



AtlanticPower
Corporation

2019
Annual Report

Report to Shareholders

Dear Fellow Shareholder:

In the present crisis, many of us are reminded of Winston Churchill during World War II. Churchill had been, of course, an early and outspoken advocate for taking the Nazi threat seriously and being prepared. (His newspaper columns from that time are collected in his book, *Step by Step: Political Writings: 1936-1939*.)⁽¹⁾

Before he became Prime Minister he said:

“... let pre-war feuds die; let personal quarrels be forgotten, and let us keep our hatreds for the common enemy. Let party interest be ignored, let all our energies be harnessed, let the whole ability and forces of the nation be hurled into the struggle, and let all the strong horses be pulling on the collar.”

Churchill was a great statesman. We'll do our best to heed his call in today's crisis.

In this letter I will address several key areas of our business before concluding with a look forward. A more detailed summary of the business and financial highlights of the past year follows this letter.

PEOPLE

On March 9, we sent an email to our corporate staff in Dedham, Massachusetts, indicating that those who were uncomfortable coming into the office should work remotely. Two days later we reiterated that advice during the day. That evening at midnight I sent an email strongly encouraging people to work from home beginning the next day. Our office essentially has been in work-from-home mode since March 12.

While our corporate office employees could readily shift to working from home, our plant employees could not for the most part. Our business is power generation. Keeping the lights on is an essential service. Our employees have been given letters from various states and provinces to allow them to travel to work. To date, we are fortunate that none of our employees has tested positive for coronavirus. Where there has been potential exposure, people have self-quarantined. Our plants have continued to operate without interruption. Our plant employees are among the many heroes at work today in the United States and Canada.

On March 13, we sent an email to all our employees announcing that there would be no layoffs, salary cuts, or benefit reductions due to the pandemic. Our financial strength—hard won after years of paying down debt and reducing corporate overhead—means we came into the crisis well positioned to navigate a perfect storm. Our financial strength is also benefiting our shareholders.

CAPITAL ALLOCATION

As I noted in our March 18 press release:

“We have highly contracted EBITDA⁽²⁾ and operating cash flow. More than 95% of our cumulative EBITDA⁽²⁾ and operating cash flow through 2024 is generated under PPAs (Power Purchase Agreements) with an average remaining term of approximately six years. These PPAs are predominantly with investment-grade counterparties. We plan to continue allocating the majority of this strong cash flow to debt repayment, and expect to amortize the balance of our Term Loan by the April 2025 maturity. During this five-year period we expect to generate significant discretionary cash flow after debt repayment, as we noted on our fourth quarter 2019 conference call.”

There are basically five things that a company can do with its discretionary capital—invest in its own business; pay down debt; undertake mergers or acquisitions; repurchase equity securities; and pay

common dividends. This is how we have allocated capital among those five potential uses during the past five to seven years:

1. Invest in the Business

In previous years we made significant discretionary investments in our power plants. These were investments in excess of maintenance capital expenditures that were made to improve operating efficiency, increase production, and/or reduce operating costs. The effort started before the current management team was in place. From 2013 through 2016, we invested a total of \$25 million. The returns on these investments were attractive, but we have picked the low-hanging fruit and there is less need for this type of investment today.

2. Pay Down Debt

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. We have reduced our consolidated debt by more than \$1.2 billion since year-end 2013. Cash interest savings resulting from this debt reduction and several re-pricings of our credit facilities total approximately \$89 million annualized. As a result of this balance sheet improvement and commitment to further delevering, we have received several credit rating upgrades from the rating agencies since late 2015, which also help to lower our cost of capital.

3. Mergers & Acquisitions

In thinking about capital allocation, we focus on intrinsic value per share, not the absolute size of our business. We want to grow the business, of course, but when returns on internal uses of capital are better than those available on external investments, we want to make the rational, disciplined choice in terms of the impact on intrinsic value per share.

We are always looking for new investments, but from 2015 through 2017, we did not find anything compelling. Then in 2018 and 2019, we invested a total of \$45 million to acquire ownership interests in a hydro facility and four biomass plants. The PPAs on these five plants expire between year-end 2027 and late 2043, so they extend our remaining average contract term and increase our long-term cash flows. The acquisition of the 50% of the Koma Kulshan hydro facility that we did not already own was in response to the other owner seeking to exit. The investment return was acceptable but not outstanding, but we know the plant well and we think hydro has a long economic life beyond the PPA term. In contrast, biomass is an unpopular technology that is more difficult to operate. Our returns on the biomass acquisitions are expected to be in excess of 15% unlevered pre-tax. We have approximately \$523 million in net operating losses, and thus we do not expect to pay significant federal cash taxes in either the United States or Canada for some time ahead.

We are also willing to sell assets when doing so represents the best outcome for our shareholders. In 2019, we reached an agreement to sell our Manchief plant to the customer under the PPA in May 2022, following the expiration of the PPA. By retaining ownership of Manchief until then, we will continue to realize the cash flows for the remaining PPA term. At closing, we will use the \$45.2 million of proceeds to further pay down debt.

4. Buy Back Shares

Since December 2015, we have invested \$47.0 million in the repurchase of approximately 20.8 million common shares at an average price of \$2.26 per share. Year to date, we have significantly accelerated our repurchases of common shares. In addition, since June 2017, we have invested Cdn\$33.6 million (US\$25.5 million equivalent) in the repurchase of more than 2.1 million preferred

shares at an average discount to par of 37% and implied after-tax returns ranging between 10% and 12%.

5. Pay Common Dividends

We paid \$10 million of common dividends in 2015. We omitted the dividend in 2016 because we believed then, and continue to believe, that payment of a common dividend is not consistent with the characteristics of our business model or current market conditions.

As we consider potential options for the use of our discretionary capital, our preference is to invest in our business, which we understand best. We pay down debt not based on the returns from doing so, but from a desire to reduce risk and costs, and to right size our debt relative to our Project Adjusted EBITDA⁽²⁾ outlook.

