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, 2020

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 (State of Incorporation)	**55-0886410** (I.R.S. Employer Identification No.)
3 Allied Drive, Suite 155 **Dedham, MA** (Address of Principal Executive Offices)	**02026** (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	Trading symbol	Name of Each Exchange on which registered
Common Shares, no par value per share, and the associated Rights to Purchase Common Shares	AT	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 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 has filed a report on and attestation to its management's assessment of the effectiveness of its internal control over financial reporting under Section 404(b) of the Sarbanes-Oxley Act (15 U.S.C. 7262(b)) by the registered public accounting firm that prepared or issued its audit report. ☒

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, 2020, the aggregate market value of the voting and nonvoting common equity held by non-affiliates of the registrant was $176.5 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 March 3, 2021, 89,714,323 of the registrant's Common Shares were outstanding.

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PART I

As used herein, the terms “Atlantic Power,” the “Company,” “we,” “our,” and “us” refer to Atlantic Power Corporation, together 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 or 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:

- the expected timing and likelihood of completion of the proposed transaction with I Squared Capital;
- the expected impact of the proposed transaction with I Squared Capital on the price of the Company’s Common Shares;
- the impact of the ongoing coronavirus (“COVID-19”) pandemic on the economy and our operations, including the measures taken by governmental authorities to address it (or failure to implement additional stimulus measures), which may precipitate or exacerbate other risks and/or uncertainties, and the current resurgence in new cases of COVID-19, which might lead to reinstatement of restrictions on individuals and businesses;
- 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 internal investments in our fleet, external acquisitions and repurchases of debt, common and preferred 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.

There are a number of risks associated with the proposed transaction with I Square Capital, including, without limitation:

- that there can be no certainty that all conditions to the proposed transaction will be satisfied;
- the Arrangement Agreement (as defined below) may be terminated in certain circumstances;
- the termination fee provided under the Arrangement Agreement may discourage other parties from attempting to acquire the Company;
- even if the Arrangement Agreement is terminated without payment of the termination fee, the Company may, in the future, be required to pay the termination fee in certain circumstances;
- while the proposed transaction is pending, the Company is restricted from taking certain actions;
- the right to match provided under the Arrangement Agreement may discourage other parties from attempting to acquire the Company;
- no solicitation of other potential purchasers of the Company may reduce the likelihood of other parties attempting to acquire the Company; and
- the pending Arrangement may divert the attention of the Company's management.

In addition, risks include, without limitation:

- deterioration in global economic and financial market conditions generally, including as a result of pandemic health issues (including COVID-19 and its effects, among other things, on global supply, demand, and distribution disruptions as the COVID-19 pandemic continues and results in an increasingly prolonged period of travel, commercial and/or other similar restrictions and limitations) and the effects on electricity demand;
- the expiration or termination of PPAs and our ability to renew or enter into new PPAs on favorable terms or at all;
- 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;
- risks inherent in the use of derivative instruments;

- the effects of weather, which affects demand for electricity and fuel as well as operating conditions;
- revenues from hydropower plants are highly dependent on precipitation and associated weather events;
- the adequacy of our insurance coverage, the timeliness of our insurance payouts, and our estimates of insurance coverage;
- risks beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters, more frequent extreme weather conditions arising as a result of climate change, pandemics (including potentially in relation to the coronavirus) or other catastrophic events;
- 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;
- the impact of hostile cyber intrusions;
- labor disruptions;
- our pension plan may require additional future contributions;
- our ability to retain, motivate and recruit executives and other key employees;
- the impact of significant energy, environmental and other regulations on our projects;
- noncompliance with federal reliability standards may subject us and our projects to penalties;
- additional and uncertain regulatory requirements mandating limitations on greenhouse gas emissions or requiring efficiency improvements;
- the impact of Canadian and U.S. federal income tax laws on our business;
- the impact of our failure to comply with the U.S. Foreign Corrupt Practices Act and/or Canadian Corruption of Foreign Public Officials Act;
- the impact of failure to fully comply with Section 404 of the Sarbanes-Oxley Act of 2002;
- our ability to service our debt obligations or generate sufficient cash flow to pay preferred dividends;
- our indebtedness and financing arrangements and the terms, covenants and restrictions included in our Credit Facilities;
- the discontinuation, reform or replacement of LIBOR;
- 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;
- 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;

- unstable capital and credit markets;
- the anti-takeover protections in the British Columbia Business Corporations Act (the “BCBCA”) and our Articles of Continuance;
- U.S., Canadian, and/or global economic uncertainty;
- the impact of impairment of goodwill, long-lived assets or equity method investments; and
- increasing competition.

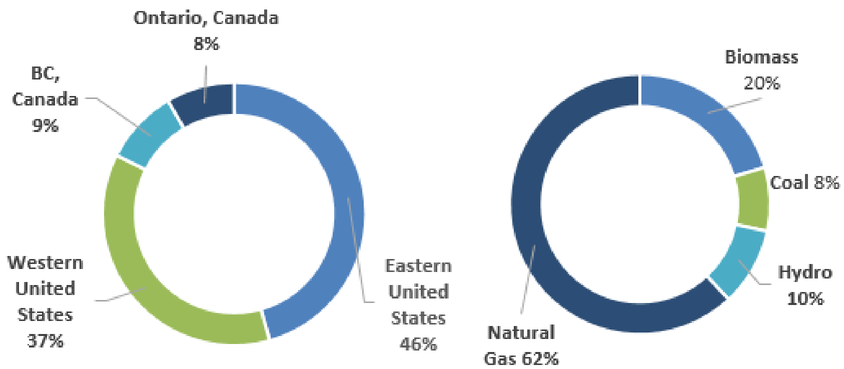
Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include, without limitation, third-party projections of regional fuel and electric capacity and energy prices based on assumptions about future economic conditions 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.

ITEM 1. BUSINESS

GENERAL

Atlantic Power, a corporation continued under the laws of British Columbia, Canada is an independent power producer that owns power generation assets in eleven states in the United States and two provinces in Canada. We were incorporated in 2004. 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, 2020, our portfolio consisted of twenty-one operating projects with an aggregate electric generating capacity of approximately 1,723 megawatts ("MW") on a gross ownership basis and approximately 1,327 MW on a net ownership basis. Sixteen of the projects are majority-owned by the Company.

The following charts show, based on generation capacity in MW, the diversification of our portfolio by geography 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 September 2021 to November 2043, 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 CMS Energy Corporation ("CMS"), 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.

PROPOSED TRANSACTION WITH I SQUARED CAPITAL

On January 14, 2021, Atlantic Power entered into a definitive agreement (the “Arrangement Agreement”) with Atlantic Power Preferred Equity Ltd. (“APPEL”) Atlantic Power Limited Partnership (“APLP”), Tidal Power Holdings Limited and Tidal Power Aggregator, LP (together with Tidal Power Holdings Limited, the “Purchasers”). The Purchasers were formed solely for the purpose of effecting the transactions contemplated by the Arrangement Agreement (the “Transaction”), and are currently owned and controlled by funds affiliated with I Squared Capital, a private equity investment group.

In connection with the Transaction:

- Holders of common shares of Atlantic Power would receive $3.03 per common share in cash.
- Atlantic Power’s 6.00% Series E Convertible Unsecured Subordinated Debentures due January 31, 2025 would be converted into common shares of Atlantic Power immediately prior to the closing of the Transaction based on the conversion ratio in effect at such time (including the “make whole premium shares” issuable under the terms of the trust indenture for the convertible debentures following a cash change of control). Holders of the convertible debentures would receive $3.03 per common share held following the conversion of the convertible debentures, plus accrued and unpaid interest on the convertible debentures up to, but excluding, the closing date of the Transaction.
- APPEL’s cumulative redeemable preferred shares, Series 1, cumulative rate reset preferred shares, Series 2, and cumulative floating rate preferred shares, Series 3, would be purchased by APPEL for Cdn$22.00 per preferred share in cash.
- APLP’s 5.95% medium term notes due June 23, 2036 (the “MTNs”) would be redeemed for consideration equal to 106.071% of the principal amount of MTNs held as of the closing of the Transaction, plus accrued and unpaid interest on the MTNs up to, but excluding, the closing date of the Transaction. Holders of MTNs that deliver a written consent to the proposed amendments to the trust indenture governing the MTNs (as described below) would also be entitled to a consent fee equal to 0.25% of the principal amount of MTNs held by such holders, conditional on closing of the transaction.

The acquisition of Atlantic Power's outstanding common shares and the redemption of the outstanding preferred shares of APPEL would be completed by way of a plan of arrangement (the “Arrangement”) under the *Business Corporations Act* (British Columbia). In connection with the Arrangement, Atlantic Power's shareholder rights plan would be terminated and all rights to purchase Atlantic Power's common shares issued pursuant to the shareholder rights plan would be cancelled.

The Arrangement Agreement

The Arrangement Agreement provides that the Transaction is subject to a number of closing conditions, including court approval of the Arrangement, regulatory approvals (including under the *Competition Act* (Canada), which approval was obtained by the parties on February 2, 2021, and the U.S. *Hart-Scott-Rodino Antitrust Improvements Act* of 1976, as amended, the *Communications Act* of 1934, as amended, and the *Federal Power Act*, as amended), as well as the receipt of certain third-party consents.

The Transaction is also conditional on the approval of two-thirds of the votes cast by holders of Atlantic Power's common shares voting in person or by proxy at a special meeting of Atlantic Power's common shareholders and the approval of two-thirds of the votes cast by holders of APPEL’s preferred shares (voting as a single class) in person or by proxy at a meeting of APPEL’s preferred shareholders in respect of both the Arrangement and the proposed continuance of APPEL under the laws of British Columbia. The Transaction must also be approved by a majority of the votes cast at the special meeting of Atlantic Power’s common shareholders, excluding votes attached to common shares held by persons described in items (a) through (d) of Section 8.1(2) of *Multilateral Instrument 61-101 Protection of Minority Security Holders in Special Transactions*.

In addition, the Transaction is conditional upon the approval of the holders of the convertible debentures and the MTNs, respectively (in each case either by way of votes of the holders of the convertible debentures and the MTNs holding at least two-thirds of the principal amount of the convertible debentures and the MTNs, respectively, voted in person or by proxy at separate meetings of the holders of the convertible debentures and the MTNs or by way of separate written consents of the holders of the convertible debentures and the MTNs holding not less than two-thirds of the principal amount of convertible debentures and MTNs outstanding, as applicable), of certain amendments to the trust indentures governing such securities, including to provide for the mandatory conversion of the convertible debentures into common shares; the addition of a redemption obligation of Atlantic Power, conditional on the closing of the Transaction, to redeem all outstanding MTNs for consideration equal to 106.701% of the principal amount of such MTNs; and the modification of the redemption notice period as to the MTNs. Atlantic Power and APLP will seek the approval of the holders of the convertible debentures and MTNs by way of separate meetings and/or consent solicitations.

A bondholder representing approximately 66% of the principal amount of MTNs and approximately 19% of the principal amount of convertible debentures outstanding has agreed to vote in favor of or otherwise consent to amendments to the trust indentures governing those securities.

The Arrangement Agreement is subject to customary non-solicitation provisions, including Atlantic Power's right to consider and accept unsolicited superior proposals in certain circumstances, subject to a right to match in favor of the Purchasers. A termination fee of $12.5 million will be payable by Atlantic Power to the Purchasers should the Transaction not close under certain circumstances, including if the Arrangement is not completed as a result of Atlantic Power accepting an unsolicited superior proposal. A reverse termination fee of $15 million will be payable by the Purchasers to Atlantic Power should the Transaction not close as a result of an uncured breach by the Purchasers of the Arrangement Agreement (provided Atlantic Power is not then in breach of the Arrangement Agreement).

Additional Information

Atlantic Power has filed a final proxy statement on Form DEF 14A with the United States Securities and Exchange Commission (the “SEC”) in connection with the proposed Arrangement Agreement. This communication does not constitute an offer to sell or the solicitation of an offer to buy any securities or a solicitation of any vote or approval. WE URGE INVESTORS TO READ THE PROXY STATEMENTS AND ANY OTHER DOCUMENTS TO BE FILED WITH THE SEC IN CONNECTION WITH THE ARRANGEMENT AGREEMENT OR INCORPORATED BY REFERENCE IN THE PROXY STATEMENT BECAUSE THEY WILL CONTAIN IMPORTANT INFORMATION.

Investors may obtain (when available) these documents free of charge at the SEC’s Web site (www.sec.gov). In addition, these documents are available through the Investors section of our website at https://investors.atlanticpower.com/corporate-profile as soon as is reasonably practical after we electronically file or furnish these reports. The proxy statement is not incorporated by reference in this Annual Report on Form 10-K and should not be considered a part of the Annual Report.

Atlantic Power, APPEL, APLP, their directors, and executive officers and other members of management and employees may be considered participants in the solicitation of proxies in connection with the Arrangement Agreement. Information regarding the participants in the proxy solicitation of Atlantic Power and a description of their direct and indirect interests, by security holdings or otherwise, is contained in the proxy statement and other relevant materials to be filed with the SEC.

BUSINESS STRATEGY

This section describes our business strategy without regards to potential effects of the Transaction except where stated otherwise.

Our primary business is the acquisition, operation and ownership of power plants in the United States and Canada. The power generation business is cyclical, capital-intensive, heavily regulated and commodity-priced. In executing our strategy, we are focused on the following priorities:

- ***Capital allocation framework****:* We are focused on enhancing shareholder value while balancing risk and reward. The key metric that we consider is the impact of capital allocation on our estimates of intrinsic value per share. Developing these estimates is a complex process that relies on inherently uncertain forecasts of power prices, market prices for assets, interest rates and other major factors outside of our control. We use these estimates to provide us a rough guideline on how we can best impact intrinsic value per share via capital allocation. Over the past six years we have invested discretionary capital in internal investments in our fleet, external acquisitions, repurchases of debt, common equity and preferred equity securities.

    - *Proposed Sale of the Company* – As discussed above under "I Squared Capital Transaction", should the Transaction close, common shareholders will receive $3.03 per common share in cash.

    - *Share repurchases* – We have returned cash to shareholders via common share repurchases, as we do not believe reinstating a common dividend would be consistent with the characteristics of our business model or current market conditions. Our key consideration in share repurchases (either common or preferred) is the price-to-value relationship. We are willing to buy shares when doing so is accretive to our estimates of intrinsic value per share. We are not interested in buying common shares above our estimates of intrinsic value per share. We have repurchased preferred shares when we believed the cash returns were attractive. During 2020, we used $48 million of our discretionary capital to repurchase and cancel common ($41.6 million) and preferred (US$6.4 million equivalent) shares at prices that we believe were attractive relative to our estimates of value.

    - *Internal investments* - Given the challenging supply and demand conditions in the power sector in the United States and Canada, low returns currently available on contracted power assets, and the superior returns that generally have been available on our internal uses of capital, we have allocated the majority of our discretionary capital to investments in our fleet and share repurchases. We invested $25 million to optimize our existing fleet in 2013 through 2016.

    - *External investments* - We invest externally only when we believe the returns are superior to those we can achieve by investing internally in plants or in share repurchases. In 2018 and 2019, we made our first significant external investments in more than five years, totaling approximately $45 million.

- ***Debt reduction****:* We have reduced our consolidated debt by more than $1.3 billion in the past seven years. By significantly repaying debt, we have strengthened our balance sheet, improved our financial flexibility and reduced our cash interest payments. We also have improved our credit profile, as reflected in two rating upgrades since October 2015 from each of S&P and Moody's. Debt reduction is not driven by the returns available on our debt, but rather the priority of strengthening our balance sheet. We believe this is prudent given the nature of our business, our asset profile and the state of the power markets.

- ***Cost management****:* As our industry lacks barriers to entry, we are keenly focused on efficiency and costs. Our existing fleet is, on average, comprised of older, smaller and less efficient plants, which limits our ability to achieve operating cost reductions. We have reduced our corporate overhead structure significantly and continue to maintain a culture of frugality.

- ***Culture****:* We are laser focused on shareholder value. Being a good corporate citizen underpins that focus but we also do not want to force our personal political views onto our employees or shareholders. In a commodity business, operating our plants safely and staying focused on costs are paramount. In all aspects of our business, we strive to follow a philosophy of servant leadership.

- ***Balanced portfolio****:* We have a balanced portfolio of technologies and fuel types including natural gas, biomass and hydro, and we own an equity interest in one coal plant. This balance creates some natural hedging characteristics. For example, higher gas prices may be beneficial for hydro plants but not necessarily for gas plants.

- ***PPA renewals**:* We seek to renew or extend expiring PPAs where economically feasible, or make alternative arrangements where possible. PPAs in our portfolio have expiration dates ranging from September 2021 to November 2043. 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 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—Risks Related to Our Business—The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations and financial condition."

ASSET MANAGEMENT

Our asset management strategy is to manage our physical assets and commercial relationships with the goal of increasing shareholder value. We proactively seek scale opportunities and to establish best practices that result in EBITDA and cash flow growth across all of our twenty-one 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 five 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 CMS, 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.

INDUSTRY AND COMPETITION

The electric power industry is one of the largest industries in the United States, generating annualized retail electricity sales of approximately $400 billion, based on information published by the Energy Information Administration. 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 42% of total net generation in 2020. 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.

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 oil 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.

Our competitive strengths

We believe 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 1,723 MW, and our net ownership interest in these projects is approximately 1,327 MW at December 31, 2020. 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 in Canada in the provinces of British Columbia and Ontario.

- ***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 sixteen of our twenty-one operating power generation projects, which represent approximately 62% of our portfolio's total net generating capacity. The remaining five generation projects are operated by third parties, which are recognized leaders in the independent power business.

OUR ORGANIZATION AND SEGMENTS

The following tables outline by segment our portfolio of power generating assets in operation as of December 31, 2020, 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: Solid Fuel, Natural Gas, Hydroelectric and Corporate. We revised our reportable business segments in the fourth quarter of 2019 as the result of recent asset acquisitions, PPA expirations and project decommissioning, and in order to align with changes to management's structure, resource allocation and performance assessment in making decisions regarding our operations. Segment information for prior periods has been revised to conform to the new segment presentation. The segment classified as Corporate (formally 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. We have previously reported our segments on a geographic basis, and consequently the segment information presented herein is significantly different than previous presentations of segment information.

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

Solid Fuel Segment

Our Solid Fuel segment accounted for approximately 13% and 29% of consolidated revenue in 2020 and 2019, respectively, and total net generation capacity of 376 MW at December 31, 2020. Set forth below is a list of our Solid Fuel projects in operation at December 31, 2020:

Project	Location	Fuel	Gross MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)[1]
Allendale	South Carolina	Biomass	20	100.00 %	20	South Carolina Public Service Authority	November 2043	A[2]
Cadillac	Michigan	Biomass	40	100.00 %	40	Consumers Energy	June 2028	A-
Calstock	Ontario	Biomass	35	100.00 %	35	Ontario Electricity Financial Corporation	December 2021[3]	AA-[2]
Chambers[4]	New Jersey	Coal	262	40.00 %	89	Atlantic City Electric [5]	March 2024	A-
					16	Chemours Co.	March 2024	B+
Craven[4]	North Carolina	Biomass	48	50.00 %	24	Duke Energy Carolinas, LLC	December 2027	A-
Dorchester	South Carolina	Biomass	20	100.00 %	20	South Carolina Public Service Authority	October 2043	A[2]
Grayling[4]	Michigan	Biomass	37	30.00 %	11	Consumers Energy	December 2027	A-
Piedmont	Georgia	Biomass	55	100.00 %	55	Georgia Power	September 2032	A-
Williams Lake	British Columbia	Biomass	66	100.00 %	66	BC Hydro	September 2029	AAA[2]

(1) Customers that have assigned ratings at the top end of the range have, in the opinion of Standard and Poor's ("S&P"), 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.

(2) Customer is rated by Moody's but not S&P; therefore, the rating shown in the table is the S&P rating that corresponds to the actual Moody's rating.

(3) In May 2020, the PPA with the Ontario Electricity Financial Corporation for Calstock, which had been scheduled to expire in June 2020, was extended to December 16, 2020 under existing terms. In December 2020, the Calstock PPA was extended for one year, also under existing terms, and runs to December 16, 2021.

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

(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.

Natural Gas Segment

Our Natural Gas segment accounted for approximately 69% and 47% of consolidated revenue in 2020 and 2019, respectively, and total net generation capacity of 822 MW at December 31, 2020. Set forth below is a list of our Natural Gas projects in operation at December 31, 2020:

Project	Location	Fuel	Gross MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)[1]
Frederickson[3]	Washington	Natural Gas	250	50.15 %	50	Benton Co. PUD	August 2022	AA-[2]
					45	Grays Harbor PUD	August 2022	A+[2]
					30	Franklin Co. PUD	August 2022	A+[2]
Kenilworth	New Jersey	Natural Gas	29	100.00 %	29	Merck & Co., Inc.	September 2021	AA-
						Merchant	N/A	NR
Manchief [4]	Colorado	Natural Gas	300	100.00 %	300	Public Service Company of Colorado	April 2022	A-
Morris [5]	Illinois	Natural Gas	177	100.00 %	100	Merchant	N/A	NR
					77	Equistar Chemicals, LP [6]	December 2034	BBB- [7]
Nipigon	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	December 2022	AA-[2]
Orlando[3]	Florida	Natural Gas	129	50.00 %	65	Duke Energy Florida, LLC	December 2023	A-
Oxnard	California	Natural Gas	49	100.00 %	49	California Independent System Operator	December 2021 [8]	A+
Tunis	Ontario	Natural Gas	37	100.00 %	37	Independent Electricity System Operator	October 2033	AA-[2]

(1) Customers that have assigned ratings at the top end of the range have, in the opinion of S&P, 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.

(2) Customer is rated by Moody's but not S&P; therefore, the rating shown in the table is the S&P rating that corresponds to the actual Moody's rating.

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

(4) In May 2019, we entered into an agreement to sell Manchief to PSCo following the expiration of the PPA in April 2022 for $45.2 million subject to working capital and other customary adjustments.

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

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

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

(8) The PPA with Southern California Edison expired on May 25, 2020 and was not renewed or extended. The Company executed a reliability must run ("RMR") contract with the California Independent System Operator that became effective June 1, 2020 and expired on December 31, 2020. On August 28, 2020, we executed an agreement to sell Resource Adequacy ("RA") capacity from the Oxnard plant effective January 1, 2021 through to December 31, 2021.

Non-operating Natural Gas Plants

In August 2018, we terminated discussions with the Navy regarding site control for our Naval Station, Naval Training Center ("NTC") and North Island projects located in San Diego, California. We are in the process of decommissioning all three sites, which is a requirement of our land use agreements with the Navy. We anticipate decommissioning will be completed in the second quarter of 2021.

Our Kapuskasing and North Bay projects are both 40 MW natural gas plants located in the Province of Ontario. These projects formerly had PPAs with the OEFC that expired in December 2017. These plants are currently being maintained, but do not operate because they do not have PPAs or a merchant market where operations would be profitable.

Hydroelectric Segment

Our Hydroelectric Segment accounted for approximately 22% and 24% of consolidated revenue in 2020 and 2019, respectively, and total net generation capacity for operational projects of 129 MW at December 31, 2020. Set forth below is a list of our Hydroelectric projects in operation or under contract at December 31, 2020:

Project	Location	Fuel	Gross MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)(1)
Curtis Palmer	New York	Hydro	60	100.00 %	60	Niagara Mohawk Power Corporation	December 2027 (3)	A-
Koma Kulshan	Washington	Hydro	13	100.00 %	13	Puget Sound Energy	March 2037	BBB
Mamquam (4)	British Columbia	Hydro	50	100.00 %	50	BC Hydro	September 2027	AAA(2)
Moresby Lake	British Columbia	Hydro	6	100.00 %	6	BC Hydro	August 2022	AAA(2)

(1) Customers that have assigned ratings at the top end of the range have, in the opinion of S&P, 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.

(2) Customer is rated by Moody's but not S&P; therefore, the rating shown in the table is the S&P rating that corresponds to the actual Moody's rating.

(3) 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, 2020, the facility has generated 8,361 GWh under its PPA. Based on cumulative generation to date and assuming average water conditions going forward, we expect the PPA to expire in the first quarter of 2026.

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

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 Regulatory 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. Regulation of related environmental matters, including greenhouse gas emissions and green building standards, are subject to federal, provincial and municipal regulation.

Generating projects

United States

Thirteen 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 thirteen 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. Nine of our projects are also subject to reliability standards developed and enforced by the North American Electric Reliability Corporation ("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.

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 and favors clean and renewable energy sources such as waterpower, windpower and ocean energy generation.

Other provincial regulators in British Columbia having authority over independent power producers include Technical Safety BC, the Ministry of Environment and Climate Change Strategy, and the Ministry of Energy, Mines and Low Carbon Innovation.

Ontario, Canada

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

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

The OEB's general functions include:

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

The OEB has the authority effectively to modify licenses by adopting "codes" that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the OEB can result in administrative monetary penalties of up to Cdn$1 million per day of violation, license revocation and other consequences. While the OEB provides reports to the Ontario Minister of Energy, Northern Development and Mines, 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. The law implemented by the OEB has been the subject of relatively frequent change, which has contributed to regulatory uncertainty.

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 Inc. ("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 Inc. and Hydro One, were intended to eventually operate as private businesses rather than as crown corporations. The Province currently owns slightly less than half of the equity of Hydro One Inc., a publicly traded corporation. Hydro One has been the subject of intervention by the Province of Ontario, including pressuring the retirement of its former chief executive officer and resignation of its entire board of directors.

The IESO is responsible for administering the wholesale electricity market and controlling Ontario's transmission grid. The IESO is a non-profit corporation. Its 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, and has an enforcement arm.

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 to comply with NERC standards and NPCC criteria.

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 that 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 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."

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 CO_2 emissions. CO_2 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 CO_2 cap in 2014, with further reductions of 2.5% each year from 2015 to 2020. On January 1, 2020, New Jersey rejoined RGGI after withdrawing from the compact in 2012. Our Chambers project operates in the state of New Jersey and is subject to RGGI. However, its PPA is grandfathered to provide some cost mitigation under the law. 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, Nova Scotia 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 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 was not implemented. In June 2019, the EPA issued the final Affordable Clean Energy Rule ("ACE"), which repealed the CPP and established emissions guidelines for states to develop plans to address greenhouse gas emissions from existing coal-fired power plants. In January 2021, the D.C. Circuit Court of Appeals vacated and remanded ACE. Provided the Supreme Court does not decide to take up the case, the Biden Administration's EPA will be able to focus on constructing a replacement.

In January 2021, the Biden Administration signed multiple executive orders related to the climate and environment. These executive orders direct federal agencies to review and reverse more than 100 Trump Administration actions on the environment, instruct the Director of National Intelligence to prepare a national intelligence estimate on the security implications of the climate crisis and direct all agencies to develop strategies for integrating climate considerations into their international work, establish the National Climate Task Force which assembles leaders from across 21 federal agencies and departments, commit to environmental justice and new, clean infrastructure projects, kick off development of emissions reduction target and establish the special presidential envoy for climate on the National

Security Council. At this time, we cannot predict the outcome of any of these executive actions or any legal challenges to these actions.

Canada - Federal

In Canada, the federal government has implemented greenhouse gas reporting regulations and is 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 pollution. On January 15, 2018, the Government of Canada released the draft *Greenhouse Gas Pollution Pricing Act*, consisting of two mechanisms: (1) a regulatory charge on fuels, and (2) an emissions trading system referred to as the Output-Based Pricing System ("OBPS"). These mechanisms establish a backstop carbon price 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. Other policy documents accompanying the Act 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 several regulations, including the *Fuel Charge Regulations* and the *Output-Based Pricing System Regulations* to implement both mechanisms.

British Columbia and Québec have compliant carbon pricing systems in place and are not expected to be subject to the federal backstop regime. Alberta is exempt from parts of the federal backstop regime. Beginning on January 1, 2020, the federal backstop regime imposed a minimum Cdn$30/tonne of CO_2e ("tCO_2e") carbon price for greenhouse gases that exceed a prescribed emissions limit set out in the *Output-Based Pricing System Regulations*, increasing by Cdn$10 increments each following year to 2023.

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 then 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 currently subject to the federal backstop regime. This means that large industrial emitters in Ontario, such as our operations in Tunis and Nipigon, are currently subject to the federal OBPS provided for in Part 2 of the *Greenhouse Gas Pollution Pricing Act*. As of July 4, 2019, Ontario has also established its own output-based performance standards for large emitters through *Ontario Regulation 241/19: Greenhouse Gas Emissions Performance Standards* ("GHGEPS"). The GHGEPS, while currently optional for facilities covered under the federal GHGRP emitting between 10,000 and 50,000 tonnes of CO_2e, appears to be similar to the federal OBPS. On September 20, 2020, the federal government accepted the GHGEPS as an equivalent program, which will exempt Ontario facilities from the federal backstop regime once in force. The implications of the federal OBPS and the GHGEPS for our operations in Ontario, such as Tunis and Nipigon, are discussed below (in the section on Canada – Ontario).

The validity of the federal backstop regime is being challenged on constitutional grounds by Alberta, Ontario and Saskatchewan. The Courts of Appeal in Ontario and Saskatchewan have held that the federal backstop regime is constitutional, while the Alberta Court of Appeal found that the federal backstop regime was unconstitutional. Canada's highest court, the Supreme Court of Canada ("SCC"), heard the three provincial challenges in September 2020. The provinces of British Columbia, Manitoba, New Brunswick, and Quebec joined the proceedings as interveners. The SCC reserved judgement after hearing the appeals and, to date, has not rendered a decision. If the SCC finds that the federal backstop regime is constitutional, then the federal backstop regime will continue to apply as described in this section.

In December 2020, the federal government announced that the OBPS charge will increase by $15 per tonne in each year after 2023 until the charge hits $170 per tonne in 2030. If provincial regimes do not match this price, then they may no longer be deemed to be equivalent and the federal backstop regime could continue to apply.

Canada – British Columbia

The Government of British Columbia has enacted a number of significant pieces of climate action legislation 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. The Province has also introduced an interim target of 16% by 2025 and will set sectoral targets by March 2021. 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) and Community Energy and Emissions Inventory Reports (prepared every two years), 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, on January 1, 2019 our operations in

Nipigon and Tunis became subject to the federal OBPS. Under the federal "Notice Establishing Criteria Respecting Facilities and Persons and Publishing Measures: SOR/2018-213", as it read before its repeal, any facility which emitted more than 50kt of CO_2e 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 CO_2e 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 currently subject to the federal OBPS and required to pay fees as described below.

