price of a long-lived asset, adverse business climate, current period loss combined with a history of losses or the projection of future losses, and a change in our intent to hold or a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life. We also review a project for impairment at the earlier of executing a new PPA (or other arrangement) or six months prior to the expiration of an existing PPA. Factors such as the business climate, including current energy and market conditions, environmental regulation, the condition of assets, and the ability to secure new PPAs are considered when evaluating long lived assets for impairment.

Recoverability of assets to be held and used is measured by a comparison of the carrying amount of the asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of the asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds its fair value. Our asset groups have been determined to be at the plant level, which is the lowest level in which independent, separately identifiable cash flows have been identified.

The valuation of long-lived assets is considered a level 3 fair value measurement, which means that the valuation of the assets and liabilities reflect management’s own judgments regarding the assumptions market participants

Table of Contents

would use in determining the fair value of the assets and liabilities. Fair value determinations require considerable judgment and are sensitive to changes in these underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of an impairment test will prove to be accurate predictions of the future. Examples of events or circumstances that could reasonably be expected to negatively affect the underlying key assumptions and ultimately impact the estimated fair value of our asset groups may include macroeconomic factors that significantly differ from our assumptions in timing or degree, increased input costs such as higher fuel prices and maintenance costs, or lower power prices than incorporated in our long term forecasts. See "Risk Factors—Risks Related to Our Business and Our Projects—Impairment of goodwill or long lived assets could have a material adverse effect on our business, results of operations and financial condition".

We did not record any long-lived asset impairments in 2018. Previously, we recorded long-lived asset impairments of $29.1 million, $22.5 million, $21.2 million and $13.5 million, respectively at our Williams Lake, Naval Station, North Island and Naval Training Center reporting units in the year ended December 31, 2017. We also recorded long-lived asset impairments of $3.8 million and $2.1 million, respectively, at our North Bay and Kapuskasing reporting units in the year ended December 31, 2016. See Item 15 — Note 8, Goodwill and long-lived asset impairment for discussion of these impairments.

Equity method investment impairment – other than temporary

Investments in and the operating results of 50% or less owned entities not consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. The standard for determining whether an impairment must be recorded is whether a decline in the value is considered an other-than-temporary decline in value. The evaluation and measurement of impairments for our equity method investments involves the same uncertainties as described for long-lived assets. Similarly, these estimates are subjective, and the impact of variations in these estimates could be material. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment or, where applicable, estimated sales proceeds that are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long term investments. Therefore, we complete our assessments with a long term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

We did not record any equity method investment impairments in 2018. We previously recorded equity method investment impairments of $47.1 million, $28.3 million and $10.1 million, respectively, at our Chambers, Frederickson and Selkirk projects in the year ended December 31, 2017. See Item 15 — Note 6, Equity method investments in unconsolidated affiliates for discussion of these impairments.

Goodwill

Goodwill is not amortized. Instead, it is reviewed for impairment annually (in the fourth quarter) or more frequently if indicators of impairment exist. A significant amount of judgment is involved in determining if an indicator of impairment has occurred. Such indicators may include a prolonged decline in our market capitalization, deterioration in general economic conditions, adverse changes in the market in which a reporting unit operates, decreases in energy or capacity revenues as the result of re contracting or increases in input costs that have a negative effect on earnings and cash flows, or a trend of negative or declining cash flows over multiple periods, among others. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill. Our goodwill is allocated among and evaluated for impairment at the reporting unit level, which is one level below our operating segments.

We apply a standard that provides an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of a reporting unit is less than its carrying amount. These factors include an assessment of macroeconomic and

Table of Contents

industry conditions, market events and circumstances as well as the overall financial performance of our reporting units. For our 2018 test, we performed qualitative assessments at our Morris and Nipigon reporting units. We performed quantitative tests these reporting units in the years ended December 31, 2017 and 2016.

Under the quantitative impairment test, the evaluation of impairment involves comparing the current fair value of each reporting unit to its carrying value, including goodwill. In January 2017, the FASB issued authoritative guidance, which removed the requirement to perform a hypothetical purchase price allocation to measure goodwill impairment. Under this guidance, goodwill impairment is measured as the amount by which a reporting unit's carrying value exceeds its fair value, not to exceed the carrying amount of goodwill. We early adopted this guidance for our annual goodwill impairment test conducted at November 30, 2017.

We determine the fair value of our reporting units using an income approach with discounted cash flow ("DCF") models, as we believe forecasted cash flows are the best indicator of such fair value. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including assumptions about discount rates, projected merchant power prices, generation, fuel costs and capital expenditure requirements. The undiscounted and discounted cash flows utilized in our goodwill impairment tests for our reporting units are generally based on approved reporting unit operating plans for years with contracted PPAs and historical relationships for estimates at the expiration of PPAs. All cash flow forecasts from DCF models utilize estimated plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. We used historical experience to determine estimated future capital investment requirements. The discount rate applied to the DCF models represents the weighted average cost of capital ("WACC") consistent with the risk inherent in future cash flows of the particular reporting unit and is based upon an assumed capital structure, cost of long term debt and cost of equity consistent with comparable independent power producers. The betas used in calculating the WACC rate were obtained from reputable third party sources. We utilized the assistance of valuation experts to perform quantitative impairment tests for several of our reporting units. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill.

We did not record any goodwill impairments in 2018. We previously recorded a goodwill impairment of $14.7 million at our Curtis Palmer reporting unit in the year ended December 31, 2017. We also recorded goodwill impairments of $50.2 million, $15.4 million, $6.7 million, $6.5 million and $1.2 million, respectively, at our Mamquam, Curtis Palmer, Kapuskasing, North Bay and Moresby Lake reporting units in the year ended December 31, 2016. See Item 15 — Note 9, Goodwill and long-lived asset impairment for discussion of these impairments.

Fair value of derivatives

We utilize derivative contracts to mitigate our exposure to fluctuations in fuel commodity prices and foreign currency rates and to balance our exposure to variable interest rates. We believe that these derivatives are generally effective in realizing these objectives. We also enter into long-term fuel purchase agreements accounted for as derivatives that do not meet the scope exclusion for normal purchase or normal sales.

In determining fair value for our derivative assets and liabilities, we generally use the market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about market risk and/or the risks inherent in the inputs to the valuation techniques.

A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. Our derivative interest rate swap, fuel purchase agreements and fuel swaps are classified as Level 2. The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified with market data and valuation techniques do not involve significant judgment. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk free interest rate. We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. The conversion option derivative for the Series E Debentures is classified within Level 3 of the fair value hierarchy. The significant unobservable inputs used in

Table of Contents

developing fair value include the volatility of our common shares and the fair value of the host contract, which is derived from recent similar convertible debenture offerings from peer companies. A discounted cash flow valuation technique is utilized to calculate to fair value of the conversion option derivative.

Certain derivative instruments qualify for a scope exception to fair value accounting, as they are considered normal purchases or normal sales. The availability of this exception is based upon the assumption that we have the ability and it is probable to deliver or take delivery of the underlying physical commodity. Derivatives that are considered to be normal purchases and normal sales are exempt from derivative accounting treatment and are recorded as executory contracts.

Acquired assets

When we acquire a business, a portion of the purchase price is typically allocated to identifiable assets, such as property, plant and equipment, PPAs or fuel supply agreements. Fair value of these assets is determined primarily using the income approach, which requires us to project future cash flows and apply an appropriate discount rate. We amortize tangible and intangible assets with finite lives over their expected useful lives. Our estimates are based upon assumptions believed to be reasonable, but which are inherently uncertain and unpredictable. Assumptions may be incomplete or inaccurate, and unanticipated events and circumstances may occur. Incorrect estimates and assumptions could result in future impairment charges, and those charges could be material to our results of operations.

Income taxes and valuation allowance for deferred tax assets

In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the United States and in Canada at each of our legal tax-paying entities and available tax planning strategies. The valuation allowance is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards at specific legal tax-paying entities without sufficient projected future taxable income to utilize the net operating losses. As of December 31, 2018, we have recorded a valuation allowance of $139.7 million.

Recent Accounting Developments

See Item 15 — Note 2, Summary of Significant Accounting Policies, to the consolidated financial statements for a discussion of recent accounting developments.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates and commodity prices, will affect our cash flows or the value of our holdings of financial instruments. The objective of market risk management is to minimize the impact that market risks have on our cash flows as described in the following paragraphs.

Our market risk sensitive instruments and positions have been determined to be “other than trading.” Our exposure to market risk as discussed below includes forward looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in fuel and electricity commodity prices, currency exchange rates or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in fuel commodity prices, currency exchange rates or interest rates and the timing of transactions. See Note 15, Accounting for derivative instruments and hedging activities for additional information.

Table of Contents

Fuel Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity, natural gas, biomass and coal 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." We often employ (i) tolling structures, whereby an offtaker is responsible for fuel procurement, (ii) long term fuel contracts, where we lock in a set quantity of fuel at a predetermined price or (iii) pass through arrangements, whereby the cost of fuel is borne by the ultimate offtaker. The combination of long term energy sales and fuel purchase agreements is generally designed to mitigate the impacts to cash flows of changes in commodity prices by passing through changes in fuel prices to the buyer of the energy.

Natural Gas

Our strategy to mitigate future exposure to changes in natural gas prices at our projects consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

Our 50%-owned Orlando project is exposed to changes in natural gas prices. We have entered into various natural gas swaps to effectively fix the price of 16.3 million MMBtu of future natural gas purchases at Orlando, which is approximately 100% of our projected gas consumption through 2022. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2018. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations. Because we have fixed the price of approximately 100% of our projected gas consumption, Orlando is not exposed to changes in the price of natural gas through 2022.

Nipigon operates under a long-term enhanced dispatch agreement through December 2022. Under the terms of the agreement, the project resells its contracted firm fixed price gas at market prices and credits the proceeds to a savings pool shared by Nipigon and the offtaker. As a result of selling the gas at market prices, Nipigon is exposed to changes in the price of natural gas. A $1.00/GJ change in the price of natural gas would have a $1.2 million impact on Nipigon based on planned 2019 natural gas sales.

Biomass

Biomass suppliers are generally small companies and unwilling or unable to enter into long-term contracts at a fixed price, volume or term. At some plants, a significant portion of the cost of biomass fuel consists of the price of diesel fuel used in forestry operations and over the road transportation of the fuel to the projects. A decline in major industries such as pulp, paper and lumber can have a negative effect on the available biomass supply. Reduction in volumes from the forestry sector can also impact availability and price.

Our Cadillac project does not have a long-term biomass fuel contract. A 10% per Ton change from our budgeted wood waste cost at Cadillac would have an estimated $0.2 million total impact on forecasted cash distributions in 2019 based on planned operations.

Our Piedmont project does not have a long-term biomass fuel contract. A 10% per Ton change from our budgeted wood waste cost at Piedmont would have an estimated $1.2 million total impact on forecasted cash distributions in 2019 based on planned operations.

Our Calstock project has six fuel suppliers, three of which provide up to 65% of its fuel requirements and are under contract to provide fuel, with a tipping fee through 2019. We are exposed to the remaining 35% of the project's estimated fuel requirements. A 10% per Ton change from our budgeted wood waste costs at Calstock would have an estimated $0.2 million impact on forecasted cash distributions in 2019 based on planned operations.

Table of Contents

Our Williams Lake project does not have a long-term biomass fuel contract. A 10% per Ton change from our budgeted wood waste cost at Williams Lake would have an estimated $0.5 million total impact on forecasted cash distributions in 2019 based on planned operations.

Coal

Our 40%-owned Chambers project is exposed to changes in coal prices. For 2019, we forecasted an average coal price of $98 per Ton. A 10% change from our forecasted price would impact cash distributions from Chambers by an estimated $1.2 million for 2019 based on planned operations.

Electricity Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity prices when our projects operate with no PPA or at projects that operate with PPAs that are based on spot market pricing. Our most significant exposure to market power prices is at the Chambers and Morris projects.

At our 40%-owned Chambers project, plant capacity is sold forward pursuant to the power purchase agreement with our utility customer. However, 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. In 2019, projected cash distributions from Chambers would change by approximately $0.7 million per 10% change in the PJM East spot price of electricity.

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. In 2019, projected cash distributions from Morris would change by approximately $0.6 million per 10% change in the spot price of electricity based on the forecasted level of approximately 200,000 MWh of grid sales and all other variables being held constant.

When a PPA expires or is terminated, it is possible that the price received by the project for power under subsequent arrangements may be reduced and in some cases, significantly. Our projects may not be able to secure a new agreement and could be exposed to sell power at spot market price. 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.” It is possible that subsequent PPAs or the spot market may not be available at prices that permit the operation of the project on a profitable basis. If this occurs, the affected project may temporarily or permanently cease operations.

Foreign Currency Exchange Risk

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates as we generate cash flow in U.S. dollars and Canadian dollars. We currently have Canadian dollar payment obligations for preferred dividends, interest on our Canadian dollar-denominated convertible debentures and our Medium Term Notes. Principal and interest payments for our senior secured term loans as well as our U.S. dollar-denominated convertible debenture are made in U.S. dollars. From time to time we will implement a hedging strategy for the purpose of mitigating the currency risk impact on the future interest and principal payments, preferred dividends and other working capital requirements. Currently, we expect Canadian dollar cash flows to exceed our Canadian dollar obligations in the upcoming years and, accordingly, have not entered into any currency hedge positions.

Table of Contents

The following table contains the components of recorded foreign exchange (gain) loss for the years ended December 31, 2018, 2017, and 2016:

	Year Ended December 31,		
	2018	2017	2016
Unrealized foreign exchange (gain) loss:			
Convertible debentures, corporate debt, and other	$ (22.2)	$ 15.1	$ 13.8
Foreign currency forwards	0.1	0.1	—
	(22.1)	15.2	13.8
Realized foreign exchange loss (gain)	(0.7)	1.1	0.1
	$ (22.8)	$ 16.3	$ 13.9

A 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar would have a $25.6 million impact on the carrying value of our corporate debt and convertible debentures denominated in Canadian dollars at December 31, 2018.

Interest Rate Risk

Changes in interest rates impact 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 variable rates or is not financially hedged through the use of interest rate swaps. After considering the impact of interest rate swaps described below, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest expense at equity investments, by approximately $0.3 million at December 31, 2018.

The Partnership

APLP Holdings has entered into several interest rate swap agreements to mitigate its exposure to changes in the Adjusted Eurodollar Rate. At December 31, 2018, these agreements totaled $421.5 million notional amount of the remaining $450.0 million aggregate principal amount of borrowings under the senior secured term loan facility. These interest rate swap agreements expire at various dates through March 31, 2020. Borrowings under the Term Loan Facility bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 2.75%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00%, resulting in a minimum of a 3.75% all-in rate on the Term Loan Facility for the non-swapped portion of the remaining principal amount. The weighted average rate of these swap agreements is 1.27%, resulting in an all-in rate of approximately 4.02% for $421.5 million of the Term Loan Facility. In January 2018, APLP Holdings entered into additional interest rate swap agreements. For the period beginning September 30, 2018 through September 30, 2019, we mitigated exposure to changes in interest rates for $100 million notional amount at a one-month LIBOR fixed rate of 2.18% and for the period beginning October 1, 2019 through December 31, 2020, for $200 million notional amount at a one-month LIBOR fixed rate of 2.42%.

Cadillac

We have an interest rate swap at our consolidated Cadillac project to economically fix its exposure to changes in interest rates related to the variable rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project level Cadillac debt and changes in its fair market value are recorded in other comprehensive loss (“OCL”). The interest rate swap expires on September 30, 2025.

In accounting for the cash flow hedge, gains and losses on the derivative contract are reported in OCL, but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net loss. That is, for a cash flow hedge, all effective components of the derivative contract’s gains and losses are recorded in OCL, pending occurrence of the expected transaction. OCL consists of those financial items that are included in “Accumulated other comprehensive loss” in our accompanying consolidated balance sheets but not included in our net loss. Thus, in highly effective cash flow hedges, where there is no ineffectiveness, OCL changes by exactly as much as the derivative contracts and there is no impact on net loss until the expected transaction occurs.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our consolidated financial statements are appended to the end of this Annual Report on Form 10 K, beginning on page F 1.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a)Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have evaluated the company’s disclosure controls and procedures, as defined in Rules 13a 15(e) and 15d 15(e) of the Exchange Act, as of the end of the period covered by this report, and have concluded that these controls and procedures were effective.

Our management, including our Chief Executive Officer and our Chief Financial Officer, concluded that the consolidated financial statements in this Annual Report on Form 10-K fairly present, in all material respects, the Company's financial condition, results of operations and cash flows for the periods presented, in conformity with GAAP.

(b)Management’s Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a 15(f) and 15d 14(f) under the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2018 using the criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (“COSO”).

Based on our evaluation under the COSO framework, management has concluded that our internal control over financial reporting is effective as of December 31, 2018 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Because of their inherent limitations, our disclosure controls and procedures and our internal control over financial reporting may not prevent errors or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to risks, including that the controls may become inadequate because of changes in conditions or that the degree of compliance with our policies or procedures may deteriorate.

The effectiveness of our internal control over financial reporting as of December 31, 2018 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 15 of this annual report Form 10 K on page F-2.

(c)Changes in Internal Control over Financial Reporting

There has been no change in our internal control over financial reporting during the fourth fiscal quarter ended December 31, 2018 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Table of Contents

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information concerning our directors and executive officers required by Item 10 will be included in the Proxy Statement and is incorporated herein by reference.

We have adopted a code of ethics that applies to directors, managers, officers and employees. This code of ethics, titled "Code of Business Conduct and Ethics," is posted on our website. The internet address for our website is www.atlanticpower.com, and the "Code of Business Conduct and Ethics" may be found from our main Web page by clicking first on "About Us" and then on "Code of Conduct."

We intend to satisfy any disclosure requirement under Item 5.05 of Form 8 K regarding an amendment to, or waiver from, a provision of the "Code of Business Conduct and Ethics" by posting such information on our website, on the Web page found by clicking through to "Conduct of Conduct" as specified above.

ITEM 11. EXECUTIVE COMPENSATION

The information concerning our directors and executive officers required by Item 11 will be included in the Proxy Statement and is incorporated herein by reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information concerning security ownership and other matters required by Item 12 will be included in the Proxy Statement and is incorporated herein by reference.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information concerning certain relationships and related transactions required by Item 13 will be included in the Proxy Statement and is incorporated herein by reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information concerning principal accountant fees and services required by Item 14 will be included in the Proxy Statement and is incorporated herein by reference.

Table of Contents

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

See “Index to Consolidated Financial Statements” on page F 1 of this Annual Report on Form 10 K.

(a)(2) Financial Statement Schedules

See “Index to Consolidated Financial Statements” on page F 1 of this Annual Report on Form 10 K. Schedules other than that listed have been omitted because of the absence of the conditions under which they are required or because the information required is shown in the consolidated financial statements or the notes thereto.