External investments grow the overall size of the business, while share buybacks take cash out of the business and return it to shareholders. Again, we are driven by intrinsic value per share. We will shrink our balance sheet through buybacks if that creates more value for shareholders than making acquisitions or new investments. We are laser focused on shareholder value.

I'll have more to say on buybacks below, but briefly on common dividends—they can be a good way to return cash to shareholders if a company has excess capital (and insufficient uses with attractive returns) and it believes it can sustain the dividend through economic cycles. Today, we have a surfeit of good things to do with our capital, along the lines of the things I noted above. Another consideration for us is that our Project Adjusted EBITDA⁽²⁾ will decline after 2022 as some of our more significant PPAs begin to expire and the plants are re-contracted either at lower prices or not at all. The impact on our operating cash flow is expected to be less, however, due to our continued repayment of debt, which should reduce cash interest payments. While we expect to generate significant cash flow in excess of our needs over the next five years, our Project Adjusted EBITDA⁽²⁾ profile is not consistent with a sustainable dividend policy.

SHARE BUYBACKS

Politicians and the media are in the process of politicizing share buybacks. When that happens, intelligent investing goes out the window, to be replaced by ideology.

When a company repurchases shares, cash goes from the corporate treasury to shareholders who choose to sell their shares. Those shareholders either spend the cash or invest the cash elsewhere. Shareholders who choose not to sell their shares effectively increase their ownership in the company.

In some industries there is overcapacity and low or no growth. Other industries have a greater need for capital for internal or external expansion. It is rational to return capital to shareholders when an industry is oversupplied with capital or the financial profile of the individual business makes that an attractive use of capital.

Warren Buffett popularized share buybacks in this country. (Although on this front, we'd have to view Henry Singleton as the Samuel Johnson and Buffett as the James Boswell.) Buffett focuses on the price-to-intrinsic value relationship. If a company repurchases shares below its estimate of intrinsic value per share, then intrinsic value per remaining share increases. If repurchases are done at a premium to intrinsic value per share, then intrinsic value per remaining share declines.

Our share buybacks are a function of the price-to-value relationship compared to other potential uses of discretionary capital. We don't buy back shares to send messages. I have never sold a share of Atlantic Power stock and don't intend to do so. If the share price moved above our estimates of intrinsic value, we would consider issuing shares if we needed the capital. We would not buy shares at a price in excess of our estimates of intrinsic value.

Unfortunately, our country and the world are experiencing a health crisis. The economic consequences will be severe. Fortunately, Atlantic Power's conservative financial management and disciplined approach allowed us to protect our employees in this crisis and to ramp up our return of capital to shareholders.

EAT YOUR OWN COOKING

Since I joined the company as CEO in January 2015 through the end of March of this year, executives and directors have bought nearly 2.3 million Atlantic Power common shares at a gross purchase price of more than \$5.1 million. These shares were purchased in the open market by those individuals using personal funds and don't include shares granted by the company as part of executive or board compensation. In my view, a history of officers and directors taking money out of their savings accounts to buy shares in the open market is the best evidence of managers aligning their interests with those of shareholders. Insider ownership, which does include shares granted under compensation programs, has increased from less than 1% of shares in 2014 to 3.4% today.

Meanwhile, the CEO and the two executive vice presidents have not had a base salary increase since 2015 (or earlier). All three received less total compensation in 2019 than in the previous year due to lower short-term bonuses and long-term equity incentives, despite 2019 being a highly successful year in terms of growth and an excellent year in many other ways, as indicated by the financial results. In both our portfolios and our executive compensation programs, we are trying to align our interests with those of shareholders.

GOING FORWARD

I did say at the beginning of this letter that I would provide a look forward.

For us, the best case scenario—as measured in terms of intrinsic value per share—would be a return to higher power prices. I have talked at length in past letters on power market fundamentals, environmental policies, and the tough dynamics in the sector.

If we see some supply destruction resulting from significant cuts to exploration and production budgets, then natural gas prices might actually rise. That would benefit our hydro projects as their PPAs expire.

If we see some improved capital discipline from institutions after a period of financial crisis, we might see a slowing of new investment in gas, wind, and solar plants, which in most cases are not needed as markets are generally oversupplied. These additions have net negative environmental impacts versus utilizing existing gas plants at higher than current levels of capacity. That development would be good for us across the board.

If, on the other hand, things muddle along with the status quo in the power sector for years to come, we have an average remaining PPA term of six years and our strong operating cash flow provides the ability to pay off our Term Loan by its maturity in April 2025. If we did nothing else with our excess cash flow, we would expect to reach a zero net debt position sometime in 2025. At that point, we'd have hydro assets with long economic lives that are difficult to replace, gas plants that are more economic, more reliable and on a holistic analysis probably better environmentally than wind, solar, and batteries, and biomass plants with significant remaining PPA term—with no net debt. We don't mind being in that position. We think about the business as if we were a family office expecting to own it for the long term, with potential upside from higher power and gas prices and investment opportunities and a downside that seems reasonably well protected.

Over the next five years we expect to generate cumulative discretionary cash flow of \$115 million to \$165 million after repaying \$423 million of term loan and project debt during this period. In addition, on March 31 of this year, we had liquidity of \$150 million, consisting of \$48 million in cash

and \$102 million in available capacity under our revolver. We have been using cash for the repurchases of common and preferred shares and the acquisitions that we made in 2018 and 2019. Our revolver is available through April 2025 for acquisitions.

Over the past several years, we have reshaped Atlantic Power to withstand hard economic times with a stronger balance sheet and leaner cost structure. This is allowing us to react to the crisis as we have, for both our employees and our shareholders. Although our remaining PPA life is not as long as that of some other power companies in Canada, it is longer than most U.S. independent power producers, and it provides us the cash flow to pay down debt and generate discretionary capital even in a severe economic downturn.

We hope that both the pandemic and the economic fallout are short-lived, but we suspect there will be some changes needed by many businesses to adapt their balance sheets and business models to the new reality. Although we are small, we believe we are well positioned to use our liquidity when hard and turbulent times hit. We'll do our best to use that position wisely for our shareholders, employees, customers, and the communities we serve.