Our operations in Ontario may also be subject to Ontario's GHGPE, as it comes into force. Under Ontario's GHGPE, facilities must register with the Director of the Ministry of the Environment, Conservation and Parks if the facility is required to submit a report under the federal GHGRP and reported emissions of more than 50,000 tonnes of CO_2e. Facilities may also choose to register if the facility submitted a report under the federal GHGRP and emits between 10,000 and 50,000 tonnes of CO_2e. Accordingly, our operations in Tunis and Nipigon are also subject to Ontario's GHGPE.

Under the federal OBPS regulations, the Tunis and Nipigon projects are required to either pay an excess emissions charge or remit compliance units as prescribed by the federal backstop regime for each tonne of CO_2e emissions in excess of 370 tonnes of CO_2e / GWh of electricity generated by such operations for the 2021 compliance period, and will receive free emissions allowances if the emissions fall below that measure. The emissions limit for both the Nipigon and Tunis facilities will be reduced to 329 tonnes of CO_2e / GWh in 2022 under the OBPS.

Facilities in Ontario subject to the GHGPE will be required to pay a similar excess emissions charge or remit compliance units per tonne of CO_2e emissions, in accordance with the *GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit* guideline prepared by the Province. 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. The Province and federal government's coordination of the transition between the federal OBPS and the provincial GHGPE also adds to some uncertainty in the future.

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 ("UNFCCC"), 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. In November 2019, the Trump Administration notified the United Nations of the U.S. withdrawal from the Paris Agreement, which became effective in November 2020. On January 21, 2021, the Biden Administration formally rejoined the Paris Agreement through executive order. The return to the agreement takes effect 30 days from the signing of the executive order. Later in 2021, the Biden Administration is expected to submit a new official commitment that pledges domestic reductions in heat-trapping emissions. In light of the legislative, judicial and executive factors influencing regulatory action, significant uncertainty exists as to how greenhouse gas restrictions in the United States will impact our facilities in the future.

HUMAN CAPITAL

As of March 3, 2021, we had 261 employees, 200 in the United States and 61 in Canada. Of our Canadian employees, 43 are covered by collective bargaining agreements, which will expire on December 19, 2021 and December 31, 2023. During 2020, we did not experience any labor stoppages or labor disputes at any of our facilities.

AVAILABLE INFORMATION

Access to our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to these reports filed with or furnished to the SEC may be obtained free of charge through the Investors section of our website at https://investors.atlanticpower.com/corporate-profile as soon as is reasonably practical after we electronically file or furnish these reports. In addition, our filings with the SEC may be accessed through the SEC's website at www.sec.gov and our filings with the Canadian Securities Administrators (CSA) may be accessed through the CSA's System for Electronic Document Analysis and Retrieval (SEDAR) at www.sedar.com. Except for the documents specifically incorporated by reference into this Annual Report, information contained on our website or the SEC or CSA websites is not incorporated by reference in the Annual Report on Form 10-K and should not be considered to be a part of the Annual Report. We have included our website address and that of the SEC and CSA only as inactive textual references and do not intend them to be active links to such websites. All statements made in any of our securities filings, including all forward-looking statements or information, are made as of the date of the document in which the statement is included, and we do not assume or undertake any obligation to update any of those statements or documents unless we are required to do so by applicable law. We are not a foreign private issuer, as defined in Rule 3b-4 under the Securities Exchange Act of 1934, as amended (the “Exchange Act”).

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 material 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.

Summary of Risk Factors

There are a number of risks associated with the proposed Transaction, including, without limitation:

- There can be no certainty that all conditions to the Transaction will be satisfied. Failure to complete the

Transaction could negatively impact the share price of the common shares or preferred shares or otherwise adversely affect the business of the Company.

- The Arrangement Agreement may be terminated in certain circumstances, and even if the Arrangement Agreement is terminated without payment of the termination fee, the Company may, in the future, be required to pay the termination fee in certain circumstances.
- Certain features of the Arrangement Agreement may discourage other parties from attempting to acquire the Company.
- While the Arrangement is pending, the Company is restricted from taking certain actions.
- The pending Transaction may divert the attention of the Company's management.

In addition, risks include, without limitation:

- The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations, financial condition and Project Adjusted EBITDA.
- 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.
- 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.
- Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the results of operations of the projects.
- Our projects may not operate as planned.
- Our projects are exposed to risks inherent in the use of derivative instruments.
- The effects of weather and climate change 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.
- Our business faces significant operating hazards and insurance may not be sufficient to cover all losses.
- Risks that are beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters, pandemics (including potentially in relation to the coronavirus) or other catastrophic events could have a material adverse effect on our business, results of operations, ability to raise capital and financial condition.
- Our business, results of operations, financial condition, cash flows and stock price can be adversely affected by pandemics, epidemics or other public health emergencies, such as the ongoing COVID-19 pandemic.
- We have limited control over management decisions at certain projects which could have an adverse effect on our business, results of operations and financial condition.
- Our equity interests in certain projects may be subject to transfer restrictions which 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 to sell our interests in these projects at the prices we desire.
- 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.
- Certain employees are subject to collective bargaining.
- Our Pension Plan may require additional future contributions.
- 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 operations are subject to the provisions of various energy laws and regulations; the introduction of new laws, or other future regulatory developments, may have a material adverse impact on our business, operations or financial condition.
- Noncompliance with federal reliability standards may subject us and our projects to penalties 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; significant costs may be incurred to

keep the projects compliant with environmental laws and regulations.

- 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.
- We are subject to Canadian tax.
- Canadian federal income tax laws and policies could be changed in a manner which adversely affects holders of our common shares.
- Our common shares may not continue to be qualified investments under Canadian tax laws.
- Our current structure may be subject to additional U.S. federal income tax liability.
- 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.
- 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 shares.
- 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 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.
- Discontinuation, reform or replacement of the London Interbank Offered Rate ("LIBOR"), or uncertainty related to the potential for any of the foregoing, may adversely affect us.
- 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.
- Exchange rate volatility may 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.
- Changes in our creditworthiness may affect the value of our common shares.
- The future issuance of additional common shares could dilute existing shareholders.
- 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.
- We have guaranteed the performance of some of our subsidiaries, which may result in substantial costs in the event of non-performance.
- We have anti-takeover protections that, in the event that the Transaction does not close, may discourage, delay or prevent a change in control that could benefit our shareholders.
- U.S., Canadian and/or global economic conditions and uncertainty could adversely affect our business, results of operations and financial condition.
- Impairment of goodwill, long-lived assets or equity method investments could have a material adverse effect on our results of operations and financial condition.
- Increasing competition could adversely affect our performance and the performance of our projects.

For a more complete discussion of risk factors relevant to our Company, see the risk factors discussion beginning on page 24.

Risks Related to the Proposed Transaction with I Squared Capital

There can be no certainty that all conditions to the Transaction will be satisfied. Failure to complete the Transaction could negatively impact the share price of the common shares or preferred shares or otherwise adversely affect the business of the Company

The completion of the Arrangement is subject to a number of conditions, certain of which are outside our control, including the obtaining of common shareholder approval, the obtaining of preferred shareholder approval, the obtaining of the consents of holders of the MTNs, the obtaining of consents or approvals from holders of convertible debentures, the obtaining of required regulatory approvals, the obtaining of required third-party consents and receipt of a final order from the Supreme Court of British Columbia. There can be no certainty, nor can we provide any assurance, that these conditions will be satisfied or, if satisfied, when. A substantial delay in obtaining satisfactory approvals and/or the imposition of unfavorable terms or conditions in the approvals to be obtained could have an adverse effect on our business, financial condition or results of operations of Atlantic Power or could result in the termination of the Arrangement Agreement. If: (i) common shareholders choose not to approve the Arrangement, (ii) preferred shareholders choose not to approve the continuance of APPEL under the laws of British Columbia and the Arrangement, (iii) holders of the MTNs choose not to amend the MTN indenture (as describe in the Arrangement Agreement), (iv) holders of the convertible debentures choose not to amend the indenture of the convertible debentures (as described in the Arrangement Agreement), (v) we otherwise fail to satisfy, or fail to obtain a waiver of the satisfaction of, the closing conditions to the transaction and the Arrangement is not completed, (vi) a material adverse effect occurs that results in the termination of the Arrangement Agreement, or (vii) any legal proceeding results in enjoining the transactions contemplated by the Arrangement, we could be subject to various adverse consequences, including that we would remain liable for significant costs relating to the Transaction, including, among others, legal, accounting, financial advisory and financial printing expenses.

If the Transaction is not completed, the market price of the common shares and preferred shares may decline to the extent that the market price reflects a market assumption that the Transaction will be completed. The US$3.03 per share to be paid for each Common Share exceeds Atlantic Power's 52-week and last five-year-high price, and represents a premium of approximately 48% to the 30-day volume weighted average price per Common Share on the NYSE. If the Transaction is not completed and the Board decides to seek another merger or business combination, there can be no assurance that it will be able to find a party willing to pay an equivalent or more attractive price than the prices offered to holders of common shares and holders of preferred shares to be paid pursuant to the Arrangement.

In addition, since the completion of the Transaction is subject to uncertainty, our officers and employees may experience uncertainty about their future roles with the Company. This may adversely affect our ability to attract or to retain key management and personnel in the period until the Arrangement is completed or terminated.

The Arrangement Agreement may be terminated in certain circumstances. Even if the Arrangement Agreement is terminated without payment of the termination fee, the Company may, in the future, be required to pay the termination fee in certain circumstances

Each of the parties to the Arrangement Agreement has the right to terminate the Arrangement Agreement in certain circumstances. Accordingly, there is no certainty, nor can we provide any assurance, that the Transaction will not be terminated by any of the parties to the Arrangement Agreement before the completion of the Transaction. Failure to complete the Arrangement could negatively impact the trading price of the common shares or preferred shares or otherwise adversely affect our business.

Under the Arrangement Agreement, we are required to pay a termination fee of $12,500,000 in the event the Arrangement Agreement is terminated following the occurrence of certain events. The termination fee may discourage other parties from attempting to acquire the common shares and preferred shares, even if those parties would otherwise be willing to offer greater value than that offered under the Arrangement.

Even if the Arrangement Agreement is terminated without payment of the termination fee, we may, in the future, be required to pay the termination fee in certain circumstances. Under the Arrangement Agreement, we may be required to pay the termination fee to the Purchasers at a date subsequent to the termination of the Arrangement Agreement if the Arrangement Agreement is terminated due (i) to common shareholder approval of the Arrangement by at least two-thirds of the votes cast by common shareholders at a special meeting of the common shareholders or preferred shareholder approval of the continuance of APPEL under the laws of British Columbia and the Arrangement by at least two thirds of the votes cast by preferred shareholders at a special meeting of the preferred shareholders not being obtained, (ii) the closing of the Transaction having not occurred prior to July 14, 2021, or (iii) our breaching certain representations and warranties if (A) prior to such termination an acquisition proposal is publicly announced after the date of the Arrangement Agreement and not withdrawn prior to the special meetings of common and preferred shareholders and (B) within twelve months of such termination, (x) an acquisition proposal (whether or not the same acquisition proposal described in clause (A) above) is consummated or (y) we or one or more of our subsidiaries enters into an agreement with respect to an acquisition proposal and such acquisition proposal is later consummated (whether or not within the twelve month period following such termination).

Certain features of the Arrangement Agreement may discourage other parties from attempting to acquire the Company

Under the Arrangement Agreement, as a condition to entering into a definitive agreement in respect of a superior proposal, we and APPEL are required to offer the Purchasers the right to match such superior proposal. This right may discourage other parties from making a superior proposal, even if they would otherwise have been willing to acquire us on more favorable terms than the Transaction.

Prior to entering into the Arrangement Agreement, we engaged in exclusive negotiations with I Squared Capital and did not solicit expressions of interest from other potential buyers. A special committee of the Board comprised entirely of independent directors and the Board concluded, after receiving advice from their financial and legal advisors, that the risks of soliciting expressions of interest from other potential buyers outweighed the benefits of doing so, particularly having regard to the financial and other terms of the Arrangement Agreement. However, there can be no assurance that, if we had solicited expressions of interest from other potential buyers, that one or more of such potential buyers would not have been willing to acquire us on more favorable terms than I Squared Capital and the Purchasers.

While the Arrangement is pending, the Company is restricted from taking certain actions

The Arrangement Agreement restricts us from taking certain specified actions until the Arrangement is completed without the consent of the Purchasers. These restrictions may prevent us from pursuing attractive business opportunities that may arise prior to the completion of the Arrangement.

The pending Transaction may divert the attention of the Company's management

The pendency of the Transaction could cause the attention of our management to be diverted from the day-to-day operations and counterparties or suppliers may seek to modify or terminate their business relationships with us. These disruptions could be exacerbated by a delay in the completion of the Arrangement and could have an adverse effect on our business, operating results or prospects.

Risks Related to the Operation of Our Business

If the Arrangement is not completed, the Company will continue to face the risks that it currently faces with respect to its affairs, business and operations and future prospects,. Such risk factors are set out below.

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 September 2021 and November 2043. 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. For example, our Kapuskasing and North Bay projects formerly had PPAs with the OEFC that expired in December 2017. These plants are currently being maintained, but do not operate because they do not have PPAs or a merchant market where operations would be profitable. 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, long lived assets or equity method investments could have a material adverse effect on our business, results of operations and financial condition." Any expiration of our existing PPAs or failure to secure new PPAs could have a material adverse effect on our business, results of operations, financial condition and Adjusted EBITDA.

Three of our projects, representing 8.5% of our operating net MW and 3.5% of our 2020 Project Adjusted EBITDA, have PPAs or other contractual arrangements that will expire in 2021. These projects are Oxnard, Kenilworth and Calstock. Another six of our other projects, representing 48.3% of our operating net MW and 55.8% of our 2020 Project Adjusted EBITDA, have PPAs or other contractual arrangements that will expire within the next five years. These projects are Manchief (2022), Frederickson (2022), Moresby Lake (2022), Nipigon (2022), Orlando (2023) and Chambers (2024). In May 2019, we entered into an agreement to sell Manchief to Public Service Company of Colorado ("PSCo") following the expiration of the PPA in 2022.

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 2020, the largest customers of our power generation projects, including projects recorded under the equity method of accounting, were Niagara Mohawk Power Corporation, IESO, BC Hydro, Equistar Chemicals L. P. and Georgia Power Company, which account for approximately 14.8%, 13.8%, 12.5%, 10.9% and 10.4%, 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 S&P. 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;
- 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 PPA with our utility customer but the project is economically dispatched, which impacts variable operating margins. For example, during periods of low demand and low spot electricity prices, the project is dispatched less, which reduces the project's operating margin. In addition, the utility customer has the right to sell a portion of the output into the spot market if it is economical to do so, and the Chambers project shares in the profit from these sales. This also adds some variability to the project's financial results.

At Morris, a portion of the capacity is contracted with the industrial customer through 2034. The remaining capacity has been sold forward into the Pennsylvania New Jersey Maryland ("PJM") capacity market through annual auctions covering the period through May 2022. The capacity revenues from these auctions generally represent the majority of the operating margin of the uncontracted portion of the project. Energy associated with the capacity sold forward into the PJM market is generally dispatched by PJM when economic to do so or when needed for other reasons.

The project can also offer ancillary services to the grid. The sale of energy and ancillary services from the uncontracted portion of the project is not at a fixed price or margin and therefore can add variability to the project's financial results.

Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the results of operations 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 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 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 $180 million Revolver 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.

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 (loss) income (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 (loss) income (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.

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. Changing temperatures and weather patterns can also lead to increases or decreases in rain, snow, or other precipitation, which can have material impacts to equipment involved in our operations.

Over the past several years, changing weather patterns and climatic conditions have added to the unpredictability of weather-related events in certain parts of the world, including the markets in which we operate and intend to operate, and have created additional uncertainty as to future trends. 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.

Our business faces significant operating hazards 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. 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, fines and/or penalties, and regulatory orders to change operations or equipment. 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 and financial condition.

Risks that are beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters, pandemics (including potentially in relation to the coronavirus) 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.

Our projects may be affected by pandemics (including potentially in relation to the coronavirus). 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. 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.

Our business, results of operations, financial condition, cash flows and stock price can be adversely affected by pandemics, epidemics or other public health emergencies, such as the ongoing COVID-19 pandemic.

Our business, results of operations, financial condition, cash flows and stock price may be adversely affected by pandemics, epidemics or other public health emergencies, such as COVID-19. The ongoing COVID-19 pandemic has resulted in governments around the world implementing stringent measures to help control the spread of the virus, including quarantines, “shelter in place” and “stay at home” orders, travel restrictions, business curtailments, school closures, and other measures. In addition, governments and central banks in several parts of the world have enacted fiscal and monetary stimulus measures to counteract the impacts of COVID-19. Although certain governments have eased their respective restrictions on individuals and businesses, there is material variation in the requirements to lift and reimpose restrictions and the pace at which those restrictions are being lifted and reimposed between jurisdictions. In some jurisdictions, increases in new cases of COVID-19 have led to reinstatement of restrictions on individuals and businesses.

The COVID-19 pandemic has caused, and is expected to continue to cause, the global slowdown of economic activity, disruptions in global supply chains and significant volatility and disruption of financial markets. Because the severity, magnitude and duration of the COVID-19 pandemic, including any resurgence in cases, and its economic consequences are uncertain, rapidly changing and difficult to predict, the pandemic’s impact on our business and results of operations, as well as its impact on our ability to successfully execute our business strategies and initiatives, remains uncertain and difficult to predict. Further, the ultimate impact of the COVID-19 pandemic on our business and results of operations depends on many factors that are not within our control, including, but not limited, to: governmental, business and individuals’ actions that have been and continue to be taken in response to the pandemic (including restrictions on travel and transport and workforce pressures) and the need to reimpose restrictions; the impact of the pandemic and actions taken in response on global and regional economies, travel, and economic activity; the availability of federal, state, local or non-U.S. funding programs (or their failure to implement additional stimulus measures); general economic uncertainty in key global markets and financial market volatility; global economic conditions and levels of economic growth; and the pace of recovery, including vaccination efforts, if and when the COVID-19 pandemic subsides.

We are considered a critical infrastructure industry, as defined by the U.S. Department of Homeland Security. Although we have continued to operate our facilities in both the United States and Canada consistent with federal guidelines and state, provincial and local orders, the outbreak of COVID-19 and any preventive or protective actions taken by governmental authorities may have a material adverse effect on our operations, supply chain, and customers, including business shutdowns or disruptions. The extent to which COVID-19 may adversely impact our business depends on future developments, which are highly uncertain and unpredictable, depending upon the severity and duration of the outbreak and the effectiveness of actions taken globally to contain or mitigate its effects, including the reimposition of restrictions in response to a resurgence in cases. Any resulting financial impact cannot be estimated reasonably at this time, but may materially adversely affect our business, results of operations, financial condition and cash flow. COVID-19 may affect us by (i) reducing economic activity, thereby resulting in lower demand for electricity consumption (with related effects on pricing), (ii) impairing our supply chain (for example, by limiting the manufacturing of materials or the supply of services used in our operations), and (iii) affecting the health of our workforce, rendering employees unable to work or travel. Even after the COVID-19 pandemic has subsided, we may experience materially adverse impacts to our business due to any resulting economic recession or depression. While the restrictions and limitations noted above may be relaxed or rolled back if and when COVID-19 abates, the actions may be reinstated as the pandemic continues to evolve. The scope and timing of any such reinstatements is difficult to predict and may materially affect our operations in the future. Additionally, concerns over the economic impact of COVID-19 have caused extreme volatility in financial and other capital markets, which has and may continue to adversely impact our stock price and our ability to access capital markets. To the extent the COVID-19 pandemic adversely affects our business and financial results, it may also have the effect of heightening many of the other risks described herein, such as those relating to our business and financial performance. We continue to monitor guidelines proposed by federal, state, provincial and local governments with respect to the proposed "reopening" measures, which may change over time depending on public health, safety and other considerations.

We have limited control over management decisions at certain projects

Five 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, as amended. Third-party operators operate five 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.

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 to sell our interests in these projects at the prices we desire.

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, adverse regulatory action, 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.

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 which will expire on December 19, 2023 and December 31, 2021, respectively. 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.

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.

Risks Related to Governmental Regulation and Laws

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.

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 introduction 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.

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 Item 1. "Business-Regulatory Matters," 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 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, permits, approvals, certificates, licenses, registrations 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, at common law and pursuant to statutory rights of compensation, 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.

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 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, or mandated regulatory reserves, could result in additional expense, capital expenditures, restrictions, fines, penalties, 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.

Commonly associated with Canadian environmental regulations are government regulations and obligations towards Indigenous communities. Canadian governments have a constitutional obligation to consult with Indigenous peoples who may be affected by a governmental decision, including decisions to approve projects/expansions or issue, amend, or repeal permits. Consultation with Indigenous communities can significantly increase approval times and the uncertainty of government approval. Any contemplated expansion to our Canadian operations or changes to permitting and regulatory requirements could be materially impacted by this requirement.

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 the results of our operations. Concerning our projects in Ontario, the federal OBPS, from the beginning of 2019, 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. This cost is expected to remain as Ontario facilities are transitioned to the GHGEPS. 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 the results of our operations.

All of our subject generating facilities have complied on a timely basis with the new EPA and applicable Canadian 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 order and policies implemented by the Biden Administration to subdue the actions taken by the Trump Administration to revoke Obama era climate regulations and actions taken and to be taken by the Biden Administration. 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.

Furthermore, there is still considerable uncertainty regarding the state of climate change regulation in Canada. The SCC has not rendered its decision on the constitutionality of the federal backstop regime, which if found to be constitutional, would result in a continuous and material increase to the cost of our operations until 2030.

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. In addition, we are required to include in computing our taxable income any income earned by Atlantic Power Limited Partnership (the “Partnership”), a wholly-owned subsidiary acquired on November 5, 2011. APPEL, a subsidiary of the Partnership, is also a Canadian corporation and is generally subject to Canadian federal, provincial and other taxes.

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 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.

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.

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 currently 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.

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 SEC 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, agents 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.

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 shares.

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 shares.

Risks Related to our Financial Position and Economic and Financial Market Conditions

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 under the terms of our Credit Agreement (defined below), 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, or secure amendments or waivers. 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, or that we will succeed in obtaining amendments or waivers. 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.

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 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, reacting to, or in responding to economic downturns or 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 Atlantic Power Limited Partnership's (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 the London Interbank Offered Rate ("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 would 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.

To address the transition away from LIBOR, we have amended our Credit Facilities to provide for an agreed upon methodology to calculate the new floating benchmark rate plus spread adjustments. 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 (as defined herein) to be materially different than expected.

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, 2020, 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 100% 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, 2020, we had (i) no amount outstanding and $77.1 million issued in letters of credit under our Revolver (as defined herein), (ii) $90.3 million of outstanding convertible debentures, and (iii) $487.3 million of outstanding Term Loan, MTNs 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 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 (as herein defined). 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

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

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

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

The future issuance of additional common shares could dilute existing shareholders

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

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

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

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

- general industry, economic and capital market conditions;
- the availability of bank credit;
- investor confidence;
- our financial condition, performance and prospects as well as companies in our industry or similar financial circumstances; and
- changes in tax and securities laws which are conducive to raising capital.

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

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

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

We have anti-takeover protections that, in the event that the Transaction does not close, 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. 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, which occur when a member of the Board vacates his or her position before the end of his or her term, 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, the Partnership will be required to offer each electing lender a prepayment of such lender's term loan 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.

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 products. 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 have from time to time raised concerns 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.

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, 2020, we had $21.3 million of goodwill, which represented approximately 3% 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 did not record any goodwill impairments, long-lived asset impairments, or equity method investment impairments in 2020. We did not record any goodwill impairments in 2019. We recorded equity method investment impairments of $49.2 million at our Chambers project in the year ended December 31, 2019. We recorded a $5.8 million long-lived asset impairment at Calstock in the year ended December 31, 2019. See Notes 6, 8 and 9 to the consolidated financial statements included in this Annual Report on Form 10-K.

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 make other capital and operating expenditures. See “Risks Related to Our Financial Position and Economic and Financial Market Conditions—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities.”

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

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. Our registered office is located at 1066 West Hastings Street, Suite 2600, Vancouver, British Columbia V6E 3X1 Canada.

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, 2020.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

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

Purchases of Equity Securities by Atlantic Power Corporation and Affiliated Purchasers

Stock Repurchase Program

On December 31, 2020, we commenced a new Normal Course Issuer Bid ("NCIB") for our Series E Debentures, our common shares and for each series of the preferred shares of APPEL, our wholly-owned subsidiary. The NCIBs expire on December 30, 2021 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 8,554,391 common shares based on 10% of our public float as of December 18, 2020 and we are limited to daily purchases of 10,420 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 Toronto Stock Exchange ("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 ("NYSE") in compliance with Rule 10b-18 under the Exchange Act, as amended, or other designated exchanges and published marketplaces in the United States 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, 2020, we have not made any repurchases under the new NCIBs due to the Transaction. In the event the Transaction does not close, the Company will review its approach on capital allocation.

This new NCIB replaced the prior NCIB that expired on December 30, 2020. Under the prior NCIB, we repurchased and cancelled 7.5 million common shares at a cost of $15.8 million. Atlantic Power Corporation and affiliated purchasers did not make any purchases of common equity securities during the period of October 1, 2020 through December 31, 2020.

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 Exchange Act, 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.

Substantial Issuer Bid

On March 25, 2020, we commenced a substantial issuer bid ("SIB") for the purchase of up to $25 million of common shares. This was equivalent to 12,820,512 common shares, or approximately 12% of our total issued and outstanding common shares based on a $1.95 per share purchase price (the minimum price per common share under the offer) as measured on the date of commencement. The SIB expired on April 30, 2020. During the time the SIB was active, the NCIB was suspended for the purchase of common shares and Series E Debentures, but not for the preferred shares of APPEL.

The SIB proceeded by way of a "modified Dutch auction." Holders of common shares were able to tender to the offer by: (i) auction tenders in which they specified the number of common shares being tendered at a price of not less than US$1.95 and not more than US$2.20 per common share in increments of US$0.05 per common share, or (ii) purchase price tenders in which they did not specify a price per common share, but rather agreed to have a specified number of common shares purchased at the purchase price determined by auction tenders.

The purchase price paid by the Company for each validly deposited common share was based on the number of common shares validly deposited pursuant to auction tenders and purchase price tenders, and the prices specified by shareholders making auction tenders. The purchase price was the lowest price which enabled the Company to purchase common shares up to the maximum amount available for auction tenders and purchase price tenders, determined in accordance with the terms of the offer. Common shares that were deposited at or below the final determined purchase price were purchased at such purchase price. Common shares that were not taken up in connection with the offer, including common shares deposited pursuant to auction tenders at prices above the purchase price, were returned to the shareholders.

We repurchased and cancelled 12,500,000 common shares under the SIB at a total cost of $25.8 million, including transaction costs, upon its expiration on April 30, 2020.

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 89,714,323 on March 3, 2021.

ITEM 6. SELECTED FINANCIAL DATA

Not applicable.

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") and in accordance with the instructions to Form 10-K related to smaller reporting companies as promulgated by the SEC. This Item 7 was prepared without regards to potential effects of the Transaction, except where stated otherwise.

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

The discussion and analysis below has been organized as follows:

1) Proposed Transaction with I Squared Capital
2) 2020 Business Overview and Recent Events
3) Performance Highlights and Overview of 2020 Results
4) Results of Operations by Segment
5) Project Operating Performance
6) Supplementary Non-GAAP Financial Information
7) Liquidity and Capital Resources
8) Critical Accounting Policies

Proposed Transaction with I Squared Capital

On January 14, 2021, Atlantic Power entered into the Arrangement Agreement with APPEL, APLP, and the Purchasers. The Purchasers were formed solely for the purposes of effecting the Transaction and are currently owned and controlled by funds affiliated with I Squared Capital, a private equity investment group.

In connection with the Transaction:

- Holders of common shares of Atlantic Power would receive $3.03 per common share in cash.
- Atlantic Power's 6.00% Series E Convertible Unsecured Subordinated Debentures due January 31, 2025 would be converted into common shares of Atlantic Power immediately prior to the closing of the Transaction based on the conversion ratio in effect at such time (including the "make whole premium shares" issuable under the terms of the trust indenture for the convertible debentures following a cash change of control). Holders of the convertible debentures would receive $3.03 per common share held following the conversion of the convertible debentures, plus accrued and unpaid interest on the convertible debentures up to, but excluding, the closing date of the Transaction.
- APPEL's cumulative redeemable preferred shares, Series 1, cumulative rate reset preferred shares, Series 2, and cumulative floating rate preferred shares, Series 3, would be purchased by APPEL for Cdn$22.00 per preferred share in cash.
- APLP's 5.95% MTNs due June 23, 2036 would be redeemed for consideration equal to 106.071% of the principal amount of MTNs held as of the closing of the transaction, plus accrued and unpaid interest on the MTNs up to, but excluding, the closing date of the transaction. Holders of MTNs that deliver a written consent to the proposed amendments to the trust indenture governing the MTNs (as described below) would also be entitled to a consent fee equal to 0.25% of the principal amount of MTNs held by such holders, conditional on closing of the transaction.

The acquisition of Atlantic Power's outstanding common shares and the redemption of the outstanding preferred shares of APPEL would be completed by way of the Arrangement under the *Business Corporations Act* (British Columbia). In connection with the Arrangement, Atlantic Power's shareholder rights plan will be terminated and all rights to purchase Atlantic Power's common shares issued pursuant to the shareholder rights plan would be cancelled.

The Arrangement Agreement

The Arrangement Agreement provides that the Transaction is subject to a number of closing conditions, including court approval of the Arrangement, regulatory approvals (including under the *Competition Act* (Canada), which approval was obtained by the parties on February 2, 2021, and the *U.S. Hart-Scott-Rodino Antitrust Improvements Act* of 1976, as amended, the *Communications Act* of 1934, as amended, and the Federal Power Act, as amended), as well as the receipt of certain third-party consents.