(a)(3) Exhibits

EXHIBIT INDEX

Exhibit No.	Description
2.1	Plan of Arrangement of Atlantic Power Corporation, dated as of November 24, 2005
2.2	Arrangement Agreement, dated as of June 20, 2011, among Capital Power

	Income L.P., CPI Income Services Ltd., CPI Investments Inc. and Atlantic Power Corporation
3.1	Articles of Continuance of Atlantic Power Corporation, dated as of June 29, 2010
4.1	Form of common share certificate
4.2	Trust Indenture, dated as of October 11, 2006 between Atlantic Power Corporation and Computershare Trust Company of Canada
4.3	First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Secured Debentures, dated November 27, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada
4.4	Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of

	December 17, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada
4.5	Form of First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, between Atlantic Power Corporation and Computershare Trust Company of Canada
4.6	Second Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated July 5, 2012, between Atlantic Power Corporation and Computershare Trust Company of Canada
4.7	Third Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated August 17,

	2012, between Atlantic Power Corporation and Computershare Trust Company of Canada
4.8	Fourth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of November 29, 2012, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A.
4.9	Fifth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 11, 2012, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A.
4.10	Sixth Supplemental Indenture to the

Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of March 22, 2013, among Atlantic Power Corporation and Computershare Trust Company of Canada

81

Table of Contents

Exhibit No.	Description
4.11	Seventh Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of January 29, 2018, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A.
4.12	Indenture, dated as of November 4, 2011, by and among Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association
4.13	First Supplemental Indenture, dated as of November 5, 2011, by and among the New Guarantors signatory thereto, Atlantic Power Corporation, the Existing Guarantors named therein and Wilmington Trust, National Association
4.14	Second Supplemental Indenture, dated as of November 5, 2011, by and among

	Curtis Palmer LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association
4.15	Third Supplemental Indenture, dated as of February 22, 2012, by and among Atlantic Oklahoma Wind, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association
4.16	Fourth Supplemental Indenture, dated as of August 3, 2012, by and among Atlantic Rockland Holdings, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association
4.17	Fifth Supplemental Indenture, dated as of November 29, 2012, by and among Atlantic Ridgeline Holdings, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association
4.18	Sixth Supplemental Indenture, dated as of January 29,

	2013, by and among the New Guarantors named therein, Atlantic Power Corporation, the Existing Guarantors named therein and Wilmington Trust, National Association
4.19	Registration Rights Agreement, dated as of November 4, 2011, by and among, Atlantic Power Corporation, the Guarantors listed on Schedule A thereto and Morgan Stanley & Co. LLC and TD Securities (USA) LLC, as representatives of the several Initial Purchasers
4.20	Shareholder Rights Plan Agreement, dated effective as of February 28, 2013, between Atlantic Power Corporation and Computershare Investor Services, Inc., which includes the Form of Right Certificate as Exhibit A
4.21	Advance Notice Policy, dated April 1, 2013
10.1	Credit and Guaranty Agreement, dated as of February 24, 2014, among Atlantic Power Limited Partnership, as Borrower, Certain Subsidiaries of

	Atlantic Power Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of American, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Joint Lead Arrangers and Joint Bookrunners, Union Bank, N.A. and RBC Capital Markets, as Revolver Joint Lead Arrangers and Revolver Joint Bookrunners, Union Bank, N.A. and Royal Bank of Canada, as Revolver Co Documentation Agents, and Goldman Sachs Lending Partners LLC, as Administrative Agent and Collateral Agent
10.2	Second Amended and Restated Credit Agreement dated August 2, 2013, as amended, among Atlantic Power Corporation, Atlantic Power

	Generation, Inc. and Atlantic Power Transmission, Inc., the Lenders signatory thereto and Bank of Montreal, as Administrative Agent
10.3	Consent, dated as of November 19, 2012, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc. the Lenders signatory thereto and Bank of Montreal, as Administrative Agent
10.4	Consent and Release, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., the Subsidiaries signatory thereto, the Lenders signatory thereto and Bank of Montreal, as Administrative Agent and Collateral Agent

Table of Contents

Exhibit No.	Description
10.5	Modification and Joinder Agreement, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Ridgeline Energy LLC, PAH RAH Holding Company LLC, Ridgeline Eastern Energy LLC, Ridgeline Energy Solar LLC, Lewis Ranch Wind Project LLC, Hurricane Wind LLC, Ridgeline Power Services LLC, Ridgeline Energy Holdings, Inc., Ridgeline Alternative Energy LLC, Frontier Solar LLC, PAH RAH Project Company LLC, Monticello Hills Wind LLC, Dry Lots Wind LLC, Smokey Avenue Wind LLC, Saunders Bros. Transportation Corporation, Bruce Hill Wind LLC, South Mountain Wind LLC, Great Basin Solar Ranch LLC, Goshen Wind Holdings LLC, Meadow Creek Holdings LLC, Ridgeline Holdings Junior Inc., Rockland

	Wind Ridgeline Holdings LLC, Meadow Creek Intermediate Holdings LLC and the other Subsidiaries party thereto in favor of Bank of Montreal, as Administrative Agent
10.6+	Employment Agreement, dated April 15, 2013, between Atlantic Power Corporation and Terrence Ronan
10.7+	Addendum to Executive Employment Agreements of each of Terrence Ronan and Edward Hall, dated August 30, 2013
10.8+	Deferred Share Unit Plan, dated as of April 24, 2007 of Atlantic Power Corporation
10.9+	Third Amended and Restated Long Term Incentive Plan
10.10+	Fourth Amended and Restated Long Term Incentive Plan
10.11+	Fifth Amended and Restated Long Term Incentive Plan
10.12+	Amendment No. 1 to the Fifth Amended and Restated Long Term Incentive Plan of the Company
10.13	Termination of the Operating Agreement of Canadian Hills Wind, LLC, dated as of December 28, 2012
10.14	Purchase and sale agreement, dated as of January 30, 2013

	among Quantum Lake LP, LLC, Quantum Lake GP, LLC, Quantum Pasco LP, LLC, Quantum Pasco GP, LLC, Quantum Auburndale LP, LLC and Quantum Auburndale GP, LLC (as Buyers) and Lake Investment, LP, NCP Lake Power, LLC, Teton New Lake, LLC, NCP Dadee Power, LLC, Dade Investment, LP, Auburndale, LLC and Auburndale GP, LLC (as Sellers)
10.15	Agreement dated November 24, 2014, by and among Clinton Group and the Company
10.16+	Employment Agreement among the Company, Atlantic Power Services, LLC and James J. Moore, Jr., dated January 22, 2015
10.17+	Transition Equity Grant Participation Agreement between Atlantic Power Services, LLC and James J. Moore, Jr., dated January 22, 2015
10.18	Membership Interest Purchase Agreement by and between Atlantic Power Transmission, Inc. and Terraform AP Acquisition Holdings, LLC dated as of March 31, 2015

10.19	Guaranty Agreement by Atlantic Power Corporation in favor of Terraform AP Acquisition Holdings, LLC, dated as of March 31, 2015
10.20	Agreement dated May 21, 2015, by and among Mangrove Partners and the Company
10.21	Amendment No.1 to Membership Interest Purchase Agreement, dated June 3, 2015
10.22+	Employment Agreement among the Company, Atlantic Power Services, LLC and Joseph E. Cofelice, dated September 15, 2015
10.23	Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs

	Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners
10.24	Securities Pledge Agreement, dated as of April 13, 2016, among Atlantic Power Corporation, Atlantic Power GP II, Inc. and Goldman Sachs Lending Partners LLC as Collateral Agent

Table of Contents

Exhibit No.		Description
10.25		Amendment dated April 17, 2017 to the Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners
10.26		Second Amendment dated October 18, 2017 to the Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners
10.27		Amendment to Employment Agreement, by and among Atlantic Power Services, LLC, the Company and Joseph Cofelice, dated as of February 27, 2018
10.28		Amendment No. 2 to the Fifth Amended and Restated Long-Term Incentive Plan of the Company
10.29	*+	Sixth Amended and Restated Long Term Incentive Plan
10.30	*+	Amendment to Transition Equity Grant Participation Agreement between Atlantic Power Services, LLC and James J. Moore, Jr., dated as of January 23, 2019
10.31	*+	Form of Legacy Award Amendment
16.1		Letter from KPMG LLP, Chartered Accountants, to the Securities and Exchange Commission, dated August 10, 2010
21.1*		Subsidiaries of Atlantic Power Corporation
23.1*		Consent of KPMG LLP
31.1*		Certification of Chief Executive Officer pursuant to Rule 13a 14(a)/15d 14(a) under the Exchange Act
31.2*		Certification of Chief Financial Officer pursuant to Rule 13a 14(a)/15d 14(a) under the Exchange Act
32.1**		Certification of the Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002
32.2**		Certification of the Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes Oxley Act of 2002
101*		The following materials from our Annual Report on Form 10 K for the year ended December 31, 2018 formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Shareholders' Equity, (iv) the Consolidated Statements of Cash Flows, and (v) related notes to these financial statements

+ Indicates management contract or compensatory plan or arrangement.

* Filed herewith.

** Furnished herewith.

(b) Exhibits:

See Item 15(a)(3) above.

Table of Contents

(c) Financial Statement Schedules:

See Item 15(a)(2) above.

ITEM 16. FORM 10-K SUMMARY.

None.

Table of Contents

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 28, 2019	Atlantic Power Corporation
	By: /s/ Terrence Ronan
	Name: Terrence Ronan
	Title: Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ James J. Moore, JR. James J. Moore, Jr.	President, Chief Executive Officer and Director (principal executive officer)	February 28, 2019
/s/ Terrence Ronan Terrence Ronan	Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)	February 28, 2019
/s/ Irving R. Gerstein Irving R. Gerstein	Chairman of the Board	February 28, 2019
/s/ R. Foster Duncan R. Foster Duncan	Director	February 28, 2019
/s/ Kevin T. Howell Kevin T. Howell	Director	February 28, 2019
/s/ Danielle S. Mottor Danielle S. Mottor	Director	February 28, 2019
/s/ Gilbert S. Palter Gilbert S. Palter	Director	February 28, 2019

Table of Contents

Atlantic Power Corporation

Index to Consolidated Financial Statements

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors

Atlantic Power Corporation:

Opinion on the Consolidated Financial Statements

We have audited the accompanying consolidated balance sheets of Atlantic Power Corporation and subsidiaries (the Company) as of December 31, 2018 and 2017, and the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three year period ended December 31, 2018, and the related notes and financial statement schedules I to II (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the years in the three year period ended December 31, 2018, in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States)(PCAOB), the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 28, 2019 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

Basis for Opinion

These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud. Our audit included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. We believe that our audits provide a reasonable basis for our opinion.

/s/ KPMG LLP

We have served as the Company's auditor since 2010.

New York, New York

February 28, 2019

F-2

Table of Contents

Report of Independent Registered Public Accounting Firm

To the Shareholders and Board of Directors

Atlantic Power Corporation:

Opinion on Internal Control over Financial Reporting

We have audited Atlantic Power Corporation and subsidiaries' (the Company) internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control—Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. In our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control – Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States) (PCAOB), the consolidated balance sheets of the Company as of December 31, 2018 and 2017, the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2018, and the related notes and financial statement schedules I to II (collectively, the consolidated financial statements) and our report dated February 28, 2019 expressed an unqualified opinion on those consolidated financial statements.

Basis for Opinion

The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit. We are a public accounting firm registered with the PCAOB and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audit in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

Definitions and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company’s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ KPMG LLP

New York, New York

February 28, 2019

Table of Contents

ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in millions of U.S. dollars)

	December 31, 2018	2017
Assets		
Current assets:		
Cash and cash equivalents	$ 68.3	$ 78.7
Restricted cash	2.1	6.2
Accounts receivable	35.7	52.7
Current portion of derivative instruments asset (Notes 14 and 15)	4.2	2.7
Inventory (Note 7)	15.8	17.7
Prepayments	4.0	6.9
Income taxes receivable	0.3	1.0
Other current assets	5.9	3.1
Total current assets	136.3	169.0
Property, plant, and equipment, net (Note 8)	549.5	602.3
Equity investments in unconsolidated affiliates (Note 6)	140.8	163.7
Power purchase agreements and intangible assets, net (Note 10)	170.1	191.2
Goodwill (Note 9)	21.3	21.3
Derivative instruments asset (Notes 14 and 15)	0.3	2.8
Other assets	6.2	8.5
Total assets	$ 1,024.5	$ 1,158.8
Liabilities		
Current liabilities:		
Accounts payable	$ 2.5	$ 2.2
Accrued interest	2.3	0.3
Other accrued liabilities	20.2	25.5
Current portion of long-term debt (Note 12)	68.1	99.5
Current portion of derivative instruments liability (Notes 14 and 15)	4.5	4.4
Convertible debentures (Note 13)	18.1	—
Other current liabilities	0.2	1.0
Total current liabilities	115.9	132.9
Long-term debt, net of unamortized discount and deferred financing costs (Note 12)	540.7	616.3
Convertible debentures, net of discount and unamortized deferred financing costs (Note 13)	75.7	105.4
Derivative instruments liability (Notes 14 and 15)	15.4	19.9
Deferred income taxes (Note 16)	9.0	11.7
Power purchase agreements and intangible liabilities, net (Note 10)	21.2	24.1

Asset retirement obligations, net (Note 11)	49.2	45.3
Other long-term liabilities (Note 11)	5.0	6.4
Total liabilities	832.1	962.0
Equity		
Common shares, no par value, unlimited authorized shares; 108,341,738 and 115,211,976 issued and outstanding at December 31, 2018 and December 31, 2017	1,260.9	1,274.8
Accumulated other comprehensive loss (Note 5)	(146.2)	(134.8)
Retained deficit	(1,121.6)	(1,158.4)
Total Atlantic Power Corporation shareholders’ equity	(6.9)	(18.4)
Preferred shares issued by a subsidiary company (Note 20)	199.3	215.2
Total equity	192.4	196.8
Total liabilities and equity	$ 1,024.5	$ 1,158.8

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

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

	Year Ended December 31,		
	2018	2017	2016
Project revenue:			
Energy sales (Note 4)	$ 130.9	$ 148.9	$ 184.2
Energy capacity revenue (Note 4)	97.9	105.8	141.9
Other (Note 4)	53.5	176.3	73.1
	282.3	431.0	399.2
Project expenses:			
Fuel	73.1	106.3	149.5
Operations and maintenance	85.0	87.8	105.2
Depreciation and amortization	83.7	113.1	113.5
	241.8	307.2	368.2
Project other income (loss):			
Change in fair value of derivative instruments (Notes 14 and 15)	2.2	2.1	37.9
Equity in earnings (loss) of unconsolidated affiliates (Note 6)	43.2	(54.8)	35.9
Interest, net	(1.8)	(17.5)	(9.2)
Impairment (Notes 8 and 9)	—	(101.1)	(85.9)
Other income, net (Notes 3 and 11)	4.1	0.1	0.4
	47.7	(171.2)	(20.9)
Project income (loss)	88.2	(47.4)	10.1
Administrative and other expenses:			
Administration	23.9	23.6	22.6
Interest expense, net	52.7	64.2	106.0
Foreign exchange (gain) loss	(22.8)	16.3	13.9
Other income, net (Note 14)	(3.0)	(0.4)	(3.9)
	50.8	103.7	138.6
Income (loss) from operations before income taxes	37.4	(151.1)	(128.5)
Income tax expense (benefit) (Note 16)	0.2	(58.1)	(14.6)
Net income (loss)	37.2	(93.0)	(113.9)
Net income attributable to preferred shares of a subsidiary company (Note 20)	0.4	5.6	8.5
Net income (loss) attributable to Atlantic Power Corporation	$ 36.8	$ (98.6)	$ (122.4)
Net earnings (loss) per share attributable to Atlantic Power Corporation shareholders: (Note 21)			
Basic	$ 0.33	$ (0.86)	$ (1.02)
Diluted	0.29	(0.86)	(1.02)

Weighted average number of common shares outstanding: (Note 21)			
Basic	112.0	115.1	119.5
Diluted	141.8	115.1	119.5

See accompanying notes to consolidated financial statements.

Table of Contents

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions of U.S. dollars)

	Year Ended December 31,		
	2018	2017	2016
Net income (loss)	$ 37.2	$ (93.0)	$ (113.9)
Other comprehensive income (loss), net of tax:			
Unrealized gain (loss) on hedging activities	$ 0.4	$ (0.1)	$ (0.2)
Net amount reclassified to earnings	0.1	0.5	0.7
Net unrealized gain on derivatives	0.5	0.4	0.5
Defined benefit plan, net of tax	0.2	(0.7)	(0.5)
Foreign currency translation adjustments	(12.1)	14.0	(9.2)
Other comprehensive (loss) income, net of tax	(11.4)	13.7	(9.2)
Comprehensive income (loss)	25.8	(79.3)	(123.1)
Less: Comprehensive income attributable to preferred shares of a subsidiary company	0.4	5.6	8.5
Comprehensive income (loss) attributable to Atlantic Power Corporation	$ 25.4	$ (84.9)	$ (131.6)

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY

(in millions of U.S. dollars)

	Common Shares (Shares)	Common Shares (Amount)	Retained Deficit	Accumulated Other Comprehensive Income (loss)	Preferred Shares of a Subsidiary Company	Total Shareholders' Equity
December 31, 2015	122.1	$ 1,290.6	$ (937.4)	$ (139.3)	$ 221.3	$ 435.2
Net (loss) income	—	—	(122.4)	—	8.5	(113.9)
Common shares issued for LTIP	0.5	1.8	—	—	—	1.8
Dividends declared on preferred shares of a subsidiary company	—	—	—	—	(8.5)	(8.5)
Common share repurchases	(8.0)	(19.5)	—	—	—	(19.5)
Unrealized gain on hedging activities, net of tax of $0.2 million	—	—	—	0.5	—	0.5
Foreign currency translation adjustments	—	—	—	(9.2)	—	(9.2)
Defined benefit plan, net of tax of $0.2 million	—	—	—	(0.5)	—	(0.5)
December 31, 2016	114.6	$ 1,272.9	$ (1,059.8)	$ (148.5)	$ 221.3	$ 285.9
Net (loss) income	—	—	(98.6)	—	5.6	(93.0)
Common shares issued for LTIP	0.7	2.1	—	—	—	2.1
Dividends declared on preferred shares of a subsidiary company	—	—	—	—	(8.6)	(8.6)
Common share repurchases	(0.1)	(0.2)	—	—	—	(0.2)
Preferred share repurchases	—	—	—	—	(3.1)	(3.1)
Unrealized gain on hedging activities, net of tax of $0.3 million	—	—	—	0.4	—	0.4
Foreign currency translation adjustments	—	—	—	14.0	—	14.0
Defined benefit plan, net of tax of $0.3 million	—	—	—	(0.7)	—	(0.7)

December 31, 2017	115.2	$ 1,274.8	$ (1,158.4)	$ (134.8)	$ 215.2	$ 196.8
Net income	—	—	36.8	—	0.4	37.2
Common shares issued for LTIP	0.9	2.7	—	—	—	2.7
Dividends declared on preferred shares of a subsidiary company	—	—	—	—	(8.3)	(8.3)
Common share repurchases	(7.8)	(16.6)	—	—	—	(16.6)
Preferred share repurchases	—	—	—	—	(8.0)	(8.0)
Unrealized gain on hedging activities, net of tax of $0.1 million	—	—	—	0.5	—	0.5
Foreign currency translation adjustments	—	—	—	(12.1)	—	(12.1)
Defined benefit plan, net of tax of $0.1 million	—	—	—	0.2	—	0.2
December 31, 2018	108.3	$ 1,260.9	$ (1,121.6)	$ (146.2)	$ 199.3	$ 192.4

See accompanying notes to consolidated financial statements.

Table of Contents

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of U.S. dollars)

	Years Ended December 31,		
	2018	2017	2016
Cash provided by operating activities:			
Net income (loss)	$ 37.2	$ (93.0)	$ (113.9)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization	83.7	113.1	113.5
(Gain) loss on disposal of fixed assets and inventory	(0.4)	0.1	—
Asset retirement obligations	3.5	—	—
Gain on purchase and cancellation of convertible debentures	—	—	(3.7)
Gain on step acquisition of equity investment	(7.2)	—	—
Share-based compensation	2.7	2.1	1.8
Long-lived asset and goodwill impairment	—	101.1	85.9
Equity in (earnings) loss from unconsolidated affiliates	(43.2)	54.8	(35.9)
Distributions from unconsolidated affiliates	61.6	47.3	55.3
Unrealized foreign exchange (gain) loss	(22.0)	15.2	13.8
Change in fair value of derivative instruments	(5.5)	(2.1)	(37.9)
Amortization of debt discount and deferred financing costs	9.4	10.8	44.6
Change in deferred income taxes	(3.6)	(62.2)	(17.5)
Change in other operating balances			
Accounts receivable	18.8	(15.4)	2.3
Inventory	1.6	(1.6)	0.9
Prepayments and other assets	8.7	0.4	5.4
Accounts payable	(1.2)	(0.9)	(0.2)
Accruals and other liabilities	(6.6)	(0.5)	(2.1)
Cash provided by operating activities	137.5	169.2	112.3
Cash used in investing activities:			
Proceeds from sale of assets and equity investments, net	—	1.0	—
Cash paid for acquisition, net of cash received	(12.8)	—	—
Reimbursement of costs for third party construction project	—	—	4.8
Deposit for acquisition	(2.6)	—	—
Proceeds from asset sales	0.2	—	—
Purchase of property, plant and equipment	(1.8)	(5.3)	(7.2)
Cash used in investing activities	(17.0)	(4.3)	(2.4)
Cash used in financing activities:			
Proceeds from convertible debenture issuance	92.2	—	—
Proceeds from term loan facility, net of discount	—	—	679.0

Repayment of convertible debentures	(88.1)	—	(188.5)
Common share repurchases	(16.6)	(0.2)	(19.5)
Preferred share repurchases	(8.0)	(3.1)	—
Repayment of corporate and project-level debt	(100.3)	(165.9)	(544.4)
Cash payments for vested LTIP units withheld for taxes	(0.8)	(0.7)	(0.5)
Deferred financing costs	(5.1)	(0.3)	(16.2)
Dividends paid to preferred shareholders	(8.3)	(8.7)	(8.5)
Cash used in financing activities:	(135.0)	(178.9)	(98.6)
Net (decrease) increase in cash, restricted cash and cash equivalents	(14.5)	(14.0)	11.3
Cash, restricted cash and cash equivalents at beginning of period	84.9	98.9	87.6
Cash, restricted cash and cash equivalents at end of period	$ 70.4	$ 84.9	$ 98.9
Supplemental cash flow information			
Interest paid	$ 41.3	$ 72.0	$ 70.7
Income taxes paid, net	$ 3.1	$ 4.4	$ 3.5
(Receivables) accruals for equipment sales and construction in progress	$ (1.5)	$ 1.2	$ 1.2

See accompanying notes to consolidated financial statements.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

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

1. Nature of 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 power purchase agreements ("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.