If you have read this far, thank you for your interest in Atlantic Power. May you and your families stay healthy and safe.



James J. Moore, Jr.
President and Chief Executive Officer
April 28, 2020

2019 Business and Financial Highlights

Safety

Environmental, health, and safety performance. Safety remains our highest priority. Despite our continued strong focus on this area, we had nine recordable injuries in 2019, up from four in 2018. Fortunately, none resulted in hospitalizations. Three of the injuries resulted in lost time (versus one in 2018). In response to these developments, we increased behavioral safety training, rolled out a survey to determine which areas required improvement, expanded sharing of best practices across our plants and simplified a safety dashboard to better track injuries, safety training, and safety improvements. Several of these recordable injuries were associated with cuts and pinches to hands and could be attributable to improper hand protection, so our teams provided revised glove training for our staff and ensured that all plants were equipped with the proper hand protection required for all tasks. In addition, our environmental health and safety team increased its visits to our plants during scheduled outages. In the first quarter of 2020, we had no recordable injuries. Looking at our safety performance over a longer period, in 2019, nine of the 16 plants that we operate completed at least five consecutive years of operation without a lost-time incident. We received two environmental notices of violation in 2019, both minor, which we responded to and corrected promptly. We did not receive any notices of violation from either the Federal Energy Regulatory Commission or the North American Electric Reliability Council.

Culture

Servant leadership. We continued to promote a culture of servant leadership throughout the organization, emphasizing the need for leaders to act with respect, integrity, and honesty. We place very high importance on this effort, as we believe a strong culture is the bedrock of building long-term sustainable value. In 2019, we continued to roll out training to the plant level.

Operational

Plant availability. In 2019, our plants had an availability factor of 94.0%, with strong performance at most of our plants. The overall average declined from 96.5% in 2018 primarily due to extended outages at our Moresby Lake hydro plant due to a main transformer failure and at our Cadillac biomass plant due to a fire in September.

Continued focus on operating costs. In 2019, we continued to advance our program to improve our operation and maintenance performance. We rolled out Mainsaver (a maintenance management system) to the South Carolina biomass plants that we acquired in July, to the Koma Kulshan hydro plant, in which we acquired the remaining ownership interests in the third quarter of 2018, and to our Piedmont biomass plant. We are continuing to focus on optimizing preventive maintenance programs for all of our facilities. Another area of focus is avoiding equipment issues that result in unplanned outages. To that end, we have installed predictive analytic maintenance software (“PRiSM”) at seven plants over the past two years. To date, the system has had 32 “good catches” (potential equipment problems that were avoided). We intend to roll PRiSM out to two more plants in 2020. Our operations team continues to look for ways to improve the reliability and efficiency of our plants while ensuring the effectiveness of our maintenance and capital expenditures.

Asset management. In 2019, we successfully integrated the acquisition of the Allendale and Dorchester biomass plants in South Carolina into our fleet. We began the process of decommissioning our three plants in San Diego, with demolition expected to be completed in 2020. In the fourth quarter of 2019, we rolled out a new system for testing and evaluating the condition of all plant step-up transformers. Understanding the condition of these critical components will allow us to better predict potential failures, plan for long-lead purchases, and avoid extended plant outages.

Commercial

New contract for our Williams Lake plant. In September 2019, we executed a new ten-year Energy Purchase Agreement with BC Hydro for our Williams Lake biomass plant in British Columbia that became effective October 1, 2019. Under the new contract, Williams Lake receives a fixed price per megawatt-hour for energy produced. This price escalates annually in line with inflation, but does not include a fuel cost pass-through. Given the state of the timber market in British Columbia, we believe that the availability and cost of fuel will be the most significant variables determining the operational and financial performance of the plant. Since executing the new contract, we have been focused on rebuilding our fuel supply sources, including traditional mill waste and forest and roadside residuals. We have entered into a new fuel supply arrangement with local First Nations, purchased and deployed a new mobile fuel grinder, and entered into other short-term agreements with third parties to extend supplies of mill waste and secure additional forest residuals. The grinder has been helpful in sourcing and transporting wood waste from forest areas.

PPA extension for our Kenilworth plant. In July 2019, Merck (the customer at our Kenilworth plant) executed its option to extend the PPA for another year, to September 2021. This was the third and final one-year extension option under the PPA. We continue to engage with Merck on short-term and long-term options for their power supply needs beyond that date.

Closed two acquisitions. In July 2019, we closed the acquisition of the Allendale and Dorchester biomass plants in South Carolina from EDF Renewables. The plants, which each have a capacity of 20 megawatts (“MW”), operate under PPAs that run through late 2043. In August 2019, we closed the acquisition of equity interests in two other biomass plants from AltaGas Power Holdings (U.S.) Inc. We acquired a 50% interest in the 48 MW Craven plant in North Carolina and a 30% interest in the 37 MW Grayling plant in Michigan; both plants operate under PPAs that run through 2027.

Agreement for the sale of our Manchief plant. In May 2019, we reached an agreement to sell our Manchief gas-fired plant to Public Service Co. of Colorado for \$45.2 million in May 2022 following the expiration of the plant’s PPA. We view this as a positive outcome that will allow us to realize the cash flows generated by the plant during the remaining contract term and further reduce debt upon closing of the sale in 2022. All regulatory approvals required for the sale have been received.

Financial

Results in line with or better than guidance. In 2019, cash provided by operating activities (a GAAP measure) was \$144.7 million. Excluding a net working capital benefit, cash flow was approximately \$128 million, which exceeded our estimated range of \$115 million to \$125 million (which was increased from our initial estimate of \$100 million to \$115 million). Project Adjusted EBITDA⁽²⁾ was \$196.1 million, which exceeded our guidance range of \$185 million to \$195 million (which was increased from our initial guidance of \$175 million to \$190 million). (Project Adjusted EBITDA is a non-GAAP measure; see Appendix A on page xii for a reconciliation to its nearest GAAP measure.)