The Transaction is also conditional on the approval of two-thirds of the votes cast by holders of Atlantic Power's common shares voting in person or by proxy at a special meeting of Atlantic Power's common shareholders and the approval of two-thirds of the votes cast by holders of APPEL's preferred shares (voting as a single class) in person or by proxy at a meeting of APPEL's preferred shareholders in respect of both the Arrangement and the proposed continuance of APPEL under the laws of British Columbia. The Arrangement must also be approved by a majority of the votes cast at the special meeting of Atlantic Power's common shareholders, excluding votes attached to common shares held by persons described in items (a) through (d) of Section 8.1(2) of *Multilateral Instrument 61-101 Protection of Minority Security Holders in Special Transactions*.

In addition, the Transaction is conditional upon the approval of the holders of the convertible debentures and the MTNs, respectively (in each case either by way of votes of the holders of the convertible debentures and the MTNs holding at least two-thirds of the principal amount of the convertible debentures and the MTNs, respectively, voted in person or by proxy at separate meetings of the holders of the convertible debentures and the MTNs or by way of separate written consents of the holders of the convertible debentures and the MTNs holding not less than two-thirds of the principal amount of convertible debentures and MTNs outstanding, as applicable), of certain amendments to the trust indentures governing such securities, including to provide for the mandatory conversion of the convertible debentures into common shares; the addition of a redemption obligation of Atlantic Power, conditional on the closing of the Transaction, to redeem all outstanding MTNs for consideration equal to 106.701% of the principal amount of such MTNs; and the modification of the redemption notice period as to the MTNs. Atlantic Power and APLP will seek the approval of the holders of the convertible debentures and MTNs by way of separate meetings and/or consent solicitations.

A bondholder representing approximately 66% of the principal amount of MTNs and approximately 19% of the principal amount of convertible debentures outstanding has agreed to vote in favor of or otherwise consent to amendments to the trust indentures governing those securities.

The Arrangement Agreement is subject to customary non-solicitation provisions, including Atlantic Power's right to consider and accept unsolicited superior proposals in certain circumstances, subject to a right to match in favor of the Purchasers. A termination fee of $12.5 million will be payable by Atlantic Power to the Purchasers should the Transaction not close under certain circumstances, including if the Arrangement is not completed as a result of Atlantic Power accepting an unsolicited superior proposal. A reverse termination fee of $15 million will be payable by the Purchasers to Atlantic Power should the Transaction not close as a result of an uncured breach by the Purchasers of the Arrangement Agreement (provided Atlantic Power is not then in breach of the Arrangement Agreement).

2020 Business Overview

Below, we discuss our progress in executing our business strategy, which is presented in detail in Item 1. Business to this Annual Report on Form 10-K.

Capital allocation

During 2020, we used $48 million of our discretionary capital to repurchase and cancel common ($41.6 million) and preferred (US$6.4 million equivalent) shares at prices that we believe were attractive relative to our estimates of value during 2020. From 2015 through 2020, we repurchased a total of approximately 37.0 million common shares, representing an investment of $80.4 million, and a total of nearly 2.1 million preferred shares, representing a total investment of Cdn$33.6 million (US$25.5 million equivalent). Common shares outstanding have been reduced approximately 27% during this period.

Debt reduction

During 2020, we made payments of $76.4 million to reduce our corporate and consolidated project-level debt. Our consolidated leverage ratio at year end 2020 was 3.6 times, an improvement from 3.8 times at year end 2019. In December 2019, S&P raised our issuer credit rating to BB- (stable) from B+ (positive) based on our improving leverage profile reflecting the predictability of contracted cash flows and our plan to continue to allocate excess cash to pay down debt.

In January 2020, we were able to reprice the Term Loan, lowering the rate from LIBOR plus 2.75% to LIBOR plus 2.50%. This is the fifth repricing since the inception of the Term Loan under which we originally paid interest at LIBOR plus 5.00%. Additionally, we amended the Term Loan to extend the maturity date by two years to April of 2025 and added customary new provisions relating to the replacement of LIBOR as the benchmark for the Eurodollar Rate (as defined in the Credit Agreement). Targeted debt balances, which prescribe required quarterly principal payments, were also adjusted and will end in December 2022. We expect to fully repay the Term Loan by its maturity date.

On March 18, 2020, we executed an amendment to our Revolver. The amendment provides for an extension of the Revolver maturity date to April 2025, to coincide with the maturity date of the senior Term Loan.

In conjunction with the extension, the Revolver capacity was reduced to $180 million from $200 million previously. The amendment allows an upsizing of the Revolver capacity by up to $30 million, to a maximum aggregate amount of $210 million, subject to approval of the two letter of credit issuer banks and increased commitments by existing or new lenders. Such an upsizing would not require a further amendment. There were no other significant changes to the terms of the Revolver.

PPA renewals

In May 2020, the PPA with the Ontario Electricity Financial Corporation for Calstock, which had been scheduled to expire in June 2020, was extended to December 16, 2020 under existing terms. In December 2020, the Calstock PPA was extended for one additional year, also under existing terms, and runs to December 16, 2021. The extension provides the provincial government additional time to consider future options for addressing mill waste in Ontario, including a potential new PPA for Calstock. The extension could be terminated early by mutual agreement if we are successful in securing a new contract.

On August 28, 2020, we executed an agreement to sell RA capacity from the Oxnard plant effective January 1, 2021 through December 31, 2021. Capacity provided under the agreement will be used to satisfy the load obligations of a community choice aggregator. Under the RA agreement, Oxnard will receive a fixed monthly capacity payment. The capacity payment represents an improved outcome compared to a potential RMR alternative for 2021. The RA agreement also provides the opportunity for the plant to receive revenue from the potential sale of energy and ancillary services as well as other non-capacity revenues.

Cost management

We cut our corporate overhead expense from approximately $54 million in 2013 to $24.8 million for 2020, which represents a cumulative reduction from 2013 of approximately 55%. We have maintained our corporate overhead in the $24 million range for the past five years.

Recent Events

Cadillac Repair and Insurance Recovery

On September 22, 2019, the Cadillac project experienced a malfunction in its steam turbine that began a cascade of events, sparking a fire that resulted in significant damage to the turbine, generator and other components in that area of the plant. The fire was contained by the plant's fire protection system and the local fire department and did not result in any injuries or known environmental violations. Reconstruction of Cadillac was completed in late July 2020 and the plant was recommissioned, tested and returned to service on August 20, 2020. Although the plant incurred significant damage, the financial impact has been limited by our comprehensive insurance coverage. For the year ended December 31, 2020, we recorded $20.8 million of capital additions related to repairs at Cadillac and cumulative additions of $25.9 million since the inception of the reconstruction.

In December 2020, we executed a final settlement of our insurance claim for the Cadillac plant under which final payments were received from the insurers as of December 31, 2020. We received insurance proceeds of $10.1 million and $29.9 million for the three and twelve months ended December 31, 2020, respectively, bringing the total cumulative proceeds received to $41.2 million. Proceeds were applied against the Cadillac insurance receivable of $13.5 million as of December 31, 2019, reducing the balance to zero as of December 31, 2020. Reimbursements for lost profits, or business interruption losses, were accounted for as a gain contingency because lost profits are not considered an incurred loss. For the three and twelve months ended December 31, 2020, we recorded business interruption proceeds of $9.4 million and $15.6 million, respectively. Insurance recoveries for property losses in excess of incurred losses were accounted for as gain contingencies. For the three and twelve months ended December 31, 2020, we recorded insurance proceeds for property losses in excess of incurred losses of $0.8 million. Insurance recoveries related to business interruption losses and property losses in excess of incurred losses are included in project other income (loss) on our condensed consolidated statements of operations.

Performance Highlights and Overview of 2020 Results

(in millions of U.S. dollars, except as otherwise stated)	Year Ended December 31, 2020	Year Ended December 31, 2019
Project revenue	$ 272.0	$ 281.6
Project income	$ 118.9	$ 46.8
Net income (loss) attributable to Atlantic Power Corporation	$ 74.2	$ (42.6)
Net cash provided by operating activities	107.3	144.7
Net cash used in investing activities	(10.4)	(21.7)
Net cash used in financing activities	(133.6)	(110.8)
Earnings (loss) per share attributable to Atlantic Power Corporation—basic	$ 0.77	$ (0.39)
Earnings (loss) per share attributable to Atlantic Power Corporation—diluted	0.62	(0.39)
Project Adjusted EBITDA[1]	$ 188.7	$ 196.1

[1] See reconciliation and definition below under Supplementary Non-GAAP Financial Information.

Revenue decreased from $281.6 million in the year ended December 31, 2019 to $272.0 million in the year ended December 31, 2020, a decrease of $9.6 million. The primary drivers of the decrease are as follows:

- *Curtis Palmer* – lower water flows resulted in a $14.5 million decrease in revenue from 2019;

- *Oxnard* – the new RMR contract, effective from June 2020 through December 2020, provides for lower energy and capacity revenue than the previous contract, resulting in a decrease in project revenue of $10.5 million;

- *Morris* – there was a $6.9 million decrease in project revenue at our Morris project due to lower fuel index prices than in 2019;

- *Cadillac* – the project was non-operational through August 20, 2020 following the fire in September 2019, resulting in a $6.0 million decrease in energy and capacity revenue; and

- *Piedmont* – a combination of forced and planned maintenance outages at our Piedmont project resulted in a $2.8 million decrease in revenue from 2019.

These decreases in project revenue were partially offset by increases in project revenue resulting from:

- *Allendale and Dorchester* – a $14.0 million increase in revenue at our Allendale and Dorchester projects, which were purchased in July 2019;

- *Williams Lake* – an $8.1 million increase in revenue from 2019 primarily due to the project's new energy purchase agreement that became effective in October 2019;

- *Mamquam* – higher water flows resulted in a $1.6 million increase in revenue from 2019;

- *Moresby Lake* – higher water flows resulted in a $1.5 million increase in revenue from 2019;

- *Nipigon* – a $1.5 million increase in capacity revenue due to contractual rate escalation and the project's savings pool shared by Nipigon and the offtaker;

- *Kenilworth* – a $1.1 million increase in revenue from 2019, primarily due to a steam revenue adjustment; and

- *Manchief* – higher dispatch resulted in a $1.1 million increase in revenue from 2019.

Consolidated project income was $118.9 million for the year ended December 31, 2020, an increase of $72.1 million from the prior year project income of $46.8 million. The primary drivers of the increase are as follows:

- *Impairment of equity investment and long-lived* assets – we recorded $55 million of impairments in 2019 and none in 2020;

- *Insurance proceeds* – Insurance recoveries of $15.6 million and $0.8 million related to business interruption losses and property losses, respectively, were recognized at Cadillac in 2020 as a result of the fire at the project in 2019. Of the $15.6 million recorded for the recovery of business interruption losses, $6.0 million relates to the expected reduction in capacity payments in 2021 under the Cadillac PPA due to the reduced availability of the plant in 2020 during the extended outage, and $9.6 million relates to the recovery of business interruption losses for 2019 and 2020;

- *Derivative instruments* – the change in the fair value of our derivative instruments increased $15.7 million from 2019; and

- *Depreciation and amortization* expense – depreciation and amortization expense decreased by $4.8 million from 2019 primarily due to a decrease of $2.5 million at our Oxnard project and a decrease of $1.6 million at our Calstock project, as their PPA intangibles were fully amortized in June and May of 2020, respectively.

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

- *Project revenue* – project revenue decreased $9.6 million as discussed above; and

- *Operation and maintenance expenses* – operation and maintenance expenses increased by $12.5 million from 2019 primarily due to an aggregate increase of $7.8 million at our Allendale and Dorchester projects, which were purchased in July 2019, an increase of $4.8 million at our Morris project due to gas turbine maintenance expense and an increase of $3.3 million at our Williams Lake project due to extensive planned maintenance, including replacement of the project's cooling tower. These increases were partially offset by a decrease of $3.8 million at our Oxnard project, which underwent a maintenance outage in 2019.

A detailed discussion of project income (loss) by segment is provided in Results of Operations by Segment below. The discussion of Project Adjusted EBITDA by segment begins on page 63.

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 three 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.

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 September 2021 and November 2043. 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 Item 1A. "Risk Factors—Risks Related to the Operation of Our Business—The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations, financial condition and Project Adjusted EBITDA."

- 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 the Operation of Our Business—Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the results of the operations of the projects" 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 PPA 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 the Operation of Our Business—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, 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 Item 1A. "Risk Factors— Risks Related to the Operation of Our Business."

- 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 the Operation of Our Business—The expiration or termination of PPAs could have a material adverse impact on our business, results of operations, financial condition and Project Adjusted EBITDA."

- Our Cadillac (consolidated) and Chambers (equity method) projects have non-recourse project-level debt that can restrict the ability of the projects to make cash distributions. The project-level debt agreements contain a cash flow coverage ratio test that restricts the projects' cash distributions if project cash flows do not exceed project-level debt service requirements by a specified amount. Although these projects are currently meeting their debt service requirements, we cannot provide any assurances that they 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—Uses of Liquidity—Debt Services Obligations—Project Level" and Item 1A. "Risk Factors—Risks Related to Our Financial Position and Economic and Financial Market Conditions—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.

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 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. Equity method investments and long-lived assets, such as property, plant and equipment, and other intangible assets and liabilities subject to depreciation and amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an equity method investment or asset group may not be recoverable. We recorded $0 and $55.0 million of impairments for the years ended December 31, 2020 and 2019, 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, long-lived asset and equity method investment impairments.

Results of Operations by Segment

We have four reportable segments: Solid Fuel, Natural Gas, Hydroelectric and Corporate. The segment classified as 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 are not allocated to the operating segments when determining segment profit or loss. Project income is the primary GAAP measure of our operating results and is discussed below by reportable segment.

The following tables summarize our consolidated results of operations and project income by reportable segment:

	Years Ended December 31,			
	2020	**2019**	**$ change**	**% change**
Project revenue:				
Energy sales	$ 137.9	$ 138.0	$ (0.1)	(0.1)%
Energy capacity revenue	113.8	125.4	(11.6)	(9.3)%
Other	20.3	18.2	2.1	11.5 %
	272.0	281.6	(9.6)	(3.4)%
Project expenses:				
Fuel	70.9	72.3	(1.4)	(1.9)%
Operations and maintenance	89.5	77.0	12.5	16.2 %
Depreciation and amortization	59.7	64.5	(4.8)	(7.4)%
	220.1	213.8	6.3	2.9 %
Project other income (loss):				
Change in fair value of derivative instruments	6.8	(8.9)	15.7	NM
Equity in earnings (loss) of unconsolidated affiliates	42.9	(3.0)	45.9	NM
Interest expense, net	(1.2)	(1.1)	(0.1)	9.1 %
Impairment	—	(5.8)	5.8	NM
Insurance gain (loss)	16.4	(1.0)	17.4	NM
Other income (expense), net	2.1	(1.2)	3.3	NM
	67.0	(21.0)	88.0	NM
Project income	118.9	46.8	72.1	NM %
Administrative and other expenses (income):				
Administration	24.8	23.9	0.9	3.8 %
Interest expense, net	42.4	44.0	(1.6)	(3.6)%
Foreign exchange loss	5.1	11.9	(6.8)	(57.1)%
Other (income) expense, net	(2.7)	1.0	(3.7)	NM
	69.6	80.8	(11.2)	(13.9)%
Income (loss) from operations before income taxes	49.3	(34.0)	83.3	NM
Income tax (benefit) expense	(24.2)	9.8	(34.0)	NM
Net income (loss)	73.5	(43.8)	117.3	NM
Net loss attributable to preferred shares of a subsidiary company	(0.7)	(1.2)	0.5	(41.7)%
Net income (loss) attributable to Atlantic Power Corporation	$ 74.2	$ (42.6)	$ 116.8	NM

[1] NM is defined as "not meaningful" and includes changes greater than 100%.

Project (Loss) Income by Segment

	Year Ended December 31, 2020				
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 58.8	$ 24.2	$ 54.9	$ —	$ 137.9
Energy capacity revenue	34.6	79.2	—	—	113.8
Other	1.1	14.8	3.4	1.0	20.3
	94.5	118.2	58.3	1.0	272.0
Project expenses:					
Fuel	37.6	33.3	—	—	70.9
Operations and maintenance	45.4	28.6	13.0	2.5	89.5
Depreciation and amortization	12.9	27.1	19.6	0.1	59.7
	95.9	89.0	32.6	2.6	220.1
Project other income (loss):					
Change in fair value of derivative instruments	—	8.9	—	(2.1)	6.8
Equity in earnings of unconsolidated affiliates	1.4	41.5	—	—	42.9
Interest expense, net	(1.2)	—	—	—	(1.2)
Insurance gain	16.4	—	—	—	16.4
Other income, net	—	2.1	—	—	2.1
	16.6	52.5	—	(2.1)	67.0
Project income (loss)	$ 15.2	$ 81.7	$ 25.7	$ (3.7)	$ 118.9

	Year Ended December 31, 2019				
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 41.1	$ 31.0	$ 65.9	$ —	$ 138
Energy capacity revenue	38.7	86.7	—	—	125.4
Other	0.2	14.1	2.9	1.0	18.2
	80.0	131.8	68.8	1.0	281.6
Project expenses:					
Fuel	28.6	43.7	—	—	72.3
Operations and maintenance	33.5	28.9	13.3	1.3	77.0
Depreciation and amortization	14.7	30.2	19.5	0.1	64.5
	76.8	102.8	32.8	1.4	213.8
Project other income (loss):					
Change in fair value of derivative instruments	—	(1.4)	—	(7.5)	(8.9)
Equity in (loss) earnings of unconsolidated affiliates	(45.0)	42.0	—	—	(3.0)
Interest expense, net	(1.2)	0.1	—	—	(1.1)
Impairment	(5.8)	—	—	—	(5.8)
Insurance loss	(1.0)	—	—	—	(1.0)
Other expense, net	—	(1.2)	—	—	(1.2)
	(53.0)	39.5	—	(7.5)	(21.0)
Project (loss) income	$ (49.8)	$ 68.5	$ 36.0	$ (7.9)	$ 46.8

Discussion of project income (loss) by reportable segment:

Solid Fuel

Project income for 2020 increased $65.0 million from 2019 primarily due to:

- increased project income of $50.4 million at Chambers primarily due to a $49.2 million impairment of our equity investment recorded in 2019;

- increased project income of $12.6 million at Cadillac primarily due to insurance proceeds of $15.6 million and $0.8 million related to business interruption losses and property losses, respectively, as a result of the fire at the project in September 2019, partially offset by a $1 million increase in maintenance expense. Of the $15.6 million recorded for the recovery of business interruption losses, $6.0 million relates to the expected reduction in capacity payments in 2021 under the Cadillac PPA due to the reduced availability of the plant in 2020 during the extended outage, and $9.6 million relates to the recovery of business interruption losses for 2019 and 2020;

- increased project income of $7.0 million at Calstock primarily due to a $5.8 million long-lived asset impairment recorded in 2019; and

- increased project income of $1.1 million at Williams Lake primarily due to the project's new energy purchase agreement that became effective in October 2019.

These increases were partially offset by:

- decreased project income of $2.0 million at Craven as a result of extended rotor repairs at the project during 2020. The project was purchased in August 2019 and therefore had a limited impact on project income in 2019;

- decreased project income of $1.8 million at Grayling as a result of extended rotor and generator repairs at the project during 2020. The project was purchased in August 2019 and therefore had a limited impact on project income in 2019; and

- decreased project income of $1.6 million at Piedmont primarily due to maintenance outages.

Natural Gas

Project income for 2020 increased $13.2 million from 2019 primarily due to:

- increased project income of $7.2 million at Nipigon primarily due to a $3.3 million increase in the fair value of the fuel agreement accounted for as a derivative financial instrument, a $1.5 million increase in capacity revenue due to contractual rate escalation and the project's savings pool shared by Nipigon and the offtaker, and a $1.3 million decrease in maintenance expense due to major maintenance at the project in 2019;

- increased project income of $6.6 million at Orlando primarily due to an $8.0 million increase in the fair value of natural gas swaps, partially offset by a $1.8 million increase in fuel expense due to unfavorable fuel prices;

- increased project income of $1.6 million, $1.3 million and $1.1 million at Naval Station, NTC and North Island, respectively, primarily due to changes in estimates for asset retirement obligations; and

- increased project income of $1.4 million at Kenilworth primarily due to a steam revenue adjustment.

These increases were partially offset by:

- decreased project income of $6.7 million at Morris primarily due to increased gas turbine maintenance expense of $4.0 million and a lower gross margin from lower PJM pricing.

Hydroelectric

Project income for 2020 decreased $10.3 million from 2019 primarily due to:

- decreased project income of $14.9 million at Curtis Palmer primarily due to lower water flows than in 2019.

This decrease was partially offset by:

- increased project income of $2.0 million at Moresby Lake primarily due to higher water flows than in 2019; and

- increased project income of $1.9 million at Mamquam primarily due to higher water flows than in 2019.

Corporate

Total project loss increased $4.2 million from 2019 primarily due to a $5.4 million increase in the fair value of interest rate swap agreements related to the Term Loan.

Discussion of Corporate segment items not included in project income (loss):

Administrative and other expenses (income)

Administrative and other expenses (income) includes the income and expenses not attributable to our projects and which are allocated to the 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 by $0.9 million from 2019 primarily due to costs related to the Transaction.

Interest, net

Interest expense decreased by $1.6 million from $44.0 million in 2019 to $42.4 million in 2020 primarily due to lower outstanding debt balances than 2019, as well as a lower interest rate on our Term Loan.

Foreign exchange loss

Foreign exchange loss decreased by $6.8 million from $11.9 million in 2019 to $5.1 million in 2020 due to the revaluation of instruments denominated in Canadian dollars (primarily MTNs and convertible debentures). The Canadian dollar appreciated 2.0% against the U.S. dollar from December 31, 2019 to December 31, 2020, as compared to a 4.8% increase in 2019.

Other (income) expense, net

Other expense, net decreased $3.7 million from other expense, net of $1.0 million in 2019 to other income, net of $2.7 million in 2020 primarily due to a $3.6 million change in the fair value of the conversion option of the Series E Debentures.

Income tax (benefit) expense

Income tax benefit for the year ended December 31, 2020 was $24.2 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 27% ,was $13.3 million. The primary item impacting the tax rate for the year ended December 31, 2020 was a net decrease to our valuation allowances of $40.2 million, consisting of $0.5 million decreases in Canada and $39.7 million decreases in the United States. In addition, the rate was further impacted by $0.6 million relating to foreign exchange, offset by $3.0 million related to changes in estimates due to tax filings and $0.3 million of other permanent differences.

Income tax expense for the year ended December 31, 2019 was $9.8 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 27%, was $9.2 million. The primary items impacting the tax rate for the year ended December 31, 2019 were $7.7 million related to impairments and a net increase to our valuation allowances of $5.7 million, consisting of $7.9 million increases in Canada and $2.2 million decreases in the United States. In addition, the rate was further impacted by $2.2 million related to changes in tax rates, $1.7 million relating to foreign exchange, $1.3 million relating to withholding and state taxes and $0.4 million of 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.

Generation

	Year ended December 31,		
(in Net GWh)	**2020**	**2019**	**% change 2020 vs. 2019**
Segment			
Solid Fuel	1,506.1	1,439.2	4.6 %
Natural Gas	2,226.8	2,475.3	(10.0)%
Hydroelectric	637.2	673.2	(5.3)%
Total	4,370.1	4,587.7	(4.7)%

Year ended December 31, 2020 compared with Year ended December 31, 2019

Aggregate power generation for 2020 decreased 4.7% from 2019 primarily due to:

- decreased generation in the Natural Gas segment primarily due to a 192.4 net GWh decrease in generation at Frederickson due to lower dispatch than 2019 and a 94.5 net GWh decrease in generation at Oxnard under the new RMR contract, effective from June 2020 through December 2020, as the project runs only when it is called upon to operate. These decreases were partially offset by a 118.7 net GWh increase in generation at Manchief due to higher dispatch than 2019; and

- decreased generation in the Hydroelectric segment, primarily due to a 110.5 net GWh decrease at Curtis Palmer as a result of lower water flows than in 2019. This decrease was partially offset by increased generation at Mamquam and Moresby Lake of 50.2 net GWh and 13.3 GWh, respectively, due to higher water flows than in 2019.

These decreases were partially offset by:

- increased generation in the Solid Fuel segment, primarily due to a combined generation increase of 226.6 net GWh at Allendale, Dorchester and Craven, which were acquired in July 2019. These increases were partially offset by a 57.5 net GWh decrease at Piedmont due to outages, a 41.8 net GWh decrease at Cadillac due to the extended outage at as a result of the fire at the project in September 2019, and a 39.3 net GWh decease at Williams Lake primarily due to the contractual curtailment during the months of May, June and July under the new PPA.

Availability

	Year ended December 31,		
	2020	2019	% change 2020 vs. 2019
Segment			
Solid Fuel	78.2 %	92.5 %	(14.3)%
Natural Gas	94.4 %	95.8 %	(1.4)%
Hydroelectric	88.8 %	92.6 %	(3.8)%
Weighted average	86.7 %	94.0 %	(7.3)%

Year ended December 31, 2020 compared with Year ended December 31, 2019

Weighted average availability for 2020 decreased 7.3% from 94.0% in 2019 primarily due to:

- decreased availability in the Solid Fuel segment primarily due to the fire at Cadillac in September 2019 and outages at Craven, Grayling and Piedmont in 2020;

- decreased availability in the Hydroelectric segment primarily due to forced outages at Koma Kulshan in 2020, partially offset by a forced outage at Moresby Lake in 2019; and

- decreased availability in the Natural Gas segment primarily due to planned outages at Orlando and Morris in 2020, partially offset by a planned outage at Nipigon in 2019.

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 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 income (loss). A reconciliation of Net income (loss) to Project 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, 2020	2019	$ change 2020
Net income (loss)	$ 73.5	$ (43.8)	$ 117.3
Income tax (benefit) expense	(24.2)	9.8	(34.0)
Income (loss) from operations before income taxes	49.3	(34.0)	83.3
Administration	24.8	23.9	0.9
Interest expense, net	42.4	44.0	(1.6)
Foreign exchange loss	5.1	11.9	(6.8)
Other (income) expense, net	(2.7)	1.0	(3.7)
Project income	$ 118.9	$ 46.8	$ 72.1
Reconciliation to Project Adjusted EBITDA			
Depreciation and amortization	76.6	80.7	(4.1)
Interest expense, net	2.8	2.5	0.3
Change in the fair value of derivative instruments	(6.8)	8.9	(15.7)
Impairment	—	55.0	(55.0)
Insurance (gain) loss	(0.7)	1.0	(1.7)
Other (income) expense, net	(2.1)	1.2	(3.3)
Project Adjusted EBITDA	$ 188.7	$ 196.1	$ (7.4)
Project Adjusted EBITDA by segment			
Solid Fuel	39.9	32.7	7.2
Natural Gas	105.0	108.2	(3.2)
Hydroelectric	45.3	55.5	(10.2)
Corporate	(1.5)	(0.3)	(1.2)
Total	$ 188.7	$ 196.1	$ (7.4)

Solid Fuel

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

	Year ended December 31, 2020	2019	% change 2020 vs. 2019
Solid Fuel			
Project Adjusted EBITDA	$ 39.9	$ 32.7	22 %

Year ended December 31, 2020 compared with Year ended December 31, 2019

Project Adjusted EBITDA for 2020 increased $7.2 million or 22% from 2019 primarily due to increased Project Adjusted EBITDA of:

- $10.1 million at Cadillac primarily due to insurance proceeds of $15.6 million for business interruption losses as a result of the fire at the project in September 2019, partially offset by a $1 million increase in maintenance expense. Of the $15.6 million recorded for the recovery of business interruption losses, $6.0 million relates to the expected reduction in capacity payments in 2021 under the Cadillac PPA due to the reduced availability of the plant in 2020 during the extended outage, and $9.6 million relates to the recovery of business interruption losses for 2019 and 2020;

- $1.3 million at Williams Lake primarily due to the project's new energy purchase agreement that became effective in October 2019; and

- $1.0 million at Chambers due to lower fuel consumption and improved heat rate than 2019.

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

- $1.6 million at Piedmont primarily due to maintenance outages in 2020;

- $1.5 million at Grayling due to extended rotor and generator repairs at the project during 2020. The project was purchased in August 2019 and therefore had a limited impact on Project Adjusted EBITDA in 2019; and

- $1.4 million at Craven due to extended rotor repairs at the project during 2020. The project was purchased in August 2019 and therefore had a limited impact on Project Adjusted EBITDA in 2019.

Natural Gas

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

	Year ended December 31,		
	2020	2019	% change 2020 vs 2019
Natural Gas			
Project Adjusted EBITDA	$ 105.0	$ 108.2	(3)%

Year ended December 31, 2020 compared with Year ended December 31, 2019

Project Adjusted EBITDA for 2020 decreased by $3.2 million or 3% from 2019 primarily due to decreases in Project Adjusted EBITDA of:

- $5.5 million at Morris due to increased gas turbine maintenance expense of $4.0 million and a lower gross margin from lower PJM pricing;

- $1.7 million at Oxnard due to the new RMR contract, effective from June 2020 through December 2020, which provides for lower energy and capacity revenue than the previous contract; and

- $1.4 million at Orlando primarily due to planned major maintenance at the project.

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

- $3.9 million at Nipigon due to rate escalation and major maintenance in 2019 at the project.

Hydroelectric

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

	Year Ended December 31,		
	2020	2019	% change 2020 vs. 2019
Hydroelectric			
Project Adjusted EBITDA	$ 45.3	$ 55.5	(18)%

Year ended December 31, 2020 compared with Year ended December 31, 2019

Project Adjusted EBITDA for 2020 decreased by $10.2 million or 18% from 2019 primarily due to a decrease in Project Adjusted EBITDA of:

- $14.9 million at Curtis Palmer primarily due to lower water flows than in 2019.

This decrease was partially offset by an increase in Project Adjusted EBITDA of:

- $2.0 million at Mamquam primarily due to higher water flows than in 2019; and
- $2.0 million at Moresby Lake primarily due to higher availability and higher water flows than in 2019.

Corporate

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

	Year Ended December 31,		
	2020	2019	% change 2020 vs. 2019
Corporate			
Project Adjusted EBITDA	$ (1.5)	$ (0.3)	NM

Year ended December 31, 2020 compared with Year ended December 31, 2019

Project Adjusted EBITDA did not change materially from 2019.

Liquidity and Capital Resources

This section does not give effect to the potential implementation of the Arrangement and closing of the Transaction.