Atlantic Power is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange under the symbol "ATP" and on the New York Stock Exchange under the symbol "AT." Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at 3 Allied Drive, Suite 155, Dedham, Massachusetts 02026, USA.

2. Summary of significant accounting policies

(a) Principles of consolidation and basis of presentation:

The accompanying consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and include the consolidated accounts and operations of our subsidiaries in which we have a controlling financial interest. The usual condition for a controlling financial interest is ownership of the majority of the voting interest of an entity. However, a controlling financial interest may also exist in entities, such as a variable interest entity ("VIE"), through arrangements that do not involve controlling voting interests.

We apply the standard that requires consolidation of VIEs, for which we are the primary beneficiary. The guidance requires a variable interest holder to consolidate a VIE if that party has both the power to direct the activities that most significantly impact the entities' economic performance, as well as either the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE. We have determined that our equity investments are not VIEs by evaluating their design and capital structure. Accordingly, we use the equity method of accounting for all of our investments in which we do not have an economic controlling interest. We eliminate all intercompany accounts and transactions in consolidation.

(b)Cash and cash equivalents:

Cash and cash equivalents include cash deposited at banks and highly liquid investments with original maturities of 90 days or less when purchased.

(c)Restricted cash:

Restricted cash represents cash and cash equivalents that are maintained by the projects or corporate to support payments for maintenance costs and meet project level and corporate contractual debt obligations. Restricted cash is classified as a current or long-term asset based on the timing and nature of when or how the cash is expected to be used or when the restrictions are expected to lapse.

(d)Accounts receivable:

Accounts Receivable are carried at cost. We periodically assesses the collectability of accounts receivable, considering factors such as specific evaluation of collectability, historical collection experience, the age of accounts receivable and other currently available evidence of the collectability, and record an allowance for doubtful accounts for the estimated uncollectible amount as appropriate. We had no allowance for doubtful accounts recorded at December 31, 2018 and 2017, respectively.

(e)Deferred financing costs:

Deferred financing costs represent costs to obtain long term financing and are amortized using the effective interest method over the term of the related debt, which ranges from 1 to 6 years. The carrying amount of deferred financing costs were recorded on the consolidated balance sheets as net of long-term debt and convertible debentures and was $11.8 million and $11.7 million at December 31, 2018 and 2017, respectively. Interest expense from the amortization of deferred finance costs for the years ended December 31, 2018, 2017, and 2016 was $5.1 million, $6.3 million, and $40.8 million, respectively.

(f)Inventory:

Inventory represents small parts and other consumables and fuel, the majority of which is consumed by our projects in provision of their services, and are valued at the lower of cost and net realizable value. Cost is the sum of the purchase price and incidental expenditures and charges incurred to bring the inventory to its existing condition or location. The cost of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs.

(g)Property, plant and equipment:

Property, plant and equipment are stated at cost, net of accumulated depreciation. Depreciation is provided on a straight line basis over the estimated useful life of the related asset. Significant additions or improvements extending asset lives or increasing generating capacity are capitalized as incurred, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred.

(h)Project development costs and capitalized interest:

Project development costs are expensed in the preliminary stages of a project and capitalized when the project is deemed to be commercially viable. Commercial viability is determined by one or a series of actions including among others, obtaining a PPA.

When a project is available for operations, capitalized interest and project development costs are reclassified to property, plant and equipment and depreciated on a straight line basis over the estimated useful life of the project's related assets. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

(i)Other intangible assets:

Other intangible assets include PPAs and fuel supply agreements at our projects acquired as part of business combinations. PPAs are valued at the time of acquisition based on the contract prices under the PPAs compared to projected market prices. Fuel supply agreements are valued at the time of acquisition based on the contract prices under the fuel supply agreement compared to projected market prices. The balances are presented net of accumulated amortization in the consolidated balance sheets. Amortization is recorded on a straight line basis over the remaining term of the agreement.

(j)Investments accounted for by the equity method:

We have investments in entities that own power-producing assets with the objective of generating cash flow. The equity method of accounting is applied to such investments in affiliates, which include joint ventures, partnerships, and limited liability companies because the ownership structure prevents us from exercising a controlling influence over the operating and financial policies of the projects. Our investments in partnerships and limited liability companies with 50% or less ownership, but greater than 5% ownership in which we do not have a controlling interest are accounted for under the equity method of accounting. We apply the equity method of accounting to investments in limited partnerships and limited liability companies with greater than 5% ownership because our influence over the investment's operating and financial policies is considered to be more than minor.

Under the equity method, equity in pre tax income or losses of our investments is reflected as equity in earnings of unconsolidated affiliates in the consolidated statements of operations. We apply the nature of distributions method for the classification of our investments accounted for by the equity method in the Consolidated Statements of Cash Flows. The cash flows that are distributed to us from these unconsolidated affiliates are directly related to the operations of the affiliates' power-producing assets and are classified as cash flows from operating activities in the consolidated statements of cash flows. We record the return of our investments in equity investees as cash flows from investing activities. Cash flows from equity investees are considered a return of capital when distributions are generated from proceeds of either the sale of our investment in its entirety or a sale by the investee of all or a portion of its capital assets.

(k)Impairment of long lived assets, intangible assets and equity method investments:

Long lived assets, such as property, plant and equipment, and other intangible assets and liabilities subject to depreciation and amortization, are reviewed for impairment annually or whenever events or changes in circumstances indicate that the carrying amount of an asset group may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset group. If the carrying amount of an asset group exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset group exceeds its fair value. Our asset groups have been determined to be at the plant level, which is the lowest level in which independent, separately identifiable cash flows have been identified.

Investments in and the operating results of 50%-or-less owned entities not consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. We also review a project for impairment at the earlier of executing a new PPA (or other arrangement) or six months prior to the expiration of an existing PPA. Factors such as the business climate, including current energy and market conditions, environmental regulation, the condition of assets, and the ability to secure new PPAs are considered when evaluating long lived assets for impairment. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment or, where applicable, estimated sales proceeds that are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long term investments. Therefore, we complete our assessments with a long term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

(l)Goodwill:

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the assets acquired, less liabilities assumed, based on their fair values. Goodwill is allocated, as of the date of the business combination, to our reporting units that are expected to benefit from the synergies of the business combination.

Goodwill is not amortized and is tested for impairment, annually in the fourth quarter, or more frequently if events or changes in circumstances indicate that the asset might be impaired.

In our test, we first perform step zero to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (i.e. more than 50%) that the fair value of a reporting unit is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions, industry and market considerations, cost factors, overall financial performance and other relevant entity specific events. If the qualitative assessment determines that an impairment is more likely than not, then we perform a quantitative impairment test. In the quantitative analysis, the carrying amount of the reporting unit is compared with its fair value. When the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not to be impaired. When the carrying amount of a reporting unit exceeds its fair value, an impairment loss is recognized in an amount equal to the excess, not to exceed the carrying amount of goodwill, and is recorded in the consolidated statements of operations.

We determine the fair value of our reporting units using an income approach with discounted cash flow models (“DCF”), as we believe forecasted cash flows are the best indicator of such fair value. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including assumptions about discount rates, projected merchant power prices, generation, fuel costs and capital expenditure requirements. The undiscounted and discounted cash flows utilized in our long lived asset recovery and goodwill impairment tests for our reporting units are generally based on approved reporting unit operating plans for years with contracted PPAs and historical relationships for estimates at the expiration of PPAs. All cash flow forecasts from DCF models utilized estimated plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. We used historical experience to determine estimated future capital investment requirements. The discount rate applied to the DCF models represents the weighted average cost of capital ("WACC") consistent with the risk inherent in future cash flows of the particular reporting unit and is based upon an assumed capital structure, cost of long term debt and cost of equity consistent with comparable independent power producers. The betas used in calculating the WACC rate were obtained from reputable third party sources. We utilized the assistance of valuation experts to perform the quantitative impairment test for our Curtis Palmer reporting units. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill.

The valuation of long-lived assets and goodwill for the impairment analyses is considered a level 3 fair value measurement, which means that the valuation of the assets and liabilities reflect management's own judgments regarding the assumptions market participants would use in determining the fair value of the assets and liabilities. Fair value determinations require considerable judgment and are sensitive to changes in these underlying assumptions and factors.

Table of Contents

As a result, there can be no assurance that the estimates and assumptions made for purposes of a goodwill impairment test will prove to be accurate predictions of the future. Examples of events or circumstances that could reasonably be expected to negatively affect the underlying key assumptions and ultimately impact the estimated fair value of our reporting units may include macroeconomic factors that significantly differ from our assumptions in timing or degree, increased input costs such as higher fuel prices and maintenance costs, or lower power prices than incorporated in our long-term forecasts.

(m)Accounts payable and other accrued liabilities:

Accounts payable consists of amounts due to trade creditors related to our core business operations. These payables include amounts owed to vendors and suppliers for items such as fuel, maintenance, inventory and other raw materials. Other accrued liabilities include items such as income taxes, legal contingencies and employee-related costs including payroll, benefits and related taxes.

(n)Derivative financial instruments:

We use derivative financial instruments in the form of interest rate swaps and foreign exchange forward contracts to manage our current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. We also separate the conversion option of certain convertible debentures from the host instrument and account for it as an embedded derivative liability as such conversion option is in a currency different from our functional currency. We have also entered into natural gas supply contracts and natural gas forwards or swaps to minimize the effects of the price volatility of natural gas, which is a significant operating cost. We do not enter into derivative financial instruments for trading or speculative purposes. Certain derivative instruments qualify for a scope exception to fair value accounting because they are considered normal purchases or normal sales in the ordinary course of conducting business. This exception applies when we have the ability to, and it is probable that we will deliver or take delivery of the underlying physical commodity.

We have designated one of our interest rate swaps as a hedge of cash flows for accounting purposes. Tests are performed to evaluate hedge effectiveness and ineffectiveness at inception and on an ongoing basis, both retroactively and prospectively. Derivatives accounted for as hedges are recorded at fair value in the balance sheet. Unrealized gains or losses on derivatives designated as a hedge for accounting purposes are deferred and recorded as a component of accumulated other comprehensive loss (“OCL”) until the hedged transactions occur and are recognized in earnings. The ineffective portion of the cash flow hedge, if any, is immediately recognized in earnings.

Derivative financial instruments not designated as a hedge for accounting purposes are measured at fair value with changes in fair value recorded in the consolidated statements of operations. Derivative financial instruments under master netting arrangements are recorded net, when applicable, in the consolidated balance sheets. The following table summarizes derivative financial instruments that are not designated as hedges for accounting purposes and the accounting treatment in the consolidated statements of operations of the changes in fair value and cash settlements of such derivative financial instrument:

Derivative financial instrument	Classification of changes in fair value	Classification of cash settlements
Natural gas swaps	Changes in fair value of derivative instrument	Fuel expense
Fuel purchase agreements	Changes in fair value of derivative instrument	Fuel expense
Interest rate swaps	Changes in fair value of derivative instrument	Interest expense
Convertible debenture conversion option	Other expense, net	NA
Foreign currency forward contract	Foreign exchange (gain) loss	Foreign exchange (gain) loss

Table of Contents

(o)Income taxes:

Income tax expense includes the current tax obligation or benefit and change in deferred income tax asset or liability for the period. We use the asset and liability method of accounting for deferred income taxes and record deferred income taxes for all significant temporary differences. Income tax benefits associated with uncertain tax positions are recognized when we determine that it is more likely than not that the tax position will be ultimately sustained. Refer to Note 16 for more information.

(p)Revenue recognition:

We recognize energy sales revenue on a gross basis when electricity and steam are delivered and capacity revenue when capacity is provided under the terms of the related contracts. PPAs, steam purchase arrangements and energy services agreements are long term contracts with performance obligations to provide electricity, steam and capacity on a predetermined basis.

For certain PPAs determined to be operating leases, we recognize lease income consistent with the recognition of energy sales and capacity revenue. When energy is delivered and capacity is provided, we recognize lease income as a component of energy sales and capacity revenue.

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. The following is a description of principal activities from which we generate our revenue.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

Products and services	Nature, timing of satisfaction of performance obligations, and significant payment terms
Energy	Energy revenue is recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in our consolidated statements of operations. The price of energy could be contracted under PPAs at set prices or merchant sales based on market merchant price. Energy revenue is also recognized under certain contracts for avoided generation during curtailment periods. Energy revenue is billed and paid on a monthly basis.
Energy capacity	Capacity revenues are recognized when contractually earned, and consist of revenues billed to a third party at a negotiated contract price under the applicable PPAs for making installed generation capacity available in order to satisfy reliability requirements or merchant capacity sales based on the market price for such capacity. Energy capacity is billed and paid on a monthly basis.
Other revenue includes the following:	
Steam energy and capacity	Steam revenue is recognized upon delivery to the customer. Steam capacity payments under the applicable PPAs are recognized as the amount billable under the respective PPA. Steam capacity is billed and paid on a monthly basis.
Waste heat	We generate electricity from excess steam provided by a nearby pipeline and its pumping station in the Canada segment. Waste heat is earned when it is generated and paid as a portion of monthly energy and capacity billing.
Enhanced dispatch contracts	Under certain contractual arrangements with our customers, we bill and are paid for not generating electricity. This revenue is recognized monthly under the terms of those agreements.
Ancillary and transmission services	We provide ancillary and transmission services to our customers under the terms of our PPAs. These services are billed and paid on a monthly basis.
Asset management and operation, operation and maintenance	We provide asset management and operation supervision to the Frederickson project, a facility that we jointly own with Puget Sound Energy. We also provide operation and maintenance services to several electric energy customers under the PPAs. All services are billed and paid on a monthly basis.

Refer to Note 4 Revenue from contracts for disaggregation of revenue and further contract balance information.

We have entered into PPAs to sell power at predetermined rates. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the project’s property, plant and equipment in return for future payments. Such arrangements are classified as either capital or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property to the PPA counterparty are classified as direct financing leases.

Finance income related to leases or arrangements accounted for as direct financing leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is comprised of net minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying value of the leased property. Unearned finance income is deferred and recognized in net income (loss) over the lease term.

For PPAs accounted for as operating leases, we recognize lease income consistent with the recognition of energy revenue. When energy is delivered, we recognize lease income in energy revenue.

(q)Administrative expenses:

Administrative expenses include corporate and other expenses primarily for executive management, finance, legal, human resources and information systems, which are not directly allocable to our business segments.

(r)Foreign currency translation and transaction gains and losses:

The local currency is the functional currency of our U.S. and Canadian projects. Our reporting currency is the U.S. dollar. Foreign currency denominated assets and liabilities are translated at end of period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted average rates of exchange for the period. The resulting currency translation adjustments are not included in the determination of our statements of operations for the period, but are accumulated and reported as a separate component of shareholders' equity until sale of the net investment in the project takes place. Foreign currency transaction gains or losses are reported within foreign exchange (gain) loss in our consolidated statements of operations.

(s)Equity compensation plans:

The officers and certain other employees are eligible to participate in the Long Term Incentive Plan ("LTIP"). Vested notional units are expected to be redeemed one third in cash and two thirds in shares of our common stock. Notional units granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional units granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Unvested notional units are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date.

We initially recognize compensation expense on the estimated number of notional units for which the requisite service is expected to be rendered. We have estimated a weighted average forfeiture rate of 11% for all notional unit grants under the LTIP. This estimate will be revisited if subsequent information indicates the actual number of notional units forfeited is likely to differ from previous estimates. Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and the fair value of the award at each balance sheet date for notional units accounted for as liability awards.

(t)Asset retirement obligations:

The fair value for an asset retirement obligation is recorded in the period in which it is incurred. Retirement obligations associated with long lived assets are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel, and for which the timing and/or method of settlement may be conditional on a future event. When the liability is initially recorded, we capitalize the cost by increasing the carrying amount of the related long lived asset. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, we either settle the obligation for its recorded amount or incur a gain or loss.

(u)Pensions:

We offer pension benefits to certain employees through a defined benefit pension plan. We recognize the funded status of our defined benefit plan in the consolidated balance sheets in other long term liabilities and record an offset to other comprehensive income (loss). In addition, we also recognize on an after tax basis, as a component of other comprehensive income (loss), gains and losses as well as all prior service costs that have not been included as part of our net periodic benefit cost. The determination of our obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets, the rate of future compensation increases and retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of our pension obligation or expense recorded.

(v)Business combinations:

We account for our business combinations in accordance with the acquisition method of accounting, which requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable users of an entity's financial statements to evaluate the nature and financial effects of the business combination. In addition, transaction costs are expensed as incurred.

(w)Concentration of credit risk:

The financial instruments that potentially expose us to credit risk consist primarily of cash and cash equivalents, restricted cash, derivative instruments and accounts receivable. Cash and restricted cash are held by major financial institutions that are also counterparties to our derivative instruments. We have long term agreements to sell electricity, gas and steam to public utilities and corporations. We have exposure to trends within the energy industry, including declines in the creditworthiness of our customers. We do not normally require collateral or other security to support energy related accounts receivable. We do not believe there is significant credit risk associated with accounts receivable due to the credit-worthiness and payment history of our customers. See Note 22, Segment and geographic information, for a further discussion of customer concentrations.

(x)Use of estimates:

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the useful lives and recoverability of property, plant and equipment, valuation of goodwill, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the fair value of financial instruments and derivatives, pension obligations, asset retirement obligations, and the fair values of acquired assets. In addition, estimates are used to test long lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(y)Recently adopted and issued accounting standards:

Accounting Standards Adopted in 2018

In May 2017, the Financial Accounting Standards Board ("FASB") issued authoritative guidance to address diversity in practice and cost and complexity of applying the guidance relating to stock compensation when there is a change to the terms or conditions of a share-based payment award. The guidance is effective for fiscal years beginning after December 15, 2017, with early adoption permitted. We adopted this guidance on January 1, 2018 and it did not have an impact on the consolidated financial statements.

In November 2016, the FASB issued authoritative guidance to address diversity in practice of presenting changes in restricted cash on the statement of cash flows. The new guidance requires that a statement of cash flows explain the change during the period in the total of cash, cash equivalents, and amounts generally described as restricted cash or restricted cash equivalents. We adopted this guidance on January 1, 2018 and it was applied retrospectively to cash flows used in investing activities on the consolidated statements of cash flows for the years ended December 31, 2017 and 2016. As a result of adoption, cash flows used in investing activities were retrospectively decreased by $7.1 million and $1.9 million for the years ended December 31, 2017 and 2016, respectively.

In October 2016, the FASB issued authoritative guidance, which amends existing guidance related to the recognition of current and deferred income taxes for intra-entity asset transfers. Under the new guidance, current and deferred income tax consequences of an intra-entity asset transfer, other than an intra-entity asset transfer of inventory, are now recognized when the transfer occurs. We adopted this guidance on January 1, 2018 and it did not have an impact on the consolidated financial statements.

In August 2016, the FASB issued authoritative guidance intended to clarify classification of specific cash flows that have aspects of more than one class of cash flows. As a result of this new guidance, entities should be applying specific GAAP in the following eight cash flow issues: Debt prepayment or debt extinguishment costs; settlement of zero-coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies; distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. We adopted this guidance on January 1, 2018 and it did not have an impact on the consolidated financial statements.