Continued to significantly reduce debt. In 2019, we repaid \$72.3 million of term loan and consolidated project debt from operating cash flow. In addition, in April 2019, we used discretionary cash to redeem Cdn\$24.7 million (US\$18.5 million equivalent) of the remaining 6.00% Series D convertible debentures that were scheduled to mature in December 2019. Our total consolidated debt reduction of \$90.8 million represented an approximate 11% reduction in debt from the year-end 2018 level. At year-end 2019, our consolidated leverage ratio⁽³⁾ was 3.8 times, improved from 4.5 times at year-end 2018. Since year-end 2013, we have reduced consolidated debt by \$1.2 billion or approximately 65%.

Reduced interest payments. In 2019, we reduced our cash interest payments by nearly \$4 million from the 2018 level. We achieved this as a result of continued debt repayment and the reductions in

the spread on our credit facilities. Since 2013, consistent with the significant debt reduction during that period, our cash interest payments have been reduced by more than \$90 million. We also continue to manage our exposure to increases in market interest rates. At year-end 2019, more than 99% of our consolidated debt carried either a fixed rate or a variable rate that has been fixed through interest rate swaps. We have hedged approximately 93% of our interest rate exposure on our Term Loan through 2021.

Credit rating upgrade. In December 2019, S&P Global Ratings raised its issuer credit rating for the Corporation to BB- (stable) from B+ (positive) based on our improving leverage profile. Ratings on our Term Loan, Revolving Credit Facility and Medium-Term Notes were raised to BB from BB-. S&P cited our highly contracted cash flow profile and demonstrated track record and commitment to deleveraging. Since October 2015, we have received four rating upgrades, two each from S&P and Moody's.

Maintained strong liquidity. Our liquidity at year-end 2019 was \$196.5 million, including approximately \$42 million of discretionary cash. Even after completing two acquisitions and repurchasing a significant amount of common and preferred shares during 2019, our liquidity increased slightly from the year-end 2018 level.

Maintained stable overhead costs. Our 2019 corporate general and administrative (“G&A”) costs of \$24 million were essentially unchanged from the 2018 level. G&A expense has been about flat since 2016, but is down approximately 56% from the 2013 level. Although the most significant cost reductions are behind us, we continue to look for additional cost reduction opportunities.

Capital Allocation

Acquisitions of contracted assets. As noted, in 2019, we closed the acquisitions of two biomass plants and equity interests in two other biomass plants for a total investment of \$31.3 million. These operating plants have long-dated PPAs that add to our capacity and extend our average remaining contract life and which have been contributing to Project Adjusted EBITDA⁽²⁾ and cash flow. (Project Adjusted EBITDA is a non-GAAP measure; see Appendix A on page xii for a reconciliation to its nearest GAAP measure.) Including the \$13.6 million acquisition of a consolidating interest in our Koma Kulshan hydro project in 2018, we invested \$44.9 million in acquisitions in 2018 and 2019, marking a significant reorientation toward growth initiatives after a multiyear restructuring effort. We funded these acquisitions from discretionary cash.

Repurchases of common and preferred shares. During 2019, we repurchased and canceled nearly 1.1 million common shares at a total cost of \$2.5 million, or an average price of \$2.31 per share. We made these purchases because we considered the trading price of our common shares to be at a discount to our estimates of intrinsic value per share. We also repurchased and canceled approximately 676,000 preferred shares at a total cost of Cdn\$10.6 million (US\$8.0 million equivalent), representing an approximate 38% discount to par value and an attractive after-tax yield of approximately 10% to 12%. We undertake repurchases of our securities when we believe that the returns from such repurchases are more compelling than the returns available from other internal or external investments. We funded these \$10.5 million of repurchases from discretionary cash. From 2015 through 2019, we repurchased a total of approximately 17.0 million common shares, representing an investment of \$38.8 million, and a total of nearly 1.6 million preferred shares, representing a total investment of Cdn\$24.7 million (US\$19.1 million equivalent). Common shares outstanding have been reduced by approximately 11% during this period.

Q1 2020 Developments

Achieved favorable changes to credit facilities. In the first quarter of 2020, we amended our credit facilities to extend the maturity dates of our \$380 million Term Loan and our Revolving Credit Facility to April 2025. The capacity of the Revolving Credit Facility was reduced to \$180 million from \$200 million, although we can seek an increase to a maximum of \$210 million without a further amendment, subject to conditions. In addition, the interest rate margin on these facilities was reduced by 25 basis points to LIBOR plus 250 basis points. Since issuing the credit facilities in 2016, we have re-priced the spread a total of five times, with a cumulative reduction in the margin of 250 basis points. The margin will be reduced another 25 basis points if we achieve a consolidated leverage ratio⁽³⁾ of 2.75 times.

Notes

- (1) Churchill, Winston S. *Step by Step: Political Writings: 1936-1939*. New York: Bloomsbury Academic, 2015.
- (2) 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. Investors are cautioned that the Company may calculate this non-GAAP measure in a manner that is different from other companies. The most directly comparable GAAP measure is Project income (loss). Project Adjusted EBITDA is defined as Project income (loss) plus interest, taxes, depreciation, and amortization (including non-cash impairment charges), and changes in the fair value of derivative instruments. Management uses Project Adjusted EBITDA at the project level to provide comparative information about project performance and believes such information is helpful to investors. A reconciliation of Project Adjusted EBITDA to Project income (loss) and to Net income (loss) on a consolidated basis is provided in Appendix A on page xii. The Company has not provided guidance for Project income or Net income because of the difficulty of making accurate forecasts and projections without unreasonable efforts with respect to certain highly variable components of these comparable GAAP metrics, including changes in the fair value of derivative instruments and foreign exchange gains or losses.
- (3) Leverage ratio is defined as the ratio of Consolidated Debt to Adjusted EBITDA, calculated for the trailing four quarters. Note that we calculate this ratio on a gross debt basis, not net of cash.