	December 31, 2020	December 31, 2019
Cash and cash equivalents	$ 38.8	$ 74.9
Restricted cash	7.1	7.7
Total	45.9	82.6
Revolving credit facility availability [(1)]	102.9	121.7
Total liquidity	$ 148.8	$ 204.3

(1) On March 18, 2020, the borrowing capacity under the Revolver was reduced to $180 million under the amendment to extend the Revolver maturity to April 2025.

For the year ended December 31, 2020, our total liquidity decreased $55.5 million. Changes in cash, restricted cash and cash equivalent balances are further discussed hereinafter under the heading *Cash Flow Discussion*. We believe that our liquidity position and cash flows from operations will be adequate to maintain our operations and meet obligations as they become due for at least the next 12 months from March 4, 2021.

Sources of Liquidity

Our primary source of liquidity is distributions from our projects and availability under our Revolver (as defined herein). 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 September 2021 to November 2043. We currently have three projects with PPAs with expiration dates in 2021, Calstock, Kenilworth and Oxnard. 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 Financial Position and Economic and Financial Market Conditions—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities."

Uses of Liquidity

Capital and Maintenance Expenditures

Our commercial operations require a significant amount of 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 invested approximately $38.5 million of project capital expenditures and maintenance expenses (excluding $20.8 million of Cadillac reconstruction costs) for the year ended December 31, 2020. In all cases, scheduled maintenance outages during the year ended December 31, 2020 occurred at such times that did not adversely impact the facilities' availability requirements under their respective PPAs.

We expect to reinvest approximately $40.0 million in 2021 in our portfolio in the form of maintenance expenses and project capital expenditures. 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 2021 level as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

Debt Service and Redemptions

During the year ended December 31, 2020, we made $72.5 million of principal payments on the Term Loan and $3.9 million on Cadillac's term loan.

Debt Service Obligations - Corporate

The following table summarizes the maturities of our corporate debt at December 31, 2020:

	Maturity Date	Interest Rates	Remaining Principal Repayments	2021	2022	2023	2024	2025	Thereafter
Senior secured term loan facility[1]	April 2025	4.70%	$ 307.5	$ 93.0	$ 106.0	$ 60.0	$ 36.0	$ 12.5	$ —
MTNs	June 2036	5.95%	164.9	—	—	—	—	—	164.9
Convertible Debenture	January 2025	6.00%	90.3	—	—	—	—	90.3	—
Total Corporate Debt			$ 562.7	$ 93.0	$ 106.0	$ 60.0	$ 36.0	$ 102.8	$ 164.9

(1) The Credit Facility contains a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of APLP 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, 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 APPEL, 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 Loan outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule through December 2022. 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 APPEL being unable to pay dividends to its shareholders. In January 2020, APLP Holdings completed the repricing of the Term Loan. As a result of the repricing, the interest rate margin on the Term Loan and the Revolver was reduced by 0.25% to LIBOR plus 2.50% with no change to the 1.00% LIBOR floor. Additionally, APLP Holdings amended its existing Term Loan to extend the maturity date by two years to April of 2025 and added customary new provisions relating to the replacement of LIBOR as the benchmark for the Eurodollar Rate (as defined in the Credit Agreement) replacement. Targeted debt balances were adjusted to reflect the previously announced anticipated closing of the proposed sale of the Company's Manchief power plant in 2022, resulting in lower targeted debt repayment in 2020 and higher targeted debt repayment in 2022 as compared to the previous schedule. The amortization profile in the table above is based on principal payments according to the targeted principal amount described in (ii) above through 2022 based on the schedule as amended in January 2020. After 2022, the amortization profile is based on (i) above and is an estimate, subject to change. See Note 12, *Long-term debt* to the consolidated financial statements for more information on our Credit Facilities.

Debt Service Obligations - Project-Level

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 share of the non-recourse project-level debt balances at December 31, 2020. 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* to the consolidated financial statements. 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.

The range of interest rates presented represents the rates in effect at December 31, 2020. 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	2021	2022	2023	2024	2025	Thereafter
Consolidated Projects:									
Cadillac	August 2025	6.26 % - 6.38 %	$ 14.8	$ 2.7	$ 3.3	$ 3.3	$ 3.7	$ 1.8	$ —
Total Consolidated Projects			14.8	2.7	3.3	3.3	3.7	1.8	—
Equity Method Projects:									
Chambers[1]	December 2023	5.00 %	30.7	8.8	10.1	11.8	—	—	—
Total Equity Method Projects			30.7	8.8	10.1	11.8	—	—	—
Total Project-Level Debt			$ 45.5	$ 11.5	$ 13.4	$ 15.1	$ 3.7	$ 1.8	$ —

(1) The above table does not include our $0.7 million proportionate share of unamortized issuance premiums.

Repurchases of Securities

On December 31, 2019, we commenced a Normal Course Issuer Bid ("NCIB") for each of our Series E Debentures, our common shares and for each series of the preferred shares of APPEL, our wholly-owned subsidiary. During the year ended December 31, 2020, we repurchased and canceled 7,540,105 common shares at a total cost of approximately $15.8 million. Additionally, we repurchased and cancelled 381,794 shares of Series 1 Shares, 62,365 shares of Series 2 Shares and 120,000 shares of Series 3 Shares of APPEL at a total cost of $6.4 million.

On December 31, 2020, we commenced a new NCIB for our 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, 2020, up to the following limits:

	Maturity Date	Interest Rates	Limit on Purchase (Principal Amount) Total Limit
Convertible Debenture	January 2025	6.00 %	Cdn$ 5,750,000

	Limit on Purchase (Number of Shares) Total Limit [1]
Common Shares	8,554,931
Series 1 Preferred Shares	346,570
Series 2 Preferred Shares	243,976
Series 3 Preferred Shares	93,889

(1) Represented 10% of the public float of the common shares and 10% of the public float of the Preferred 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 Exchange Act, 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. The NCIBs will expire on December 30, 2021 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.

Dividends from 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. The Series 1 Shares are redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all accrued and unpaid dividends thereon. At December 31, 2020, there were 3,465,706 Series 1 Shares outstanding.

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 pays a fixed dividend when declared. The dividend on the Series 2 Shares is cumulative. Beginning on December 31, 2014 and each fifth-year anniversary thereafter, (i) the rate on the Series 2 shares is reset at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%, and (ii) holders of Series 2 Shares have the right, subject to certain limitations, to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the “Series 3 Shares”) of the subsidiary. On December 31, 2019, the rate on the Series 2 Shares was reset to 5.74% and holders of the Series 2 Shares converted 23,618 Series 2 Shares into Series 3 Shares.

The holders of Series 3 Shares are entitled to receive quarterly floating rate 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%. The dividend on the Series 3 Shares is cumulative. The dividend rate for the Series 3 Shares was reset on December 31, 2020 to 4.30%. Beginning on December 31, 2019, and on each fifth-year anniversary thereafter, holders of Series 3 Shares have the right, subject to certain limitations, to convert their shares into Series 2 Shares. On December 31, 2019, holders of the Series 3 Shares converted 295,032 Series 3 Shares into Series 2 Shares.

The Series 2 Shares and Series 3 Shares are redeemable by the subsidiary company at Cdn$25.00 on the five-year reset date and Cdn$25.50, respectively, per share, plus an amount equal to all accrued and unpaid dividends thereon. At December 31, 2020, there were 2,441,766 Series 2 Shares and 957,391 Series 3 Shares outstanding.

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.

The subsidiary company paid aggregate dividends of $6.8 million and $7.4 million on Series 1 Shares, Series 2 Shares and Series 3 Shares for the years ended December 31, 2020 and 2019, respectively.

Contributions to our pension plan

We expect to contribute Cdn$0.5 million to our pension plan in 2021.

Cash Flow Discussion

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

	Year ended December 31, 2020	Year ended December 31, 2019	Change
Net cash provided by operating activities	$ 107.3	$ 144.7	$ (37.4)
Net cash used in investing activities	(10.4)	(21.7)	11.3
Net cash used in financing activities	(133.6)	(110.8)	(22.8)

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, 2020, the net decrease in cash flows provided by operating activities of $37.4 million was primarily the result of the following:

- *Working capital* – changes in working capital resulted in a $25.6 million decrease in cash flows from operating activities. The unfavorable change in working capital is primarily due to the timing of cash receipts at Cadillac, Williams Lake, and Nipigon, as well as larger cash disbursements for payables at Cadillac for repair work and at Morris for a maintenance outage in 2020;

- *Hydrological conditions* – lower water flows at our Curtis Palmer project, partially offset by higher water flows at our Mamquam and Moresby Lake projects, had an $11.0 million negative impact on cash flows provided by operating activities;

- *Distributions from unconsolidated affiliates* – we received distributions from our unconsolidated affiliates of $5.3 million less than were received in the comparable 2019 period, primarily at Chambers which began repaying principal on its project-level debt in the fourth quarter of 2019.

These decreases were partially offset by the following increase in net cash provided by operating activities:

- *Cadillac* – In December 2020, we executed a final settlement of our insurance claim for the Cadillac plant under which we received insurance proceeds of $29.9 million for the twelve months ended December 31, 2020. Of the $29.9 million in insurance proceeds received, $16.4 million related to operating activities, including $15.6 million for business interruption losses and $0.8 million for fuel inventory losses.

Investing Activities

For the year ended December 31, 2020, the net decrease in cash flows used in investing activities of $11.3 million was primarily the result of the following:

- *Investment in unconsolidated affiliates* – we paid $18.7 million in the comparable 2019 period to acquire a 50% interest in Craven and a 30% interest in Grayling in August 2019;

- *Acquisitions* – we paid $8.6 million, net of cash received, during the comparable 2019 period to complete the acquisitions of Dorchester and Allendale in July 2019; and

- *Insurance proceeds* – insurance recoveries related to the Cadillac fire were $2.2 million higher than the comparable 2019 period. For the year ended December 31, 2020, we received insurance proceeds of $29.9 million, of which $13.5 million related to property, plant and equipment. In 2019, we received insurance proceeds of $11.3 million.

These decreases were partially offset by the following increase in cash used in investing activities:

- *Capitalized plant additions* – investments in capitalized plant additions were $17.5 million higher than the comparable 2019 period, primarily due to repairs at Cadillac.

Financing Activities

For the year ended December 31, 2020, the net increase in cash flows used in financing activities of $22.8 million was primarily the result of the following:

- *Common share repurchases* – we paid $41.6 million (which includes $25.8 million for the SIB, including transaction costs) in the twelve months ended December 31, 2020 to repurchase and cancel common shares as compared to $2.5 million in the comparable 2019 period;

- *Corporate and project-level debt repayments* – we made principal payments that were $4.1 million greater than in 2019; and

- *Deferred financing costs* – we incurred $1.7 million of deferred financing costs related to amending the Term Loan and the Revolver in the twelve months ended December 31, 2020.

These increases were partially offset by the following decreases in cash flows used in financing activities:

- *Convertible debenture redemptions* – we paid $18.5 million to redeem and cancel the Series D Debentures in the comparable 2019 period;

- *Preferred share repurchases* – we paid $6.4 million to repurchase and cancel preferred shares as compared to $8.0 million in the comparable 2019 period; and

- *Vested LTIP* – we made $1.4 million of lower cash payments for vested LTIP tax withholdings than in the comparable 2019 period.

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 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.

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 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 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 Financial Position and Economic and Financial Market Conditions— Impairment of goodwill, long-lived assets or equity method investments could have a material adverse effect on our results of operations and financial condition."

For the year ended December 31, 2020, there were no impairment indicators present and we did not record any long-lived asset impairments in 2020. We recorded a $5.8 million long-lived asset impairment at Calstock in the year ended December 31, 2019. See Item 15 — Note 8, *Property, plant and equipment, net* 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.

For the year ended December 31, 2020, there were no equity investments that required an assessment as to whether an other-than-temporary decline in value exists and we did not record any equity method investment impairments in 2020. We recorded equity method investment impairments of $49.2 million at our Chambers project in the year ended December 31, 2019. 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 industry conditions, market events and circumstances as well as the overall financial performance of our reporting units. For our 2020 test, we elected to perform a quantitative assessment at each of our three reporting units, as opposed to a qualitative assessment.

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 tests beginning in November 2017.

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 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, including forecasted revenues after the expected contractual expiration of the related PPAs, 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 fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of our reporting units.

We did not record any goodwill impairments in 2020 or 2019. See Item 15 — Note 9, *Goodwill* 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 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.

Accounting for insurance proceeds

We have insurance policies from various insurers which provides coverage for losses that may occur involving our assets or operations of our projects. We record insurance recoveries for property losses only when we can reasonably estimate the amount of an incurred loss for an event, or its range, and it is deemed probable that a recovery of that claim will occur. Insurance proceeds received in excess of incurred losses will be accounted for as gain contingencies. The assessment of whether recovery is probable or reasonably possible, and whether the recovery or a range of recoveries is estimable, often involves a series of complex judgments about future events. Anticipated reimbursements for lost profits, or business interruption losses, are accounted for as a gain contingency because lost profits are not considered an incurred loss. Further, all contingencies related to business interruption claims must be resolved before the reimbursement can be recognized in earnings. For any insurance proceeds received that are unallocated from the insurer and cover more than one type of loss (e.g., property, business interruption), we will allocate the proceeds to each type of loss. Insurance recoveries are reviewed quarterly and estimates are adjusted to reflect the impact of all known information, including advice of legal counsel, discussions with insurers and other information and events pertaining to a particular matter.

In December 2020, we executed a final settlement of our insurance claim for the Cadillac plant under which final payments were received by insurers as of December 31, 2020. For the three and twelve months ended December 31, 2020, we received insurance proceeds of $10.1 million and $29.9 million, respectively, bringing the total cumulative proceeds received to $41.2 million. Proceeds were applied against the Cadillac insurance receivable of $13.5 million as of December 31, 2019, reducing the balance to zero as of December 31, 2020. Reimbursements for lost profits, or business interruption losses, were accounted for as a gain contingency because lost profits are not considered an incurred loss. For the three and twelve months ended December 31, 2020, we recorded business interruption proceeds of $9.4 million and $15.6 million, respectively. These business interruption proceeds are included in project other income (loss) on our condensed consolidated statements of operations. Insurance recoveries for property losses in excess of incurred losses were accounted for as gain contingencies. For the three months ended December 31, 2020 and for the full year 2020, we recorded insurance proceeds for property losses in excess of incurred losses of $0.8 million. These insurance recoveries related to property losses are included in project other income (loss) on our condensed consolidated statements of operations. See Item 15 — Note 23, *Commitments and contingencies* for discussion of insurance proceeds.

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, 2020, we have recorded a valuation allowance of $105.2 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

As a "smaller reporting company," as defined in Rule 12b-2 of the Exchange Act, we are electing scaled disclosure reporting obligations and are therefore not required to provide the information called for by this item.

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, 2020 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, 2020 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, 2020 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 on 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, 2020 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

As a "smaller reporting company" as defined in Rule 12b-2 of the Exchange Act, we are electing scaled disclosure reporting obligations and are not required to provide certain information called for in Part III.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Board of Directors

The following table sets forth the names of, and certain information for our current Directors. Biographies for each Director, which include a summary of each Director's age, positions with the Company, principal occupation and employment within the five preceding years, are set out below.

Name and Province/State of Residence	Age	Position	Principal Occupation	Date Appointed
KEVIN T. HOWELL (1)(2) Texas, U.S.A.	63	Director; Chairman of the Board	Corporate Director	December 23, 2014
R. FOSTER DUNCAN (1)(3) Louisiana, U.S.A.	67	Director	Operating Partner, Bernhard Capital Partners and Senior Advisor, EHS Partners	June 29, 2010
DANIELLE S. MOTTOR (4) Massachusetts, U.S.A.	54	Director	Senior Vice President, Concentric Energy Advisors	January 23, 2019
GILBERT S. PALTER (5) Ontario, Canada	55	Director	Managing Partner and Chief Investment Officer, EdgeStone Capital Partners	June 23, 2015
JAMES J. MOORE, JR. Massachusetts, U.S.A.	63	Director, President and Chief Executive Officer	President and Chief Executive Officer of the Company	January 26, 2015

(1) The Board of Directors has determined that each of Messrs. Howell, Duncan and Palter and Ms. Mottor is an independent Director. Each independent Director is also a member of each of the committees of the Board of Directors (Audit Committee, Compensation Committee, Nominating and Corporate Governance Committee, and Operations and Commercial Oversight Committee).

(2) Chair of the Nominating and Corporate Governance Committee.

(3) Chair of the Audit Committee.

(4) Chair of the Compensation Committee.

(5) Chair of the Operations and Commercial Oversight Committee.

The following paragraphs provide information about each Director, including all positions he or she holds, his or her principal occupation and business experience for the past five years, and the names of other publicly-held companies of which he or she currently serves as a director or has served as a director during the past five years.

Kevin T. Howell: Mr. Howell has been a Director of the Company since December 2014 and Chairman of the Board since January 2019. He is a retired executive with more than 35 years of industry experience and is an accomplished power and natural gas executive with extensive commercial leadership at the executive levels of affiliates of Duke Energy, Dominion Resources, NRG Energy Inc. ("NRG Energy") and Dynegy Inc. ("Dynegy"). Mr. Howell served as Executive Vice President and Regional President of Texas of NRG Energy, a large energy company that owns and operates a diverse portfolio of power-generating facilities, primarily in the United States, from March 2008 until his retirement in August 2010. In July 2011, he joined Dynegy as Executive Vice President and Chief Operating Officer, where he ran commercial and plant operations and oversaw environmental health and safety. In November 2011, when Mr. Howell was acting in this capacity, two Dynegy subsidiaries filed for bankruptcy protection. In 2011 and 2012, Mr. Howell was involved in significant restructuring activities at Dynegy, and was named as a defendant in a shareholder class action lawsuit in connection with that restructuring process. He was also named as a defendant in three other matters brought by other participants in the restructuring, which reached settlement in June 2012. Mr. Howell retired from Dynegy in January 2013 after a successful restructuring that brought the company out of bankruptcy with a relisting on the NYSE. In April 2014, the shareholder class action lawsuit in which Mr. Howell was a named defendant was dismissed with prejudice. Mr. Howell previously served as the Chairman of the Board of Directors of Illinois Power Generating Company, an affiliate of Dynegy. Mr. Howell previously served as a director on the boards of Entrust Energy, a privately-held energy retailer, and Nanosolar Inc., a thin film solar manufacturer. From April 2017 through December 2019, Mr. Howell served as a director on the board of Homer City Holdings, LLC and was Chair of that board's Risk Oversight Committee and a member of that board's Audit Committee. In April 2018, Mr. Howell joined the board and began serving as Chair of the Risk Oversight Committee of TexGen Power LLC, a privately held fleet of gas power plants located in Texas, following its emergence from bankruptcy proceedings initiated by its previous owner, Exelon (when it was known as ExGen Texas Power LLC). In February 2020, Mr. Howell joined the board of Energy Harbor Corp., where he serves on the Audit Committee, Nominations and Governance Committee and Nuclear Oversight Committee. Energy Harbor Corp. is a public independent power producer and retail energy provider that resulted from the emergence of FirstEnergy Solutions from bankruptcy in February 2020. Mr. Howell's extensive experience in commercial and plant operations management, as well as his expertise in the electric power sector, make him a valued advisor and highly qualified to serve as Chairman of our Board of Directors and as Chair of our Nominating and Corporate Governance Committee.

R. Foster Duncan: Mr. Duncan has been a Director of the Company since June 2010. He has more than 30 years of senior corporate, investment banking, and private equity experience. Mr. Duncan is an Operating Partner of Bernhard Capital Partners, an energy services and infrastructure focused private equity firm that targets businesses providing critical services to the energy sector, throughout the midstream, downstream and power verticals, and serves as a Senior Advisor to EHS Partners in New York, a management consulting firm focused on improving operational effectiveness, earnings, and growth. Previously, Mr. Duncan was a Member of MFB Energy Partners, LLC and was a Managing Director at Advantage Capital Partners with senior management responsibility for the firm's energy portfolio and energy initiatives. From 2005 through 2009, Mr. Duncan was managing member of KD Capital L.L.C., an affiliate of Kohlberg Kravis Roberts & Co. ("KKR") which he and KKR formed. Mr. Duncan was located in KKR's offices and worked exclusively with KKR and its portfolio companies in connection with creating value and investing in the energy, utility, natural resources, and infrastructure sectors. Previously, Mr. Duncan was Executive Vice President and Chief Financial Officer of Cinergy Corp., Chairman of Cinergy's Investment Committee and Chief Executive Officer and President of Cinergy's Commercial Business Unit. Mr. Duncan is active with the Edison Electric Institute, including as a past member of the Wall Street Advisory Group and a past Chairman of the Finance Executive Advisory Committee. He has also held senior management positions at LG&E Energy Corp., Freeport-McMoRan Copper & Gold and Howard Weil, a premier energy investment banking boutique. From 2009 to 2014, Mr. Duncan served as a director of Xtreme Power, LLC, a small, privately held company, which filed for Chapter 11 bankruptcy protection in 2013 and was sold to Younicos AG in April 2014. From February 2006 to 2013, Mr. Duncan also served as a director of Essential Power, LLC, a portfolio company of Industry Funds Management (US), LLC. Mr. Duncan served on the Advisory Council of Greentech Capital Advisors in New York from January 2013 to December 2018 and served as Chair of the Board of Directors of Charah, Inc. in Louisville, Kentucky from March 2017 to March 2018. Since March 2020, Mr. Duncan has served on the board of Atlas Technical Consultants, Inc. and as Chairman of that board's Audit Committee. Atlas Technical Consultants is a public company that provides professional testing, inspection, engineering, program management and consulting services. Mr. Duncan is active in a number of civic organizations, including serving on the Board of Directors of the Eye, Ear, Nose and Throat Hospital Foundation in New Orleans, the Nature Conservancy of Louisiana, the Greater New Orleans Foundation, the New Orleans Museum of Art and the National Advisory Board of the University of Virginia Jefferson Scholars Program. He graduated with Distinction from the University of Virginia and later received his Masters of Business Administration degree from the A. B. Freeman Graduate School of Business at Tulane University. Mr. Duncan's extensive experience in energy services, as well as his extensive financial background, make him highly qualified to serve on our Board of Directors and as Chair of the Audit Committee.

Danielle S. Mottor: Ms. Mottor has been a director of the Company since January 2019. She has nearly 30 years of experience in the wholesale and retail electricity markets, power generation, and energy consulting fields. Ms. Mottor is presently a Senior Vice President of Concentric Energy Advisors ("Concentric"), a consulting firm focused on the North American energy industry. Her tenure at Concentric dates from 2005. Prior to joining Concentric, she was a Principal Analyst at ISO New England. Before joining ISO New England, she worked as an advisor to Concentric. She also held management roles at Navigant Consulting and XENERGY, Inc. Earlier in her career, she was a production engineer at New England Power Company. Ms. Mottor earned a Master of Business Administration magna cum laude from Bentley College and a Bachelor of Science in Mechanical Engineering from the University of Massachusetts at Amherst. She holds an Engineer-in-Training (EIT) Certification and is a member of the Massachusetts Restructuring Roundtable. Ms. Mottor's extensive background in power markets and energy consulting make her a valued advisor and highly qualified to serve on our Board of Directors.

Gilbert S. Palter: Mr. Palter has been a Director of the Company since June 2015. He co-founded EdgeStone Capital Partners in 1999, has served as its Chief Investment Officer & Managing Partner since 1999, and has grown EdgeStone to be one of Canada's leading independent private capital managers, with in excess of $2 billion of capital commitments for its private equity, mezzanine debt, and venture capital funds. Mr. Palter attended Harvard Business School on a Frank Knox Memorial Fellowship, where he graduated as a Baker Scholar and winner of the John L. Loeb Fellowship in Finance, and he was the Gold Medalist in his graduating class at the University of Toronto, where he attended on the J.W. Billes Scholarship, earning a Bachelor of Science degree in computer science and economics. He was a 2003 recipient of "Canada's Top 40 Under 40" award, and was a recipient of the Ernst & Young Entrepreneur Of The Year® Award 2006. Mr. Palter has served as Chairman and as director on more than 25 public and private company boards, and is actively involved in a variety of community and philanthropic organizations. Mr. Palter's extensive financial experience, as well as his presence on numerous company Boards, make him a valued advisor and highly qualified to serve as a member of our Board of Directors.

James J. Moore, Jr.: Mr. Moore has been our President and Chief Executive Officer and a Director of the Company since January 2015. Mr. Moore has more than 30 years of experience in the energy industry, including building two other independent power businesses and serving as Chief Executive Officer at both. Prior to joining the Company, he was the Chairman of Energy and Power at Diamond Castle Holdings LLC ("DCH"), a $1.8 billion private equity firm in New York City, where he served as a director on the board of a solar portfolio company and as Chairman of the Board of a directional drilling services portfolio company. Prior to joining DCH in 2008, he served as President and Chief Executive Officer of Catamount Energy Corporation ("Catamount"). After joining Catamount in 2001, Mr. Moore's new strategy helped transform a small Vermont energy company into a wind-focused growth company, leading to the sale of the company to DCH in 2005 and later to Duke Energy in 2008. Prior to his tenure at Catamount, he served as Chief Executive Officer of American National Power from 1994 to 2001. Mr. Moore previously served on the boards of Comverge, Inc. in 2012, Green Mountain College from 2008 to 2011 and International Power PLC from 2000 to 2001. He earned a Bachelor of Arts degree from the College of the Holy Cross and a Juris Doctor degree from the University of Houston. Mr. Moore's extensive experience in the energy industry, as well as his in-depth knowledge of the Company through his position as President and Chief Executive Officer, make him highly qualified to serve as a member of our Board of Directors.

If the Arrangement is consummated pursuant to the Arrangement Agreement, the annual general meeting will not be held and no proxies will be solicited.

Under the Company's independence standards and under the NYSE corporate governance rules and NP 58-201, a majority of the Board of Directors must qualify as "independent directors." At least annually, the Board of Directors is required to evaluate all relationships between the Company and each Director in light of relevant facts and circumstances for the purposes of determining whether a material relationship exists that might signal a potential conflict of interest or otherwise interfere with such Director's ability to satisfy his or her responsibilities as an independent Director. The Board of Directors has determined that each of Kevin T. Howell, R. Foster Duncan, Danielle S. Mottor and Gilbert S. Palter is or was an independent Director in 2020.

The Board of Directors has established four committees:

- The Audit Committee;
- The Compensation Committee:
- The Nominating and Corporate Governance Committee: and
- The Operations and Commercial Oversight Committee.

The chart below identifies the members and chair of each committee at the end of 2020:

Name	Audit	Compensation	Nominating and Corporate Governance	Operations and Commercial Oversight
Kevin T. Howell	X	X	C	X
R. Foster Duncan	C, FE	X	X	X
Danielle S. Mottor	X	C	X	X
Gilbert S. Palter	X, FE	X	X	C
James J. Moore, Jr.				

FE = “Audit Committee Financial Expert” as the term is defined in the rules of the SEC.

C = Chair

X = Committee member

Audit Committee. The Audit Committee’s primary purposes are, among other things, to: (i) assist the Board of Directors in its oversight and supervision of the integrity of the accounting and financial reporting practices and procedures, the implementation and adequacy of the internal accounting controls and procedures, and the compliance with legal and regulatory requirements in respect of financial disclosure; (ii) assess and monitor the strategic, operating, reporting and compliance risks of the business, including cybersecurity risks; and (iii) supervise the qualification, independence and performance of independent accountants of the Company. Kevin T. Howell, R. Foster Duncan (chair), Danielle S. Mottor and Gilbert S. Palter serve as members of the Audit Committee. Each member of the Audit Committee is “independent,” as defined under Rule 10A-3 of the Exchange Act. Each of R. Foster Duncan and Gilbert S. Palter are audit committee financial experts as the term is defined in the rules of the SEC.

Executive Officers Who Are Not Directors

The following table sets forth the names, ages and positions of the executive officers of the Company other than Mr. Moore, who is a Director of the Company:

Name	Age	Position	Date Appointed as Officer
Terrence Ronan	61	Executive Vice President— Chief Financial Officer and Principal Financial and Accounting Officer	August 20, 2012
Joseph E. Cofelice	63	Executive Vice President —Commercial Development	September 16, 2015
James P. D'Angelo	50	Senior Vice President —Chief Administrative Officer	November 7, 2017

Terrence Ronan: Mr. Ronan joined Atlantic Power in August 2012 as Executive Vice President—Chief Financial Officer. He is the Company’s Principal Financial and Accounting Officer and has primary responsibility for all finance-related functions, as well as a central role in the development and execution of the Company’s operational and strategic initiatives. Mr. Ronan is a financial professional with more than 25 years of management and capital-raising experience. From April 2011 through August 2012, Mr. Ronan served as Managing Director—Finance and Assistant

Treasurer at Plains All American Pipeline, L.P., a publicly traded master limited partnership engaged in the transportation, storage, terminalling and marketing of crude oil, refined products, liquefied petroleum gas (LPG) and other natural gas related products. Prior to that, Mr. Ronan served as President and Chief Executive Officer of SemGroup, L.P. (" SemGroup "), where he oversaw the operations of the privately held partnership engaged in the transportation, storage, terminalling and marketing of crude oil, LPG and natural gas. Appointed on the eve of SemGroup's bankruptcy filing in the United States and Canada in 2008, he led the company through its reorganization until it emerged from bankruptcy in November 2009. From 2006 through March 2008, Mr. Ronan served as Managing Director at Merrill Lynch Capital, where he co-founded the start-up Energy Finance practice, in which he was responsible for origination activities in the midstream and Exploration and Production (" E&P ") sectors. Mr. Ronan also spent 14 years at Bank of America and predecessors Fleet Boston and BankBoston, culminating in his role as Managing Director where he focused on financing industry-leading E&P, midstream and refining and marketing companies. Mr. Ronan graduated with a Bachelor of Science degree from Bates College and later received a Master of Business Administration degree from the University of Michigan Ross School of Business. He also served in the U.S. Navy from 1981 to 2007, active and reserve components, retiring after 26 years with the rank of Captain.