In May 2014, the FASB issued new recognition and disclosure requirements for revenue from contracts with customers, which supersedes the existing revenue recognition guidance. The new recognition requirements focus on when the customer obtains control of the goods or services, rather than the current risks and rewards model of recognition. The core principle of the new standard is that an entity recognizes revenue when it transfers goods or services to its customers in an amount that reflects the consideration an entity expects to be entitled to for those goods or services. We adopted this guidance on January 1, 2018 and it did not have an impact on the consolidated financial statements. Accordingly, we did not record a transition adjustment. The standard also requires new disclosures that include information intended to communicate the nature, amount, timing and any uncertainty of revenue and cash flows from applicable contracts, including any significant judgments and changes in judgments and assets recognized from the costs to obtain or fulfill a contract. These disclosures can be found in Note 4 Revenue from contracts.

Accounting Standards Not Yet Adopted

In February 2016, the FASB issued authoritative guidance intended to increase transparency and comparability among organizations by recognizing lease assets and liabilities on the balance sheet and disclosing key information about leasing arrangements. Under the new guidance, lessees will be required to recognize a right-of-use asset and a lease liability, measured on a discounted basis, at the commencement date for all leases with terms greater than twelve months. Additionally, this guidance will require disclosures to help investors and other financial statement users to better understand the amount, timing, and uncertainty of cash flows arising from leases, including qualitative and quantitative requirements. Any leases that expire before the initial application date will not require any accounting adjustment. This guidance is effective for annual reporting periods beginning after December 15, 2018, including interim periods within those fiscal years, with early adoption permitted. We expect to elect certain practical expedients permitted, including the expedient that permits us to retain our existing lease assessment and classification. In July 2018, the FASB issued further

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

authoritative guidance to provide an additional transition method to adopt the new lease requirements by allowing entities to initially apply the requirements by recognizing a cumulative-effect adjustments to the opening balance of retained earnings in the period of adoption. We will elect this transition method. We are currently finalizing our adoption process, which includes the evaluation of lease contracts compared to the new standard. While we are currently completing our evaluation of the impact of the new guidance, we expect to record a right of use asset of approximately $6.5 million, a lease liability of approximately $7.1 million and an adjustment to other assets of approximately $0.6 million in the consolidated balance sheets on January 1, 2019. We do not expect adoption to impact opening retained earnings or our consolidated statements of operations.

In August 2017, the FASB issued authoritative guidance to align an entity's risk management activities and financial reporting for hedging relationships through changes to both the designation and measurement guidance for qualifying hedging relationships and the presentation of hedge results. The guidance expands and refines hedge accounting for both nonfinancial and financial risk components and aligns the recognition and presentation of the effects of the hedging instrument and the hedged item in the financial statements. The guidance is effective for fiscal years beginning after December 15, 2018, with early adoption permitted. Adoption of this guidance will not have a material impact on the consolidated financial statements.

In February 2018, the FASB issued authoritative guidance to allow a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. The guidance is effective for fiscal years beginning after December 15, 2018. Adoption of this guidance will not have a material impact on the consolidated financial statements.

In August 2018, the FASB issued authoritative guidance to modify the disclosure requirements on fair value measurement disclosures. The guidance requires removals of certain disclosures, such as the amount of and reasons for transfers between level 1 and level 2 of fair value hierarchy and the policy for timing of transfers between levels. The guidance further requires modifications and additions surrounding the disclosures of level 3 fair value measurements and related unrealized gains and losses. The guidance is effective for fiscal years beginning after December 15, 2019. We do not expect this to have a material impact on the consolidated financial statements upon adoption.

In August 2018, the FASB issued authoritative guidance to remove disclosures that no longer are considered cost-beneficial, clarify the specific requirements of disclosures, and add disclosure requirements identified as relevant. The scope of the guidance is broad and includes reporting comprehensive income, debt modifications and extinguishments and other sub topics. The guidance is effective for fiscal years beginning after December 15, 2019. We are currently evaluating the impact that adoption will have on our disclosures.

3. Acquisitions and divestments

2018 Acquisitions

(a)Koma Kulshan Associates

On June 18, 2018, we purchased a 0.5% general partner interest in Concrete Hydro Partners L.P. (“Concrete”) for $1.1 million from Mt. Baker Corporation with cash on-hand. Prior to the purchase, we owned a 0.5% general partner interest and a 99.0% limited partner interest in Concrete; following the purchase, we own 100% of the entity. Concrete is the owner of a 50% limited partner interest in Koma Kulshan Associates, L.P. (“Koma”). As a result of the purchase, our ownership of Koma increased from 49.75% to 50.00%. With 50.00% percent ownership of Koma, we did not have financial control of the entity as the two owner parties had joint control and substantive participating rights through the structure of the partnership agreement. Accordingly, since we did not obtain control of the project, we continued to account for Koma under the equity method of accounting as of June 30, 2018. The $1.1 million purchase was accounted for as an additional equity method investment in Koma.

On July 27, 2018, we acquired the remaining 50% partnership interest in Koma from Covanta Energy Americas, Inc. (“Covanta”) for a total purchase price of $12.5 million including working capital. As a result of this purchase, we own 100% of Koma and consolidated the project on the date of the acquisition. We completed this acquisition because we view hydro projects as assets that will provide us both near and long-term value.

Our acquisition of Koma is accounted for under the acquisition method of accounting as of the transaction closing date. The $12.5 million total purchase price was funded with cash on-hand. We assumed operation of the project from Covanta on the acquisition date of July 27, 2018. The preliminary purchase price allocation for the business combination is estimated as follows:

Fair value of consideration transferred:		
Cash	$	12.5
Other items to be allocated to identifiable assets acquired and liabilities assumed:		
Book value of our investment in Koma at the acquisition date		5.4
Gain recognized from step acquisition		7.2
Total purchase price	$	25.1
Preliminary purchase price allocation		
Cash	$	0.8
Working capital		0.1
Property, plant, and equipment		1.2
Intangible assets		24.8
Asset retirement obligation		(1.8)
Total identifiable net assets	$	25.1

The fair values of the assets acquired and liabilities assumed, as well as the fair value of our previous 50% equity interest in Koma, were estimated by applying an income approach using the discounted cash flow method. These measurements were based on significant inputs not observable in the market and thus represent a level 3 fair value measurement. The primary considerations and assumptions that affected the discounted cash flows included the operational characteristics and financial forecasts of the acquired facility, remaining useful life and a discount rate based on the weighted average cost of capital adjusted for the risk and characteristics of the project. We recognized a $7.2 million gain recorded in other income in the consolidated statements of operations for the year ended December

31, 2018 as a result of remeasuring our previous 50% equity interest in Koma immediately before the business combination to fair value. The $24.8 million of intangible assets recorded will be amortized straight-line through the remaining life of Koma's PPA, which expires on March 31, 2037. Additionally, we recorded $0.5 million of deferred tax liabilities and deferred tax expense related to the step acquisition of Koma Kulshan.

Koma contributed $1.1 million of revenue and net income of $0.0 million (excluding the $7.2 million gain recognized from the step acquisition) to the consolidated statements of operations for the period from July 27, 2018 to December 31, 2018. The impact to pro forma results of operations was not significant to the years ended December 31, 2018, 2017 and 2016.

(b)South Carolina Biomass Plants

On September 20, 2018, we executed an agreement to acquire two biomass plants in South Carolina from EDF Renewables for $13.0 million. Closing of the transaction is expected to occur late in the third quarter or in the fourth quarter of 2019, subject to restructuring of the plants' ownership structure by EDF Renewables after the end of relevant tax credit recapture periods. We have paid $2.6 million of the purchase price, which will be held in escrow until the

Table of Contents

closing date. The remainder of the purchase price will be paid at closing.

Each of the plants has a capacity of 20 megawatts. All of the output of the two plants is sold to Santee Cooper, a state-owned utility, under PPAs that run to 2043. Under the terms of the PPAs, the plants receive energy payments for energy produced. The fuel cost component of the energy revenues is based on a biomass market index. There is no project-level debt at either plant.

2017 Divestment

(a)Selkirk Project

On November 2017, we sold our 17.7% interest in Selkirk Cogen Partners, LP ("Selkirk") to JMC Selkirk LLC, the project's majority owner, for $1.0 million. Selkirk was accounted for under the equity method of accounting. In the second quarter of 2017, we recorded a $10.6 million impairment at Selkirk and wrote our equity investment down to zero. As a result of the sale, we recorded a $1.0 million gain on sale, which is included as a component of equity in earnings (loss) from unconsolidated affiliates in the consolidated statement of operations for the year ended December 31, 2017.

4. Revenue from contracts

Revenue, receivables and contract liabilities by segment consists of following:

	Year Ended December 31, 2018				
				Un-Allocated	Consolidated
	East U.S.	West U.S.	Canada	Corporate	Total
Project revenue:					
Energy sales	$ 87.5	$ 13.5	$ 29.9	$ —	$ 130.9

Energy capacity revenue	52.8	27.8	17.3	—	97.9
Steam energy and capacity revenue	12.9	2.8	—	—	15.7
Waste heat revenue	—	—	0.3	—	0.3
Enhanced dispatch contracts	—	—	23.9	—	23.9
Ancillary and transmission services	5.5	—	7.5	—	13.0
Asset management and operation	—	—	—	0.9	0.9
Miscellaneous revenue	—	(0.3)	—	—	(0.3)
	158.7	43.8	78.9	0.9	282.3

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

	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
Steam energy and capacity revenue	11.1	31.2	—	—	42.3
Waste heat revenue	—	—	0.5	—	0.5
Enhanced dispatch contracts	—	—	109.9	—	109.9
Ancillary and transmission services	—	—	18.8	—	18.8
Asset management and operation	4.7	—	—	1.0	5.7
Miscellaneous revenue	—	(0.9)	—	—	(0.9)
	152.5	108.9	168.6	1.0	431.0

Contract balances

The following table provides information about receivables, contract assets and contract liabilities from contracts with customers.

	December 31, 2018	December 31, 2017
Accounts receivables	$ 35.7	$ 52.7
Contract assets	—	—
Contract liabilities	0.1	1.0

Contract liabilities as of December 31, 2018 include a $0.1 million steam sale credit at San Diego plants. Contract liabilities as of December 31, 2017 include recoverable wood fuel costs under the PPA and property tax at Williams

Lake, which is proportionally estimated, pending receipt of an actual tax bill. The total $1.0 million was recognized as revenues from ancillary and transmission services in the first quarter of 2018.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

5. Changes in accumulated other comprehensive loss by component

The changes in accumulated OCL by component are as follows:

	Year Ended December 31, 2018	2017	2016
Foreign currency translation			
Balance at beginning of period	$ (134.3)	$ (148.3)	$ (139.1)
Other comprehensive loss:			
Foreign currency translation adjustments(1)	(12.1)	14.0	(9.2)
Balance at end of period	$ (146.4)	$ (134.3)	$ (148.3)
Pension			
Balance at beginning of period	$ (1.6)	$ (0.9)	$ (0.4)
Other comprehensive loss:			
Curtailment gain	—	(1.6)	(0.7)
Tax expense	—	0.4	0.2
Total Other comprehensive income before reclassifications, net of tax	—	(1.2)	(0.5)
Total amount reclassified from accumulated other comprehensive income, net of tax	0.2	0.5	—
Total other comprehensive income	0.2	(0.7)	(0.5)
Balance at end of period	$ (1.4)	$ (1.6)	$ (0.9)
Cash flow hedges			
Balance at beginning of period	$ 1.1	$ 0.7	$ 0.2
Other comprehensive income (loss):			
Net change from periodic revaluations	0.5	(0.2)	(0.3)
Tax (expense) benefit	(0.1)	0.1	0.1
Total Other comprehensive (loss) income before reclassifications, net of tax	0.4	(0.1)	(0.2)
Net amount reclassified to earnings:			
Interest rate swaps(2)	0.2	0.9	1.0
Tax expense	(0.1)	(0.4)	(0.3)
Total amount reclassified from accumulated other comprehensive loss, net of tax	0.1	0.5	0.7
Total other comprehensive income	0.5	0.4	0.5
Balance at end of period	$ 1.6	$ 1.1	$ 0.7

(1) In all periods presented, there were no tax impacts related to rate changes and no amounts were reclassified to earnings (loss).

(2) This amount was included in interest expense, net on the accompanying consolidated statements of operations.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

6. Equity method investments in unconsolidated affiliates

The following tables summarize our equity method investments in unconsolidated affiliates:

Entity name	Percentage of Ownership as of December 31, 2018		Carrying value as of December 31, 2018	2017
Frederickson(1)	50.2	%	$ 72.0	$ 77.3
Orlando Cogen, LP	50.0	%	4.5	7.0
Koma Kulshan Associates (2)	—	%	—	4.9
Chambers Cogen, LP	40.0	%	64.3	74.5
Total			$ 140.8	$ 163.7

(1) We own 50.15% of Frederickson. However, we do not have financial control of the entity. The Frederickson entity is organized under a joint ownership agreement. Under the terms of that agreement, the two owner parties have joint control of the asset and substantive participating rights through the structure of its Owner's Committee. Each party has equal representation on this committee and unanimous consent is required over all significant decisions of the entity. These significant decisions include, but are not limited to (i) approval of the annual operating plan, annual operating budget, annual capital budget and five-year forecasts, (ii) approval of all expenditures in excess of the approved budget, (iii) adoption of procedures intended to govern the operation and conduct of the facility, and (iv) entering into, amending, supplementing or terminating any project agreement. Disputes between the owners for these significant decisions are subject to independent arbitration. Accordingly, since we do not control the project, Frederickson is accounted for under the equity method of accounting.

(2) In July 2018, we purchased the remaining 50% partnership interest in Koma and consolidated the project in our financial statements. See Note 3 Acquisition and divestments.

Deficit in earnings of equity method investments, net of distributions, was as follows:

Entity name	Year Ended December 31, 2018	2017	2016
Frederickson	$ 6.9	$ (27.9)	$ 2.2
Orlando Cogen, LP	30.1	25.6	27.8

Koma Kulshan Associates (1)	0.6	0.7	0.8
Chambers Cogen, LP	5.6	(42.6)	5.5
Selkirk Cogen Partners, LP (2)	—	(10.6)	(0.4)
Total earnings (loss) of unconsolidated affiliates	43.2	(54.8)	35.9
Distributions from equity method investments	(61.6)	(47.3)	(55.3)
Deficit in earnings of equity method investments, net of distributions	$ (18.4)	$ (102.1)	$ (19.4)

(1) In July 2018, we purchased the remaining 50% partnership interest in Koma and consolidated the project in our financial statements. See Note 3 Acquisition and divestments.

(2) In November 2017, we sold our 17.7% interest in Selkirk.

Distributions from equity method investments exceeded earnings (loss) of equity method investments for the years ended December 31, 2018, 2017 and 2016, respectively. Distributions from our equity method investments are typically based on project-level cash flows from operations or other non-GAAP metrics, whereas equity earnings include non-cash expenses such as depreciation and amortization, investment impairments or changes in the fair value of derivative financial instruments.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

The following summarizes the financial position at December 31, 2018, 2017 and 2016, and operating results for the years ended December 31, 2018, 2017 and 2016, respectively, for our proportional ownership interest in equity method investments:

	2018	2017	2016
Assets			
Current assets			
Frederickson	$ 2.5	$ 1.9	$ 1.7
Orlando Cogen, LP	7.7	9.2	7.5
Koma Kulshan Associates (1)	—	0.5	0.6
Chambers Cogen, LP	15.6	17.3	15.0
Selkirk Cogen Partners, LP (2)	—	—	11.3
Non-current assets			
Frederickson	70.0	76.2	114.1
Orlando Cogen, LP	7.1	8.1	9.1
Koma Kulshan Associates (1)	—	4.7	5.0
Chambers Cogen, LP	117.4	130.9	190.0
Selkirk Cogen Partners, LP (2)	—	—	2.4
	$ 220.3	$ 248.8	$ 356.7
Liabilities			
Current liabilities			
Frederickson	$ —	$ 0.4	$ 0.1
Orlando Cogen, LP	10.3	10.3	9.2
Koma Kulshan Associates (1)	—	0.1	0.1
Chambers Cogen, LP	9.2	3.7	3.8
Selkirk Cogen Partners, LP (2)	—	—	0.6
Non-current liabilities			
Frederickson	0.5	0.4	0.5
Orlando Cogen, LP	—	—	—
Koma Kulshan Associates (1)	—	0.2	0.5
Chambers Cogen, LP	59.5	70.0	73.6
Selkirk Cogen Partners, LP (2)	—	—	1.5
	$ 79.5	$ 85.1	$ 89.9

(1) In July 2018, we purchased the remaining 50% partnership interest in Koma and consolidated the project in our financial statements. See Note 3 Acquisition and divestments.

(2) In November 2017, we sold our 17.7% interest in Selkirk.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

Operating results	2018	2017	2016
Revenue			
Frederickson	$ 21.0	$ 21.6	$ 20.7
Orlando Cogen, LP	60.2	55.0	54.6
Koma Kulshan Associates (1)	1.2	1.8	1.9
Chambers Cogen, LP	43.3	43.8	44.7
Selkirk Cogen Partners, LP (2)	—	1.8	7.9
	125.7	124.0	129.8
Project expenses			
Frederickson	14.1	21.0	18.5
Orlando Cogen, LP	30.1	29.4	26.9
Koma Kulshan Associates (1)	0.6	1.1	1.1
Chambers Cogen, LP	36.1	37.5	37.4
Selkirk Cogen Partners, LP (2)	—	2.8	8.2
	80.9	91.8	92.1
Project other expense			
Frederickson	—	(28.4)	—
Orlando Cogen, LP	—	—	—
Koma Kulshan Associates (1)	—	—	—
Chambers Cogen, LP	(1.6)	(48.9)	(1.8)
Selkirk Cogen Partners, LP (2)	—	(9.7)	—
	(1.6)	(87.0)	(1.8)
Project income (loss)			
Frederickson	6.9	(27.8)	2.2
Orlando Cogen, LP	30.1	25.6	27.7
Koma Kulshan Associates (1)	0.6	0.7	0.8
Chambers Cogen, LP	5.6	(42.6)	5.5
Selkirk Cogen Partners, LP (2)	—	(10.7)	(0.3)
Equity in earnings (loss) of unconsolidated affiliates	$ 43.2	$ (54.8)	$ 35.9

(1) In July 2018, we purchased the remaining 50% partnership interest in Koma and consolidated the project in our financial statements. Amounts in the above table relate to the period Koma was accounted for under the equity method of accounting. See Note 3 Acquisition and divestments.

(2) In November 2017, we sold our 17.7% interest in Selkirk.

We recorded investment impairments of $47.1 million, $28.3 million and $10.6 million, respectively, at our Chambers, Frederickson and Selkirk projects in the year ended December 31, 2017. These impairments are a component of the operating results in the table above. There were no impairment triggers during 2018 and accordingly no impairment tests were performed on equity method investments.

2017 – Event-driven test in the fourth quarter

Frederickson

In the fourth quarter of 2017, we performed an impairment test of our investment in our Frederickson project. The Frederickson project operates under three PPAs that expire in August 2022. Prior to our impairment analysis, Frederickson was recorded as a $108.3 million component of our equity investments in unconsolidated affiliates on the consolidated balance sheets.

We performed an analysis of the post-PPA value of Frederickson operating as a merchant facility. In our long-term forecast completed in December 2017, we identified a significant decrease in the long-term peak demand outlook for power prices in the Pacific Northwest, the region where Frederickson operates, which management determined to be an other than temporary decline in prices. These forward prices, which were obtained from a third party, had a significant negative impact on the estimated discounted cash flows of Frederickson post-PPA. The estimated post-PPA value is a significant component of the project's overall value when compared to its pre-impairment carrying value of $108.3 million.

When determining if the decrease in fair value estimated in our 2017 test was other than temporary, we considered the likelihood that future conditions would change such that the power prices currently observed in the forward pricing models would become more favorable over time. Frederickson operates in a region with large, planned coal facility retirements and strong population growth. However, it was our assessment that natural gas prices were likely to remain low when considering the current and expected future supply of shale gas and that these factors would negatively impact future merchant pricing. Based on these factors, we determined that the decline in the fair value of our equity investment in Frederickson was other than temporary. We recorded a $28.3 million impairment in earnings from unconsolidated affiliates in the consolidated statements of operations for the year ended December 31, 2017.

2017 – Event-driven test in the second quarter

In the second quarter of 2017, we performed event-driven impairment tests of our investments in our Chambers and Selkirk projects, which are accounted for under the equity method of accounting.