Cautionary Note Regarding Forward-Looking Statements

To the extent any statements made in this news release contain information that is not historical, these statements are forward-looking statements within the meaning of Section 27A of the U.S. Securities Act of 1933, as amended, and Section 21E of the U.S. Securities Exchange Act of 1934, as amended, and under Canadian securities law (collectively, “forward-looking statements”).

Certain statements in this news release may constitute forward-looking information or forward-looking statements within the meaning of applicable securities laws (collectively, “forward-looking statements”), which reflect the expectations of management regarding the future growth, results of operations, performance and business prospects and opportunities of the Company and its projects. These statements, which are based on certain assumptions and describe the Company’s future plans, strategies and expectations, can generally be identified by the use of the words “plans”, “expects”, “does not expect”, “is expected”, “budget”, “estimates”, “forecasts”, “intends”, “anticipates” or “does not anticipate”, “believes”, “outlook”, “objective”, or “continue”, or equivalents or variations, including negative variations, of such words and phrases, or state that certain actions, events or results, “may”, “could”, “would”, “should”, “might” or “will” be taken, occur or be achieved. Examples of such statements in this press release include, but are not limited to, statements with respect to the following:

- that the Company’s financial strength means it is well positioned to navigate the COVID-19 crisis;
- the Company’s plan to continue allocating its discretionary capital to debt repayment;
- the Company’s expectation that it will pay off its term loan in full in April 2025;
- the Company’s expectation that there is less need for discretionary investments in existing assets;
- the Company’s expectation that the return on the biomass plants acquired in 2019 will be in excess of 15% unlevered pre-tax;

- the Company’s expectation that it will not pay U.S. federal or Canadian income taxes for some time;
- the Company’s plan to use the proceeds of the Manchief plant sale to pay down debt;
- the Company’s expectation with respect to the impact of PPA expirations on its Project Adjusted EBITDA and operating cash flow after 2022;
- the Company’s expectation with respect to generation of cumulative discretionary cash flow over the next five years;
- the Company’s plan to roll out PRiSM to two more plants in 2020;
- the Company’s plans to demolish the three San Diego plants;
- the Company’s assessment of its credit profile and liquidity;
- the Company’s view that the Koma Kulshan hydro facility has economic life beyond the PPA term;
- the Company’s expectation that the acquisition of the South Carolina biomass plants will extend average remaining contract life and strengthen longer-term cash flows; and
- the Company’s estimate that the repurchase of preferred shares yielded an after-tax return of approximately 10% to 12%.

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. Please refer to the factors discussed under “Risk Factors” and “Forward-Looking Information” in the Company’s periodic reports as filed with the U.S. Securities and Exchange Commission (the “SEC”) from time to time for a detailed discussion of the risks and uncertainties affecting the Company. Although the forward-looking statements contained in this news release 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. These forward-looking statements are made as of the date of this news release and, except as expressly required by applicable law, the Company assumes no obligation to update or revise them to reflect new events or circumstances.

ATLANTIC POWER CORPORATION

**RECONCILIATION OF NET (LOSS) INCOME (A GAAP MEASURE) TO PROJECT ADJUSTED
EBITDA FOR THE YEARS ENDED DECEMBER 31, 2019 AND DECEMBER 31, 2018
(UNAUDITED)**

(in millions of U.S. dollars, except as otherwise stated)

	<u>2019</u>	<u>2018</u>
Net (loss) income attributable to Atlantic Power Corporation	(\$42.6)	\$ 36.8
Net (loss) income attributable to preferred share dividends of a subsidiary company . .	(1.2)	0.4
Net (loss) income	(\$43.8)	\$ 37.2
Income tax expense	9.8	0.2
(Loss) income from operations before income taxes	(34.0)	37.4
Administration	23.9	23.9
Interest expense, net	44.0	52.7
Foreign exchange loss (gain)	11.9	(22.8)
Other expense (income), net	1.0	(3.0)
Project income	\$ 46.8	\$ 88.2
Reconciliation to Project Adjusted EBITDA		
Depreciation and amortization	\$ 80.7	\$ 99.7
Interest expense, net	2.5	3.4
Change in the fair value of derivative instruments	8.9	(2.2)
Impairment	55.0	—
Insurance loss	1.0	—
Other expense (income), net	1.2	(4.0)
Project Adjusted EBITDA	\$196.1	\$185.1

**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, 2019

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:

<u>Title of Each Class</u>	<u>Trading symbol</u>	<u>Name of Each Exchange on which registered</u>
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 is a shell company (as defined in Rule 12b-2 of the Act). Yes No

As of June 30, 2019, the aggregate market value of the voting and nonvoting common equity held by non-affiliates of the registrant was \$256.6 million based upon the last reported sale price on the New York Stock Exchange. For purposes of the foregoing calculation only, all directors and executive officers of the registrant have been deemed affiliates.

As of February 26, 2020, 106,932,375 of the registrant's Common Shares were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2020 Annual Meeting of Shareholders, to be filed not later than 120 days after the end of the registrant's fiscal year, are incorporated by reference into Items 10 through 14 of Part III of this Annual Report on Form 10-K.

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PART I

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

- 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;
- our belief that it is probable that insurance proceeds will cover the estimated plant write-down for the damage to the Cadillac project; 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.

These risks include, without limitation:

- 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, 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 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.