Joseph E. Cofelice: Mr. Cofelice joined Atlantic Power as Executive Vice President—Commercial Development in September 2015 from General Compression, Inc., a compressed air energy storage technology company, where he had been Chief Executive Officer and served as a member of its Board of Directors since December 2012. From 2010 to April 2013, Mr. Cofelice served as Chief Executive Officer and a member of the Board of Westerly Wind LLC, a provider of project development capital to the wind industry. Mr. Cofelice served as the Chairman of the Board of Westerly Wind LLC from April 2013 through September 2015. From December 2012 to April 2013, Mr. Cofelice served as Chief Executive Officer of both General Compression, Inc. and Westerly Wind LLC concurrently. Both General Compression and Westerly Wind were part of US Renewables Group's portfolio of investments. From 2002 to 2008, Mr. Cofelice was the President of Catamount Energy Corporation. Prior to his tenure at Catamount, he served in a number of management roles at American National Power from 1987 to 2002, including serving as Chief Executive Officer. Mr. Cofelice has more than 30 years of experience in the energy industry. Mr. Cofelice graduated with a Bachelor of Science degree in Business Administration from Northeastern University.

James P. D'Angelo: Mr. D'Angelo is Chief Administrative Officer of Atlantic Power, with responsibility for key corporate functions including Human Resources, Information Technology, Environmental, Health and Safety, Corporate Insurance, and Facilities. Prior to joining Atlantic Power in September 2012, Mr. D'Angelo spent more than 20 years in the energy industry, holding positions of increasing responsibility. These positions include Vice President of Human Resources for FloDesign Wind Turbine, GreatPoint Energy and Trigen. Prior to that, Mr. D'Angelo was the Director, Human Resources at Calpine Corporation with responsibility for all Human Resource related functions for more than 80 plant locations and 3,000 employees. Mr. D'Angelo holds a Bachelor of Arts degree in Political Science from Bridgewater State College and a Masters of Business Administration degree from Suffolk University.

Code of Ethics

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

Summary Compensation Table

Name and principal position	Year	Salary (1)	Bonus (2)	Stock Awards (3)	Non-equity incentive plan compensation (4)	All other compensation (5)	Total compensation
James J. Moore, Jr.							
Director, President and	2020	$ 597,115	$ 172,500	$ 517,500	$ 402,500	$ 25,965	$ 1,715,580
Chief Executive Officer	2019	575,000	115,000	575,000	402,500	25,715	1,693,215
Terrence Ronan							
Executive Vice President—	2020	415,385	120,000	380,000	280,000	14,250	1,209,635
Chief Financial Officer	2019	400,000	100,000	400,000	280,000	14,000	1,194,000
Joseph E. Cofelice							
Executive Vice President—	2020	415,385	120,000	380,000	280,000	14,250	1,209,635
Commercial Development	2019	400,000	100,000	400,000	280,000	14,000	1,194,000

(1) The amounts shown in the "Salary" column for 2020 for Mr. Moore, Mr. Ronan and Mr. Cofelice are reflective of their regularly calculated bi-weekly salaries across twenty-seven (27) pay periods in 2020 due to the leap year and bank holiday schedules. On an annualized basis, Mr. Moore’s, Mr. Ronan’s and Mr. Cofelice’s annual base salaries remained $575,000, $400,000 and $400,000, respectively.

(2) The amounts shown in the "Bonus" column include, for all executives, the discretionary component of the Company’s Short-Term Incentive Plan (the “STIP”) for 2020 and 2019 (though the amounts were paid in the first quarter of the following year). For each of 2020 and 2019, each executive’s aggregate STIP target was 100% of his annual base salary, and the discretionary component of the STIP comprised 30% of each executive’s target STIP award. In 2020, each named executive officer received a 100% payout for the discretionary component of the STIP. In 2019, Mr. Moore received a 66.7% payout for the discretionary component of the STIP, and Messrs. Ronan and Cofelice each received an 83.3% payout. See the STIP discussion below for further discussion of 2020 STIP awards.

(3) The amounts shown in the “Stock Awards” column reflect the grant date fair value of notional shares granted during the year and are calculated in accordance with Financial Accounting Standards Board Accounting Standards Codification (“FASB ASC”) Topic 718. The assumptions used in determining the grant date fair value of these awards are described in Item 15. “Exhibits and Financial Statements Schedule”—Note 2(s), Equity compensation plans. All other amounts in the Stock Awards column represent awards made under the LTIP in the year shown with respect to performance for the previous year (e.g., the amounts shown for 2020 were awarded in early 2020 with respect to performance in 2019).

(4) The amounts shown in the “Non-equity incentive plan compensation” column represent the non-discretionary component of awards made under the STIP for performance in 2020 and 2019 (though the amounts were paid in the first quarter of the following year). For each of 2020 and 2019, each executive’s aggregate STIP target was 100% of his annual base salary, and the non-discretionary components of the STIP comprised an aggregate of 70% of each executive’s target STIP award. In each of 2020 and 2019, each named executive officer received a 100% payout for the non-discretionary component of the STIP. See the STIP discussion below for further discussion of 2020 STIP awards.

(5) For 2020, amounts include the Company’s matching 401(k) plan contributions of $14,250 for each executive officer, and, for Mr. Moore only, $11,715 for additional life insurance under the terms of his employment agreement. For 2019, amounts include the Company’s matching 401(k) plan contributions of $14,000 for each

executive officer, and, for Mr. Moore only, $11,715 for additional life insurance under the terms of his employment agreement.

STIP

The named executive officers and other employees of the Company are eligible to participate in the STIP as determined by the Board of Directors. The STIP is intended to compensate executives for executing on the Company's short-term business strategy based on the achievement of goals set by the Compensation Committee. In 2020, the STIP had four performance components, with weightings and descriptions provided as follows:

25% Financial – Adjusted Cash Flow from Operating Activities

Threshold	Target	Stretch
50% payout	100% payout	150% payout
15% lower	$108 million (budget)	20% higher

20% Financial – Costs = G&A + Non-Fuel O&M Activities (excluding growth costs)

50% payout	100% payout	150% payout
10% higher	$113.7 million (budget)	15% lower (better)

25% Operational – Average of all Annual Incentive Plan (AIP) scores

Threshold	Target	Stretch
50% payout	100% payout	150% payout
93% average score	100% average score	107% average score

30% Strategic – The strategic component of the award is discretionary and based on the evaluation of the individual's performance, the Company's overall performance, shareholder value, stakeholder value, and other qualitative measures including leadership, commitment and overall effectiveness, as determined by the Compensation Committee.

For the 2020 performance year, the Compensation Committee set the target STIP award for each of Messrs. Moore, Ronan and Cofelice at 100% of such executive officer's annual base salary. In January 2021, the Compensation Committee determined that Messrs. Moore, Ronan, Cofelice and Levy were eligible for annual incentive awards under the pre-established performance criteria noted above, and awarded each of them a 100% payout of their target STIP. The Compensation Committee made this determination based primarily on the achievements of the Company relating to the four performance categories. In determining the STIP awards described above, the Compensation Committee assessed the performance of Messrs. Moore, Ronan, Cofelice and Levy in terms of their individual groups as well as the relationship of their achievements to the performance of the Company as a whole. Based on that assessment, the Compensation Committee determined these STIP awards were appropriate for each of the named executive officers. These were paid in February 2021 with respect to performance during 2020.

Outstanding Equity Awards at Year End

The following table sets forth, for each named executive officer, all equity-based awards outstanding as of December 31, 2020:

Name	Number of shares or units of stock that have not vested (1)	Market value of shares or units of stock that have not vested (2)	Equity Incentive Plan Awards: Number of unearned shares, units or other rights that have not vested (3)	Equity Incentive Plan Awards: Market or payout value of unearned shares units or other rights that have not vested (2)(3)
James J. Moore, Jr.	594,119	$ 1,241,709	269,952	$ 564,200
Terrence Ronan	316,984	662,497	-	-
Joseph E. Cofelice	316,984	662,497	-	-

(1) Notional shares are subject to time-based vesting. For Mr. Moore, 235,099 notional shares vested in February 2021, 150,000 are scheduled to vest in March 2021, 139,743 notional shares are scheduled to vest in February 2022 and 69,277 notional shares are scheduled to vest in February 2023, subject to Mr. Moore's continued employment. For Mr. Ronan, 166,225 notional shares vested in February 2021, 99,890 notional shares are scheduled to vest in February 2022 and 50,869 notional shares are scheduled to vest in February 2023, subject to Mr. Ronan's continued employment. For Mr. Cofelice, 166,225 notional shares vested in February 2021, 99,890 notional shares are scheduled to vest in February 2022 and 50,869 notional shares are scheduled to vest in February 2023, subject to Mr. Cofelice's continued employment.

(2) This amount is calculated based on the five-day weighted average closing price of a Common Share on the NYSE as of December 31, 2020 ($2.09).

(3) The amount shown for Mr. Moore in this column includes 269,952 transitional notional shares under his Transition Equity Grant Participation Agreement that will vest on or any time after January 22, 2017 if the weighted average Canadian dollar closing price of the Company's 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% (Cdn$4.77).

Additional Narrative Disclosures

The Company's employment agreement with James J. Moore, Jr., President and Chief Executive Officer, provides that Mr. Moore is employed for an indefinite term, subject to termination in accordance with the terms of his employment agreement. During his employment, Mr. Moore is entitled to compensation comprising of base salary, an annual bonus under the STIP, and equity-based compensation under the LTIP. If he is terminated by the Company for any reason other than cause, or if Mr. Moore terminates his employment for good reason, then the following are paid or provided under the employment agreement: (i) his base salary through the termination date, to the extent not yet paid; (ii) a lump sum termination payment equal to two times his then-current base salary (without giving effect to any material salary reduction), plus a pro-rata amount, based on the number of days elapsed during the fiscal year in which the Date of Termination occurs, of the target bonus provided for in Mr. Moore's employment agreement (75% of annual base salary); (iii) immediate vesting of any LTIP awards which had not yet vested (including any unvested portion of his transitional grant) and (iv) continuation of medical and life insurance benefits for a period of eighteen months following termination. In the event that Mr. Moore's employment is terminated as a result of his death, disability or retirement, he will be entitled to receive his accrued salary through the date of termination, and each equity-based award held by Mr. Moore shall vest in accordance with the applicable plan or grant or agreement. Mr. Moore's employment agreement contains provisions addressing confidentiality, non-disclosure, non-competition, non-solicitation, non-disparagement and ownership of intellectual property.

The Company's employment agreement with Terrence Ronan, CFO, provides that Mr. Ronan is employed for an indefinite term, subject to termination in accordance with the terms of his employment letter agreement, as amended. During his employment, Mr. Ronan is entitled to compensation comprising of base salary, an annual bonus under the STIP, and equity-based compensation under the LTIP. If Mr. Ronan is terminated by the Company either following a determination by the Board of Directors that the executive officer's performance is unsatisfactory with respect to annually approved goals and objectives (with 90 days prior written notice to the executive officer, and not during any period that is 90 days preceding or one year following a change of control, during which period the Company cannot terminate Mr. Ronan's employment) or for any reason other than cause, or if he resigns within 90 days preceding or one year after a change of control because certain further triggering events have occurred including material reduction in salary or benefits (including annual STIP or LTIP), relocation, change in position (including status, offices, titles and reporting relationships), authority, duties or responsibilities, or the Company's breach of the employment agreement, then the following are paid or provided under the employment agreement: (i) his base salary through the termination date, to the extent not yet paid; (ii) a lump sum termination payment equal to two times the average, during the last two years, of the sum of his: (a) base salary, (b) annual STIP, and (c) the most recent matching contribution to his 401(k) plan (the sum of (a), (b) and (c) being the executive officer's " Total Annual Compensation "); (iii) immediate vesting of all previous awards under the LTIP which had not yet vested; (iv) continuation of all employee benefits for a period of one year following termination; and (v) costs of outplacement services customary for senior executives at the respective executive officer's level for a period of 12 months following termination with the cost capped at $25,000. In order to secure his cash severance entitlements described in item (ii) of the previous sentence, within 10 days following the consummation of a change of control, the Company is required to deposit such amounts into a "rabbi trust" for the benefit of Mr. Ronan. Mr. Ronan's employment agreement contains provisions addressing confidentiality, non-disclosure, non-competition, non-solicitation and ownership of intellectual property.

The Company's employment agreement with Joseph E. Cofelice, Executive Vice President of Commercial Development, provides that Mr. Cofelice is employed for an indefinite term, subject to termination in accordance with the terms of his employment letter agreement, as amended. During his employment, Mr. Cofelice is entitled to compensation comprising of base salary, an annual bonus under the STIP, and equity-based compensation under the LTIP. If Mr. Cofelice is terminated by the Company for any reason other than cause, or if Mr. Cofelice terminates his employment for good reason, then the following are paid under the employment agreement: (i) his base salary through the termination date, to the extent not yet paid or provided; (ii) a lump sum termination payment equal to his then-current base salary (without giving effect to any material salary reduction), plus a pro-rata amount, based on the number of days elapsed during the fiscal year in which the Date of Termination occurs, of the target bonus provided for in Mr. Cofelice's employment agreement (75% of annual base salary); (iii) if such termination was by the Company other than for cause or, following a change of control, by Mr. Cofelice for good reason, immediate vesting of LTIP which had not yet vested, and (iv) continuation of medical insurance benefits for a period of one year following termination. In order to receive these termination benefits (other than unpaid base salary through termination date), the executive officer must execute a general waiver and release of claims against the Company and its affiliates. In the event that Mr. Cofelice's employment is terminated as a result of his death, disability or retirement, he will be entitled to receive his accrued salary through the date of termination, and each equity-based award held by Mr. Cofelice shall vest in accordance with the applicable plan or grant or agreement. Effective February 27, 2018, Mr. Cofelice's employment agreement was amended to provide that, if he is terminated by the Company for any reason other than cause, or if Mr. Cofelice terminates his employment for good reason, in each case occurring within the 12-month period following a change of control, (x) the termination payment described in item (ii) above will instead be equal to the sum of (a) two times his then-current base salary without giving effect to a material salary reduction, if any, and (b) a pro-rata amount, based on the number of days elapsed during the fiscal year in which the Date of Termination occurs, of the target bonus provided for in Mr. Cofelice's employment agreement (75% of annual base salary), and (y) the continuation of medical insurance benefits described in item (iv) above will instead be for a period of 18 months following termination. Mr. Cofelice's employment agreement contains provisions addressing confidentiality, non-disclosure, non-competition, non-solicitation, non-disparagement and ownership of intellectual property.

In January 2019, our Board of Directors approved certain amendments to the LTIP, applicable to awards granted after January 2019 (the LTIP as amended, the "6th A&R LTIP"); certain amendments to awards outstanding under the LTIP granted prior to January 2019, including those of each of our named executive officers (the "Legacy Award Amendments"), and certain amendments to the Transition Equity Grant Participation Agreement between the Company and Mr. Moore (the "Transition Award Amendment").

Under the 6th A&R LTIP, (i) in the event a named executive officer's employment is terminated (x) due to retirement after attaining the age of 62 and following the occurrence of a change of control or (y) due to disability, his or her notional share awards will immediately vest in full and be settled as soon as practicable thereafter, rather than continuing to vest on their original schedule, and (ii) in the event that the Company experiences a change of control, unless a named executive officer's notional share awards either (x) continue to remain outstanding and the Company's common shares continue to be publicly traded on a national securities exchange or (y) are replaced with or converted into substantially equivalent awards, including with respect to the vesting schedule, accelerated vesting terms, redemption terms and value of the original notional share awards, that are in respect of equity interests that are publicly traded on a national securities exchange (a change of control where such conditions are not satisfied, a "Non-Qualifying Change of Control"), then, all notional share awards held by such named executive officer will immediately vest and be settled in cash as soon as practicable thereafter, rather than requiring a qualifying termination of employment to occur following such Non-Qualifying Change of Control. Both under the 6th A&R LTIP and the prior version of the LTIP, in the event (a) a named executive officer is terminated by the Company without Cause, his or her notional share awards will immediately vest in full, (b) a named executive officer resigns for good reason following a change of control, his or her notional share awards will immediately vest in full, or (c) a named executive officer retires after attaining the age of 62 and prior to the occurrence of a change of control, his or her notional share awards will continue to vest on their original schedule notwithstanding such retirement.

In connection with the adoption of the 6th A&R LTIP, our Board of Directors also approved the Legacy Award Amendments, in order to conform the vesting schedule applicable to notional share awards granted under the prior version of the LTIP in the event of a Non-Qualifying Change of Control of the Company to those of awards granted under the 6th A&R LTIP. Specifically, in the event the Company experiences a Non-Qualifying Change of Control, the notional share awards of named executive officers will immediately vest in full, rather than requiring a qualifying termination of employment to occur following such Non-Qualifying Change of Control. In order to comply with Section 409A of the U.S. Internal Revenue Code, following such accelerated vesting, such notional share awards will be settled in cash on the earlier of (i) their originally scheduled vesting date or (ii) the named executive officer's separation from service (other than due to disability or retirement).

The Company also entered into the Transition Award Amendment with Mr. Moore, in order to conform the vesting schedule applicable to the performance-based portion of Mr. Moore's transition notional share award in the event of a change of control of the Company to those of awards granted under the 6th A&R LTIP. The original Transition Equity Grant Participation Agreement between Mr. Moore and the Company provided that his transition notional share award will immediately vest in full and be settled as soon as practicable thereafter in the event Mr. Moore is terminated without cause, resigns for good reason or dies. The Transition Award Amendment provides that, in addition, in the event the Company experiences a change of control, following which Mr. Moore retires after attaining the age of 62 or becomes disabled, the performance-based portion of Mr. Moore's transition notional share award will similarly immediately vest in full. The Transition Award Amendment also (i) clarifies that, in the event of a change of control, the redemption price of Mr. Moore's transition notional share award will be locked-in at the transaction price, although the redemption of such award will remain subject to Mr. Moore experiencing a qualifying termination, and (ii) clarifies the language providing that upon a termination without cause or resignation for good reason, Mr. Moore's transition notional share award will vest in full.

Compensation of Directors

Director Fees

Each independent Director is entitled to receive an annual retainer of $120,000, of which 50% is paid in cash and 50% is granted in deferred share units (" DSUs "), with the goal of aligning Director compensation with the long-term interests of Shareholders via mandatory share holdings. Directors may elect to receive all or a portion of their cash retainer in DSUs. Directors who serve in a leadership role receive an additional annual fee, as follows:

- Chair of the Board of Directors—$35,000
- Chair of the Audit Committee—$15,000
- Chair of the Compensation Committee—$10,000
- Chair of the Nominating and Corporate Governance Committee—$10,000

- Chair of the Operations and Commercial Oversight Committee—$10,000

These additional fees are also paid 50% in cash and 50% in DSUs. Retainers and fees are pro-rated for partial years of service on the Board of Directors or as a Committee Chair. Directors are reimbursed for out-of-pocket expenses for attending meetings but do not receive a per-meeting fee. Directors also participate in insurance and indemnification arrangements. Directors who are also executive officers of the Company are not entitled to any compensation for their services as a Director.

Certain Directors also serve on the board of Atlantic Power Preferred Equity Ltd., a wholly-owned subsidiary of Atlantic Power Corporation, for which they receive an annual cash retainer of $10,000.

Deferred Share Unit Plan

On April 24, 2007, the Board of Directors established a Deferred Share Unit Plan (" DSU Plan ") for Directors. Under the DSU Plan, each non-management Director is entitled to elect to have a portion of the fees paid to him or her by the Company for his or her services as Directors contributed to the DSU Plan. All fees contributed to the DSU Plan are credited to such Director in the form of DSUs with the number of DSUs calculated based on the current market price of the Company's Common Shares at the time of contribution. For as long as the participant continues to serve on the Board of Directors, dividends, if any are declared, accrue on the DSUs consistent with amounts declared by the Board of Directors on the Company's Common Shares and additional DSUs representing the dividends are credited to the Director's account. DSUs credited to the participant's DSU account are redeemed only when a participant ceases to serve on the Board of Directors for any reason. DSUs are redeemed in cash no later than the first anniversary of the participant's termination as a Director (unless a participant elects another time no later than the end of the calendar year following the year of termination), or, in the case of participants subject to United States income tax, as soon as practicable following the participant's termination. Under the DSU Plan, the Company also has the discretion to provide for the redemption or substitution of DSUs upon a reorganization of the Company.

2020 Director Compensation

The following table describes Director compensation for non-management Directors for the year ended December 31, 2020:

Name	Fees Earned or Paid in Cash	Stock Awards (1)(2)	Total Compensation
R. Foster Duncan (3)	$ 77,500	$ 67,500	$ 145,000
Kevin T. Howell	82,500	82,500	165,000
Danielle S. Mottor	-	130,000	130,000
Gilbert S. Palter (3)	75,000	65,000	140,000

(1) Reflects the grant date fair value of DSUs awarded in 2020 determined in accordance with FASB ASC Topic 718, Compensation-Stock Compensation.

(2) As of December 31, 2020, directors held the following DSUs: 240,756 for R. Foster Duncan, 180,602 for Kevin T. Howell, 113,906 for Danielle S. Mottor and 153,794 for Gilbert S. Palter.

(3) Includes fees paid in cash to the Director for service as a director on the board of Atlantic Power Preferred Equity Ltd., as follows: $10,000 for R. Foster Duncan and $10,000 for Gilbert S. Palter (pro-rated amount).

Compensation Risk Assessment

The Company has reviewed the Company's compensation policies and practices for all employees and concluded that any risks arising from the Company's policies, plans and programs are not reasonably likely to have a material adverse effect on the Company. The Company reviewed the elements of executive compensation to determine whether any portion of executive compensation encouraged excessive risk-taking and concluded:

- the allocation of compensation between cash compensation and long-term equity compensation, combined with the vesting schedule under the LTIP, discourages short-term risk-taking;

- the approach to goal setting, setting of targets with payouts at multiple levels of performance, capping the amount of the Company's incentive payouts, and evaluation of performance results assist in mitigating excessive risk-taking; and

- the compensation decisions include subjective considerations, which limit the influence of formulae or objective factors on excessive risk-taking.

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

The following table sets forth information regarding the beneficial ownership of common shares of the Company according to the most recent filings available as of March 3, 2021 (determined pursuant to Rule 13d-3 under the Exchange Act) with respect to:

- each person (including any "group" of persons as that term is used in Section 13(d)(3) of the Exchange Act) who is known to the Company to be the beneficial owner of more than 5% of the outstanding common shares;

- each of the Directors of the Company;

- each of the named executive officers of the Company; and

- all of the Directors and the current executive officers of the Company as a group.

Unless otherwise indicated in the footnotes to the following table, the address of each beneficial owner listed in the following table is c/o Atlantic Power Corporation, 3 Allied Drive, Suite 155, Dedham, Massachusetts 02026.

Except as otherwise indicated in the footnotes to the following table, the Company believes, based on the information provided to it, that the persons named in the following table have sole voting and investment power with respect to the shares they beneficially own, subject to applicable community property laws.

Name of beneficial owner	Number of common shares beneficially owned	Percentage of common shares beneficially owned (1)	Deferred Share Units owned (2)
Neuberger Berman Group LLC [3]	7,089,334	7.9%	—
RBC Global Asset Management Inc. [4]	6,438,094	7.2%	
BlackRock, Inc. [5]	6,143,790	6.8%	—
Directors and named executive officers			
Kevin T. Howell	193,000	*	180,602
R. Foster Duncan	15,105	*	240,756
Danielle S. Mottor	—	—	114,086
Gilbert S. Palter [6]	625,000	*	153,794
James J. Moore, Jr. [7]	1,232,559	1.4%	—
Terrence Ronan [7]	653,637	*	—
Joseph E. Cofelice [7]	987,322	1.1%	—
All Directors and current executive officers as a group (eight persons) [8]	3,871,681	4.3%	689,238

* Less than 1%

(1) The applicable percentage ownership is based on 89,714,323 common shares issued and outstanding as of March 3, 2021.

(2) DSUs owned by Directors are excluded from the calculation of common shares beneficially owned.

(3) Based on Schedule 13G/A filed on February 11, 2021 (the **"Neuberger Berman 13G/A"**) with the SEC by Neuberger Berman Group LLC and Neuberger Berman Investment Advisors LLC (collectively, "**Neuberger Berman**") with respect to beneficial ownership of 7,089,334 Common Shares. According to the Neuberger Berman 13G/A, Neuberger Berman has shared voting power with respect to 5,792,226 Common Shares and shared power to dispose of or to direct disposition of 7,089,334 Common Shares. The address of each Neuberger Berman entity is 1290 Avenue of the Americas, New York, New York 10104.

(4) Based on Schedule 13G filed on February 16, 2021 (the "**RBC Global 13G**") with the SEC by RBC Global Asset Management Inc. with respect to beneficial ownership of 6,438,094 Common Shares. According to the RBC Global 13G, RBC Global Asset Management Inc. has shared voting power with respect to 6,438,094 Common Shares and shared power to dispose of or to direct disposition of 6,438,094 Common Shares. The address of RBC Global Asset Management Inc. is RBC Centre, 155 Wellington Street West, Suite 2300, Toronto, Canada M5V 3K7.

(5) Based on Schedule 13G/A filed on February 5, 2021 (the "**BlackRock 13G/A**") with the SEC by BlackRock, Inc. ("BlackRock") with respect to the beneficial ownership of 6,143,790 common shares, of which (i) BlackRock Advisors, LLC, (ii) BlackRock Investment Manager (UK) Limited, (iii) BlackRock Asset Management Canada Limited, (iv) BlackRock Fund Advisors, (v) BlackRock Institutional Trust Company, National Association, (vi) BlackRock Financial Management, Inc. and (vii) BlackRock Investment Management, LLC, all of which are wholly-owned subsidiaries of BlackRock, are the beneficial owners. According to the BlackRock 13G/A, BlackRock has sole voting power with respect to 5,921,486 common shares and sole power to dispose of or direct disposition of 6,143,790 common shares. The address of each Blackrock entity is 55 East 52nd Street, New York, New York 10055.

(6) In addition to the common shares owned by Mr. Palter as shown in the table, Mr. Palter also owns 2,000 shares of the 7.0% Cumulative Rate Reset Preferred Shares, Series 2 and 18,500 shares of the Cumulative Floating Rate Preferred Shares, Series 3. The preferred shares are issued by APPEL, an indirect wholly-owned subsidiary of Atlantic Power, and are non-voting.

(7) Common shares beneficially owned exclude 269,952 unvested notional shares held under the Transition Equity Grant Participation Agreement and 359,020 unvested notional shares granted under the LTIP for Mr. Moore, President and Chief Executive Officer; 150,760 unvested notional shares granted under the LTIP for Mr. Ronan, Executive Vice President—Chief Financial Officer and 150,760 unvested notional shares granted under the LTIP for Mr. Cofelice, Executive Vice President—Commercial Development.

(8) The eight persons include the five Directors, two current named executive officers who are not Directors of the Company, and James P. D'Angelo, Senior Vice President—Chief Administrative Officer and an executive officer.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2020 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)]	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))[(1)(2)]
	(a)	(b)	(c)
Equity compensation plans approved by security holders	1,143,399	$ —	1,320,385
Equity compensation plans not approved by security holders	179,968	—	89,984
Total	1,323,367	$ —	1,410,369

(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 for officers and one hundred percent in cash for non-officers. Specifically, the number of securities to be issued upon exercise of the outstanding awards reflects two-thirds of the number of outstanding notional shares held by officers; it does not include notional shares expected to be settled in cash See Item 15. “Exhibits and Financial Statements Schedule”—Note 2(s), 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 8,000,000 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 539,903. See Item 15. “Exhibits and Financial Statements Schedule”—Note 2(s), Equity compensation plans.

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

Certain Relationships and Related Party Transactions

Other than the compensation agreements and arrangements described herein, there has not been since the beginning of the Company’s 2019 fiscal year, and there is not currently proposed, any transaction or series of similar transactions to which the Company was or will be a party in which the amount involved exceeded or will exceed $120,000 and in which any related person had or will have a direct or indirect material interest.

Policies and Procedures for Review of Transactions with Related Persons

The Company requires that any related party transaction be brought to the attention of the Board of Directors for review and pre-approval. The Board of Directors will review and pre-approve all relationships and transactions in which the Company and any of the Directors, director nominees and executive officers and their immediate family members, as well as holders of more than 5% of any class of its voting securities and their family members, have a direct or indirect material interest. In pre-approving or rejecting such proposed relationships and transactions, the Board of Directors shall consider the relevant facts and circumstances available and deemed relevant to this determination. When appropriate, the Board of Directors will review a report of an independent financial advisor in making a decision on whether to pre-approve a related party transaction.

Indebtedness of Directors and Officers

None of the directors and executive officers, or former directors or executive officers, nor any associate of such individuals, of the Company is as at the date hereof, or has been, during the financial year ended December 31, 2020, indebted to the Company or its subsidiaries in connection with a purchase of securities or otherwise. In addition, no indebtedness of these individuals to another entity has been the subject of a guarantee, support agreement, letter of credit or similar arrangement or understanding with the Company or any of its subsidiaries.

Interest of Informed Persons in Material Transactions

To the knowledge of the Directors, other than as disclosed under the heading "Certain Relationships and Related Transactions," no executive officer, Director or proposed nominee for election as a Director, or any associate or affiliate of any such persons, had any material interest, direct or indirect, by way of beneficial ownership of securities or otherwise, in any material transaction with the Company since the commencement of the Company's 2020 fiscal year.

Director Independence

The disclosure included in Item 10 of the report under heading "Board of Directors" is incorporated by reference into this Item 13.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

KPMG LLP served as our independent registered public accounting firm for fiscal year 2020. Aggregate fees for professional services rendered by KPMG LLP for the years ended December 31, 2020 and 2019 were as follows:

Fees		**2020**		**2019**
Audit Fees (1)	$	1,229,661	$	1,669,500
Audit-Related Fees (2)		15,000		15,000
Tax Fees (3)		204,831		146,355
Total Fees	$	1,449,492	$	1,830,855

(1) Audit fees in 2020 and 2019 consisted primarily of fees related to the audit of the Company's annual consolidated financial statements. Audit fees also included auditing procedures performed in accordance with Sarbanes-Oxley Act Section 404 and the related Public Company Accounting Oversight Board ("PCAOB") Auditing Standard Number 5 regarding the Company's internal control over financial reporting. This category also includes work generally only the independent registered accounting firm can reasonably provide.

(2) Audit-related fees consisted principally of attestation services for one of the Company's subsidiaries in 2020 and 2019.

(3) Tax fees consisted principally of advisory and compliance services. Tax services are rendered based on facts already in existence, transactions that have already occurred, as well as tax consequences of proposed transactions.