Selkirk

We previously owned a 17.7% limited partner interest in Selkirk Cogen Partners, L.P. The project operated as a merchant facility since the expiration of its PPA in August 2014. Since the expiration of its PPA, we did not receive a distribution from Selkirk and recorded a cumulative $2.6 million project loss. Based on the project's history of providing no cash distributions while operating as a merchant facility, the short-term and long-term operational forecast, as well as the likelihood that further investment would be required in order to operate the facility, we determined that our investment in Selkirk was impaired and the decline in value was other than temporary. Accordingly, we recorded a $10.6 million full impairment in earnings from unconsolidated affiliates in the consolidated statements of operations in the three months ended June 30, 2017. We sold our interest in Selkirk in November 2017 and recorded a $1 million gain on sale in the year ended December 31, 2017. The impairment charge and the gain on sale are both recorded in earnings from unconsolidated affiliates in the statement of operations for the year ended December 31, 2017.

Chambers

We own a 40% limited partner interest in Chambers Cogeneration Limited Partnership. The Chambers project operates under a PPA that expires in March 2024. Prior to our impairment analysis, Chambers was recorded as a $124 million component of our equity investments in unconsolidated affiliates on the consolidated balance sheets.

During the second quarter of 2017, we performed an analysis of the post-PPA value of Chambers operating as a merchant facility. While declining power prices had been observed over the past several years, in our long-term forecast completed in July 2017, we identified a significant decrease in the long-term outlook for power prices in Pennsylvania New Jersey Maryland (“PJM”), the region where Chambers operates, which management determined to be an other than temporary decline in prices. These forward power prices, which were obtained from a third party, including analysis of the forward prices for natural gas and coal, had a significant negative impact on the DCFs of Chambers post-PPA. The estimated post-PPA value is a significant component of the project’s overall value when compared to its carrying value of $124 million.

When determining if this decrease in fair value estimated in our event-driven 2017 test was other than temporary, we considered the likelihood that future conditions would change such that the gas and coal prices currently observed in the forward pricing models would become more favorable over time in order for the plant to be profitable in a merchant market. We also engaged a separate third party to provide its outlook on post-PPA value for Chambers. It was our assessment that future merchant pricing was likely to remain low due to lower natural gas prices from the current and expected future supply of shale gas. The third party provided similar conclusions to our assessment.

Based on these factors, we determined that the decline in the fair value of our equity investment in Chambers was other than temporary. We recorded a $47.1 million impairment in earnings from unconsolidated affiliates in the consolidated statements of operations for the three months ended June 30, 2017.

7. Inventory

Inventory consists of the following:

	December 31,	
	2018	2017
Parts and other consumables	$ 9.6	$ 12.1
Fuel	6.2	5.6
Total inventory	$ 15.8	$ 17.7

8. Property, plant and equipment, net

Property, plant and equipment, net consists of the following:

	December 31, 2018	December 31, 2017	Depreciable Lives
Land	$ 5.3	$ 5.5	
Office equipment, machinery and other	6.0	6.0	3 - 10 years
Leasehold improvements	2.1	2.2	7 - 15 years
Asset retirement obligation	24.1	28.4	1 - 43 years
Plant in service	874.4	942.5	1 - 45 years
	911.9	984.6	
Less accumulated depreciation	(362.4)	(382.3)	
Total property, plant and equipment, net	$ 549.5	$ 602.3	

Depreciation expense of $40.0 million, $83.3 million and $49.5 million, was recorded for the years ended December 31, 2018, 2017 and 2016, respectively.

As described in Note 9, Goodwill and long-lived asset impairment, we recorded $67.6 million of long-lived asset impairments to property, plant and equipment in the year ended December 31, 2017.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

9. Goodwill and long-lived asset impairment

Goodwill Rollforward

The following table is a rollforward of goodwill for the years ended December 31, 2018 and 2017:

Reporting unit	Segment	December 31, 2017	Impairment	Translation adjustment	December 31, 2018
Curtis Palmer	East U.S.	$ 14.4	$ —	$ —	$ 14.4
Morris	East U.S.	3.3	—	—	3.3
Nipigon	Canada	3.6	—	—	3.6
		$ 21.3	$ —	$ —	$ 21.3

Reporting unit	Segment	December 31, 2016	Impairment	Translation adjustment	December 31, 2017
Curtis Palmer	East U.S.	$ 29.1	$ (14.7)	$ —	$ 14.4
Morris	East U.S.	3.3	—	—	3.3
Nipigon	Canada	3.6	—	—	3.6
		$ 36.0	$ (14.7)	$ —	$ 21.3

2018 – Annual test performed in fourth quarter

Goodwill

In the fourth quarter of 2018, we performed our annual goodwill impairment test as of November 30, 2018. All reporting units with goodwill had fair values that exceeded their carrying values and accordingly, no goodwill impairment was recorded. We performed a quantitative test at our Curtis Palmer reporting unit and qualitative assessments at our Morris and Nipigon reporting units. Curtis Palmer's fair value exceeded its carrying value by approximately $8.3 million or 9% at November 30, 2018.

2018 – Event-driven test performed in fourth quarter

Williams Lake – Long-lived assets

Williams Lake operates under a PPA that expires June 30, 2019, or September 30, 2019 at the option of BC Hydro, the project's customer. The near-term expiration of the PPA resulted in a triggering event to test for long-lived asset impairment. We performed the test as of December 31, 2018, six months prior to the earliest contract expiration date. Williams Lake's asset group for testing of long-lived assets totaled $11.4 million consisting of PPE, net and spare parts inventory.

Because of the uncertainty of our ability to recontract the project, we performed a probability-based approach when determining the weighted average fair value of Williams Lake. This approach considered the cash flows remaining under the current contract assuming a September 30, 2019 expiration date, as well as a modeled hypothetical long-term extension. In February 2019, the office of the Minister of Energy, Mines and Petroleum Resources in British Columbia made recommendations that the government could direct BC Hydro to pursue renewal transactions for existing biomass plants with expiring contracts. We considered these factors when creating our modeled hypothetical long-term extension. This model incorporates significant judgments and estimates by management when determining outcome likelihood, as

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

well as long-term extension economics. Williams Lake has approximately 20 years of remaining useful life. We believe that Williams Lake provides value to British Columbia based on its positioning as a renewable resource, its synergy with the local forestry industry and its lower $/KW cost than new biomass construction.

Upon testing Williams Lake for long-lived asset impairment, the estimated weighted-average undiscounted cash flows exceeded the carrying value of the asset group. Accordingly, no long-lived asset impairment was recorded at December 31, 2018. Because of the judgmental aspect of estimating a potential contract extension and the near-term expiration of our current contract, we will continue to update this analysis on a quarterly basis and could record a long-lived asset impairment if circumstances indicate a contract extension is unlikely.

2017 – Annual test performed in fourth quarter

In the fourth quarter of 2017, we performed our annual goodwill impairment test as of November 30, 2017. Of the remaining reporting units with goodwill recorded, Nipigon ($3.6 million of goodwill at December 31, 2017) and Morris ($3.3 million of goodwill at December 31, 2017) had fair values that exceeded their carrying values by approximately $111.7 million or 118% and accordingly, no goodwill impairment was recorded.

Curtis Palmer - Goodwill

In applying the goodwill test, the Curtis Palmer reporting unit's carrying value exceeded its estimated fair value by $14.7 million at November 30, 2017. Accordingly, we recorded a $14.7 million goodwill impairment at Curtis Palmer in the year ended December 31, 2017. Subsequent to the impairment, Curtis Palmer has $14.4 million of goodwill remaining at December 31, 2017. As a hydro facility, Curtis Palmer has substantial useful life beyond the expiration of its PPA in 2027. Estimates of fair value beyond the end of its PPA expiration utilize merchant pricing assumptions and are sensitive to changes in forward power prices. These forward prices declined significantly from those observed in our 2016 test, resulting in a reduction of the fair value from our impairment test performed in the fourth quarter of 2016.

Williams Lake – Long-lived assets

Williams Lake previously operated under a PPA that expired on March 31, 2018 with BC Hydro. BC Hydro elected not to exercise its renewal options under that PPA. Additionally, the Province of British Columbia planned to commence an Integrated Resource Plan Process (IRP) in late 2018. This process is the Province's long-term plan to meet future electricity demand through conservation, generation and transmission and through upgrades to existing infrastructure. At the time of our assessment, we believed that obtaining a long-term PPA extension prior to the conclusion of the IRP was unlikely. In January 2018, the project entered into a PPA extension that commenced on April 1, 2018 and expires June 30, 2019, or September 30, 2019 at the option of BC Hydro. The project entered into this extension in order to bridge the period of the expiration of the previous PPA in March 2018 until the conclusion of the IRP in order to increase the likelihood for the potential of a future long-term extension. The uncertainty of the results of the IRP resulted in a triggering event to test for long-lived asset impairment. We performed the test as of December 31, 2017 in order to include the economics of the January 2018 extension in our long-term cash flow forecasts as the terms of the extension were known at December 31, 2017. Williams Lake's asset group for testing of long-lived assets totaled $40.0 million consisting of $39.4 million in PPE, net and a $0.6 million intangible PPA asset.

Because of the uncertainty of the results of the IRP, we performed a probability-based approach when determining the weighted average fair value of Williams Lake. This approach considered the cash flows under the January 2018 extension, as well as a modeled long-term extension post-IRP incorporating similar economics to the 2018 extension with some additional allowances. These factors incorporated significant judgments and estimates by management when determining outcome likelihood, as well as long-term extension economics. Williams Lake has approximately 22 years of remaining useful life. We believe that Williams Lake provides value to the Province's long-term plan based on its positioning as a renewable resource, its synergy with the local forestry industry and its lower $/KW cost than new biomass construction.

Upon testing Williams Lake for long-lived asset impairment, the carrying value of the asset group exceeded the estimated weighted-average undiscounted cash flows. Because Williams Lake failed the recovery test, we calculated the estimated weighted-average fair value utilizing a probability-based DCF and recorded a $29.1 million long-lived asset impairment in the year ended December 31, 2017, which is the difference between the fair value and carrying value of the reporting unit’s asset group. The impairment was allocated as a $0.6 million full impairment of intangible PPA assets and a $28.5 million partial impairment of property, plant and equipment.

2017 – Event-driven test in the third quarter

In the third quarter of 2017, we performed event-driven long-lived asset impairment tests at Naval Station, North Island and Naval Training Center (“NTC”) (collectively, the “San Diego Projects”).

The San Diego Projects sold power to San Diego Gas & Electric (“SDG&E”) under PPAs that were scheduled to expire in December 2019. In addition, the three projects supplied steam to the U.S. Navy under agreements that provided these projects with the right to use the property at the respective sites on which each project is located (the "Navy agreements"). In August 2017, we were unsuccessful in obtaining contracts to provide the Navy with energy security that would have provided us with the right to use the Naval Station and North Island sites beyond February 2018. Following notification of the outcome of the Navy solicitation, we determined that it was unlikely that these projects will operate beyond the expiration of the Navy agreements. As a result, we performed long-lived asset impairment tests at each of these projects as of July 31, 2017.

In order to test the recoverability of the long-lived assets in the asset groups, we compared the carrying amount of the assets to estimated undiscounted future cash flows expected to be generated by each of the San Diego Projects through their expected decommissioning dates. The carrying value of each asset group includes its recorded property, plant equipment and intangible assets related to PPAs. As a result of this test, we recorded a total $57.3 million impairment ($22.5 million at Naval Station, $13.5 million at NTC and $21.2 million at North Island) in the year ended December 31, 2017. This impairment is composed of an $18.2 million full impairment of intangible assets related to PPAs ($10.3 million at Naval Station, $3.6 million at NTC and $4.2 million at North Island) and a $39.1 million partial impairment of property, plant and equipment ($12.1 million at Naval Station, $9.9 million at NTC and $17.0 million at North Island). At December 31, 2017, the San Diego projects' remaining property, plant and equipment, which represents our estimate of the projects' remaining undiscounted cash flows and salvage values.

We were unable to extend our land use license agreements through the end of our PPAs and ceased operations at these plants on February 7, 2018.

2016 – Annual test performed in fourth quarter

In the fourth quarter of 2016, we performed our annual goodwill impairment test as of November 30, 2016. Of the total remaining reporting units with goodwill recorded, Curtis Palmer ($29.1 million of goodwill at December 31, 2016) and Nipigon ($3.6 million of goodwill at December 31, 2016) passed step 1 of the two step test. The total fair value of these reporting units exceeded their carrying value by approximately $62.7 million or 45%. For our Morris reporting unit, we performed a qualitative assessment and concluded that it was likely that the fair value significantly exceeded the reporting unit's carrying value. The Morris reporting unit has goodwill of $3.3 million and has a PPA with significant remaining time before its expiration and is not significantly impacted by the decrease in the long-term outlook for power prices.

The Moresby Lake reporting units failed step 1 of the two-step test. Accordingly, we performed a step 2 analysis for Moresby Lake and, as a result, recorded a $1.2 million full impairment in the year ended December 31, 2016. Moresby Lake has substantial useful life beyond the expiration of its PPA in 2022. However, Moresby Lake's fair value is estimated using a discounted cash flow approach and is sensitive to changes in forward power prices. These forward prices had declined significantly over the past several years. Moresby failed step 1 in our event-driven impairment test at July 31, 2016, but recorded no impairment as its implied goodwill exceeded its recorded goodwill. The further decline in forward power prices since our event-driven test resulted in the full impairment recorded at November 30, 2016.

2016 – Event-driven test in the third quarter

In the third quarter of 2016, we performed an event-driven goodwill impairment test as of July 31, 2016. While declining power prices had been observed over the past two years, we identified a significant decrease in the long-term outlook for power prices in the regions where our reporting units operate in the third quarter of 2016. Because the estimated future cash flows of our reporting units are sensitive to fluctuations in forward power prices and these prices are the most impactful input in calculating a reporting unit's fair value, we determined that it was appropriate to perform an event-driven impairment test. For two of our reporting units (Morris and Nipigon) we performed a qualitative assessment and concluded that it was likely that the fair values significantly exceed the carrying values. These reporting units have aggregate goodwill of $6.9 million and have PPAs with significant remaining time before their expiration and are not significantly impacted by the decrease in the long-term outlook for power prices.

The other five of the reporting units tested (Curtis Palmer, Mamquam, North Bay, Kapuskasing and Moresby Lake) failed step 1 of our quantitative two step test. Because five reporting units failed step 1 of the two-step goodwill impairment test, we identified a triggering event and initiated a test of the recoverability of their long-lived assets. The asset group for testing the long-lived assets for impairment is the same as the reporting unit for goodwill impairment testing purposes. In order to test the recoverability of the assets in the asset groups, we compared the carrying amount of the assets to estimated undiscounted future cash flows expected to be generated by the asset group. The carrying value of each asset group includes its recorded property, plant equipment, intangible assets related to PPAs and goodwill. Of the five asset groups tested, the North Bay and Kapuskasing asset groups (Canada segment) failed the recoverability test and we recorded property, plant and equipment impairment charges aggregating $5.9 million for the periods ended September 30, 2016. For these asset groups, we estimated their fair value utilizing an income approach based on market participant assumptions. These assumptions include estimated cash flows under the remaining period of their respective PPAs.

Subsequent to recording long-lived asset impairments, we performed the step 2 goodwill impairment test and recorded a $50.2 million full impairment at the Mamquam reporting unit, a $15.4 million partial impairment at the Curtis Palmer reporting unit, a $6.5 million full impairment at the North Bay reporting unit, a $6.7 million full impairment at the Kapuskasing reporting unit and no impairment at the Moresby Lake reporting unit for a total goodwill impairment charge of $78.8 million for the period ended September 30, 2016. At the time of their acquisition in November 2011, the fair value of the assets acquired and liabilities assumed for the Mamquam and Curtis Palmer reporting units were valued assuming a merchant basis for the period subsequent to the expiration of the projects' original PPAs. The forecasted energy revenue on a merchant basis, in the respective markets in which those plants operate, was higher than the energy prices currently forecasted to be in effect subsequent to the expiration of the reporting unit's PPA. Power prices, in the respective markets in which those plants operate, have declined from 2011 and from the dates of our previous impairment assessments due to several factors including decreased demand, lower oil prices and lower natural gas prices resulting from an abundance of shale gas. Our forecasts for discounted cash flows also reflect a higher level of uncertainty for re contracting at prices than were previously forecasted in 2011. The decline in forward power prices for British Columbia since our last goodwill impairment performed as of November 30, 2015, in particular, had a significant impact on the estimated discounted cash flows of our Mamquam reporting unit and was the primary driver for its recorded goodwill impairment. British Columbia's peak demand outlook has declined primarily attributable to a reduction in forecasted liquefaction build and need in the region and the associated loss of power demand. The resulting drop in the peak demand reduces the amount of needed capacity and therefore the capacity prices also were reduced. Furthermore, the PPA at the Curtis Palmer reporting unit expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. Based on Curtis Palmer's cumulative generation through the date of the goodwill impairment test, we anticipate the PPA expiring before December 2027. As a result, the discounted cash flow model for Curtis Palmer utilizes forward power prices for that period that are substantially lower than the prices under the current PPA.

The long-lived asset and goodwill impairment charges were recorded in the third quarter of 2016 and not earlier in the fiscal year because we did not identify any triggering events that would have required an event-driven impairment assessment. Although declining power prices had been observed over the two years prior to the impairment, the significant decrease in the long-term outlook for power prices in the regions where our reporting units operate identified in the third quarter of 2016 had the most significant impact to the key inputs to our long-term forecasted cash flow models. Additionally, the PPAs at our North Bay and Kapuskasing reporting units expire on December 31, 2017. As these projects approach the expiration date, the remaining estimated contracted future cash flows decrease.

The following tables provide a summary of impairment charges by type for the years ended December 31, 2017:

	Year Ended December 31, 2017					
	Curtis Palmer	Williams Lake	Naval Station	North Island	Naval Training Center	Total
Goodwill	$ 14.7	$ —	$ —	$ —	$ —	$ 14.7
Property, plant and equipment	—	28.5	12.1	17.0	10.0	67.6
Power purchase agreement intangible assets	—	0.6	10.4	4.2	3.6	18.8
Total	$ 14.7	$ 29.1	$ 22.5	$ 21.2	$ 13.6	$ 101.1

10. PPAs and other definite-lived intangible assets and liabilities

Other intangible assets and liabilities include PPAs, fuel supply agreements and capitalized development costs.