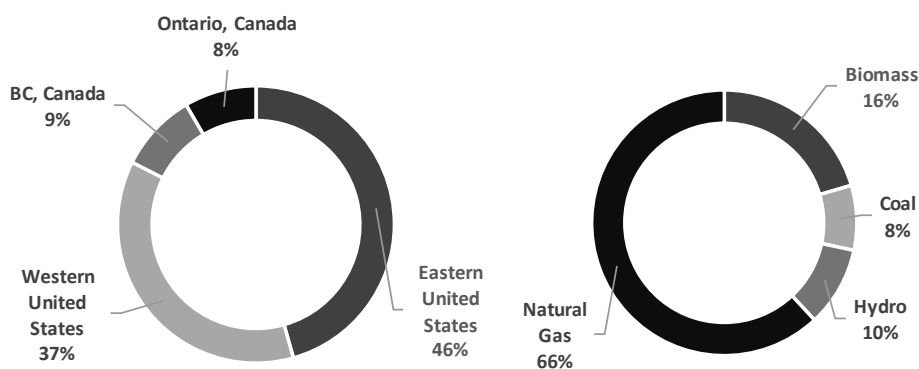
Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include, without limitation, third-party projections of regional fuel and electric capacity and energy prices based on assumptions about future economic conditions 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, 2019, 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 May 2020 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 Pureenergy LLC (“Pureenergy”). Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

BUSINESS STRATEGY

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:

- **Debt reduction:** We have reduced our consolidated debt by more than \$1.2 billion in the past six 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 over the past four-plus years from each of S&P and Moody’s. We expect to continue reducing debt and improving our leverage ratio over the next several years. 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.

- **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 five years we have invested discretionary capital in internal investments in our fleet, external acquisitions and repurchases of debt, common and preferred securities.
 - *Internal investments and share repurchases* - 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 and realized attractive returns, but see less need for such investments at present. 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.
 - *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.
- **Cost management:** As we lack 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 hedging characteristics. Higher gas prices ought to be beneficial for hydro plants but not necessarily for gas plants, for example.
- **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 May 2020 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 \$380 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 40% of total net generation in 2019. 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, 2019. 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, 2019, 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 29%, 30% and 22% of consolidated revenue in 2019, 2018 and 2017, respectively, and total net generation capacity of 376 MW at December 31, 2019. Set forth below is a list of our Solid Fuel projects in operation at December 31, 2019:

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
Cadillac	Michigan	Biomass	40	100.00 %	40	Consumers Energy	June 2028	A-
Calstock	Ontario	Biomass	35	100.00 %	35	Ontario Electricity Financial Corporation	June 2020	A+
Chambers ⁽²⁾	New Jersey	Coal	262	40.00 %	89	Atlantic City Electric ⁽³⁾	March 2024	A-
					16	Chemours Co.	March 2024	BB-
Craven ⁽²⁾	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
Grayling ⁽²⁾	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

- (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) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.
- (3) 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 47%, 49% and 64% of consolidated revenue in 2019, 2018 and 2017, respectively, and total net generation capacity of 822 MW at December 31, 2019. Set forth below is a list of our Natural Gas projects in operation at December 31, 2019:

Project	Location	Fuel	Gross MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P) ⁽¹⁾
Frederickson ⁽²⁾	Washington	Natural Gas	250	50.15 %	50	Benton Co. PUD	August 2022	AA-
					45	Grays Harbor PUD	August 2022	A+
					30	Franklin Co. PUD	August 2022	A+
Kenilworth	New Jersey	Natural Gas	29	100.00 %	29	Merck & Co., Inc.	September 2021	AA
Manchief ⁽³⁾	Colorado	Natural Gas	300	100.00 %	300	Public Service Company of Colorado	April 2022	A-
Morris ⁽⁴⁾	Illinois	Natural Gas	177	100.00 %	100	Merchant	N/A	NR
					77	Equistar Chemicals, LP ⁽⁵⁾	December 2034	BBB+ ⁽⁶⁾
Nipigon	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	December 2022	AA-
Orlando ⁽²⁾	Florida	Natural Gas	129	50.00 %	65	Progress Energy Florida	December 2023	A-
Oxnard	California	Natural Gas	49	100.00 %	49	Southern California Edison	May 2020	BBB
Tunis	Ontario	Natural Gas	37	100.00 %	37	Independent Electricity System Operator	October 2033	AA-

- (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) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.
- (3) 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.
- (4) Equistar has an option to purchase Morris that is exercisable in December 2020 and in December 2027.
- (5) Equistar has the right under the PPA to take up to 77 MW, but on average has taken approximately 50 MW.
- (6) Represents the credit rating of LyondellBasell, the parent company of Equistar Chemicals, as Equistar is not rated.

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.

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 24%, 21% and 14% of consolidated revenue in 2019, 2018 and 2017, respectively, and total net generation capacity for operational projects of 129 MW at December 31, 2019. Set forth below is a list of our Hydroelectric projects in operation or under contract at December 31, 2019:

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 ⁽²⁾	A-
Koma Kulshan	Washington	Hydro	13	100.00 %	13	Puget Sound Energy	March 2037	BBB
Mamquam ⁽³⁾	British Columbia	Hydro	50	100.00 %	50	BC Hydro	September 2027	AAA
Moresby Lake	British Columbia	Hydro	6	100.00 %	6	BC Hydro	August 2022	AAA

- (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) 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, 2019, the facility has generated 8,060 GWh under its PPA. Based on cumulative generation to date, we expect the PPA to expire prior to December 2027.
- (3) 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.

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 prudence 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, 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 the British Columbia Safety Authority, the Ministry of Environment and Climate Change Strategy, and the Integrated Land Management Bureau.

Ontario, Canada

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

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

The OEB's general functions include:

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

- Enforcement and compliance.

The OEB has the authority effectively to modify licenses by adopting “codes” that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the OEB can result in 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, 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, including in 2019, 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 (“OPG”), the Ontario Hydro Services Company (later renamed Hydro One), the Independent Electricity Market Operator (later renamed the IESO), the ESA, and OEFC. The two commercial companies, Ontario Power Generation and Hydro One, were intended to eventually operate as private businesses rather than as crown corporations. 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, 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 whose directors are appointed by the government of Ontario. The IESO’s “Market Rules” form the regulatory framework for the operation of Ontario’s transmission grid and electricity market. The Market Rules require, among other things, that generators meet certain equipment and performance standards and certain system reliability obligations. The IESO may enforce the Market Rules by imposing financial penalties. The IESO may also terminate, suspend or restrict participatory rights, 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.