The Audit Committee pre-approves all auditing services and the terms thereof (which may include providing comfort letters in connection with securities underwritings) and non-audit services (other than non-audit services prohibited under Section 10A(g) of the Exchange Act, or the applicable rules of the SEC or the PCAOB) to be provided to the Company by KPMG LLP; however, the pre-approval requirement is waived with respect to the provision of non-audit services for the Company if the “de minimis” provisions of Section 10A(i)(1)(B) of the Exchange Act are satisfied. There were no services provided under the “de minimis” provisions in 2020 or 2019. The authority to pre-approve non-audit services may be delegated to one or more members of the Audit Committee, who shall present all decisions to pre-approve an activity to the full Audit Committee at its first meeting following such decision.

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
2.3	Arrangement Agreement, dated as of January 14, 2021, among the Company, Atlantic Power Preferred Equity Ltd., Atlantic Power Limited Partnership, Tidal Power Holdings Limited and Tidal Power Aggregator, L.P.
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.

Exhibit No.	Description
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
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
4.22	Description of the Registrant’s Securities Registered Pursuant to Section 12 of the Securities Exchange Act of 1934
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

Exhibit No.	Description
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
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

Exhibit No.	Description
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
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
10.32	Third Amendment dated April 19, 2018 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.
10.33	Fourth Amendment dated October 31, 2018 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.
10.34	Fifth Amendment to the Credit and Guaranty Agreement, dated as of January 31, 2020, among APLP Holdings, the Company and certain subsidiaries of APLP Holdings, as guarantors, Goldman Sachs Lending Partners LLC, as administrative agent and collateral agent, and the other lenders and L/C issuers party thereto.

Exhibit No.	Description
10.35	Sixth Amendment to the Credit and Guaranty Agreement, dated as of March 18, 2020, among APLP Holdings, the Company and certain subsidiaries of APLP Holdings, as guarantors, Goldman Sachs Lending Partners LLC, as administrative agent and collateral agent, and the other lenders and L/C issuers party thereto.
10.36	Consulting Agreement dated as of January 14, 2021, between Jeffrey S. Levy and Atlantic Power Corporation
16.1	Letter from KPMG LLP, Chartered Accountants, to the SEC, 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, 2020 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
104	Cover Page Interactive Data File—the cover page interactive data file does not appear in the Interactive Data File because its XBRL tags are embedded within the Inline XBRL document.

+ Indicates management contract or compensatory plan or arrangement.

* Filed herewith.

** Furnished herewith.

(b) Exhibits:

See Item 15(a)(3) above.

(c) Financial Statement Schedules:

See Item 15(a)(2) above.

ITEM 16. FORM 10-K SUMMARY.

None.

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: March 4, 2021

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)	March 4, 2021
/s/ TERRENCE RONAN Terrence Ronan	Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)	March 4, 2021
/s/ KEVIN HOWELL Kevin Howell	Chairman of the Board, Director	March 4, 2021
/s/ R. FOSTER DUNCAN R. Foster Duncan	Director	March 4, 2021
/s/ DANIELLE S. MOTTOR Danielle S. Mottor	Director	March 4, 2021
/s/ GILBERT S. PALTER Gilbert S. Palter	Director	March 4, 2021

Atlantic Power Corporation

Index to Consolidated Financial Statements

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, 2020 and 2019, the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for the years then ended, and the related notes (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, 2020 and 2019, and the results of its operations and its cash flows for the years then ended, 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, 2020, 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 March 4, 2021 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 audits 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.

Critical Audit Matter

The critical audit matter communicated below is a matter arising from the current period audit of the consolidated financial statements that was communicated or required to be communicated to the audit committee and that: (1) relates to accounts or disclosures that are material to the consolidated financial statements and (2) involved our especially challenging, subjective, or complex judgments. The communication of a critical audit matter does not alter in any way our opinion on the consolidated financial statements, taken as a whole, and we are not, by communicating the critical audit matter below, providing a separate opinion on the critical audit matter or on the accounts or disclosures to which it relates.

Goodwill impairment analysis for the Curtis Palmer reporting unit

As discussed in Notes 2 and 9 to the consolidated financial statements, the Company performs goodwill impairment testing on an annual basis and more frequently if events occur or circumstances change that would more likely than not reduce the fair value of a reporting unit below its carrying value. The goodwill balance as of December 31, 2020 was $21.3 million, of which $14.4 million related to the Curtis Palmer reporting unit.

We identified the evaluation of the goodwill impairment analysis for the Curtis Palmer reporting unit as a critical audit matter. A high degree of auditor judgment was required to evaluate certain assumptions used in the Company's estimate of the fair value of the Curtis Palmer reporting unit. Specifically, the Company's determination of forecasted revenue after the expected contractual expiration of the related power purchase agreement (PPA) and the determination of the discount rate related to the merchant market required subjective and challenging auditor judgment due to the sensitivity of the fair value determination to changes in these assumptions.

The following are the primary procedures we performed to address this critical audit matter. We evaluated the design and tested the operating effectiveness of certain internal controls over the Company's goodwill impairment assessment process, including controls related to the determination of forecasted revenue after the expected contractual expiration of the PPA and the determination of the discount rate related to the merchant market used to estimate the fair value of the Curtis Palmer reporting unit. We performed a sensitivity analysis over the forecasted revenue after the expected contractual expiration of the PPA to assess the impact of changes on the Company's determination of fair value. We evaluated the reasonableness of the Company's forecasted revenue after the expected contractual expiration of the PPA by comparing the Curtis Palmer reporting unit's forecasted power production to historical power production, and by comparing the forecasted energy prices to third-party vendor energy price forecasts in the applicable power market. In addition, we involved valuation professionals with specialized skills and knowledge, who assisted in evaluating the Company's discount rate related to the merchant market by independently developing a discount rate range using publicly available market data for comparable entities and comparing the results to the Company's discount rate.

/s/ KPMG LLP

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

New York, New York

March 4, 2021

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, 2020, 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, 2020, 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, 2020 and 2019, the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for the years then ended and the related notes, (collectively, the consolidated financial statements), and our report dated March 4, 2021 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.

Definition 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

March 4, 2021

ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in millions of U.S. dollars)

	December 31, 2020	December 31, 2019
Assets		
Current assets:		
Cash and cash equivalents	$ 38.8	$ 74.9
Restricted cash	7.1	7.7
Accounts receivable	31.3	30.4
Insurance recovery receivable (Note 23)	—	13.5
Current portion of derivative instruments asset (Notes 14 and 15)	0.4	0.7
Inventory (Note 7)	18.3	18.6
Prepayments	7.0	3.8
Income taxes receivable (Note 16)	3.2	1.8
Lease receivable	—	0.9
Other current assets	0.3	0.4
Total current assets	106.4	152.7
Property, plant, and equipment, net (Note 8)	491.8	502.1
Equity investments in unconsolidated affiliates (Note 6)	85.0	96.6
Power purchase agreements and intangible assets, net (Note 10)	120.3	144.3
Goodwill (Note 9)	21.3	21.3
Operating lease right-of-use assets (Note 24)	4.6	6.3
Deferred income taxes (Note 16)	17.2	10.4
Other assets	0.6	1.9
Total assets	$ 847.2	$ 935.6
Liabilities		
Current liabilities:		
Accounts payable	$ 6.3	$ 8.9
Accrued interest	2.5	2.6
Other accrued liabilities	19.3	20.8
Current portion of long-term debt (Note 12)	95.7	76.4
Current portion of derivative instruments liability (Notes 14 and 15)	11.0	12.0
Operating lease liabilities (Note 24)	1.9	2.0
Other current liabilities	0.2	0.2
Total current liabilities	136.9	122.9
Long-term debt, net of unamortized discount and deferred financing costs (Note 12)	384.1	473.5
Convertible debentures, net of discount and unamortized deferred financing costs (Note 13)	84.1	81.1
Derivative instruments liability (Notes 14 and 15)	8.1	15.9
Deferred income taxes (Note 16)	—	23.7
Power purchase agreements and intangible liabilities, net (Note 10)	18.0	19.8
Asset retirement obligations, net (Note 11)	48.1	51.5
Operating lease liabilities (Note 24)	3.1	4.8
Other long-term liabilities (Note 11)	6.2	4.7
Total liabilities	688.6	797.9
Equity		
Common shares, no par value, unlimited authorized shares; 89,222,568 and 108,675,294 issued and outstanding at December 31, 2020 and 2019	1,219.7	1,259.9
Accumulated other comprehensive loss (Note 5)	(139.9)	(140.7)
Retained deficit	(1,090.0)	(1,164.2)
Total Atlantic Power Corporation shareholders' deficit	(10.2)	(45.0)
Preferred shares issued by a subsidiary company (Note 20)	168.8	182.7
Total equity	158.6	137.7
Total liabilities and equity	$ 847.2	$ 935.6

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, 2020	Year Ended December 31, 2019
Project revenue:		
Energy sales (Note 4)	$ 137.9	$ 138.0
Energy capacity revenue (Note 4)	113.8	125.4
Other (Note 4)	20.3	18.2
	272.0	281.6
Project expenses:		
Fuel	70.9	72.3
Operations and maintenance	89.5	77.0
Depreciation and amortization	59.7	64.5
	220.1	213.8
Project other income (loss):		
Change in fair value of derivative instruments (Notes 14 and 15)	6.8	(8.9)
Equity in earnings (loss) of unconsolidated affiliates (Note 6)	42.9	(3.0)
Interest, net	(1.2)	(1.1)
Impairment (Note 8)	—	(5.8)
Insurance gain (loss) (Note 23)	16.4	(1.0)
Other income (expense), net	2.1	(1.2)
	67.0	(21.0)
Project income	118.9	46.8
Administrative and other expenses:		
Administration	24.8	23.9
Interest expense, net	42.4	44.0
Foreign exchange loss	5.1	11.9
Other (income) expense, net (Note 14)	(2.7)	1.0
	69.6	80.8
Income (loss) from operations before income taxes	49.3	(34.0)
Income tax (benefit) expense (Note 16)	(24.2)	9.8
Net income (loss)	73.5	(43.8)
Net loss attributable to preferred shares of a subsidiary company (Note 20)	(0.7)	(1.2)
Net income (loss) attributable to Atlantic Power Corporation	$ 74.2	$ (42.6)
Net earnings (loss) per share attributable to Atlantic Power Corporation shareholders: (Note 21)		
Basic	$ 0.77	$ (0.39)
Diluted	0.62	(0.39)
Weighted average number of common shares outstanding: (Note 21)		
Basic	95.8	109.3
Diluted	124.9	109.3

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions of U.S. dollars)

	Year Ended December 31, 2020	Year Ended December 31, 2019
Net income (loss)	$ 73.5	$ (43.8)
Other comprehensive income, net of tax:		
Unrealized loss on hedging activities	$ (0.5)	$ (0.3)
Net amount reclassified to earnings	0.5	0.3
Net realized and unrealized gain (loss) on derivatives	—	—
Defined benefit plan, net of tax	(1.4)	(0.3)
Foreign currency translation adjustments	2.2	5.8
Other comprehensive income, net of tax	0.8	5.5
Comprehensive income (loss)	74.3	(38.3)
Less: Comprehensive loss attributable to preferred shares of a subsidiary company	(0.7)	(1.2)
Comprehensive income (loss) attributable to Atlantic Power Corporation	$ 75.0	$ (37.1)

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 (Loss) Income	Total Atlantic Power Corporation Shareholders' Deficit	Preferred Shares of a Subsidiary Company	Total Equity
Balance as of December 31, 2018	108.3	$ 1,260.9	$ (1,121.6)	$ (146.2)	$ (6.9)	$ 199.3	$ 192.4
Net loss	—	—	(42.6)	—	(42.6)	(1.2)	(43.8)
Share-based compensation	1.4	1.5	—	—	1.5	—	1.5
Common share repurchases	(1.1)	(2.5)	—	—	(2.5)	—	(2.5)
Preferred share repurchases	—	—	—	—	—	(8.0)	(8.0)
Dividends on preferred shares of a subsidiary company - Series 1 (Cdn$1.212500 per share)	—	—	—	—	—	(3.5)	(3.5)
Dividends on preferred shares of a subsidiary company - Series 2 (Cdn$1.392500 per share)	—	—	—	—	—	(2.4)	(2.4)
Dividends on preferred shares of a subsidiary company - Series 3 (Cdn$1.459115 per share)	—	—	—	—	—	(1.5)	(1.5)
Foreign currency translation adjustments	—	—	—	5.8	5.8	—	5.8
Defined benefit plan, net of tax of $0.1 million	—	—	—	(0.3)	(0.3)	—	(0.3)
Balance as of December 31, 2019	108.6	$ 1,259.9	$ (1,164.2)	$ (140.7)	$ (45.0)	$ 182.7	$ 137.7
Net income (loss)	—	—	74.2	—	74.2	(0.7)	73.5
Share-based compensation	0.6	1.4	—	—	1.4	—	1.4
Common share repurchases	(20.0)	(41.6)	—	—	(41.6)	—	(41.6)
Preferred share repurchases	—	—	—	—	—	(6.4)	(6.4)
Dividends on preferred shares of a subsidiary company - Series 1 (Cdn$1.212500 per share)	—	—	—	—	—	(3.3)	(3.3)
Dividends on preferred shares of a subsidiary company - Series 2 (Cdn$1.434752 per share)	—	—	—	—	—	(2.6)	(2.6)
Dividends on preferred shares of a subsidiary company - Series 3 (Cdn$1.288117 per share)	—	—	—	—	—	(0.9)	(0.9)
Foreign currency translation adjustments	—	—	—	2.2	2.2	—	2.2
Defined benefit plan, net of tax of $0.4 million	—	—	—	(1.4)	(1.4)	—	(1.4)
Balance as of December 31, 2020	89.2	$ 1,219.7	$ (1,090.0)	$ (139.9)	$ (10.2)	$ 168.8	$ 158.6

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of U.S. dollars)

	Years Ended December 31, 2020	2019
Cash provided by operating activities:		
Net income (loss)	$ 73.5	$ (43.8)
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization	59.7	64.4
Share-based compensation	1.4	1.5
Asset retirement obligations	(2.1)	1.4
Gain on disposal of fixed assets and inventory	(0.8)	(0.9)
Impairment	—	5.8
Insurance (gain) loss	(0.7)	1.0
Equity in (earnings) loss from unconsolidated affiliates	(42.9)	3.0
Distributions from unconsolidated affiliates	54.2	59.5
Unrealized foreign exchange loss	4.7	12.2
Change in fair value of derivative instruments	(8.6)	10.7
Amortization of debt discount and deferred financing costs	6.0	6.9
Non-cash operating lease expense	1.9	1.7
Deferred income taxes	(29.9)	4.8
Change in other operating balances		
Accounts receivable	(0.6)	8.2
Inventory	0.2	(1.8)
Prepayments and other assets	(1.1)	3.9
Accounts payable	(2.1)	5.1
Accruals and other liabilities	(5.5)	1.1
Cash provided by operating activities	107.3	144.7
Cash used in investing activities:		
Investment in unconsolidated affiliate	—	(18.7)
Insurance proceeds	13.5	11.3
Cash paid for acquisition, net of cash received	—	(8.6)
Proceeds from sales of assets	0.9	1.6
Purchase of property, plant and equipment	(24.8)	(7.3)
Cash used in investing activities	(10.4)	(21.7)
Cash used in financing activities:		
Common share repurchases	(41.6)	(2.5)
Preferred share repurchases	(6.4)	(8.0)
Repayment of corporate and project-level debt	(76.4)	(72.3)
Repayment of convertible debentures	—	(18.5)
Cash payments for vested LTIP withheld for taxes	(0.7)	(2.1)
Deferred financing costs	(1.7)	—
Dividends paid to preferred shareholders	(6.8)	(7.4)
Cash used in financing activities	(133.6)	(110.8)
Net (decrease) increase in cash, restricted cash and cash equivalents	(36.7)	12.2
Cash, restricted cash and cash equivalents at beginning of period	82.6	70.4
Cash, restricted cash and cash equivalents at end of period	$ 45.9	$ 82.6
Supplemental cash flow information		
Interest paid	$ 37.2	$ 37.6
Income taxes paid, net	$ 5.7	$ 2.3
Accruals for construction in progress	$ 0.1	$ 0.3

See accompanying notes to consolidated financial statements.

1. Nature of business

General

Atlantic Power is an independent power producer that owns power generation assets in eleven 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, 2020, our portfolio consisted of twenty-one projects operating with an aggregate electric generating capacity of approximately 1,723 megawatts (“MW”) on a gross ownership basis and approximately 1,327 MW on a net ownership basis. Sixteen of the projects are majority-owned by the Company.

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 TSX under the symbol “ATP” and on the New York Stock Exchange (“NYSE”) under the symbol “AT.” Our registered office is located at 1066 West Hastings Street, Suite 2600, Vancouver, British Columbia V6E 3X1 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, cash equivalents and cash advances that are maintained by the projects or corporate to support payments for maintenance costs, reconstruction 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, 2020 and 2019, 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 $7.1 million and $8.5 million at December 31, 2020 and 2019, respectively. Interest expense from the amortization of deferred financing costs for the years ended December 31, 2020 and 2019 was $2.6 million and $3.2 million, respectively.

(f) Inventory:

Inventory represents spare parts, biofuel and natural gas, 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.

(i) Power purchase agreements and intangible assets:

Intangible assets include PPAs and fuel supply agreements at our projects acquired as part of business combinations. Carrying amounts for PPAs and fuel supply agreements are based on the fair value assigned in the allocation of the purchase price of the acquired business. 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 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. 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.

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. 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 estimated 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, or more frequently if events or changes in circumstances indicate that would more likely than not reduce the fair value of a reporting unit below its carrying value. In 2020, we changed our annual impairment testing from November 30 to October 31. We made the change to better align the timing of the goodwill impairment test with the timing of our annual planning and budgeting processes and to provide us with adequate time to evaluate goodwill for impairment. This change did not result in the delay, acceleration or avoidance of an impairment charge. We completed our annual impairment testing in the fourth quarter of 2020 and determined that no adjustments to the carrying value of goodwill were necessary.

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, equity method investment, 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 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 fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of our reporting units.

The valuation of long-lived assets, equity method investments 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. 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 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 the 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 income (loss) ("OCI") 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	Change in fair value of derivative instrument	Fuel expense
Fuel purchase agreements	Change in fair value of derivative instrument	Fuel expense
Interest rate swaps	Change in fair value of derivative instrument	Interest expense, net
Convertible debenture conversion option	Other (income) expense, net	NA
Foreign currency forward contract	Foreign exchange loss	Foreign exchange loss

(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 September 2021 to November 2043, 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.

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 Solid Fuel segment. Waste heat is earned when it is generated and paid as a portion of monthly energy and capacity billing.
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.

For PPAs accounted for as operating leases, we recognize lease income consistent with the recognition of energy revenue due to variable volume of the generation. 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"). Notional shares granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional shares granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Unvested notional shares are entitled to receive dividends, if paid, equal to the dividends per common share during the vesting period in the form of additional notional shares. Unvested shares 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 shares for which the requisite service is expected to be rendered. We have estimated a weighted average forfeiture rate of 11% for all notional share grants under the LTIP. This estimate will be revisited if subsequent information indicates the actual number of notional shares 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 shares accounted for as equity awards and the fair value of the award at each balance sheet date for notional shares 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) Pension:

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 and Asset Acquisitions:

Business combinations are accounted for using 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.

Asset acquisitions are measured based on their cost to the Company, including transaction costs. Asset acquisition costs, or the consideration transferred by the Company, are assumed to be equal to the fair value of the net assets acquired. If the consideration transferred is cash, measurement is based on the amount of cash the Company paid to the seller as well as transaction costs incurred. Consideration given in the form of nonmonetary assets, liabilities incurred or equity interests issued is measured based on either the cost to the Company or the fair value of the assets or net assets acquired, whichever is more clearly evident. The cost of an asset acquisition is allocated to the assets acquired based on their estimated relative fair values. Goodwill is not recognized in an asset acquisition.

(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 and liabilities assumed. 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) COVID-19 Pandemic

There are many uncertainties regarding the ongoing COVID-19 pandemic, and we are closely monitoring the impact of COVID-19 on all aspects of our business, including how it will impact our customers, employees, suppliers, vendors and business partners. We have taken extra precautions for our employees who continue to work at our facilities and have implemented work-from-home policies where appropriate. Currently, we do not anticipate any employee layoffs and are continuing to maintain the high level of reliability and availability of our plants. We continue to implement strong physical and cybersecurity measures to ensure that our systems remain functional in order to serve our operational needs with a remote workforce and to keep our operations running to ensure uninterrupted service to our offtakers. While COVID-19 did not materially adversely affect our financial results and business operations for the year ended December 31, 2020, we are unable to predict the impact that COVID-19 will have on our financial position and operating results due to numerous uncertainties. We will continue to assess the evolving impact of the COVID-19 pandemic and intend to make adjustments accordingly.

(z) Recently adopted and issued accounting standards:

Accounting Standards Adopted in 2020

In June 2016, the FASB issued ASU 2016-13, *"Financial Instruments-Credit Losses"(Topic 326), Measurement of Credit Losses on Financial Instruments* ("ASU 2016-13"). This guidance amends the guidance on measuring credit losses on financial assets held at amortized cost. ASU 2016-13 requires the measurement of all expected credit losses for financial assets held at the reporting date based on historical experience, current conditions, and reasonable and supportable forecasts. This guidance was effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years. The Company has adopted ASU 2016-13 effective January 1, 2020. Adoption of this guidance did not impact 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 was effective for fiscal years beginning after December 15, 2019. The Company has adopted this guidance effective January 1, 2020. Adoption of this guidance did not impact the consolidated financial statements.

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 was effective for fiscal years beginning after December 15, 2019. The Company has adopted this guidance effective January 1, 2020. Adoption of this guidance did not impact the consolidated financial statements.

In August 2018, the FASB issued ASU No. 2018-14, *"Compensation -Retirement Benefits -Defined Benefit Plans -General (Subtopic 715-20)"*, to improve the effectiveness of benefit plan disclosures in the notes to financial statements by facilitating clear communication of the information required by GAAP that is most important to users of each entity's financial statements. The amendments in this ASU modify the disclosure requirements for employers that sponsor defined benefit pension or other postretirement plans. Additionally, the amendments in this ASU remove disclosures that no longer are considered cost beneficial, clarify the specific requirements of disclosures, and add disclosure requirements identified as relevant. The amendments in this ASU were effective for fiscal years ending after December 15, 2020. The Company has adopted ASU 2018-14 effective December 31, 2020. Adoption of this guidance did not have a material impact on the consolidated financial statements.

Accounting Standards Not Yet Adopted

In December 2019, the FASB issued amendments to the guidance for income taxes through ASU 2019-12, "*Income Taxes (Topic 740): Simplifying the Accounting for Income Taxes.*" The amendments in this update simplify the accounting for income taxes by removing certain exceptions such as: 1) the incremental approach for intraperiod tax allocation when there is a loss from continuing operations and income or a gain from other items, 2) the requirement to recognize a deferred tax liability for equity method investments when a foreign subsidiary becomes an equity method investment, 3) the ability not to recognize a deferred tax liability for a foreign subsidiary when a foreign equity method investment becomes a subsidiary, and 4) the general methodology for calculating income taxes in an interim period when a year-to-date loss exceeds the anticipated loss for the year. For public entities, the amendments are effective for reporting periods beginning after December 15, 2020. Early adoption is permitted. While we are continuing to evaluate the potential impact of the new guidance on our consolidated financial statements, we do not expect adoption of this new guidance to have a material impact on the consolidate financial statements.

In March 2020, the FASB issued amendments to the guidance for reference rate reform through ASU 2020-04, "Reference Rate Reform (Topic 848): Facilitation of the effects of reference rate reform on financial reporting." The amendments in this update provide optional expedients and exceptions for applying GAAP to contracts, hedging relationships, and other transactions affected by reference rate reform if certain criteria are met. The amendments apply only to contracts and hedging relationships that reference LIBOR or another reference rate expected to be discontinued due to reference rate reform. The expedients and exceptions provided by the amendments do not apply to contract modifications made and hedging relationships entered into or evaluated after December 31, 2022. The amendments are elective and are effective upon issuance for all entities. We are in the process of evaluating the potential impact of the new guidance on our consolidated financial statements.

3. Acquisitions and divestments

2019 Acquisitions

(a) South Carolina Biomass Plants

On July 31, 2019, we completed the acquisition of two biomass plants in South Carolina, Allendale and Dorchester, from EDF Renewables Inc. The Allendale plant is located in Allendale, South Carolina and has been in service since November 2013. The Dorchester plant is located in Harleyville, South Carolina and has been in service since October 2013. The two plants are identical in design and 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. The biomass fuel for the plants consists primarily of mill and harvesting residues. We believe the acquisition represents a meaningful addition to the level and length of our existing contracted cash flows.

The final consideration paid for the two plants was $12.6 million. In September 2018, we made a $2.6 million down payment for the acquisition of the plants and paid the remaining due at closing, less working capital adjustments and transaction costs, from discretionary cash and cash equivalents. The South Carolina biomass plants are reflected in our Solid Fuel segment. See Note 22, *Segment and geographic information*. The following is a summary of the estimated fair values of the assets acquired and liabilities assumed:

Fair values		
Cash[(1)]	$	1.4
Accounts receivable		4.3
Inventory		2.9
Property, plant, and equipment		4.0
Intangible assets		2.6
Accounts payable		(2.0)
Accrued liabilities		(0.3)
Other liabilities		(0.3)
Total purchase consideration	$	12.6

(1) The cash acquired was received in October 2019 and has been included in the *Cash paid for acquisition, net of cash received* within the Statement of Cash Flows.

The $2.6 million of intangible assets recorded will be amortized straight-line through the remaining life of each plant's PPA, which expire on October 31, 2043 (Dorchester) and November 18, 2043 (Allendale).

Allendale and Dorchester contributed $10.8 million of revenue and net income of $1.0 million to the consolidated statements of operations for the period from July 31, 2019 to December 31, 2019.

(b) AltaGas

On August 13, 2019, we completed our acquisition of the equity ownership interests held by AltaGas Power Holdings (U.S.) Inc. ("AltaGas") in two contracted biomass plants, Craven and Grayling (as defined below), in North Carolina and Michigan. Craven County Wood Energy ("Craven") is a 48 megawatt (MW) biomass plant in North Carolina that has been in service since October 1990. We acquired a 50% interest in the plant from AltaGas. The remaining 50% interest is held by CMS Energy. Craven has a PPA with Duke Energy Carolinas that will expire on December 31, 2027. The plant burns wood waste and poultry litter. Grayling Generating Station ("Grayling") is a 37 MW biomass plant in Michigan that has been in service since June 1992. We acquired a 30% interest in the plant from AltaGas. The remaining interests are held by Fortistar (20%) and CMS Energy (50%). Grayling has a PPA with Consumers Energy, the utility subsidiary of CMS Energy, which will expire on December 31, 2027. The plant burns wood waste from local mills, forestry residues, mill waste and bark. Both plants are operated by an affiliate of CMS Energy. The purchase price totaled $18.7 million in cash consideration inclusive of approximately $0.2 million of acquisition-related transaction costs.

Craven and Grayling are limited partnerships. We do not have financial control of the partnerships because decision-making is shared and the partners must agree on all major decisions for each of the entities. Accordingly, we account for our ownership in Craven and Grayling under the equity method of accounting because our ownership is between five and fifty percent resulting in Atlantic Power Corporation maintaining more than minor influence over the partnerships' operating and financing policies.

Craven and Grayling contributed $1.0 million in equity in earnings from unconsolidated affiliates to the consolidated statements of operations, and $0.9 million in equity method distributions for the period from August 13, 2019 to December 31, 2019.

4. Revenue from contracts

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

	Year Ended December 31, 2020				
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 58.8	$ 24.2	$ 54.9	$ —	$ 137.9
Energy capacity revenue	34.6	79.2	—	—	113.8
Steam energy and capacity revenue	—	10.5	—	—	10.5
Waste heat revenue	1.0	—	—	—	1.0
Ancillary and transmission services	—	3.1	3.4	—	6.5
Asset management and operation	—	—	—	1.0	1.0
Miscellaneous revenue	0.1	1.2	—	—	1.3
	94.5	118.2	58.3	1.0	272.0

	Year Ended December 31, 2019				
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 41.1	$ 31.0	$ 65.9	$ —	$ 138.0
Energy capacity revenue	38.7	86.7	—	—	125.4
Steam energy and capacity revenue	—	11.7	—	—	11.7
Waste heat revenue	0.2	—	—	—	0.2
Ancillary and transmission services	—	4.7	2.9	—	7.6
Asset management and operation	—	—	—	1.0	1.0
Miscellaneous revenue	—	(2.3)	—	—	(2.3)
	80.0	131.8	68.8	1.0	281.6

Contract balances

Contract liabilities as of December 31, 2020 include a $0.2 million fuel reserve fund at Dorchester and a $0.1 million steam sale credit at the San Diego plants. Contract liabilities as of December 31, 2019 include a $0.2 million fuel reserve fund at Dorchester and a $0.1 million steam sale credit at the San Diego plants. We had no contract assets at December 31, 2020.

5. Changes in accumulated other comprehensive income (loss) by component

The changes in accumulated other comprehensive income (loss) by component were as follows:

	Year Ended December 31,	
	2020	**2019**
Foreign currency translation		
Balance at beginning of period	$ (140.6)	$ (146.4)
Other comprehensive income:		
Foreign currency translation adjustments[1]	2.2	5.8
Balance at end of period	$ (138.4)	$ (140.6)
Pension		
Balance at beginning and end of period	$ (1.7)	$ (1.4)
Other comprehensive income:		
Settlement	—	0.3
Tax expense	—	(0.1)
Total Other comprehensive income before reclassifications, net of tax	—	0.2
Total amount reclassified from accumulated other comprehensive (loss), net of tax	(1.4)	(0.5)
Total other comprehensive (loss)	(1.4)	(0.3)
Balance at end of period	$ (3.1)	$ (1.7)
Cash flow hedges		
Balance at beginning of period	$ 1.6	$ 1.6
Other comprehensive (loss):		
Net change from periodic revaluations	(0.7)	(0.5)
Tax benefit	0.2	0.2
Total other comprehensive (loss) before reclassifications, net of tax	(0.5)	(0.3)
Net amount reclassified to earnings:		
Interest rate swaps[2]	0.6	0.4
Tax expense	(0.1)	(0.1)
Total amount reclassified from accumulated other comprehensive income, net of tax	0.5	0.3
Total other comprehensive (loss)	—	—
Balance at end of period	$ 1.6	$ 1.6

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

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

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, 2020	Carrying value as of December 31, 2020	Carrying value as of December 31, 2019
Frederickson[1]	50%	$ 58.9	$ 65.2
Orlando Cogen, LP	50%	2.5	3.6
Chambers Cogen, LP	40%	8.0	9.0
Craven County Wood Energy, LP [2]	50%	8.2	9.5
Grayling Generating Station, LP [2]	30%	7.4	9.3
Total		$ 85.0	$ 96.6

(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 May 2019, we acquired the equity ownership interests held by AltaGas in Craven and Grayling. See Note 3, *Acquisitions and divestments*.