The following tables summarize the components of our intangible assets and other liabilities subject to amortization at December 31, 2018 and 2017:

Assets

	Other Intangible Assets, Net	
	Power Purchase Agreements	Total
Gross balances, December 31, 2018	$ 362.7	$ 362.7
Less: accumulated amortization	(192.6)	(192.6)
Net carrying amounts, December 31, 2018	$ 170.1	$ 170.1

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

	Other Intangible Assets, Net		
	Power Purchase Agreements	Development Costs	Total
Gross balances, December 31, 2017	$ 476.3	$ 13.0	$ 489.3
Less: accumulated amortization	(285.1)	(13.0)	(298.1)
Net carrying amounts, December 31, 2017	$ 191.2	$ —	$ 191.2

Liabilities

	Power Purchase and Fuel Supply Agreement Liabilities, Net		
	Power Purchase Agreements	Fuel Supply Agreements	Total
Gross balances, December 31, 2018	$ (28.7)	(12.6)	$ (41.3)
Less: accumulated amortization	14.0	6.1	20.1
Net carrying amounts, December 31, 2018	$ (14.7)	$ (6.5)	$ (21.2)

	Power Purchase and Fuel Supply Agreement Liabilities, Net		
	Power Purchase Agreements	Fuel Supply Agreements	Total
Gross balances, December 31, 2017	$ (30.4)	$ (12.6)	$ (43.0)
Less: accumulated amortization	11.6	7.3	18.9
Net carrying amounts, December 31, 2017	$ (18.8)	$ (5.3)	$ (24.1)

The following table presents amortization expense of intangible assets for the years ended December 31, 2018, 2017 and 2016:

	2018	2017	2016
PPAs	$ 43.4	$ 36.5	$ 63.3
Fuel supply agreements	(0.4)	(0.4)	(0.4)
Total amortization	$ 43.0	$ 36.1	$ 62.9

The following table presents estimated future amortization expense for the next five years:

Year Ended December 31,	
2019	$ 25.9
2020	22.7
2021	20.1
2022	15.8
2023	12.5

The weighted average remaining amortization period related to our intangible assets and liabilities was 9.7 years as of December 31, 2018.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

11. Other long term liabilities

Other long term liabilities consist of the following at December 31:

	2018	2017
Net pension liability	1.2	1.9
Accrued LTIP and director share units	1.4	2.2
Other	2.4	2.3
	$ 5.0	$ 6.4

The following table is a rollforward of asset retirement obligations for the years ended December 31:

	2018	2017
Asset retirement obligations beginning of year	$ 45.3	$ 50.3
Accretion and change in estimate of asset retirement obligation	4.3	(6.5)
Acquisition	1.8	—
Costs incurred	(0.5)	—
Translation adjustments	(1.7)	1.5
Asset retirement obligations, end of year	$ 49.2	$ 45.3

In the third quarter of 2017, we performed an event-driven long-lived asset impairment test at our Naval Station, North Island and Naval Training Center projects. See Note 9, Goodwill and long-lived asset impairment for discussion of the facts and circumstances resulting in the impairment. At the time of the assessment, we had not completed our process for estimating decommissioning costs at those facilities. In the fourth quarter of 2017, based on information provided by third parties, we determined that the estimated costs to remove the facilities and return the land to the conditions required under their respective land rights agreements was approximately $1.7 million. Prior to adjustment, we had recorded asset retirement obligations for Naval Station, North Island and Naval Training Center of $6.7 million. These retirement obligations were based on estimates made at the time of their acquisition in November 2011, as well as engineering studies performed at the inception of these projects. These asset retirement obligations were accreted based on inflation and discount rates. As a result of the change in estimate for decommissioning costs, we recorded a $5.0 million decrease to amortization expense in the fourth quarter of 2017. These projects ceased operations in February 2018. Subsequent to their shutdown, we have been actively planning the decommissioning of these facilities. Although the process is not final, changes to both the scope and cost of decommissioning these facilities resulted in a change of estimate of the asset retirement obligation. We increased the asset retirement obligation by $3.5 million and recorded a corresponding decommissioning loss in the consolidated statements of operations for the year ended December 31, 2018. We expect to begin the decommissioning process in 2019 and will further evaluate the asset retirement obligation when both the scope and cost are confirmed and record any changes in estimate as necessary.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

12. Long term debt

Long term debt consists of the following:

	December 31, 2018	December 31, 2017	Interest Rate
Recourse Debt:			
Senior secured term loan facility, due 2023(1)	$ 450.0	$ 540.0	LIBOR(2) plus 2.75 %
Senior unsecured notes, due June 2036 (Cdn$210.0)	154.0	167.4	5.95 %
Non-Recourse Debt:			
Epsilon Power Partners term facility, due 2019 (3)	—	7.2	LIBOR plus 3.125 %
Cadillac term loan, due 2025 (4)	21.0	24.0	LIBOR plus 1.49 %
Other long-term debt	—	0.1	5.50 % - 6.70 %
Less: unamortized discount	(9.0)	(12.8)	
Less: unamortized deferred financing costs	(7.2)	(10.1)	
Less: current maturities	(68.1)	(99.5)	
Total long-term debt	$ 540.7	$ 616.3	

Current maturities consist of the following:

	December 31, 2018	December 31, 2017	Interest Rate
Current Maturities:			
Senior secured term loan facility, due 2023(1)	$ 65.0	$ 90.0	LIBOR(2) plus 2.75 %
Epsilon Power Partners term facility, due 2019 (3)	—	6.5	LIBOR plus 3.125 %
Cadillac term loan, due 2025 (4)	3.1	3.0	LIBOR plus 1.49 %
Total current maturities	$ 68.1	$ 99.5	

(1) On a quarterly basis, we make a cash sweep payment to fund the principal balance, based on terms as defined in the credit agreement and disclosed below. The portion of the Term Loan facility classified as current is based on principal payments required to reduce the aggregate principal amount of Term Loans outstanding to achieve a

target principal amount that declines quarterly based on a pre-determined specified schedule.

(2) LIBOR cannot be less than 1.00%. We have entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $421.5 million of the $450 million outstanding aggregate borrowings under our Term Loan facility at December 31, 2018. See Note 15, Accounting for derivative instruments and hedging activities for further details. On October 31, 2018, the repricing of the senior secured term loan facility became effective, reducing the interest rate to LIBOR plus 2.75% from 3.00% with no change to the 1.00% LIBOR floor.

(3) In June 2018, we pre-paid the remaining $5.6 million principal amount originally due in 2018 and 2019.

(4) We have entered into interest rate swap agreements to economically fix our exposure to changes in interest rates for this non-recourse debt. See Note 15, Accounting for derivative instruments and hedging activities, for further details.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

Principal payments on the maturities of our debt due in the next five years and thereafter are as follows:

2019	$ 68.1
2020	108.1
2021	82.7
2022	78.3
2023	128.3
Thereafter	159.5
	$ 625.0

Credit Facilities

On April 13, 2016, APLP Holdings Limited Partnership (“APLP Holdings”), our wholly-owned subsidiary, entered into new Senior Secured Credit Facilities, comprising $700 million in aggregate principal amount of Senior Secured Term Loan facilities (the “Term Loans”) and $200 million in aggregate principal amount of senior secured credit facilities (the “Revolver” and together with the Term Loans, the “Credit Facilities”). At December 31, 2018, $450.0 million of the Term Loans is outstanding and letters of credit in an aggregate face amount of $76.9 million are issued (but not drawn) pursuant to the revolving commitments under the Revolver and used (i) to fund a debt service reserve in an amount equivalent to six months of debt service, and (ii) to support contractual credit support obligations of APLP Holdings and its subsidiaries and of certain other affiliates of the Company.

Borrowings under Credit Facilities are available in U.S. dollars and Canadian dollars and, at inception, bore interest at a rate equal to the Adjusted Eurodollar Rate, the Base Rate or the Canadian Prime Rate as applicable, plus an applicable margin between 4.00% and 5.00% that varied depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. In April 2017, the repricing of the Credit Facilities became effective reducing the interest rate margin on the term loan and revolver by 0.75% to LIBOR plus 4.25%. In October 2017, a second repricing reduced the interest rate margin on the Credit Facilities by another 0.75% to LIBOR plus 3.50%. In April 2018, a third repricing reduced the interest rate margin on the Credit Facilities by an additional 0.50% to LIBOR plus 3.00% and in October 2018, a fourth repricing reduced the interest rate margin on the Credit Facilities by 0.25% to LIBOR plus 2.75%. We also extended the maturity date of the Revolver by one year through April 2022. The Term Loans mature in April 2023.

The Term Loans include a 3% original issue discount. Letters of credit are available to be issued under the Revolver until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. In addition to paying interest on outstanding principal under the Credit Facilities, APLP Holdings is required to pay a commitment fee of 0.75% times the unused commitments under the Revolver.

The Credit Facilities are secured by a pledge of the equity interests in APLP Holdings and certain of its subsidiaries, guaranties from certain of the subsidiaries of APLP Holdings (the "Subsidiary Guarantors"), a downstream guarantee from the Company, a limited recourse guaranty from Atlantic Power GP II, Inc., the entity that holds all of the equity interest in APLP Holdings, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of APLP Holdings and its subsidiaries (subject to certain exceptions), and certain other assets. The Credit Facilities also have the benefit of a debt service reserve account, which is required to be funded and maintained at the debt service reserve requirement, equal to six months of debt service. The reserve requirement is maintained utilizing a letter of credit. APLP, a wholly-owned, indirect subsidiary of the Company, is a party to an existing indenture governing its Cdn$210 million aggregate principal amount of Medium Term Notes ("MTNs") that prohibits APLP (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, APLP Holdings has granted an equal and ratable security interest in the collateral package securing the Credit Facilities in favor of the trustee under the indenture governing the MTNs for the benefit of the holders of the MTNs.

The Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The negative covenants include a requirement that APLP Holdings and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 5.50:1.00 at December 2018 to 4.25:1.00 from June 30, 2020, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 3.00:1.00 at December 31, 2018 to 4.00:1.00 from June 30, 2022. At December 31, 2018, we were in compliance with these covenants. In addition, the Credit Agreement includes customary restrictions and limitations on APLP Holdings' 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 certain exceptions and other customary carve-outs and various thresholds. Specifically, APLP Holdings may be restricted from making dividend payments or other distributions to Atlantic Power Corporation, and APLP and its subsidiaries may be prohibited from making dividends or distributions to Atlantic Power Preferred Equity Limited shareholders in the event of a covenant default or if APLP Holdings fails to achieve a target principal amount on the new term loan that declines quarterly based on a predetermined specified schedule.

Under the Credit Agreement, if a Change of Control (as defined in the Credit Agreement) occurs, unless APLP Holdings elects to make a voluntary prepayment of the term loans under the Credit Facilities, it 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. In addition, in the event that APLP Holdings elects to repay, prepay, refinance or replace all or any portion of the term loan facilities within six months from the repricing date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid, refinanced or replaced.

The Credit Agreement also contains a mandatory amortization feature and other mandatory prepayment provisions, including prepayments:

from the proceeds of asset sales (except from the sale proceeds of certain excluded projects), insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and with respect to excess cash flows, to be determined by using the greater of (i) 50% of the cash flow of APLP Holdings and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP Holdings and its subsidiaries, debt service on the Credit Facilities and the MTNs, funding of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of Term Loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Failure to achieve the specified target principal amount for any quarter does not constitute a default by APLP Holdings.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of APLP Holdings and its subsidiaries, bankruptcy, material judgments rendered against APLP Holdings or certain of its subsidiaries, certain

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

ERISA or regulatory events, a Change of Control of APLP Holdings (solely with respect to the Revolver), or defaults under certain guaranties and collateral documents securing the Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

Notes of the Partnership

Atlantic Power Limited Partnership (the "Partnership"), a wholly-owned subsidiary acquired on November 5, 2011, has outstanding Cdn$210.0 million ($153.9 million as of December 31, 2018) aggregate principal amount of 5.95% senior unsecured notes, due June 2036 (MTNs). Interest on the MTNs is payable semi-annually at 5.95%. Pursuant to the terms of the MTNs, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. At December 31, 2018, we were in compliance with these covenants. The MTNs are guaranteed by Atlantic Power Corporation and Atlantic Power Preferred Equity Ltd., an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership.

Non Recourse Debt

Project-level debt at our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The loans have certain financial covenants that must be met in order to distribute available cash. At December 31, 2018, all of our projects were in compliance with the covenants contained in project-level debt. Projects that do not meet their debt service coverage ratios are limited from making distributions, but the debt is not callable or subject to acceleration under the terms of their debt agreements.

On October 13, 2017, we repaid the $54.6 million Piedmont term loan due August 2018, in full, with cash on hand. In addition to the principal repayment, we paid $0.1 million of accrued interest, $9.4 million to terminate interest rate swap agreements and wrote off $0.9 million of deferred financing costs. The swap termination costs and deferred financing costs write down was recorded as interest expense in the year ended December 31, 2017.

13. Convertible debentures

The following table provides details related to outstanding convertible debentures:

	December 31, 2018	December 31, 2017
6.00% Debentures due January 2025 (Series E) (Cdn $115.0 million)	$ 84.3	$ —
5.75% Debentures due June 2019 (Series C)	—	42.5
6.00% Debentures due December 2019 (Series D) (Cdn $24.7 million)	18.1	64.5
Less: Unamortized deferred financing costs	(4.6)	(1.6)
Less: Unamortized discount	(4.0)	—
Total current and long-term convertible debentures	$ 93.8	$ 105.4

Series E Debentures

On January 29, 2018, we closed the Series E Debentures Offering of Cdn$100 million aggregate principal amount of Series E Debentures. We also granted the underwriters the option to purchase up to an additional Cdn$15 million aggregate principal amount of Series E Debentures at any time up to 30 days after the date of closing of the Series E Debentures offering to cover over-allotments. The underwriters exercised that option, for the full Cdn$15 million aggregate principal amount, on February 2, 2018.

The Series E Debentures have a maturity date of January 31, 2025. The Series E Debentures bear interest at a rate of 6.00% per year, and are convertible into our common shares at an initial conversion rate of approximately 238.0952 common shares per Cdn$1,000 principal amount, representing a conversion price of Cdn$4.20 per common share. The Series E Debentures may not be redeemed by the Company prior to January 31, 2021 (except in certain limited circumstances following a change of control). On and after January 31, 2021 and prior to January 31, 2023, the Series E Debentures may be redeemed by us, in whole or in part from time to time, on not more than 60 days and not less than 30 days prior notice at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption, provided that the daily volume-weighted average trading price of our common shares on the Toronto Stock Exchange, averaged for the 20 consecutive trading days ending five trading days prior to the date on which notice of redemption is provided, is not less than 125% of the conversion price at the time notice of redemption is given. On and after January 31, 2023 and prior to the maturity date, the Series E Debentures may be redeemed in whole or in part from time to time, on not more than 60 days and not less than 30 days prior notice, at a redemption price equal to their principal amount plus accrued and unpaid interest, if any, up to but excluding the date set for redemption. The Series E Debentures are our direct, subordinated, unsecured obligations and rank equally with the other series of debentures and with all other future subordinated unsecured indebtedness and rank subordinate to all of our existing and future senior indebtedness.

On the initial closing date, we received net proceeds from the Series E Debentures offering, after deducting the underwriting fee and expenses, of approximately Cdn$94.7 million. We received an additional Cdn$14.4 million of net proceeds from the exercise of the over-allotment option. On March 2, 2018, we redeemed all of the $42.5 million remaining principal amount of Series C Debentures with the use of a portion of the proceeds from the Series E Debentures Offering. On March 3, 2018, we redeemed Cdn$56.2 million principal amount of the Series D Debentures with the remaining proceeds from the Series E Debentures Offering.

Series D Debentures

At December 31, 2018, we had $18.1 million (Cdn$24.7 million) principal amount outstanding 6.00% Debentures due December 2019 (the “Series D Debentures”). We pay interest semi annually on the last day of June and December of each year for the Series D Debentures. They are convertible into our common shares at an initial conversion rate of 68.9655 common shares per Cdn$1,000 principal amount, representing a conversion price of Cdn$14.50 per common share. On March 3, 2018, we redeemed Cdn$56.2 million principal amount of the Series D Debentures with a portion of the proceeds from the Series E Debentures Offering.

Series C Debentures

On March 2, 2018, we redeemed all of the $42.5 million remaining principal amount of Series C Debentures with the use of a portion of the proceeds from the Series E Debentures Offering.

Series E Conversion Option

We assessed the conversion option of the Series E Debentures and determined it should be separated from the host instrument and accounted for as an embedded derivative liability as the conversion option is in a currency different from our functional currency. Changes in the fair value of the conversion option derivative are recorded in the consolidated statements of operation. The conversion option derivative was initially measured at fair value ($4.7 million), with the host contract carried at a value equal to the difference between the carrying value of the Series E Debenture and the fair value of the derivative. Accordingly, no gain or loss was recorded on the initial measurement of the derivative. The fair value of the conversion option derivative was $1.2 million as of December 31, 2018. The portion of the proceeds allocated to the separated derivative also created a discount of $4.7 million, which will be amortized to interest expense over the maturity period of the Series E Debentures. For additional information, see Note 15, Accounting for derivative instruments and hedging activities.

14. Fair value of financial instruments

The estimated carrying values and fair values of our recorded financial instruments related to operations are as follows:

	December 31, 2018		2017	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	$ 68.3	$ 68.3	$ 78.7	$ 78.7
Restricted cash	2.1	2.1	6.2	6.2
Derivative assets current	4.2	4.2	2.7	2.7
Derivative assets non-current	0.3	0.3	2.8	2.8
Derivative liabilities current	4.5	4.5	4.4	4.4
Derivative liabilities non-current	15.4	15.4	19.9	19.9
Long-term debt, including current portion	625.0	607.6	738.7	749.3
Convertible debentures	102.4	101.8	107.0	108.1

Our financial instruments that are recorded at fair value have been classified into levels using a fair value hierarchy.

The three levels of the fair value hierarchy are defined below:

Level 1—Unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Financial assets utilizing Level 1 inputs include active exchange traded securities.

Level 2—Quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.

Level 3—Unobservable inputs from objective sources. These inputs may be based on entity specific inputs. Level 3 inputs include all inputs that do not meet the requirements of Level 1 or Level 2.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of December 31, 2018 and December 31, 2017. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	December 31, 2018			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 68.3	$ —	$ —	$ 68.3
Restricted cash	2.1	—	—	2.1
Derivative instruments asset	—	4.5	—	4.5
Total	$ 70.4	$ 4.5	$ —	$ 74.9
Liabilities:				
Derivative instruments liability	$ —	$ 18.7	$ 1.2	$ 19.9
Total	$ —	$ 18.7	$ 1.2	$ 19.9

	December 31, 2017			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 78.7	$ —	$ —	$ 78.7
Restricted cash	6.2	—	—	6.2
Derivative instruments asset	—	5.5	—	5.5
Total	$ 84.9	$ 5.5	$ —	$ 90.4
Liabilities:				
Derivative instruments liability	$ —	$ 24.3	$ —	$ 24.3
Total	$ —	$ 24.3	$ —	$ 24.3

For cash and cash equivalents and restricted cash, the carrying amount approximates fair value because of the short-term maturity of those instruments and are classified as Level 1 within the fair value hierarchy.

The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk free interest rate.

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of December 31, 2018, the credit valuation adjustments resulted in a $1.0 million net increase in fair value, which consists of a $0.1 million pre tax gain in other comprehensive income and a $0.9 million gain in change in fair value of derivative instruments. As of December 31, 2017, the credit valuation adjustments resulted in a $2.2 million net increase in fair value, which consists of a $0.2 million pre tax gain in other comprehensive income and a $2.0 million gain in change in fair value of derivative instruments.

The carrying amounts for cash and cash equivalents and restricted cash approximate fair value due to their short term nature. The fair value of long term debt and convertible debentures was determined using quoted market prices, as well as discounting the remaining contractual cash flows using a rate at which we could issue debt with a similar maturity as of the balance sheet date.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

The conversion option derivative for the Series E Debentures is classified within Level 3 of the fair value hierarchy. The significant unobservable inputs used in developing fair value include the volatility of our common shares and the fair value of the host contract, which is derived from recent similar convertible debenture offerings from peer companies. A discounted cash flow valuation technique is utilized to calculate to fair value of the conversion option derivative.

The following table reconciles, for the year ended December 31, 2018, the beginning and ending balances for the conversion option derivative liability that is recognized at fair value in the consolidated financial statements, using significant unobservable inputs:

	Fair value Measurement Using Significant Unobservable Inputs (Level 3) Year ended December 31, 2018
Balance of liability at inception (January 2018)	$ 4.7
Total unrealized gain	(3.2)
Currency transaction gain	(0.3)
Ending balance of liability at December 31, 2018	$ 1.2

15. Accounting for derivative instruments and hedging activities

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. We have one contract designated as a cash flow hedge, and we defer the effective portion of the change in fair value of the derivatives in accumulated other comprehensive income (loss), until the hedged transactions occur and are recognized in earnings (loss). The ineffective portion of a cash flow hedge is immediately recognized in earnings (loss). For our other derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in earnings (loss). These guidelines apply to our natural gas swaps, interest rate swaps, and foreign exchange contracts.

Gas purchase and sale agreements

We have a gas purchase agreement at our Nipigon project that expires on December 31, 2022 under which we purchase a minimum of 6,500 Gigajoules (“Gj”) of natural gas per day at a price of Cdn$4.57 per Gj. This agreement does not qualify for the normal purchase normal sales (“NPNS”) exemption and is accounted for as a derivative financial instrument because we could not conclude that it is probable that this contract will not settle net and will result in physical delivery. This derivative financial instrument is recorded in the consolidated balance sheets at fair value and the changes in its fair market value is recorded in the consolidated statements of operations. We also have a corresponding gas sales agreement at Nipigon, whereby of 6,500 Gj of natural gas per day is sold at the spot market price. This contract is not accounted for as a derivative.