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

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 CO₂ emissions. CO₂ allowances are now a tradable commodity in the RGGI states. The nine states currently participating in RGGI have varied implementation plans and schedules. RGGI implemented a new, reduced CO₂ cap in 2014, with further reductions of 2.5% each year from 2015 to 2020. On January 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 CO₂ 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 December 2018, the EPA issued a proposed rule to considerably ease the greenhouse gas standards for new power plants. Any such rulemaking activities could take years to complete, and are likely to draw legal challenges. At this time, we cannot predict the outcome of any legal challenges to future administrative 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 (“CO₂e”) 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*, setting out the mechanics to be used to backstop the federal government’s pan-Canadian approach to carbon pricing in provinces that have not implemented, by January 1, 2019, a carbon pricing system that the federal government has determined complies with its carbon pricing requirements. It also included a proposed design of rules to enhance market liquidity. In May 2018, the federal Government published “Carbon pricing: compliance options under the federal output-based pricing system,” a document that describes the proposed rules, and on June 21, 2018 the *Greenhouse Gas Pollution Pricing Act* went into effect. Since that time the federal government has published, on October 31, 2018, SOR/2018-212, 213 and 214 (the “GHGPPA SOR”), to amend Schedule 1 to the *Greenhouse Gas Pollution Pricing Act*, to establish criteria respecting facilities and persons, and to issue the greenhouse gas emissions information production order.

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. Although at the beginning of 2017, Ontario had implemented a compliant cap and trade system, there was a change in the provincial government as a result of the election held in June 2018. The newly elected Ontario government cancelled the cap and trade regulation and prohibited all trading of emission allowances, effective as of July 3, 2018, and on October 31, 2018 formally repealed the cap-and-trade legislation. As a result, our Ontario operations are now subject to the federal backstop regime. Under the federal GHGPPA SOR, large industrial emitters, such as our operations in Tunis and Nipigon, are subject to the federal output-based pricing system (“OBPS”) provided for in Part 2 of the *Greenhouse Gas Pollution Pricing Act*. As of January 1, 2020, the federal backstop regime imposes a minimum Cdn\$30/tonne of CO₂e (“tCO₂e”) 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 2022.

The validity of the federal backstop regime is being challenged on constitutional grounds by Alberta, Ontario and Saskatchewan. Canada’s highest court, the Supreme Court of Canada, is scheduled to hear the provincial challenges in the spring of 2020.

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 optional for facilities covered under the federal GHGRP emitting between 10,000 and 50,000 tonnes of CO₂e, appears to be similar to the federal OBPS. The implications of the federal OBPS the GHGEPs for our operations in Ontario, such as Tunis and Nipigon, is discussed below (in the section on Canada – Ontario).

Canada – British Columbia

The Government of British Columbia has enacted a number of significant pieces of climate action legislation 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. Under the CCAA, by December 31, 2020, the province will be required to additionally specify a reduction target for a year that is earlier than 2030. Also required in connection with CCAA are (from 2020 onward) British Columbia Greenhouse Gas Inventory Reports (reports are prepared in even-numbered years and tables are updated in odd-numbered years), Community Energy and Emissions Inventory Reports (prepared every two years) and Carbon Neutral Action Reports (prepared annually), all of which are designed to provide scientific, comparable and consistent reporting of greenhouse gas sources.

Other related, key pieces of legislation include the *Carbon Tax Act* (“CTA”) and the *Greenhouse Gas Industrial Reporting and Control Act* (“GGIRCA”). CTA operates to put a price on greenhouse gas emissions, providing an incentive for sustainable choices and practices by producers of greenhouse gases. GGIRCA came into force on January 1, 2016 and combined several pieces of British Columbia’s existing greenhouse gas legislation into a single legislative framework. It includes the ability to set a greenhouse gas emissions intensity benchmark for regulated industries and enables the benchmark to be met through flexible options, such as purchasing offsets or paying a set price per tonne of greenhouse gas emissions that would be dedicated to a technology fund. Three regulations necessary to implement GGIRCA also came into force on January 1, 2016: the *Greenhouse Gas Emission Reporting Regulation* (“GGERR”), the *Greenhouse Gas Emission Administrative Penalties and Appeals Regulation* (“GGEAPAR”) and the *Greenhouse Gas Emission Control Regulation* (“GGECCR”). 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. GGECCR establishes the BC Carbon Registry and sets criteria for developing emission offsets issued by the provincial government. GGECCR 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 OBP. Under the federal “Notice Establishing Criteria Respecting Facilities and Persons and Publishing Measures: SOR/2018-213,” any facility which emitted more than 50kt of CO₂e during any of the 2014, 2015, 2016 or 2017 calendar years, and which carries out, as its primary activity, the generation of electricity using fossil fuels, is a covered facility and subject to the OBPS. Since the Nipigon and Tunis projects are each generating electricity using natural gas and each reported emissions in excess of 50kt of CO₂e for one of the 2014, 2015, 2016 or 2017 calendar years (119,248 tonnes for 2014 in the case of Tunis and

115,725 tonnes for 2016 in the case of Nipigon), each is considered a covered facility and subject to the federal OBPS.

Our operations in Ontario may also be subject to Ontario's GHGPE, if required to register. 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 CO₂e. 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 CO₂e. 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 CO₂e emissions in excess of 370 tonnes of CO₂e / GWh of electricity generated by such operations and will receive free emissions allowances if the emissions fall below that measure. Facilities in Ontario subject to the GHGPE will be required to pay a similar excess emissions charge or remit compliance units per tonne of CO₂e emissions. The details of arrangements for the possible recovery of these potential additional costs from the IESO will depend on the terms of the applicable PPA.

Renewable Energy

More than half of the U.S. states and most Canadian provinces have set mandates requiring the achievement of certain levels of renewable energy production and/or energy efficiency during target timeframes. This includes generation from wind, solar and biomass, and/or renewable fuel mandates. For example, in 2011, California enacted a law requiring retail sellers of electricity to deliver 33% of their customers' electricity requirements from renewable resources, as defined in the statute, by 2020. In 2015, California enacted SB 350, which increases the amount of electricity from renewable resources that California retail sellers must deliver after 2020 to 40% of retail sales by December 2024, 45% of retail sales by December 2027, and 50% of retail sales by December 2030. In order to meet CO₂ 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. However, in November 2019, the Trump Administration formally notified the United Nations of the U.S. withdrawal from the Paris Agreement, to be effective in November 2020. 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.