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

Entity name	Year Ended December 31, 2020	Year Ended December 31, 2019
Frederickson	$ 8.3	$ 9.1
Orlando Cogen, LP	33.1	33.0
Chambers Cogen, LP	4.4	(46.0)
Craven County Wood Energy, LP [1]	(1.8)	0.1
Grayling Generating Station, LP [1]	(1.1)	0.8
Total earnings (loss) of unconsolidated affiliates	42.9	(3.0)
Distributions from equity method investments	(54.2)	(59.5)
Deficit in earnings of equity method investments, net of distributions	$ (11.3)	$ (62.5)

(1) In May 2019, we acquired the equity ownership interests held by AltaGas in Craven and Grayling. See Note 3, *Acquisitions and divestments*.

Distributions from equity method investments exceeded earnings (loss) for equity method investments for the years ended December 31, 2020 and 2019, 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.

The following summarizes the financial position at December 31, 2020 and 2019, and operating results for the years ended December 31, 2020 and 2019, respectively, for our proportional ownership interest in equity method investments:

	2020	2019
Assets		
Current assets		
Frederickson	$ 1.9	$ 2.1
Orlando Cogen, LP	7.8	7.8
Chambers Cogen, LP	14.8	14.4
Craven County Wood Energy, LP [1]	2.2	4.4
Grayling Generating Station, LP [1]	2.6	3.3
Non-current assets		
Frederickson	57.8	63.9
Orlando Cogen, LP	5.1	6.1
Chambers Cogen, LP	44.6	56.5
Craven County Wood Energy, LP [1]	7.9	5.8
Grayling Generating Station, LP [1]	6.5	6.8
	$ 151.2	$ 171.1
Liabilities		
Current liabilities		
Frederickson	$ 0.3	$ 0.3
Orlando Cogen, LP	10.3	10.2
Chambers Cogen, LP	15.8	13.7
Craven County Wood Energy, LP [1]	2.3	0.8
Grayling Generating Station, LP [1]	0.7	0.5
Non-current liabilities		
Frederickson	0.5	0.5
Orlando Cogen, LP	0.1	—
Chambers Cogen, LP	35.6	48.2
Craven County Wood Energy, LP [1]	0.4	—
Grayling Generating Station, LP [1]	0.2	0.3
	$ 66.2	$ 74.5

(1) In May 2019, we acquired the equity ownership interests held by AltaGas in Craven and Grayling. See Note 3, *Acquisitions and divestments*.

Operating results	2020	2019
Revenue		
Frederickson	$ 29.2	$ 36.0
Orlando Cogen, LP	60.2	61.5
Chambers Cogen, LP	38.4	39.4
Craven County Wood Energy, LP [1]	9.6	4.9
Grayling Generating Station, LP [1]	3.5	2.2
	140.9	144.0
Project expenses		
Frederickson	20.9	26.9
Orlando Cogen, LP	27.0	28.5
Chambers Cogen, LP	32.5	34.6
Craven County Wood Energy, LP [1]	11.4	4.7
Grayling Generating Station, LP [1]	4.5	1.8
	96.3	96.5
Project other (income) expenses		
Frederickson	—	—
Orlando Cogen, LP	(0.1)	—
Chambers Cogen, LP	(1.5)	(50.9)
Craven County Wood Energy, LP [1]	—	—
Grayling Generating Station, LP [1]	(0.1)	0.4
	(1.7)	(50.5)
Net income (loss)		
Frederickson	8.3	9.1
Orlando Cogen, LP	33.1	33.0
Chambers Cogen, LP	4.4	(46.1)
Craven County Wood Energy, LP [1]	(1.8)	0.2
Grayling Generating Station, LP [1]	(1.1)	0.8
Equity in earnings (loss) of unconsolidated affiliates	$ 42.9	$ (3.0)

(1) In May 2019, we acquired the equity ownership interests held by AltaGas in Craven and Grayling. See Note 3, *Acquisitions and divestments*.

During the year ended December 31, 2019, we recorded an investment impairment of $49.2 million at our Chambers project. This impairment is a component of the operating results in the table above. There were no impairment triggers during 2020, and accordingly no impairment tests were performed on equity method investments.

2019 – Event-driven test in the fourth quarter

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 $58.2 million component of our equity investments in unconsolidated affiliates on the consolidated balance sheets.

In connection with the preparation of the long-term forecast during the fourth quarter of 2019, we performed an analysis of the post-PPA value of Chambers operating as a merchant facility. As a result, we identified a significant decrease in the long-term outlook for power prices and spark spreads in PJM, the region where Chambers operates. 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 discounted cash flows 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 $58.2

million.

When determining if this decrease in estimated fair value 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. While declining power prices have been observed over the past several years, given that merchant curves have declined further than what was observed in 2017, it was our assessment that future merchant pricing and spark spreads were likely to remain low and that Chambers would be unable to recover its start fuel and start operations and maintenance costs after expiration of its PPA in 2024. Based on these factors, we determined that the decline in the fair value of our investment in Chambers was other than temporary. We recorded a $49.2 million impairment in earnings (loss) from unconsolidated affiliates in the consolidated statements of operations for the year ended December 31, 2019.

7. Inventory

Inventory consists of the following:

	December 31, 2020	December 31, 2019
Parts and other consumables	$ 11.9	$ 12.2
Fuel	6.4	6.4
Total inventory	$ 18.3	$ 18.6

8. Property, plant and equipment, net

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

	December 31, 2020	December 31, 2019	Depreciable Lives
Land	$ 6.4	$ 6.4	
Office equipment, machinery and other	6.7	6.5	3 - 10 years
Leasehold improvements	2.1	2.1	7 - 15 years
Asset retirement obligation	23.6	23.4	1 - 43 years
Plant in service	885.1	848.1	1 - 45 years
Construction in progress	0.8	7.2	
	924.7	893.7	
Less accumulated depreciation	(432.9)	(391.6)	
Total property, plant and equipment, net	$ 491.8	$ 502.1	

Depreciation expense of $36.8 million and $37.6 million was recorded for the years ended December 31, 2020 and 2019, respectively.

No long-lived asset impairments to property, plant and equipment were recorded in the year ended December 31, 2020. As described below, we recorded $4.0 million of long-lived asset impairments to property, plant and equipment in the years ended December 31, 2019, respectively, with a corresponding charge to Impairment in the statement of operations.

2019 – Event-driven test performed in fourth quarter

Calstock – Long-lived assets

Calstock previously operated under a PPA that expired in June 2020. We performed the test as of December 31, 2019, six months prior to the contract expiration date. Calstock's asset group for testing of long-lived assets totaled $7.8 million consisting of $2.3 million of net working capital, $4.7 million property, plant and equipment ("PPE"), net and a

$0.8 million intangible PPA asset.

Because of the uncertainty of our ability to recontract the project, fair value of Calstock was determined based solely on the cash flows remaining under the current contract. If our efforts to recontract are unsuccessful, the project will be taken out of service but not decommissioned. Upon testing Calstock for long-lived asset impairment, the carrying value of the asset group exceeded the estimated cash flows. Accordingly, we recorded a $4.7 million long-lived asset impairment in the year ended December 31, 2019, which is the difference between the fair value and carrying value of the reporting unit's asset group, $0.7 million of the impairment related to intangible PPA assets and $4.0 million of the impairment related to property, plant and equipment. We also recorded impairment losses of $1.1 million related to spare parts inventory at Calstock. The Calstock biomass plant is a component of our Solid Fuel segment.

9. Goodwill

The following table presents goodwill by reportable segment for the years ended December 31, 2020 and 2019:

	Segment	2020	2019
Curtis Palmer	Hydroelectric	$ 14.4	$ 14.4
Morris	Natural Gas	3.3	3.3
Nipigon	Natural Gas	3.6	3.6
Total		$ 21.3	$ 21.3

Goodwill Impairment Testing

We perform our annual goodwill impairment test as of October 31 and update the test between annual tests if events or circumstances occur that would more likely than not reduce the fair value of a reporting unit below its carrying value.

For the years ended December 31, 2020 and 2019, we performed a quantitative test at each reporting unit. Based on the results of the annual goodwill impairment tests for years ended December 31, 2020 and 2019, management determined that no adjustment to the carrying value for any reporting unit was necessary because in all cases, the estimated fair values of the reporting units exceeded their respective carrying values. The fair value of all reporting units was determined using an income approach and considered project-specific assumptions for the future discounted cash flows.

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, 2020 and 2019:

Assets

	Other Intangible Assets, Net	
	Power Purchase Agreements	Total
Gross balances, January 1, 2020	$ 365.6	$ 365.6
Write-off of fully amortized balances	(13.5)	(13.5)
Gross balances, December 31, 2020	352.1	352.1
Less: accumulated amortization	(231.8)	(231.8)
Net carrying amounts, December 31, 2020	$ 120.3	$ 120.3

	Other Intangible Assets, Net	
	Power Purchase Agreements	Total
Gross balances, December 31, 2019	$ 365.6	$ 365.6
Less: accumulated amortization	(221.3)	(221.3)
Net carrying amounts, December 31, 2019	$ 144.3	$ 144.3

Liabilities

	Power Purchase and Fuel Supply Agreement Liabilities, Net		
	Power Purchase Agreements	Fuel Supply Agreements	Total
Gross balances, December 31, 2020	$ (28.5)	$ (12.6)	$ (41.1)
Less: accumulated amortization	16.2	6.9	23.1
Net carrying amounts, December 31, 2020	$ (12.3)	$ (5.7)	$ (18.0)

	Power Purchase and Fuel Supply Agreement Liabilities, Net		
	Power Purchase Agreements	Fuel Supply Agreements	Total
Gross balances, December 31, 2019	$ (28.1)	$ (12.6)	$ (40.7)
Less: accumulated amortization	14.4	6.5	20.9
Net carrying amounts, December 31, 2019	$ (13.7)	$ (6.1)	$ (19.8)

The following table presents amortization expense of intangible assets for the years ended December 31, 2020 and 2019:

	2020	2019
PPAs	$ 22.5	$ 26.4
Fuel supply agreements	(0.4)	(0.4)
Total amortization	$ 22.1	$ 26.0

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

Year Ended December 31,	
2021	$ 20.2
2022	15.9
2023	12.6
2024	12.6
2025	12.6

The weighted average remaining amortization period related to our intangible assets and liabilities was 8.1 years as of December 31, 2020.

11. Other long-term liabilities

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

	2020	2019
Long-term contract liability	$ 0.2	$ 0.2
Net pension liability	3.1	1.2
Accrued LTIP and director share units	1.5	1.6
Other	1.4	1.7
	$ 6.2	$ 4.7

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

	2020	2019
Asset retirement obligations beginning of year	$ 51.5	$ 49.2
Accretion and change in estimate of asset retirement obligation	(1.3)	2.3
Costs incurred	(2.5)	(1.0)
Translation adjustments	0.4	1.0
Asset retirement obligations, end of year	$ 48.1	$ 51.5

12. Long-term debt

Long-term debt consists of the following:

	December 31, 2020	December 31, 2019	Interest Rate	
Recourse Debt:				
Senior secured term loan facility, due 2025[1]	$ 307.5	$ 380.0	LIBOR[2] plus	2.50 %
Senior unsecured notes, due June 2036 (Cdn$210.0)	164.9	161.7		5.95 %
Non-Recourse Debt:				
Cadillac term loan, due 2025 [3]	14.8	18.7	LIBOR plus	1.61 %
Less: unamortized discount	(3.5)	(5.8)		
Less: unamortized deferred financing costs	(3.9)	(4.7)		
Less: current maturities	(95.7)	(76.4)		
Total long-term debt	$ 384.1	$ 473.5		

Current maturities consist of the following:

	December 31, 2020	December 31, 2019	Interest Rate	
Current Maturities:				
Senior secured term loan facility, due 2025[1]	$ 93.0	$ 72.5	LIBOR[2] plus	2.50 %
Cadillac term loan, due 2025 [3]	2.7	3.9	LIBOR plus	1.61 %
Total current maturities	$ 95.7	$ 76.4		

(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 classified as current is based on principal payments required to reduce the aggregate principal amount of Term Loan 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 $307.5 million remaining aggregate borrowings under our Term Loan at December 31, 2020. See Note 15, *Accounting for derivative instruments and hedging activities,* for further details. On January 31, 2020, the repricing of the Term Loan became effective, reducing the interest rate to LIBOR plus 2.50% with no change to the 1.00% LIBOR floor. The maturity date for the Term Loan was also extended to April 2025. The repricing also adds customary new provisions relating to the replacement of LIBOR as the benchmark for the Eurodollar Rate (as defined in the Credit Agreement) replacement.

(3) 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.

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

2021	$ 95.7
2022	109.3
2023	63.3
2024	39.7
2025	14.3
Thereafter	164.9
	$ 487.2

Credit Facilities

On April 13, 2016, 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 Loan") and $200 million in aggregate principal amount of senior secured credit facilities (the "Revolver" and together with the Term Loan, the "Credit Facilities"). At December 31, 2020, $307.5 million of the Term Loan is outstanding and letters of credit in an aggregate face amount of $77.1 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%.

In January 2020, APLP Holdings completed the repricing of the $307.5 million Term Loan and Revolver. As a result of the repricing, the interest rate margin on the Term Loan and the Revolver was reduced by 0.25% to LIBOR plus 2.50% with no change to the 1.00% LIBOR floor. An additional 0.25% step down in the interest rate margin will become effective in the event the Leverage Ratio (as defined in the Credit Agreement) is 2.75:1.00. Additionally, APLP Holdings amended its existing Term Loan to extend the maturity date by two years to April 2025. The repricing also adds customary new provisions relating to the replacement of LIBOR as the benchmark for the Eurodollar Rate (as defined in the Credit Agreement) replacement. Targeted debt balances were adjusted to reflect the previously announced anticipated closing of the sale of our Manchief power plant in 2022, resulting in lower targeted debt repayment in 2020 and higher targeted debt repayment in 2022 as compared to the previous schedule. For the year ended December 31, 2020, we recorded $0.8 million of new deferred financing costs associated with the amendment, which will be amortized over the remaining terms of the Term Loan and the Revolver. Additionally, we wrote off $0.5 million of existing deferred financing costs to interest expense.

In March 2020, APLP Holdings executed an amendment to the Revolver providing for an extension of the Revolver maturity date to April 2025, to coincide with the maturity date of the Term Loan. Both the Revolver and the Term Loan are at our APLP Holdings subsidiary. As of December 31, 2020, we had no borrowings under the Revolver and utilized $77.1 issued in letters of credit. In conjunction with the extension, the Revolver capacity was reduced to $180 million from $200 million previously. The amendment allows an upsizing of the Revolver capacity by up to $30 million, to a maximum aggregate amount of $210 million, subject to approval of the two letter of credit issuer banks and increased commitments by existing or new lenders. Such an upsizing would not require a further amendment. As a result of the extension, for the year ended December 31, 2020, we recorded $0.9 million of new deferred financing costs, which will be amortized over the remaining term of the Revolver.

The Term Loan includes 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 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) of 4.25:1.00 at December 31, 2020 through March 31, 2023, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 3.5:1.00 at December 31, 2020 to 4.00:1.00 through March 31, 2023. At December 31, 2020, 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 Loan under the Credit Facilities, it will be required to offer each electing lender a prepayment of such lender’s term loan 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 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 APPEL, 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 Loan 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.

Notes of the Partnership

The Partnership has outstanding Cdn$210.0 million ($164.9 million as of December 31, 2020) 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, 2020, we were in compliance with these covenants. The MTNs are guaranteed by Atlantic Power Corporation and APPEL, 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, 2020, 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.

13. Convertible debentures

The following table provides details related to outstanding convertible debentures:

	December 31, 2020	December 31, 2019
6.00% Debentures due January 2025 (Series E) (Cdn$115.0 million)	$ 90.3	$ 88.5
Less: Unamortized deferred financing costs	(3.2)	(3.8)
Less: Unamortized discount	(3.0)	(3.6)
Total current and long-term convertible debentures	$ 84.1	$ 81.1

On April 10, 2019, we redeemed, in full, the aggregate principal amount of Cdn$24.7 million of the outstanding 6.00% Debentures due December 2019 (the “Series D Debentures”) and paid accrued interest of Cdn$0.4 million.

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 TSX, 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 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 liability was $1.5 million and $3.2 million at December 31, 2020 and December 31, 2019, respectively. 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,			
	2020		2019	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	$ 487.2	$ 539.0	$ 560.4	$ 589.5
Convertible debentures	90.3	94.6	88.5	93.0

At both December 31, 2020, and December 31, 2019, fair value of cash and cash equivalents, restricted cash, accounts receivable and accounts payable are not materially different from their carrying amounts because of the short-term nature of these instruments and/or because the stated rates approximate market rates.

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.

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, 2020 and December 31, 2019. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	December 31, 2020			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 38.8	$ —	$ —	$ 38.8
Restricted cash	7.1	—	—	7.1
Derivative instruments asset	—	0.4	—	0.4
Total	$ 45.9	$ 0.4	$ —	$ 46.3
Liabilities:				
Derivative instruments liability	$ —	$ 17.6	$ 1.5	$ 19.1
Total	$ —	$ 17.6	$ 1.5	$ 19.1

	December 31, 2019			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 74.9	$ —	$ —	$ 74.9
Restricted cash	7.7	—	—	7.7
Derivative instruments asset	—	0.7	—	0.7
Total	$ 82.6	$ 0.7	$ —	$ 83.3
Liabilities:				
Derivative instruments liability	$ —	$ 24.7	$ 3.2	$ 27.9
Total	$ —	$ 24.7	$ 3.2	$ 27.9

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, 2020, the credit valuation adjustments resulted in a $0.5 million net increase in fair value, which consists of a $0.1 million pre-tax gain in other comprehensive income and a $0.4 million gain in change in fair value of derivative instruments. As of December 31, 2019, the credit valuation adjustments resulted in a $1.1 million net increase in fair value, which consists of a $0.1 million pre-tax gain in other comprehensive income and a $1.0 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.

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, 2020, 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, 2020
Beginning balance of liability at January 1, 2020	$	3.2
Total unrealized gain		(1.8)
Currency translation loss		0.1
Ending balance of liability at December 31, 2020	$	1.5

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 (loss) earnings. The ineffective portion of a cash flow hedge is immediately recognized in (loss) earnings. For our other derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in (loss) earnings. 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 6,500 Gj of natural gas per day is sold at the spot market price. This contract is not accounted for as a derivative.

On May 15, 2020, we also entered into natural gas purchase agreements at our Morris project for approximately 700,000 MMBtu to effectively mitigate seasonal fluctuations of future natural gas prices from January 2021 through February 2021. This contract is accounted for as a derivative financial instrument and is recorded in the consolidated balance sheet at fair value. Changes in the fair market value of this contract 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 12.4 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 2021 through 2023. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2020. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

Interest rate swaps

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, 2020, these agreements totaled $307.5 million notional amount of the remaining $307.5 million aggregate principal amount of borrowings under the Term loan. These interest rate swap agreements expire at various dates through March 31, 2022. Borrowings under the $700.0 million Term Loan bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 2.50%. Based on the terms of the Term Loan, the Adjusted Eurodollar Rate cannot be less than 1.00%, resulting in a minimum of a 3.50% all-in rate on the Term Loan for the remaining principal amount. The weighted average rate of these swap agreements is 2.20%, resulting in an all-in rate of approximately 4.70% for $307.5 million of the Term Loan.

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.3% through 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 the Cadillac Term Loan. 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 due June 23, 2036. Principal and interest payments for our Term Loan 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, 2020, we have no foreign currency forward contracts.

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, 2020 and December 31, 2019:

	Units	**December 31, 2020**	**December 31, 2019**
Natural gas swaps	Natural Gas (MMBtu)	12.4	16.3
Gas purchase agreements	Natural Gas (Gigajoules)	4.0	6.4
Interest rate swaps	Interest (US$)	122.3	468.4

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, 2020	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.6
Interest rate swaps long-term	—	1.0
Total derivative instruments designated as cash flow hedges	—	1.6
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	—	4.1
Interest rate swaps long-term	—	0.9
Natural gas swaps current	—	0.8
Natural gas swaps long-term	—	1.9
Gas purchase agreements current	0.4	4.0
Gas purchase agreements long-term	—	4.3
Convertible debenture conversion option	—	1.5
Total derivative instruments not designated as cash flow hedges	0.4	17.5
Total derivative instruments	$ 0.4	$ 19.1

	December 31, 2019	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$ —	$ 0.4
Interest rate swaps long-term	—	1.1
Total derivative instruments designated as cash flow hedges	—	1.5
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	—	1.9
Interest rate swaps long-term	—	1.1
Natural gas swaps current	—	1.9
Natural gas swaps long-term	—	4.2
Gas purchase agreements current	0.7	4.6
Gas purchase agreements long-term	—	9.5
Convertible debenture conversion option	—	3.2
Total derivative instruments not designated as cash flow hedges	0.7	26.4
Total derivative instruments	$ 0.7	$ 27.9

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, 2020	Interest Rate Swaps
Accumulated OCI balance at January 1, 2020	$ 1.6
Change in fair value of cash flow hedges	(0.5)
Realized from OCI during the period	0.5
Accumulated OCI balance at December 31, 2020	$ 1.6
Settlements expected to be recognized from OCI in expense in the next 12 months, net of $0.1 million of tax	$ 0.5

Year Ended December 31, 2019	Interest Rate Swaps
Accumulated OCI balance at January 1, 2019	$ 1.6
Change in fair value of cash flow hedges	(0.3)
Realized from OCI during the period	0.3
Accumulated OCI balance at December 31, 2019	$ 1.6

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,	
		2020	2019
Gas purchase agreements	Fuel	$ 8.3	$ 8.2
Natural gas swaps	Fuel	2.5	0.9
Interest rate swaps	Interest, net	5.0	(3.2)

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

	Classification of gain (loss) recognized in income	Year ended December 31,	
		2020	2019
Natural gas swaps	Change in fair value of derivative instruments	$ 3.4	$ (4.6)
Gas purchase agreements	Change in fair value of derivative instruments	5.4	3.2
Interest rate swaps	Change in fair value of derivative instruments	(2.0)	(7.5)
		6.8	(8.9)
Convertible debenture conversion option	Other (income) expense, net	(1.8)	1.8
Foreign currency forwards	Foreign exchange loss	$ —	$ —

16. Income tax expense

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

	Year Ended December 31,			
	2020		2019	
	U.S.	Canada	U.S.	Canada
Current income tax expense	$ 2.8	$ 2.8	$ 1.9	$ 3.0
Deferred income tax (benefit) expense	(28.1)	(1.7)	7.7	(2.8)
Total income tax (benefit) expense, net	$ (25.3)	$ 1.1	$ 9.6	$ 0.2

The following is a reconciliation of the income taxes calculated at the Canadian enacted statutory rate of 27% for the years ended December 31, 2020 and 2019, respectively, to the provision for income taxes in the consolidated statements of operations:

	Year Ended December 31,			
	2020		2019	
	U.S.	Canada	U.S.	Canada
Computed income tax expense (benefit) at Canadian statutory rate	$ 11.2	$ 2.1	$ (2.2)	$ (7.0)
(Decreases) increases resulting from:				
Operating in countries with different income tax rates	(0.3)	—	0.1	—
	10.9	2.1	(2.1)	(7.0)
Change in valuation allowance	(39.7)	(0.5)	(2.2)	7.9
	(28.8)	1.6	(4.3)	0.9
Dividend withholding tax and other cash taxes	1.8	0.2	1.1	0.2
Foreign exchange	—	(0.6)		1.7
Changes in tax rates	(0.1)	—	2.2	—
Changes in estimates due to tax filings	3.0	—	(0.1)	(0.2)
Capital gain on intercompany notes	—	0.2	0.1	—
Impairments	—	—	7.7	—
Other	(1.2)	(0.3)	2.9	(2.4)
	3.5	(0.5)	13.9	(0.7)
Income tax (benefit) expense	$ (25.3)	1.1	$ 9.6	$ 0.2

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2020 and 2019 are presented below:

	Year Ended December 31, 2020	2019
Deferred tax assets:		
Loss carryforwards	$ 123.9	$ 135.9
Capital loss carryforwards	35.3	35.8
Interest expense limitation carryforwards	-	9.7
Finance and share issuance costs	-	0.1
Tax credits	1.4	1.4
Stock-based compensation	2.4	2.4
Derivative contracts	3.8	5.7
Other long-term notes	2.3	—
Other	3.1	0.9
Total deferred tax assets	172.2	191.9
Less: Valuation allowance	(105.2)	(145.4)
	67.0	46.5
Deferred tax liabilities:		
Intangible assets	(22.0)	(21.9)
Property, plant and equipment	(22.0)	(31.2)
Basis difference in joint ventures	(5.8)	(5.4)
Other long-term investments	-	(1.3)
Total deferred tax liabilities	(49.8)	(59.8)
Net deferred tax asset (liability)	$ 17.2	$ (13.3)

Net deferred tax asset (liability) by jurisdiction	Year Ended December 31, 2020	2019
U.S. Federal and State	$ 4.5	$ (23.7)
Canada	12.7	10.4
Net deferred tax asset (liability)	$ 17.2	$ (13.3)

Income tax benefit for the year ended December 31, 2020 was $24.2 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 27%, was $13.3 million. The primary item impacting the tax rate for the year ended December 31, 2020 was a net decrease to our valuation allowances of $40.2 million, consisting of $0.5 million decreases in Canada and $39.7 million decreases in the United States.

As of December 31, 2020, in the United States our deferred tax assets were primarily the result of net operating losses. For the year ended December 31, 2020, we recorded a net valuation allowance release of $39.7 million in the United States on the basis of management's reassessment of the amount of its deferred tax assets that are more likely than not to be realized.

As of each reporting date, management considers new evidence, both positive and negative, that could affect its view of the future realization of deferred tax assets. As of December 31, 2020, in part because in the current year we achieved three years of cumulative pre-tax income in the United States federal tax jurisdiction, management determined that there is sufficient positive evidence to conclude that it is more likely than not that deferred taxes of $39.7 million are realizable. We reduced the valuation allowances accordingly. Any remaining valuation allowances in the United States is related to tax credits and a portion of state net operating losses that were determined to be currently unrealizable based on our expected ability to generate income on remaining purchase price agreements in certain state jurisdictions. Valuation allowances remain on certain net operating losses in Canada.

In addition, the rate was further impacted by $0.6 million relating to foreign exchange.

These items were offset by $3.0 million related to changes in estimates due to tax filings and $0.3 million of other permanent differences.

Income tax expense for the year ended December 31, 2019 was $9.8 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 27%, was $9.2 million. The primary items impacting the tax rate for the year ended December 31, 2019 were $7.7 million related to impairments and a net increase to our valuation allowances of $5.7 million, consisting of $7.9 million increases in Canada and $2.2 million decreases in the United States. In addition, the rate was further impacted by $2.2 million related to changes in tax rates, $1.7 million relating to foreign exchange, $1.3 million relating to withholding and state taxes and $0.4 million of other permanent differences.

As of December 31, 2020, we have recorded a valuation allowance of $105.2 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.

As of December 31, 2020, we had the following net operating loss carryforwards that are scheduled to expire in the following years:

	U.S.	Canada	Total
2029	$ -	$ 19.9	$ 19.9
2030	-	-	-
2031	25.4	-	25.4
2032	13.4	6.0	19.4
2033	20.6	24.0	44.6
2034	122.3	9.3	131.6
2035	154.1	-	154.1
2036	17.0	20.7	37.7
2037	16.7	9.0	25.7
2038	-	10.3	10.3
2039	-	7.2	7.2
2040	-	1.2	1.2
	$ 369.5	$ 107.6	$ 477.1

17. Equity compensation plans

Long-term incentive plan ("LTIP")

The following table summarizes the changes in outstanding LTIP notional shares during the years ended December 31, 2020 and 2019:

	Notional Shares	Grant Date Weighted-Average Fair Value per Notional Share
Outstanding at December 31, 2018	3,952,201	$ 2.09
Granted	1,724,081	2.72
Vested and redeemed	(2,071,335)	2.10
Forfeitures	(26,855)	2.17
Outstanding at December 31, 2019	3,578,092	$ 2.38
Granted	1,866,748	2.49
Vested and redeemed	(1,702,571)	2.34
Forfeitures	(31,929)	2.42
Outstanding at December 31, 2020	3,710,340	$ 2.45

On March 29, 2019, the compensation committee of our board of directors determined that all notional shares granted under the LTIP held by non-officer employees will be settled in cash following vesting, rather than two-thirds in common shares and one-third in cash, with the cash portion being utilized to satisfy the tax withholding and remittance obligations related to the common share settlement. As a result of the modification, all future vesting of notional shares for this employee group will be settled in cash. The portion of LTIP grants settled in common shares was accounted for as equity awards. On the modification date, the equity awards were reclassified as liability awards and a liability equal to the modification-date fair value was recognized. The impact of the modification was not material on the date of the change in accounting.

The total grant date fair value of all outstanding notional shares under the LTIP was $9.1 million and $8.5 million for the years ended December 31, 2020 and 2019. The weighted average remaining vesting term for outstanding notional shares was 1.7 years at December 31, 2020. Approximately $3.0 million of total unrecognized compensation expense is expected to be recognized over the term of the outstanding LTIP shares. Compensation expense related to LTIP was $4.1 million and $4.9 million for the years ended December 31, 2020 and 2019, respectively. Cash payments made for vested notional shares were $3.3 million and $2.1 million for the years ended December 31, 2020 and 2019, respectively.

Transition Equity Participation Agreement

We also have 269,952 transition notional shares outstanding at December 31, 2020 under the Transition Equity Participation Agreement with James J. Moore, Jr. These notional shares will vest on or any time after January 22, 2017 if the weighted average Canadian dollar closing price of our common shares on the TSX for a period of 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% (Cdn$4.77). These notional shares will also vest in the event that Mr. Moore is terminated without cause, resigns for good reason, retirement after attaining the age of 62 or dies.