We have also entered into various natural gas sales and purchase agreements for approximately 700,000 MMBtu to effectively mitigate seasonal fluctuation of future natural gas price at Morris from January 2019 through February 2019. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2018. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

Natural gas swaps

Our strategy to mitigate future exposure to changes in natural gas prices at our projects consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

We have entered into various natural gas swaps to effectively fix the price of 16.3 million MMBtu of future natural gas purchases at our Orlando project, which is approximately 100% of our share of the expected natural gas purchases in 2019 through 2022. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2018. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

Interest rate swaps

Atlantic Power Limited Partnership Holdings ("APLP Holdings") has entered into several interest rate swap agreements to mitigate its exposure to changes in interest at the Adjusted Eurodollar Rate. At December 31, 2018, these agreements totaled $421.5 million notional amount of the remaining $450.0 million aggregate principal amount of borrowings under the senior secured term loan facility ("Term Loan Facility"). These interest rate swap agreements expire at various dates through March 31, 2020. Borrowings under the $700.0 million Term Loan Facility bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 2.75%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00%, resulting in a minimum of a 3.75% all-in rate on the Term Loan Facility for the non-swapped portion of the remaining principal amount. The weighted average rate of these swap agreements is 1.27%, resulting in an all-in rate of approximately 4.02% for $421.5 million of the Term Loan Facility. In January 2018, APLP Holdings entered into additional interest rate swap agreements. For the period beginning September 30, 2018 through September 30, 2019, we mitigated exposure to changes in interest rates for $100 million notional amount at a one-month LIBOR fixed rate of 2.18% and for the period beginning October 1, 2019 through December 31, 2020, for $200 million notional amount at a one-month LIBOR fixed rate of 2.42%.

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.1% through February 15, 2019, 6.3% from February 16, 2019 to February 15, 2023, and 6.4% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies for and is designated as a cash flow hedge, is effective through June 2025 and the effective portion of the changes in the fair market value is recorded in accumulated other comprehensive income (loss).

Foreign currency forward contracts

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates as we generate cash flow in U.S. dollars and Canadian dollars. We currently have Canadian dollar payment obligations for preferred dividends, interest on our Canadian dollar-denominated convertible debentures and our MTNs. Principal and interest payments for our senior secured term loans as well as our U.S. dollar-denominated convertible debentures are made in U.S. dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the future interest and principal payments, preferred dividends and other working capital requirements. Foreign currency forward contracts are not designated as hedges, and changes in their market value are recorded in foreign exchange on the consolidated statements of operations. As of December 31, 2018, we have no foreign currency forward contracts.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

Volume of forecasted transactions

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the NPNS exemption at December 31, 2018 and December 31, 2017:

	Units	December 31, 2018	December 31, 2017
Natural gas swaps	Natural Gas (Mmbtu)	16.3	9.9
Gas purchase agreements	Natural Gas (Gigajoules)	9.0	9.9
Interest rate swaps	Interest (US$)	616.6	412.6
Foreign currency forward contracts	Dollars (Cdn$)	—	25.0

Fair value of derivative instruments

We have elected to disclose derivative instrument assets and liabilities on a trade by trade basis and do not offset amounts at the counterparty master agreement level. The following table summarizes the fair value of our derivative assets and liabilities:

	December 31, 2018	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.4
Interest rate swaps long-term	—	1.0
Total derivative instruments designated as cash flow hedges	—	1.4
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	4.2	—
Interest rate swaps long-term	0.3	—
Natural gas swaps current	—	0.1

Natural gas swaps long-term	—	1.4
Gas purchase agreements current	—	2.8
Gas purchase agreements long-term	—	13.0
Convertible debenture conversion option	—	1.2
Total derivative instruments not designated as cash flow hedges	4.5	18.5
Total derivative instruments	$ 4.5	$ 19.9

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

	December 31, 2017	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.6
Interest rate swaps long-term	—	1.5
Total derivative instruments designated as cash flow hedges	—	2.1
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	2.7	—
Interest rate swaps long-term	2.8	—
Natural gas swaps current	—	0.8
Natural gas swaps long-term	—	0.2
Gas purchase agreements current	—	2.9
Gas purchase agreements long-term	—	18.2
Foreign currency forward contracts current	—	0.1
Total derivative instruments not designated as cash flow hedges	5.5	22.2
Total derivative instruments	$ 5.5	$ 24.3

Accumulated other comprehensive income

The following table summarizes the changes in the accumulated other comprehensive income ("OCI") balance attributable to derivative financial instruments designated as a hedge, net of tax:

Year Ended December 31, 2018	Interest Rate Swaps
Accumulated OCI balance at January 1, 2018	$ 1.1
Change in fair value of cash flow hedges	0.4
Realized from OCI during the period	0.1
Accumulated OCI balance at December 31, 2018	$ 1.6
Settlements expected to be recognized from OCI in expense in the next 12 months, net of $0.2 million of tax	$ 0.5

Year Ended December 31, 2017	Interest Rate Swaps
Accumulated OCI balance at January 1, 2017	$ 0.7
Change in fair value of cash flow hedges	(0.1)
Realized from OCI during the period	0.5
Accumulated OCI balance at December 31, 2017	$ 1.1

Year Ended December 31, 2016	Interest Rate Swaps
Accumulated OCI balance at January 1, 2016	$ 0.2
Change in fair value of cash flow hedges	(0.2)
Realized from OCI during the period	0.7
Accumulated OCI balance at December 31, 2016	$ 0.7

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

Impact of derivative instruments on the consolidated statements of operations

The following table summarizes realized loss (gain) for derivative instruments not designated as cash flow hedges:

	Classification of loss (gain) recognized in income	Year Ended December 31, 2018	2017	2016
Gas purchase agreements	Fuel	$ 4.1	$ 7.5	$ 48.5
Natural gas swaps	Fuel	0.3	0.4	4.9
Interest rate swaps	Interest, net	(3.3)	0.9	3.9

The following table summarizes the unrealized gain (loss) resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

	Classification of (loss) gain recognized in income	Year ended December 31, 2018	2017	2016
Natural gas swaps	Change in fair value of derivatives	$ (0.5)	$ (1.8)	$ 9.0
Gas purchase agreements	Change in fair value of derivatives	3.7	(5.0)	22.8
Interest rate swaps	Change in fair value of derivatives	(1.0)	8.9	6.1
		2.2	2.1	37.9
Convertible debenture conversion option	Other income, net	(1.2)	—	—
Foreign currency forwards	Foreign exchange (loss) gain	$ —	$ 0.1	$ —

16. Income tax expense

The following table summarizes the current and deferred portions of the net income tax expense (benefit):

	Year Ended December 31		
	2018	2017	2016
Current income tax expense	$ 3.8	$ 4.1	$ 2.9
Deferred income tax benefit	(3.6)	(62.2)	(17.5)
Total income tax expense (benefit), net	$ 0.2	$ (58.1)	$ (14.6)

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

The following is a reconciliation of the income taxes calculated at the Canadian enacted statutory rate of 27% for the years ended December 31, 2018, 2017 and 2016, respectively, to the provision for income taxes in the consolidated statements of operations:

	Year ended December 31,		
	2018	2017	2016
Income (loss) before income taxes	$ 37.4	$ (151.1)	$ (128.5)
Computed income taxes at 27% Canadian statutory rate	10.1	(39.3)	(33.4)
Decreases resulting from:			
Operating countries with different income tax rates	0.1	(20.1)	(2.9)
	10.2	(59.4)	(36.3)
Change in valuation allowance	(6.7)	(34.6)	10.8
	3.5	(94.0)	(25.5)
Dividend withholding tax and other cash taxes	0.5	0.2	(0.4)
Foreign exchange	—	(2.4)	6.9
Changes in tax rates	(3.3)	(1.5)	(1.5)
Remeasurement of deferred tax assets and liabilities	—	28.5	—
Capital loss on intercompany notes	(1.1)	(0.1)	(0.2)
Impairments	—	9.9	22.3
Capital loss recognized on tax restructuring	—	—	(18.0)
Other	0.6	1.3	1.8
	(3.3)	35.9	10.9
Income tax expense (benefit)	$ 0.2	$ (58.1)	$ (14.6)
Effective income tax rate	1 %	38 %	11 %

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2018 and 2017 are presented below:

	2018	2017
Deferred tax assets:		
Loss carryforwards	$ 163.3	$ 157.7
Capital loss carryforwards	34.4	35.4
Interest expense limitation carryforwards	10.9	—
Finance and share issuance costs	0.5	3.0
Tax credits	1.4	1.4

Stock-based compensation	2.9	2.8
Derivative contracts	3.2	4.0
Other long-term notes	1.5	1.1
Other	—	2.2
Total deferred tax assets	218.1	207.6
Valuation allowance	(139.7)	(151.4)
	78.4	56.2
Deferred tax liabilities:		
Intangible assets	(30.0)	(27.9)
Property, plant and equipment	(57.4)	(40.0)
Total deferred tax liabilities	(87.4)	(67.9)
Net deferred tax liability	$ (9.0)	$ (11.7)

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

The following table summarizes the net deferred tax position as of December 31, 2018 and 2017:

	2018	2017
Long-term deferred liability	$ (9.0)	$ (11.7)
Net deferred tax liability	$ (9.0)	$ (11.7)

As of December 31, 2018, we have recorded a valuation allowance of $139.7 million. This amount is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax asset will be realized. The ultimate realization of the deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

Tax benefits related to uncertain tax positions taken or expected to be taken on a tax return are recorded when such benefits meet a more likely than not threshold. Otherwise, these tax benefits are recorded when a tax position has been effectively settled, which means that the statute of limitations has expired or the appropriate taxing authority has completed their examination even though the statute of limitations remains open. Interest and penalties related to uncertain tax positions are recognized as part of the provision for income taxes and are accrued beginning in the period that such interest and penalties would be applicable under relevant tax law until such time that the related tax benefits are recognized. As of December 31, 2018, we have not recorded any tax benefits related to uncertain tax positions.

On December 22, 2017, the Tax Cuts and Jobs Act of 2017 was signed into law, making significant changes to the U.S. Internal Revenue Code of 1986, as amended (the "Internal Revenue Code"). The 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, which were reflected in our 2017 year-end financials, limitation on the deduction of net business interest expense, and base erosion and anti-abuse tax. Based on estimates as of the date of this filing, we will not be subject to the base erosion and anti-abuse tax. Our interest expense deduction may be limited, but it will not have a material impact on cash taxes.

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.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

As of December 31, 2018, we had the following net operating loss carryforwards that are scheduled to expire in the following years:

2027	$ 4.0
2028	69.1
2029	70.2
2030	25.8
2031	13.4
2032	24.6
2033	145.5
2034	164.4
2035	17.0
2036	35.9
2037	8.4
2038	9.1
	$ 587.4

17. Equity compensation plans

Long term incentive plan ("LTIP")

The following table summarizes the changes in outstanding LTIP notional units during the years ended December 31, 2018, 2017 and 2016:

	Units	Grant Date Weighted-Average Fair Value per Unit
Outstanding at December 31, 2015	1,298,401	2.88

Granted	1,594,954		1.81
Vested and redeemed	(784,806)		2.83
Forfeitures	(7,431)		2.71
Outstanding at December 31, 2016	2,101,118		2.08
Granted	1,817,463		2.38
Vested and redeemed	(1,009,780)		2.22
Forfeitures	(24,227)		2.32
Outstanding at December 31, 2017	2,884,574		2.22
Granted	2,483,237		2.02
Vested and redeemed	(1,388,671)		2.22
Forfeitures	(26,939)		2.09
Outstanding at December 31, 2018	3,952,201	$	2.09

The total grant date fair value of all outstanding notional units under the LTIP was $8.3 million, $6.4 million and $4.4 million for the years ended December 31, 2018, 2017 and 2016. The weighted average remaining vesting term for outstanding notional units was 1.8 years at December 31, 2018. Approximately $4.1 million of total unrecognized compensation expense is expected to be recognized over the term of the outstanding LTIP units. Compensation expense related to LTIP was $3.6 million, $3.4 million and $2.8 million for the years ended December 31, 2018, 2017 and 2016, respectively. Cash payments made for vested notional units were $0.9 million, $0.7 million and $0.5 million for the years ended December 31, 2018, 2017 and 2016, respectively.

Transition Equity Participation Agreement

We also have 539,904 transition notional shares outstanding at December 31, 2018 under the Transition Equity Participation Agreement with James J. Moore, Jr. Fifty percent (269,952) of the transition notional shares granted vested on January 22, 2019, the four-year anniversary of the date of grant and the remaining portion will vest on or any time after the two-year anniversary of the grant if the weighted average Canadian dollar closing price of our common shares on the TSX for at least three consecutive calendar months has exceeded the market price per common share determined as of January 22, 2015 (Cdn$3.18) by at least 50%.

18. Employee benefit plans

Defined benefit pension plan

We sponsor and operate a defined benefit pension plan that is available to certain legacy employees of Atlantic Power Limited. The Atlantic Power Services Canada LP Pension Plan (the "Plan") is maintained solely for certain eligible legacy Partnership participants. The Plan is a defined benefit pension plan that allows for employee contributions. We expect to contribute $0.3 million to the pension plan in 2019.

The net annual periodic pension cost related to the pension plan for the years ended December 31, 2018, 2017 and 2016 includes the following components:

	2018	2017	2016
Service cost benefits earned	$ 0.3	$ 0.5	$ 0.7
Interest cost on benefit obligation	0.5	0.6	0.7
Expected return on plan assets	(0.7)	(0.9)	(0.9)
Net period benefit cost	$ 0.1	$ 0.2	$ 0.5

F-51

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

A comparison of the pension benefit obligation and related plan assets for the pension plan at December 31 is as follows:

	2018	2017
Project benefit obligation at January 1	$ (15.8)	$ (17.4)
Service cost	(0.3)	(0.5)
Interest cost	(0.5)	(0.6)
Actuarial loss (gain)	1.4	(0.9)
Employee contributions	(0.1)	(0.1)
Benefits paid	0.8	0.2
Settlements	—	4.5
Foreign currency adjustment	1.3	(1.0)
Projected benefit obligation at December 31	(13.2)	(15.8)
Fair value of plan assets at January 1	$ 13.9	$ 16.1
Actual return on plan assets	(0.4)	1.1
Employer contributions	0.4	1.3
Employee contributions	0.1	0.1
Benefits paid	(0.8)	(0.2)
Settlements	—	(5.4)
Foreign currency adjustment	(1.2)	0.9
Fair value of plan assets at December 31	12.0	13.9
Funded status at December 31-excess of obligation over assets	$ (1.2)	$ (1.9)

Amounts recognized in the balance sheet at December 31 were as follows:

	2018	2017
Non-current liabilities	$ 1.2	$ 1.9

Amounts recognized in accumulated OCL that have not yet been recognized as components of net periodic benefit cost were as follows, net of tax:

	2018	2017
Unrecognized loss	$ 1.4	$ 1.6

We estimate that there will be no amortization of net loss for the pension plan from accumulated OCI to net periodic cost over the next fiscal year.

The following table presents the balances of significant components of the pension plan:

	2018	2017
Projected benefit obligation	$ 13.2	$ 15.8
Accumulated benefit obligation	12.2	14.4
Fair value of plan assets	12.0	13.9

The market related value of the pension plan's assets is the fair value of the assets. Plan assets are invested in a common collective trust which totaled $12.0 million and $13.9 million for the years ended December 31, 2018 and 2017, respectively.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

We determine the level in the fair value hierarchy within which the fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety. The fair value of the common/collective trust is valued at a fair value which is equal to the sum of the market value of the fund's investments, and is categorized as Level 2. There are no investments categorized as Level 1 or 3.

The following table presents the significant assumptions used to calculate our benefit obligations:

	2018	2017
Weighted-Average Assumptions		
Discount rate	4.0 %	3.5 %
Rate of compensation increase	2.0 %	2.0 %

The following table presents the significant assumptions used to calculate our benefit expense:

	2018	2017	2016
Weighted-Average Assumptions			
Discount rate	3.5 %	4.0 %	4.3 %
Rate of return on plan assets	5.8 %	5.8 %	5.8 %
Rate of compensation increase	2.0 %	2.0 %	3.0 %

We use December 31 as the measurement date for the Plan, and we set the discount rate assumptions on an annual basis on the measurement date. This rate is determined by management based on information agreed with our actuary. The discount rate assumptions reflect the current rate at which the associated liabilities could be effectively settled at the end of the year. The discount rate assumptions used to determine future pension obligations as of the year ended December 31, 2018, 2017 and 2016, were based on the CIA / Natcan curve, which was designed by the Canadian Institute of Actuaries and Natcan Investment Management to provide a means for sponsors of Canadian plans to value the liabilities of their postretirement benefit plans. The CIA / Natcan curve is a hypothetical yield curve represented by extrapolating the corporate AA rated yield curve beyond 10 years using yields on provincial AA bonds with a spread added to the provincial AA yields to approximate the difference between corporate AA and provincial AA credit risk. The CIA / Natcan curve utilizes this approach because there are very few corporate bonds rated AA or above with maturities of 10 years or more in Canada.

We employ a balanced total return investment approach, whereby a mix of equities and fixed income investments are used to maximize the long term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, and the plan's funded status. Plan assets in the common collective trust are currently invested in a diversified blend of equity and fixed income investments. Furthermore, equity investments are diversified across Canadian, U.S. and other international equities, as well as among growth, value and small and large capitalization stocks.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

The pension plan assets weighted average allocations in the common collective trust were as follows:

	2018		2017	
Canadian equity	29	%	30	%
U.S. equity	14	%	14	%
International equity	13	%	14	%
Canadian fixed income	41	%	39	%
Real estate equities	3	%	—	%
International fixed income	—	%	3	%
	100	%	100	%

Our expected future benefit payments for each of the next five years and in the aggregate for the five years thereafter, are as follows in Cdn$:

	2018	
2019	Cdn$	0.4
2020		0.4
2021		0.5
2022		0.6
2023		0.7
2024-2028		4.4

Defined Contribution Plans

We maintain a 401(k) retirement savings plan, registered retirement savings plan, and another defined contribution plan for the benefit of our eligible employees. Substantially all of our employees who meet certain service and age requirements are eligible to participate in these plans. Our plan documents provide that any matching contributions by us are discretionary. We have made or accrued matching contributions to these plans of $1.4 million, $1.2 million, and $1.4 million for the years ended December 31, 2018, 2017 and 2016, respectively.

19. Common shares

Our common shares have no par value and unlimited authorization. We had 108,341,738 and 115,211,976 common shares issued and outstanding at December 31, 2018 and December 31, 2017, respectively.

Stock Repurchase Program

On December 31, 2018, we commenced new NCIBs for 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 new NCIBs expire on December 30, 2019. Under the new NCIBs, 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 new 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.

During the year ended December 31, 2018, we repurchased and canceled 7,772,971 common shares at a total cost of approximately $16.6 million. In the year ended December 31, 2017, we repurchased and canceled 93,391 common shares at a total cost of approximately $0.2 million.

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.

Shelf Registration

On February 9, 2016, we announced the elimination of our common stock dividend, effective immediately. In conjunction with the elimination of the common stock dividend, our dividend reinvestment plan (the “Plan”) also was eliminated. We filed a post-effective amendment to our registration statement on Form S-3 (Registration No. 333-194204) to deregister all of the Company’s common shares that remain unissued under the Plan.

20. Preferred shares issued by a subsidiary company

In 2007, a subsidiary acquired in our acquisition of the Partnership issued 5.0 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the “Series 1 Shares”) priced at Cdn$25.00 per share. Cumulative dividends are payable on a quarterly basis at the annual rate of Cdn$1.2125 per share. Beginning on June 30, 2012, the Series 1 Shares were redeemable by the subsidiary company at Cdn$26.00 per share, declining by Cdn$0.25 each year to Cdn$25.00 per share on or after June 30, 2016, plus, in each case, an amount equal to all accrued and unpaid dividends thereon.

In 2009, a subsidiary company acquired in our acquisition of the Partnership issued 4.0 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the “Series 2 Shares”) priced at Cdn$25.00 per share. The Series 2 Shares pay fixed cumulative dividends of Cdn$1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate was reset on December 31, 2014 and will reset every five years thereafter at a rate equal to the sum of the then five year Government of Canada bond yield and 4.18%. On December 31, 2014 and on December 31 every five years thereafter, the Series 2 Shares were and will be redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all declared and unpaid dividends thereon to, but excluding the date fixed for redemption. The holders of the Series 2 Shares had and will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the” Series 3 Shares”) of the subsidiary, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the subsidiary, at a rate equal to the sum of the then 90 day Government of Canada Treasury bill rate and 4.18%. On December 31, 2014, 1,661,906 of Series 2 shares were converted to Series 3 shares.