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 Cdn$0.5 million to the pension plan in 2021.

The net annual periodic pension cost related to the pension plan for the years ended December 31, 2020 and 2019 includes the following components:

	2020	2019
Service cost benefits earned	$ 0.3	$ 0.3
Interest cost on benefit obligation	0.4	0.5
Expected return on plan assets	(0.7)	(0.7)
Amortization of actuarial loss	0.1	—
Settlements	—	0.3
Net period benefit cost	$ 0.1	$ 0.4

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

	2020	2019
Projected benefit obligation at January 1	$ (14.1)	$ (13.2)
Service cost	(0.3)	(0.3)
Interest cost	(0.4)	(0.5)
Actuarial loss	(2.3)	(2.0)
Employee contributions	(0.1)	(0.1)
Benefits paid	0.3	0.2
Settlements	—	2.4
Foreign currency adjustment	(0.5)	(0.6)
Projected benefit obligation at December 31	(17.4)	(14.1)
Fair value of plan assets at January 1	$ 12.9	$ 12.0
Actual return on plan assets	1.2	2.0
Employer contributions	0.2	0.8
Employee contributions	0.1	0.1
Benefits paid	(0.3)	(0.2)
Settlements	—	(2.4)
Foreign currency adjustment	0.2	0.6
Fair value of plan assets at December 31	14.3	12.9
Funded status at December 31-excess of obligation over assets	$ (3.1)	$ (1.2)

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

	2020	2019
Non-current liabilities	$ 3.1	$ 1.2

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

	2020	2019
Unrecognized loss	$ (3.1)	$ (1.7)

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

	2020	2019
Projected benefit obligation	$ 17.4	$ 14.1
Accumulated benefit obligation	16.4	12.9
Fair value of plan assets	14.3	12.9

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 $14.3 million and $12.9 million for the years ended December 31, 2020 and 2019, respectively.

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:

	2020	2019
Weighted-Average Assumptions		
Discount rate	2.50 %	3.25 %
Rate of compensation increase	2.0 %	2.0 %

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

	2020	2019
Weighted-Average Assumptions		
Discount rate	3.3 %	4.0 %
Rate of return on plan assets	5.5 %	5.8 %
Rate of compensation increase	2.0 %	2.0 %

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, 2020 and 2019, were based on the CIA / Fiera curve, which was designed by the Canadian Institute of Actuaries and Fiera Capital Investment Management Inc. to provide a means for sponsors of Canadian plans to value the liabilities of their pension and postretirement benefit plans. The CIA / Fiera 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 / Fiera 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.

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

	2020	2019
Canadian equity	31 %	30 %
U.S. equity	14 %	14 %
International equity	17 %	14 %
Canadian fixed income	38 %	39 %
Real estate equities	— %	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$:

Years ending December 31,	
2021	Cdn$ 0.5
2022	0.5
2023	0.6
2024	0.6
2025	0.6
2026-2030	4.0

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 $1.5 million and $1.3 million for the years ended December 31, 2020 and 2019, respectively.

19. Common shares

Our common shares have no par value and unlimited authorization. We had 89,222,568 and 108,675,294 common shares issued and outstanding at December 31, 2020 and December 31, 2019, respectively.

Stock Repurchase Program

During the year ended December 31, 2020, we repurchased and canceled 7,540,105 common shares at a total cost of approximately $15.8 million under an NCIB that expired on December 30, 2020.

On December 31, 2020, we commenced a new NCIB for our Series E Debentures, our common shares and for each series of the preferred shares of APPEL, our wholly-owned subsidiary. The NCIBs expire on December 30, 2021 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the NCIB. Under the NCIBs, we may purchase up to a total of 8,554,391 common shares based on 10% of our public float as of December 18, 2020 and we are limited to daily purchases of 10,420 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 NYSE in compliance with Rule 10b-18 under the Exchange Act, 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.

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 Exchange Act, 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.

Substantial Issuer Bid

On March 25, 2020, we commenced a SIB for the purchase of up to $25 million of common shares. This was equivalent to 12,820,512 common shares, or approximately 12% of our total issued and outstanding common shares based on a $1.95 per share purchase price (the minimum price per common share under the offer) as measured on the date of commencement. The SIB expired on April 30, 2020. During the time the SIB was active, the NCIB was suspended for the purchase of common shares and Series E Debentures, but not for the preferred shares of APPEL.

The SIB proceeded by way of a “modified Dutch auction.” Holders of common shares were able to tender to the offer by: (i) auction tenders in which they specified the number of common shares being tendered at a price of not less than US$1.95 and not more than US$2.20 per common share in increments of US$0.05 per common share, or (ii) purchase price tenders in which they did not specify a price per common share, but rather agreed to have a specified number of common shares purchased at the purchase price determined by auction tenders.

The purchase price paid by the Company for each validly deposited common share was based on the number of common shares validly deposited pursuant to auction tenders and purchase price tenders, and the prices specified by shareholders making auction tenders. The purchase price was the lowest price which enabled the Company to purchase common shares up to the maximum amount available for auction tenders and purchase price tenders, determined in accordance with the terms of the offer. Common shares that were deposited at or below the final determined purchase price were purchased at such purchase price. Common shares that were not taken up in connection with the offer, including common shares deposited pursuant to auction tenders at prices above the purchase price, were returned to the shareholders. On May 1, 2020, the Company completed a SIB for its common shares, repurchasing 12.5 million common shares at a price of $2.00 per share. The shares repurchased have been canceled. The total cost of the SIB including transaction costs was $25.8 million.

We repurchased and cancelled 12,500,000 common shares under the SIB at a total cost of $25.8 million, including transaction costs, upon its expiration on April 30, 2020.

Renewal of Shelf Registration Statement

On August 24, 2020, we filed a shelf registration statement on Form S-3, which was declared effective by the SEC on August 25, 2020 (the “Shelf Registration Statement”), and is available for use for three years in the United States. The Shelf Registration Statement allows the Company to sell from time to time up to $250 million of common shares, debt securities, warrants, subscription receipts or units comprised of any combination of these securities, for its own account in one or more offerings. We also filed a base short-form prospectus dated August 24, 2020 qualifying the distribution of such securities concurrently with Canadian securities regulators.

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. The Series 1 Shares are redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all accrued and unpaid dividends thereon. At December 31, 2020, there were 3,465,706 Series 1 Shares outstanding.

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 pays a fixed dividend when declared. The dividend on the Series 2 Shares is cumulative. Beginning on December 31, 2014 and each fifth-year anniversary thereafter, (i) the rate on the Series 2 shares is reset at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%, and (ii) holders of Series 2 Shares have the right, subject to certain limitations, to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the “Series 3 Shares”) of the subsidiary. The dividend rate for the Series 2 Shares was reset on December 31, 2019 to 5.74%.

The holders of Series 3 Shares are entitled to receive quarterly floating rate 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%. The dividend on the Series 3 Shares is cumulative. The dividend rate for the Series 3 Shares was reset on December 31, 2020 to 4.30%. Beginning on December 31, 2019, and on each fifth-year anniversary thereafter, holders of Series 3 Shares have the right, subject to certain limitations, to convert their shares into Series 2 Shares.

The Series 2 Shares are redeemable by the subsidiary company at Cdn$25.00 per share, on each fifth-year anniversary date, plus an amount equal to all accrued and unpaid dividends thereon. The Series 3 Shares are redeemable at any time by the subsidiary company at Cdn$25.50 per share, plus an amount equal to all accrued and unpaid dividends thereon. At December 31, 2020, there were 2,441,766 Series 2 Shares and 957,391 Series 3 Shares outstanding.

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.

The Series 1 Shares, the Series 2 Shares and the Series 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 $6.8 million and $7.4 million for the years ended December 31, 2020 and 2019, respectively. For the year ended December 31, 2020, we repurchased and cancelled 381,794 Series 1 Shares, 62,365 Series 2 Shares and 120,000 Series 3 Shares, respectively for a total cost of $6.4 million. We also repurchased and cancelled preferred shares at a cost of $8.0 million in the year ended December 31, 2019. As a result of the repurchases, losses of $7.4 million and $8.6 million were attributed to the preferred shares of a subsidiary company in the Consolidated Statements of Operations for the years ended December 31, 2020 and 2019, respectively.

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 (loss) and potentially dilutive shares utilized in the per share calculation for the years ended December 31, 2020 and 2019:

Basic	**2020**	**2019**
Numerator:		
Net income (loss) attributable to Atlantic Power Corporation	$ 74.2	$ (42.6)
Denominator:		
Weighted average basic shares outstanding	95.8	109.3
Basic earnings (loss) per share attributable to Atlantic Power Corporation	$ 0.77	$ (0.39)
Diluted		
Numerator:		
Net income (loss) attributable to Atlantic Power Corporation	74.2	(42.6)
Add: convertible debenture interest expense	3.8	—
	78.0	(42.6)
Denominator:		
Weighted average basic shares outstanding	95.8	109.3
Share-based compensation	1.7	—
Convertible debentures	27.4	—
	124.9	109.3
Diluted earnings (loss) per share attributable to Atlantic Power Corporation	0.62	(0.39)

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

	2020	**2019**
Share-based compensation	—	1.5
Convertible debentures	—	27.8
Total	—	29.3

22. Segment and geographic information

We have four reportable segments: Solid Fuel, Natural Gas, Hydroelectric and Corporate. We revised our reportable business segments in the fourth quarter of 2019 as the result of recent asset acquisitions, PPA expirations and project decommissioning, and in order to align with changes to management's structure, resource allocation and performance assessment in making decisions regarding our operations. 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, impairment charges, insurance loss (gain), other (income) expenses 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 method investments in unconsolidated affiliates are presented as proportionately consolidated based on our ownership percentage in the reconciliation of Project Adjusted EBITDA to project income.

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

	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Consolidated
Year Ended December 31, 2020					
Project revenues	$ 94.5	$ 118.2	$ 58.3	$ 1.0	$ 272.0
Segment assets	202.8	190.8	306.3	147.3	847.2
Goodwill	—	6.9	14.4	—	21.3
Capital expenditures	24.1	—	0.6	0.1	24.8
Project Adjusted EBITDA	$ 39.9	$ 105.0	$ 45.3	$ (1.5)	$ 188.7
Change in fair value of derivative instruments	—	(8.9)	—	2.1	(6.8)
Depreciation and amortization	22.7	34.3	19.6	—	76.6
Interest, net	2.7	—	—	0.1	2.8
Insurance gain	(0.7)	—	—	—	(0.7)
Other project income	—	(2.1)	—	—	(2.1)
Project income (loss)	15.2	81.7	25.7	(3.7)	118.9
Administration	—	—	—	24.8	24.8
Interest expense, net	—	—	—	42.4	42.4
Foreign exchange loss	—	—	—	5.1	5.1
Other income, net	—	—	—	(2.7)	(2.7)
Net income (loss) before income taxes	15.2	81.7	25.7	(73.3)	49.3
Income tax benefit	—	—	—	(24.2)	(24.2)
Net income (loss)	$ 15.2	$ 81.7	$ 25.7	$ (49.1)	$ 73.5

	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Consolidated
Year Ended December 31, 2019					
Project revenues	$ 80.0	$ 131.8	$ 68.8	$ 1.0	$ 281.6
Segment assets	222.7	241.0	388.3	83.6	935.6
Goodwill	—	6.9	14.4	—	21.3
Capital expenditures	6.8	0.1	0.4	—	7.3
Project Adjusted EBITDA	$ 32.7	$ 108.2	$ 55.5	$ (0.3)	$ 196.1
Change in fair value of derivative instruments	—	1.4	—	7.5	8.9
Depreciation and amortization	23.9	37.2	19.5	0.1	80.7
Interest, net	2.6	(0.1)	—	—	2.5
Insurance loss	1.0	—	—	—	1.0
Impairment	55.0	—	—	—	55.0
Other project expense	—	1.2	—	—	1.2
Project (loss) income	(49.8)	68.5	36.0	(7.9)	46.8
Administration	—	—	—	23.9	23.9
Interest expense, net	—	—	—	44.0	44.0
Foreign exchange loss	—	—	—	11.9	11.9
Other expense, net	—	—	—	1.0	1.0
Net (loss) income before income taxes	(49.8)	68.5	36.0	(88.7)	(34.0)
Income tax expense	—	—	—	9.8	9.8
Net (loss) income	$ (49.8)	$ 68.5	$ 36.0	$ (98.5)	$ (43.8)

The table below provides information, by country, about our consolidated operations for each of the years ended December 31, 2020 and 2019 and Property, Plant and Equipment, PPAs and other Intangible and total assets as of December 31, 2020 and 2019, 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	
	2020	2019
United States	$ 184.9	$ 208.4
Canada	87.1	73.2
Total	$ 272.0	$ 281.6

	Property, Plant and Equipment, net of accumulated depreciation		PPAs and other intangible assets, net of accumulated amortization		Total assets	
	2020	2019	2020	2019	2020	2019
United States	$ 351.2	$ 353.9	$ 119.4	$ 142.8	$ 666.4	$ 762.3
Canada	140.6	148.2	0.9	1.5	180.8	173.3
Total	$ 491.8	$ 502.1	$ 120.3	$ 144.3	$ 847.2	$ 935.6

Niagara Mohawk Power Corporation, IESO, BC Hydro, Equistar Chemicals L.P. and Georgia Power Company provided 14.8%, 13.8%, 12.5%, 10.9% and 10.4%, respectively, of total consolidated revenues for the year ended December 31, 2020. Niagara Mohawk Power Corporation, IESO, Equistar Chemicals L.P. and Georgia Power Company provided 19.6%, 12.9%, 12.0% and 11.1%, respectively, of total consolidated revenues for the year ended December 31, 2019. IESO purchased electricity from the Calstock, Nipigon and Tunis projects and previously purchased electricity from our North Bay and Kapuskasing projects in the Natural Gas segment. BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the Hydroelectric and Solid Fuel segments and Niagara Mohawk purchases electricity from the Curtis Palmer project in the Hydroelectric segment. Equistar Chemicals L.P. purchases electricity from the Morris project in the Natural Gas segment and Georgia Power Company purchases electricity from the Piedmont project in the Solid Fuel segment.

23. Commitments and contingencies

Commitments

Management Service Commitments

Our Manchief project is operated by a third party under a contract that expires in April 2022. As of December 31, 2020, our commitments under this agreement are estimated as follows:

2021	$ 0.4
2022	0.2
2023	—
2024	—
2025	—
Thereafter	—
	$ 0.6

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, 2020, our commitments under such outstanding agreements are estimated as follows:

2021	$ 4.2
2022	4.4
2023	—
2024	—
2025	—
Thereafter	—
	$ 8.6

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.

Contingencies

Fire at Cadillac project

On September 22, 2019, the Cadillac project experienced a malfunction in its steam turbine that began a cascade of events, sparking a fire. The fire was contained by the local fire department and did not result in any injuries or known environmental violations.

Physical Damage

The biomass plant suffered significant damage to the turbine, generator and other components in that area of the plant as a result of the fire. The boiler, cooling tower, fuel pile and fuel handling equipment were not affected. Reconstruction of Cadillac was completed in late July 2020 and the plant was recommissioned, tested and returned to service on August 20, 2020. Our insurance covers the repair or replacement of the assets that experienced loss or damage. The property damage deductible under the policies insuring the Cadillac assets is $1.0 million. Losses have exceeded the deductible under these insurance policies.

Business Interruption

Our insurance policies also provide coverage for interruption to Cadillac’s business, including lost profits. The policies also reimburse for other expenses and costs it has incurred relating to the damages and loss it has suffered. The policies provide for coverage during the reconstruction period. The business interruption deductible under the policies insuring the Cadillac assets is 45 days of lost production, which we estimate had an approximate $1.4 million impact to cash flows from operations in the year ended December 31, 2019, the period when the deductible was fulfilled.

Impact

The Cadillac biomass plant is a component of our Solid Fuel segment. The fire resulted in a triggering event to test the Cadillac's asset group for long-lived asset impairment. Based on our expectation of insurance recoveries and a full repair of the plant, we did not record an impairment at Cadillac because its estimated undiscounted future cash flows exceed the carrying value of the asset group at the date of the incident.

Because the plant experienced significant damage and it was probable that insurance proceeds would be received in order to repair the facility, we applied accounting for gains and losses on involuntary conversions. Insurance proceeds received in excess of incurred losses were accounted for as gain contingencies. Reimbursements for lost profits, or business interruption losses, were accounted for as a gain contingency because lost profits are not considered an incurred loss. Based on loss estimates and expenses incurred through December 31, 2019, we recorded a $25 million write-down of Cadillac's property, plant and equipment and a $0.8 million write-down of capital spares inventory during the year ended December 31, 2020. We also recorded a corresponding insurance receivable ($24.8 million), a component of other current assets, less the $1.0 million property damage deductible, which was recorded as a charge to project other income (loss), because we believed that it was probable we would receive insurance recoveries up to our estimated plant write-down. As the plant was repaired, any costs incurred were capitalized to property, plant and equipment. During the year ended December 31, 2019, we received $11.3 million of insurance proceeds with respect to the fire at Cadillac, which were applied against the cumulative insurance receivable of $24.8 million.

In December 2020, we executed a final settlement of our insurance claim for the Cadillac plant under which final payments were received from the insurers as of December 31, 2020. We received insurance proceeds of $10.1 million and $29.9 million for the three and twelve months ended December 31, 2020, respectively, bringing the total cumulative proceeds received to $41.2 million. Proceeds were applied against the Cadillac insurance receivable of $13.5 million as of December 31, 2019, reducing the balance to zero as of December 31, 2020. Reimbursements for lost profits, or business interruption losses, were accounted for as a gain contingency. For the three and twelve months ended December 31, 2020, we recorded business interruption proceeds of $9.4 million and $15.6 million, respectively. Insurance recoveries for property losses in excess of incurred losses were accounted for as a gain contingency. For the three and twelve months ended December 31, 2020, we recorded insurance proceeds for property losses in excess of incurred losses of $0.8 million. Insurance recoveries related to business interruption losses and property losses in excess of incurred losses are included in project other income (loss) on our condensed consolidated statements of operations.

	Balance at Beginning of Period	Additions	Insurance Proceeds Received	Insurance Gain (Loss)	Balance at End of Period
Insurance recovery receivable:					
Year ended December 31, 2020	$ 13.5	$ —	$ (29.9)	$ 16.4 [(1)]	$ —
Year ended December 31, 2019	$ —	$ 25.8	$ (11.3)	$ (1.0)[(2)]	$ 13.5

(1) Represents recoveries for business interruption losses and property losses in excess of incurred losses of $15.6 million and $0.8 million, respectively. Of the $15.6 million recorded for the recovery of business interruption losses, $6.0 million relates to the expected reduction in capacity payments in 2021 under the Cadillac PPA due to the reduced availability of the plant in 2020 during the extended outage.

(2) Represents the $1.0 million property damage deductible.

General

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, 2020.

24. Leases

Real estate leases and equipment leases

We lease our office properties and equipment under operating leases expiring on various dates through 2024. Certain operating lease agreements include provisions for scheduled rent increases over their lease terms. We recognize the effects of these scheduled rent increases on a straight-line basis over the lease term. One of our leased office properties is sub-leased to third parties. The sub-lease is an operating lease and the rental income received is recorded net of rental expense in the Consolidated Statements of Operations.

On January 1, 2019, we implemented FASB ASU No. 2016-02, Leases (Topic 842). To calculate lease liabilities on the implementation date, we utilized an incremental borrowing rate of 3.75%, which was our minimum all-in rate on the Term Loan for the non-swapped portion of the remaining principal amount.

The following table presents the components of lease expense.

	Year Ended December 31, 2020	Year Ended December 31, 2019
Lease cost: [1]		
Operating lease cost	$ 2.1	$ 1.9
Short-term lease cost	—	0.1
Sublease income	(1.1)	(1.2)
Total lease cost	$ 1.0	$ 0.8

(1) Finance lease costs are immaterial to the Company.

The following table presents operating lease maturities and a reconciliation of the undiscounted cash flows to operating lease liabilities.

	Lease Payments	Income from subleasing	Net lease payments
2021	$ 2.0	$ (1.1)	$ 0.9
2022	1.8	(1.1)	0.7
2023	1.3	(0.7)	0.6
2024	0.2	—	0.2
2025	—	—	—
Thereafter	—	—	—
Total operating lease payments	$ 5.3	$ (2.9)	$ 2.4
Less: present value discount	(0.3)		
Total operating lease liabilities	$ 5.0		

	Lease Payments
2021	$ 0.1
2022	0.1
2023	—
Thereafter	—
Total finance lease payments	$ 0.2
Less: amount representing interest	(0.1)
Total finance lease liabilities	$ 0.1

Other Information:		
Cash paid for amounts included in the measurement of lease liabilities [1]:		
Operating cash flows from operating leases	$	1.1
Lease assets obtained in exchange for new lease liabilities (non-cash):		
Operating	$	0.1
Weighted average remaining lease term (in years):		
Operating leases		2.7
Finance leases		1.4
Weighted average discount rate - operating leases		3.9 %
Weighted average discount rate - finance leases		4.1 %

(1) Cash flows from finance leases are immaterial to the Company.

We have no lease transactions with related parties.

PPA Leases

We have entered into PPAs to sell power at predetermined rates. PPAs were assessed as to whether they contain leases, which convey to the counterparty the right to control the use of the project's property, plant and equipment in return for future payments. Such arrangements are classified as either operating or finance 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. Finance income related to leases or arrangements accounted for as finance 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. We elected the practical expedient that permits us to retain our existing lease assessment and classification.

As of December 31, 2020, we have ten PPAs accounted for as operating leases among our twenty-one projects in operation. No extension terms exist for our PPAs accounted for as leases and the remaining lease term varies from one year to twenty-three years. The following table provides lease income recorded as energy and capacity sales by segment from PPAs accounted for as operating leases:

	Rental Income from operating leases Year Ended December 31,	
	2020	**2019**
Solid Fuel	$ 65.9	$ 79.1
Natural Gas	25.4	24.4
Hydroelectric	58.3	68.8
	$ 149.6	$ 172.3

For certain of our PPAs accounted for as leases, the lessee has the option to purchase the plant. In May 2019, we entered into an agreement to sell Manchief to PSCo following the expiration of the PPA in April 2022 for $45.2 million subject to working capital and other customary adjustments. BC Hydro has an option to purchase Mamquam that is exercisable in November 2021 and every five-year anniversary thereafter.

25. Subsequent events

On January 14, 2021, Atlantic Power announced that it has entered into a definitive agreement with I Squared Capital, a leading global infrastructure investor, under which the company's outstanding common shares and convertible debentures, and the outstanding preferred shares and medium term notes of certain of its subsidiaries, will be acquired. The total enterprise value of the deal is approximately $961 million and the Transaction was unanimously approved by Atlantic Power's board of directors. The Transaction is subject to a number of closing conditions, including court approval, regulatory approvals, as well as the receipt of certain third-party consents. A termination fee of $12.5 million will be payable by Atlantic Power to the Purchasers should the Transaction not close under certain circumstances, including if the Arrangement is not completed as a result of Atlantic Power accepting an unsolicited superior proposal. A reverse termination fee of $15 million will be payable by the Purchasers to Atlantic Power should the Transaction not close as a result of an uncured breach by the Purchasers of the Arrangement Agreement (provided Atlantic Power is not then in breach of the Arrangement Agreement). Following closing of the Transaction, the common shares of Atlantic Power will be delisted from the TSX and the NYSE and the preferred shares and convertible debentures will be delisted from the TSX. The parties currently expect to close the Transaction in the second quarter of 2021.

Exhibit 21.1

Subsidiaries of Atlantic Power Corporation

(as of March 3, 2021)

Subsidiary	State of Organization
Atlantic Power Holdings, LLC	Delaware
Atlantic Power Services, LLC	Delaware
Atlantic Piedmont Holdings, LLC	Delaware
Atlantic Power (US) GP Holdings, Inc.	Delaware
AP USGP Holdings, LLC	Delaware
Atlantic CDP, Inc.	Delaware
Piedmont Green Power, LLC	Delaware
Atlantic Cadillac Holdings, LLC	Delaware
Cadillac Renewable Energy, LLC	Delaware
Orlando Power Generation I, LLC	Delaware
Orlando Power Generation II, LLC	Delaware
Orlando Cogen Limited, LP	Delaware
Baker Lake Hydro, LLC	Delaware
Olympia Hydro, LLC	Delaware
Koma Kulshan Associates, a California Limited Partnership	California
Harbor Capital Holdings, LLC	Delaware
Epsilon Power Partners, LLC	Delaware
Chambers Cogeneration Limited Partnership	Delaware
Atlantic Ridgeline Holdings, LLC.	Delaware
Delta Person LLC	Delaware
Epsilon Power Funding, LLC.	Delaware
Teton East Coast Generation, LLC.	Delaware
Teton Selkirk, LLC	Delaware
Teton Power Funding, LLC	Delaware
Atlantic Power Services Canada GP Inc.	British Columbia
Atlantic Power Services Canada LP	Ontario
Atlantic Power Limited Partnership (f/k/a Capital Power Income L.P.)	Ontario
Atlantic Power GP Inc. (f/k/a CPI Income Services Ltd.)	British Columbia
Atlantic Power Preferred Equity Ltd. (f/k/a CPI Preferred Equity Ltd.)	Alberta
Atlantic Power Energy Services (Canada) Inc. (f/k/a CP Energy Services (Canada) Inc.)	British Columbia
Atlantic Power (US) GP (f/k/a CP Power (US) GP)	Delaware
Atlantic Power (Coastal Rivers) Corporation (f/k/a Coastal Rivers Power Corporation)	British Columbia
Atlantic Power (Williams Lake) Ltd. (f/k/a CPI Power (Williams Lake) Ltd.)	British Columbia
Atlantic Power FPLP Holdings LLC (f/k/a CPI FPLP Holdings LLC)	Delaware
Frederickson Power Management Inc.	Washington
Atlantic Power GP II Inc.	British Columbia
APLP Holdings Limited Partnership	Ontario
Frederickson Power L.P.	Washington
APDC, Inc. (f/k/a CPIDC, Inc.)	Washington
AP Power Holdings LLC (f/k/a CPI Power Holdings Inc.)	Delaware
Atlantic Power USA LLC (f/k/a CPI Power USA LLC)	Delaware
Atlantic Power USA Holdings LLC (f/k/a CPI Power Holdings USA LLC)	Delaware
Atlantic Power Enterprises LLC (f/k/a CPI Power Enterprises LLC)	Delaware

Subsidiary	State of Organization
Manchief LLC.	Delaware
Manchief Holding LLC	Delaware
Manchief Power Company LLC	Delaware
Curtis Palmer LLC	Delaware
AP (Curtis Palmer) LLC	Delaware
Curtis/Palmer Hydroelectric Company L.P.	New York
Atlantic Power Energy Services (US) LLC (f/k/a CPI Energy Services (US) LLC)	Delaware
Morris Cogeneration, LLC	Delaware
Atlantic Power USA Ventures, LLC (f/k/a CPI USA Ventures LLC)	Delaware
EF Oxnard LLC	California
EF Kenilworth LLC	California
Applied Energy LLC	California
Ridgeline Energy Holdings LLC	Delaware
Ridgeline Energy LLC	Delaware
Ridgeline Energy Solar LLC	Delaware
Atlantic Midway Ventures LLC	Delaware
Allendale Biomass LLC	Delaware
Atlantic Decker Energy, Inc.	Delaware
Decker Energy – Craven GP LLC	Delaware
Decker Energy – Craven LP LLC	Delaware
Decker Energy Grayling, Inc.	Michigan
Dorchester Biomass, LLC	Delaware
AJD Forest Products Limited Partnership	Michigan
Craven County Wood Energy LP	Delaware
GGS Holdings Company	Delaware
Grayling Development Partners	Michigan
Grayling Partners Land Development, LLC	Michigan
Grayling Generating Station Limited Partnership	Michigan
Javelin Energy, LLC	Delaware

Exhibit 23.1

Consent of Independent Registered Public Accounting Firm

The Board of Directors
Atlantic Power Corporation:

We consent to the incorporation by reference in the registration statements (No. 333-172926, No. 333-219001, and No. 333-197940) on Form S-8 and the registration statement (No. 333-245462) on Form S-3 of Atlantic Power Corporation and subsidiaries (the Company) of our reports dated March 4, 2021, with respect to the consolidated balance sheets of the Company as of December 31, 2020 and 2019, the related consolidated statements of operations, comprehensive income (loss), shareholders' equity, and cash flows for each of the years then ended, and the related notes, and the effectiveness of internal control over financial reporting as of December 31, 2020, which reports appear in the December 31, 2020 annual report on Form 10-K of the Company.

/s/ KPMG LLP
New York, New York
March 4, 2021

Exhibit 31.1

I, James J. Moore, Jr., certify that:

1. I have reviewed this Annual Report on Form 10-K of Atlantic Power Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rule 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted account principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and
   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 4, 2021

/s/ JAMES J. MOORE, JR.
James J. Moore, Jr.
President and Chief Executive Officer

Exhibit 31.2

I, Terrence Ronan, certify that:

1. I have reviewed this Quarterly Report on Form 10-K of Atlantic Power Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted account principles;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: March 4, 2021

/s/ TERRENCE RONAN

Terrence Ronan

Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)

Exhibit 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

The undersigned officer of Atlantic Power Corporation (the “Company”) hereby certifies to his knowledge that the Company’s Annual Report on Form 10-K for the year ended December 31, 2020 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended, and that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company. This certification shall not be deemed “filed” for any purpose, nor shall it be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934 regardless of any general incorporation language in such filing.

Date: March 4, 2021

/s/ JAMES J. MOORE, JR.
James J. Moore, Jr.
President and Chief Executive Officer

Exhibit 32.2

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO SECTION 906 OF THE
SARBANES-OXLEY ACT OF 2002

The undersigned officer of Atlantic Power Corporation (the “Company”) hereby certifies to his knowledge that the Company’s Annual Report on Form 10-K for the year ended December 31, 2020 (the “Report”), as filed with the Securities and Exchange Commission on the date hereof, fully complies with the requirements of Section 13(a) or 15(d), as applicable, of the Securities Exchange Act of 1934, as amended, and that the information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company. This certification shall not be deemed “filed” for any purpose, nor shall it be deemed to be incorporated by reference into any filing under the Securities Act of 1933 or the Securities Exchange Act of 1934 regardless of any general incorporation language in such filing.

Date: March 4, 2021

/s/ TERRENCE RONAN

Terrence Ronan
Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)