The Series 1 Shares, the Series 2 Shares and the Series 3 Shares are fully and unconditionally guaranteed by us and by the Partnership on a subordinated basis as to: (i) the payment of dividends, as and when declared; (ii) the payment of amounts due on a redemption for cash; and (iii) the payment of amounts due on the liquidation, dissolution or winding up of the subsidiary company. If, and for so long as, the declaration or payment of dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares is in arrears, the Partnership will not make any distributions on its limited partnership units and we will not pay any dividends on our common shares.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

The Series 1, 2 and 3 Shares are accounted for as a non-controlling interest on our consolidated balance sheets and consolidated statements of operations. The subsidiary company paid aggregate dividends of $8.3 million, $8.7 million and $8.5 million for the years ended December 31, 2018, 2017 and 2016, respectively. In 2018, we repurchased and cancelled 475,000 of the Series 1 Shares at Cdn$15.27 per share for Cdn$7.3 million. We also purchased and cancelled 5,000 and 164,790 of the Series 2 and 3 Shares at Cdn$17.99 and Cdn$17.89 per share for Cdn$0.1 million and Cdn$2.9 million, respectively for a total cost of $8.0 million. A $7.9 million gain on the redemption was recorded as a component of income attributable to preferred shares of a subsidiary company in the year ended December 31, 2018. From December 31, 2018 through February 27, 2019, we purchased the maximum limit of 427,500 shares of Series 1 Preferred Shares, 27,777 of Series 2 Preferred Shares and the maximum limit of 148,311 Series 3 Preferred Shares at a total cost of Cdn$9.2 million.

21. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing net income (loss) attributable to Atlantic Power Corporation by the weighted average common shares outstanding during their respective periods. Shares issued and shares repurchased during the year are weighted for the portion of the year that they were outstanding. Diluted earnings (loss) per share is computed in a manner consistent with that of basic earnings (loss) per share while giving effect to all potentially dilutive common shares that were outstanding during the period. The dilutive effect of our convertible debentures is calculated using the “if-converted method.” Under the if-converted method, the debentures are assumed to be converted at the beginning of the period, and the resulting common shares are included in the denominator of the diluted earnings (loss) per share calculation for the entire period being presented. Interest expense, net of any income tax effects, would be added back to the numerator for purposes of the if-converted calculation. The outstanding equity compensation for non-vested LTIP and Transition Equity Participation Agreement notional shares are not considered outstanding for purposes of computing basic earnings (loss) per share. However, these instruments are included in the denominator, when dilutive, for purposes of computing diluted earnings (loss) per share under the treasury stock method.

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the years ended December 31, 2018, 2017 and 2016:

Basic	2018	2017	2016
Numerator:			

Income (loss) attributable to Atlantic Power Corporation	$ 36.8	$ (98.6)	$ (122.4)
Denominator:			
Weighted average basic shares outstanding	112.0	115.1	119.5
Basic earnings (loss) per share attributable to Atlantic Power Corporation	$ 0.33	$ (0.86)	$ (1.02)
Diluted			
Numerator:			
Net income (loss) attributable to Atlantic Power Corporation	36.8	(98.6)	(122.4)
Add: convertible debenture interest expense	4.7	—	—
	41.5	(98.6)	(122.4)
Denominator:			
Weighted average basic shares outstanding	112.0	115.1	119.5
Convertible debentures	27.8	—	—
Share-based compensation	2.0	—	—
	141.8	115.1	119.5
Diluted earnings (loss) per share attributable to Atlantic Power Corporation	0.29	(0.86)	(1.02)

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

The following table summarizes our outstanding instruments that are anti-dilutive and were not included in the computation of our diluted (loss) earnings per share:

	2018	2017	2016
Share-based compensation	—	1.6	1.4
Convertible debentures	—	8.1	13.1
Total	—	9.7	14.5

22. Segment and geographic information

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. We analyze the performance of our operating segments based on Project Adjusted EBITDA which 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 use Project Adjusted EBITDA to provide comparative information about segment performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. Our equity investments in unconsolidated affiliates are presented on a proportionally consolidated basis in Project Adjusted EBITDA and in the reconciliation of Project Adjusted EBITDA to project income (loss).

A reconciliation of Project Adjusted EBITDA to net income (loss) is included in the tables below:

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Year Ended December 31, 2018					
Project revenues	$ 158.7	$ 43.8	$ 78.9	$ 0.9	$ 282.3

Segment assets	585.3	176.0	182.3	80.9	1,024.5
Goodwill	17.7	—	3.6	—	21.3
Capital expenditures	1.3	0.1	0.1	0.3	1.8
Project Adjusted EBITDA	$ 120.8	$ 21.9	$ 41.9	$ 0.5	$ 185.1
Change in fair value of derivative instruments	0.4	—	(3.6)	1.0	(2.2)
Depreciation and amortization	46.1	25.0	28.5	0.1	99.7
Interest, net	3.4	—	—	—	3.4
Other project income	—	(4.0)	—	—	(4.0)
Project income (loss)	70.9	0.9	17.0	(0.6)	88.2
Administration	—	—	—	23.9	23.9
Interest expense, net	—	—	—	52.7	52.7
Foreign exchange gain	—	—	—	(22.8)	(22.8)
Other income, net	—	—	—	(3.0)	(3.0)
Net income (loss) before income taxes	70.9	0.9	17.0	(51.4)	37.4
Income tax expense	—	—	—	0.2	0.2
Net income (loss)	$ 70.9	$ 0.9	$ 17.0	$ (51.6)	$ 37.2

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Year Ended December 31, 2017					
Project revenues	$ 152.5	$ 108.9	$ 168.6	$ 1.0	$ 431.0
Segment assets	632.4	189.9	239.6	96.9	1,158.8
Goodwill	17.7	—	3.6	—	21.3
Capital expenditures	4.6	0.1	0.8	—	5.5
Project Adjusted EBITDA	$ 112.5	$ 49.1	$ 125.8	$ 1.4	$ 288.8
Change in fair value of derivative instruments	(6.3)	—	6.1	(1.9)	(2.1)
Depreciation and amortization	45.2	35.5	51.9	0.6	133.2
Interest, net	19.2	—	—	—	19.2
Impairment	72.4	85.6	29.1	—	187.1
Other project income	(1.0)	—	(0.1)	(0.1)	(1.2)
Project (loss) income	(17.0)	(72.0)	38.8	2.8	(47.4)
Administration	—	—	—	23.6	23.6
Interest expense, net	—	—	—	64.2	64.2
Foreign exchange loss	—	—	—	16.3	16.3
Other income, net	—	—	—	(0.4)	(0.4)
Net (loss) income before income taxes	(17.0)	(72.0)	38.8	(100.9)	$ (151.1)
Income tax benefit	—	—	—	(58.1)	(58.1)
Net (loss) income	$ (17.0)	$ (72.0)	$ 38.8	$ (42.8)	$ (93.0)

	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated
Year Ended December 31, 2016					
Project revenues	$ 134.5	$ 101.3	$ 162.5	$ 0.9	$ 399.2
Segment assets	754.2	313.6	291.8	97.2	1,456.8
Goodwill	32.4	—	3.6	—	36.0
Capital expenditures	6.2	—	0.9	0.1	7.2
Project Adjusted EBITDA	$ 92.4	$ 51.2	$ 58.8	$ (0.2)	$ 202.2

Change in fair value of derivative instruments	(9.2)	—	(25.5)	(3.2)	(37.9)
Depreciation and amortization	44.1	39.4	49.5	0.5	133.5
Interest, net	10.9	—	—	—	10.9
Impairment	15.4	—	70.5	—	85.9
Other project expense	—	—	—	(0.3)	(0.3)
Project income (loss)	31.2	$ 11.8	$ (35.7)	$ 2.8	10.1
Administration	—	—	—	22.6	22.6
Interest, net	—	—	—	106.0	106.0
Foreign exchange loss	—	—	—	13.9	13.9
Other income, net	—	—	—	(3.9)	(3.9)
Net income (loss) before income taxes	31.2	11.8	(35.7)	(135.8)	(128.5)
Income tax benefit	—	—	—	(14.6)	(14.6)
Net income (loss)	$ 31.2	$ 11.8	$ (35.7)	$ (121.2)	$ (113.9)

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

The table below provides information, by country, about our consolidated operations for each of the years ended December 31, 2018, 2017 and 2016 and Property, Plant & Equipment as of December 31, 2018 and 2017, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Revenue			Property, Plant and Equipment, net of accumulated depreciation	
	2018	2017	2016	2018	2017
United States	$ 203.4	$ 262.4	$ 236.7	$ 396.5	$ 426.2
Canada	78.9	168.6	162.5	153.0	176.1
Total	$ 282.3	$ 431.0	$ 399.2	$ 549.5	$ 602.3

Niagara Mohawk, Atlantic City Electric, BC Hydro, Georgia Power Company and IESO provided 15.1%, 12.6%, 12.5%, 10.9% and 10.8%, respectively, of total consolidated revenues for the year ended December 31, 2018. IESO, Niagara Mohawk, San Diego Gas & Electric and BC Hydro provided 20.3%, 10.7%, 10.6% and 10.3%, respectively, of total consolidated revenues for the year ended December 31, 2017. OEFC, San Diego Gas & Electric, and BC Hydro provided 29.2%, 11.5%, and 10.9%, respectively, of total consolidated revenues for the year ended December 31, 2016. IESO and OEFC purchase electricity from the Calstock, Nipigon and Tunis projects and previously purchased electricity from our North Bay and Kapuskasing projects in the Canada segment. San Diego Gas & Electric previously purchased electricity from the Naval Station, Naval Training Center, and North Island projects in the West U.S. segment, Niagara Mohawk purchases electricity from the Curtis Palmer project in the East U.S. segment, and BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the Canada segment.

23. Commitments and contingencies

Commitments

Operating Lease Commitments

We lease our office properties and equipment under operating leases expiring on various dates through 2024. Certain operating lease agreements over their lease term include provisions for scheduled rent increases. We recognize the effects of these scheduled rent increases on a straight line basis over the lease term. We also have leased office properties for which we have entered into sub-lease agreements with tenants. The table below nets future rental income from these sub-lease agreements against the future rental expense obligations for the company. Lease expense under operating leases was $0.4 million, $0.5 million and $0.6 million for the years ended December 31, 2018, 2017, and 2016, respectively. Future minimum lease commitments under operating leases for the years ending after December 31, 2018, are as follows:

2019	$ 0.6
2020	0.3
2021	0.3
2022	0.3
2023	0.1
Thereafter	—
	$ 1.6

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

Management Service Commitments

Our Manchief project is operated by a third party under a contract that expires in April 2022. As of December 31, 2018, our commitments under this agreement are estimated as follows:

2019	$ 0.4
2020	0.4
2021	0.4
2022	0.2
2023	0.1
Thereafter	—
	$ 1.5

Fuel Supply and Transportation Commitments

We have entered into long term contractual arrangements to procure fuel and transportation services for our projects. We have also entered into long-term arrangements for firm gas sales. The commitments listed below include only contracts for fuel contracts that are not reimbursed or passed through under the terms of the relevant PPAs and are presented net of estimated future gas sales. As of December 31, 2018, our commitments under such outstanding agreements are estimated as follows:

2019	$ 7.5
2020	4.2
2021	4.2
2022	5.1
2023	—
Thereafter	—
	$ 21.0

Acquisition Commitment

On September 20, 2018, we executed an agreement to acquire two biomass plants in South Carolina from EDF Renewables for $13.0 million. Closing of the transaction is expected to occur late in the third quarter or in the fourth quarter of 2019, subject to restructuring of the plants' ownership structure by EDF Renewables after the end of relevant tax credit recapture periods. We have paid $2.6 million of the purchase price, which will be held in escrow until the closing date. The remainder of the purchase price will be paid at closing. If we do not proceed with the transaction close due to circumstances related to Atlantic Power, we will forfeit the $2.6 million held in escrow to EDF Renewables.

Guarantees

We and our subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchases and sale agreements, joint venture agreements, operation and maintenance agreements, and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)

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

Contingencies

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.

24. Unaudited selected quarterly financial data

Unaudited selected quarterly financial data are as follows:

	Quarter Ended 2018				
	December 31,	September 30,	June 30,	March 31,	Total
Project revenue	$ 70.7	$ 65.4	$ 66.2	$ 80.0	$ 282.3
Project income	20.1	26.2	13.6	28.3	88.2
Net income (loss)	26.7	(4.7)	1.0	14.2	37.2
Net income (loss) attributable to Atlantic Power Corporation	24.7	(3.2)	(0.6)	15.9	36.8
Income (loss) per share attributable to Atlantic Power Corporation	$ 0.23	$ (0.03)	$ (0.01)	$ 0.14	$ 0.33
Weighted average number of common shares outstanding-basic	109.6	111.1	112.4	114.8	112.0
Diluted income (loss) per share attributable to Atlantic Power Corporation	$ 0.18	$ (0.03)	$ (0.01)	$ 0.12	$ 0.29
Weighted average number of common shares outstanding-diluted	140.7	111.1	112.4	140.6	141.8

	Quarter Ended 2017 December 31,	September 30,	June 30,	March 31,	Total
Project revenue	$ 100.0	$ 108.6	$ 124.0	$ 98.4	$ 431.0
Project (loss) income	(39.7)	(20.9)	(12.1)	25.3	(47.4)
Net loss	(38.9)	(33.7)	(19.8)	(0.6)	(93.0)
Net loss attributable to Atlantic Power Corporation	(41.1)	(32.9)	(21.9)	(2.7)	(98.6)
Loss per share attributable to Atlantic Power Corporation	$ (0.36)	$ (0.29)	$ (0.19)	$ (0.02)	$ (0.86)
Weighted average number of common shares outstanding-basic	115.2	115.3	115.2	114.8	115.1
Diluted loss per share attributable to Atlantic Power Corporation	$ (0.36)	$ (0.29)	$ (0.19)	$ (0.02)	$ (0.86)
Weighted average number of common shares outstanding-diluted	115.2	115.3	115.2	114.8	115.1

Table of Contents

ATLANTIC POWER CORPORATION

SCHEDULE I—CONDENSED BALANCE SHEETS (PARENT COMPANY ONLY)

(in millions of U.S. dollars)

	December 31, 2018	December 31, 2017
Assets		
Current assets:		
Cash and cash equivalents	$ 42.4	$ 41.8
Prepayments and other current assets	3.3	1.8
Total current assets	45.7	43.6
Investment in and advances to / from subsidiaries	51.6	46.6
Total assets	$ 97.3	$ 90.2
Liabilities		
Current liabilities:		
Accounts payable and accrued liabilities	$ 3.4	$ 1.7
Derivative liability	1.2	—
Convertible debentures	18.1	—
Total current liabilities	22.7	1.7
Convertible debentures	80.4	105.5
Other long-term liabilities	1.1	1.3
Total liabilities	104.2	108.5
Shareholders' equity	(6.9)	(18.3)
Total liabilities and shareholders' equity	$ 97.3	$ 90.2

See accompanying notes to condensed financial statements.

Table of Contents

ATLANTIC POWER CORPORATION

SCHEDULE I—CONDENSED STATEMENTS OF OPERATIONS (PARENT COMPANY ONLY)

(in millions of U.S. dollars)

	Year Ended December 31,		
	2018	2017	2016
Administrative and other expenses:			
Administrative expense	$ 5.0	$ 5.4	$ 5.9
Interest expense, net	13.5	11.6	7.3
Foreign exchange (gain) loss	(9.4)	4.0	10.6
Other (income) expense	(3.1)	0.2	(3.6)
Loss from parent company	(6.0)	(21.2)	(20.2)
Equity earnings (loss) of subsidiaries, net of income tax benefit	43.2	(71.8)	(93.7)
Net income (loss)	$ 37.2	$ (93.0)	$ (113.9)

See accompanying notes to condensed financial statements.

Table of Contents

ATLANTIC POWER CORPORATION

SCHEDULE I—CONDENSED STATEMENTS OF CASH FLOWS (PARENT COMPANY ONLY)

(in millions of U.S. dollars)

	Years Ended December 31,		
	2018	2017	2016
Cash provided by operating activities:			
Net income (loss)	$ 37.2	$ (93.0)	$ (113.9)
Adjustments to reconcile net loss to net cash provided by operating activities:			
Non-cash (earning) losses from subsidiaries, net of taxes	(43.2)	71.8	93.7
Dividends received from subsidiaries	39.0	67.9	33.6
Unrealized foreign exchange (gain) loss	(9.4)	4.0	10.6
Gain on purchase and cancellation of convertible debentures	—	—	(4.7)
Change in fair value of convertible debenture conversion option derivative	(3.2)	—	—
Amortization of debt discount and deferred financing costs	2.6	—	—
Change in other operating balances			
Accounts receivable	7.4	(1.1)	11.5
Prepayments and other assets	1.0	1.4	6.0
Accounts payable and accrued liabilities	0.8	0.5	(1.1)
Cash provided by operating activities	32.2	51.5	35.7
Cash (used in) provided by investing activities:			
Advances to / from investments in subsidiaries	2.4	(57.8)	216.7
Cash paid for acquisition	(13.6)	—	—
Deposit for acquisition	(2.6)	—	—
Cash (used in) provided by investing activities	(13.8)	(57.8)	216.7
Cash used in financing activities:			
Common share repurchases	(16.6)	(0.2)	(19.5)
Repayment of convertible debentures	(88.1)	—	(187.5)
Deferred financing costs	(5.1)	—	—
Proceeds from convertible debenture issuance	92.2	—	—
Payments received from intercompany note	—	—	1.5
Repayment of intercompany note	(0.2)	(0.9)	(9.2)
Cash used in financing activities	(17.8)	(1.1)	(214.7)
Net increase (decrease) in cash and cash equivalents	0.6	(7.4)	37.7

Cash, restricted cash and cash equivalents at beginning of period	41.8	49.2	11.5
Cash, restricted cash and cash equivalents at end of period	$ 42.4	$ 41.8	$ 49.2
Supplemental cash flow information			
Interest paid	$ 4.7	$ 6.2	$ 48.3

See accompanying notes to condensed financial statements

Table of Contents

ATLANTIC POWER CORPORATION

SCHEDULE I—NOTES TO CONDENSED FINANCIAL STATEMENTS (PARENT COMPANY ONLY)

(in millions of U.S. dollars)

1. Nature of business

Atlantic Power Corporation (the “Parent Company”) is a holding company that conducts substantially all of its business through its subsidiaries. As specified in certain of its subsidiaries' credit agreements, there are restrictions on the Parent Company's ability to obtain funds from certain of its subsidiaries through dividends (refer to Note 11, “Long-term debt”, to the consolidated financial statements). As of December 31, 2018, total Atlantic Power Corporation shareholders’ deficit was $6.9 million and approximately $5.5 million of net assets at certain subsidiaries constituted restricted net assets as defined in Rule 4-08(e)(3) of Regulation S-X. The restricted net assets of these subsidiaries exceeded 80% of our consolidated net assets, thus requiring this Schedule I, “Condensed Financial Information of the Registrant.” Accordingly, the balance sheets as of December 31, 2018 and 2017, and the statements of operations and cash flows for the years ended December 31, 2018, 2017 and 2016, have been presented on a “Parent-only” basis. In these statements, the Parent Company's investments in its consolidated subsidiaries are presented under the equity method of accounting. We had no undistributed earnings from our unconsolidated investments for the years ended December 31, 2018, 2017 and 2016, respectively.

As disclosed in Note 12 of the consolidated financial statements, APLP Holdings may be restricted from making dividend payments or other distributions to Atlantic Power Corporation, and APLP and its subsidiaries may be prohibited from making dividends or distributions to Atlantic Power Preferred Equity Limited shareholders in the event of a covenant default or if APLP Holdings fails to achieve a target principal amount on the term loan that declines quarterly based on a predetermined specified schedule. APLP Holdings has made principal payments to meet the targeted debt balance requirement as of December 31, 2018 and is not prohibited from making dividends to the Parent Company. The consolidated equity of APLP Holdings was approximately $62.7 million at December 31, 2018 and includes the subsidiaries with restricted net assets of $5.5 million at December 31, 2018 disclosed above.

The Parent-only financial statements should be read in conjunction with our consolidated financial statements included elsewhere herein.

2. Dividends received

The Parent Company received dividends of $39.0 million, $67.9 million and $33.6 million in 2018, 2017 and 2016, respectively, from its consolidated and unconsolidated subsidiaries.

Table of Contents

ATLANTIC POWER CORPORATION

SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS

FOR THE YEARS ENDED DECEMBER 31, 2018, 2017 and 2016

(in millions of U.S. dollars)

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
Income tax valuation allowance, deducted from deferred tax assets:					
Year ended December 31, 2018	$ 151.4	$ (11.7)	$ —	$ —	$ 139.7
Year ended December 31, 2017	186.0	(34.6)	—	—	151.4
Year ended December 31, 2016	175.2	10.8	—	—	186.0

F-66