EMPLOYEES

As of February 26, 2020, we had 266 employees, 205 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, 2020 and December 31, 2020. During 2019, 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. Information contained on our website or that can be accessed through our website is not incorporated into and does not constitute a part of this Annual Report on Form 10-K. We have included our website address 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 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 most significant risk factors affecting our Company. However, the risks and uncertainties described below are not the only ones related to our business and are not necessarily listed in the order of their importance. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business, results of operations or financial condition.

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

Risks Related to the Operation of Our Business

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 May 2020 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.”

Two of our projects, representing 6% of our operating net MW and 3% of our 2019 Project Adjusted EBITDA, have PPAs or other contractual arrangements that will expire in 2020. These projects are Oxnard and Calstock. Another seven of our other projects, representing 51% of our operating net MW and 52% of our 2019 Project Adjusted EBITDA, have PPAs or other contractual arrangements that will expire within the next five years. These projects are Kenilworth (2021), 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 2019, the largest customers of our power generation projects, including projects recorded under the equity method of accounting, were Niagara Mohawk Power Corporation, IESO, Equistar Chemicals L. P. and Georgia Power Company, which account for approximately 19.3%, 12.7%, 11.4% and 10.9%, 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 \$200 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.

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 and fines and/or penalties. While we believe that the projects maintain an amount of insurance coverage that is adequate and similar to what would be maintained by a prudent owner/operator of similar facilities, and are subject to deductibles, limits and exclusions which are customary or reasonable given the cost of procuring insurance, current operating conditions and insurance market conditions, there can be no assurance that such insurance will continue to be offered on an economically feasible basis, nor that all events that could give rise to a loss or liability are insurable or insured, nor that the amounts of insurance will at all times be sufficient to cover each and every loss or claim that may occur involving our assets or operations of our projects. Any losses in excess of those covered by insurance, which may include a significant judgment against any project or project operator, the loss of a significant permit or other approval or the imposition of a significant fine or penalty, could have a material adverse effect on our business, results of operations 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.

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

The North American power industry is continuing to undergo consolidation and may present attractive investment opportunities, but we are likely to confront significant competition for those opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments. A payout of a significant portion of our cash flow to service our debt obligations may result in us not retaining a sufficient amount of cash to finance any acquisition or other growth opportunities, to the extent any such acquisition or other opportunities are available to us. As a result, we may have to forego such opportunities, even if they would otherwise be necessary or desirable, if we do not find alternative sources of financing for such opportunities to make cash available to us. In addition, even if we are able to find alternative sources of financing for such opportunities, we may be precluded from pursuing an otherwise attractive acquisition or investment if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund such acquisition or investment. This could limit our flexibility in planning for, or reacting to, changes in our business and industry, placing us at a competitive disadvantage compared to our competitors.

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

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, 2020 and December 31, 2020, 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 prudence of utilities entering into PPAs entered into by QF projects and the siting of the generation facilities. The majority of our generation is sold by QF projects under PPAs that required approval by state authorities.

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

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

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

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

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

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

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

British Columbia

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

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, 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 and delays in the projects' activities, the extent of which cannot be predicted and which could have a material adverse effect on our business, results of operations and financial condition.

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

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

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

Concerning our projects in British Columbia, regulatory restrictions stemming from GGIRCA, CCAA, and financial commitments arising in connection with the requirements under the CTA, could affect our ability to operate our projects in British Columbia and affect 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. 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 actions taken by the Trump Administration to revoke Obama era climate regulations. We cannot estimate the aggregate effect of such requirements on our business, results of operations, financial condition or our customers.

However, such expenditures, if material, could make our generation facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect our business, results of operations and financial condition.

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 the Partnership. Atlantic Power Preferred Equity Ltd., a subsidiary of the Partnership, is also a Canadian corporation and is generally subject to Canadian federal, provincial and other taxes.

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 Securities and Exchange Commission has increased its enforcement of the FCPA during the past several years. In recent years, enforcement of the CFPOA in Canada has also increased and can be attributed, in part, to the establishment of the Royal Canadian Mounted Police's International Anti-Corruption Unit in 2008. Although we have implemented policies and procedures designed to ensure that we, our employees and other intermediaries comply with the FCPA and/or the CFPOA, there is no assurance that such policies or procedures will work effectively all of the time or protect us against liability under the FCPA and/or the CFPOA for actions taken by our employees, 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, 2019, our consolidated debt represented approximately 82% 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 98% 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, 2019, we had (i) no amount outstanding and \$78.3 million issued in letters of credit under our Revolver (as defined herein), (ii) \$88.5 million of outstanding convertible debentures, and (iii) \$560.4 million of outstanding Term Loan, Medium Term Notes and non-recourse project-level debt.

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

In many cases, an uncured default by any party under key project agreements (such as a PPA or a fuel supply agreement) will also constitute a default under the project's term loan or other financing arrangement. Failure to comply with the terms of these term loans or other financing arrangements, or events of default thereunder, may prevent cash distributions by the particular project(s) to us and may entitle the lenders to demand repayment and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition. In addition, failure to comply with the terms, restrictions or obligations of any of our 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 may discourage, delay or prevent a change in control that could benefit our shareholders.

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

- As a notice of meeting is required to include certain particulars in the case where a shareholder meeting is being requisitioned by shareholders, our Board must be given advance notice regarding special business that is to be brought by such requisitioning shareholders before the shareholder meeting. For special business, advance notice describing the special business to be discussed at the meeting must be provided and that notice must include any documents to be approved or ratified as an addendum or state that such document will be available for inspection at our records office or other reasonably accessible location;
- Under the BCBCA, shareholders may make proposals for matters to be considered at the annual general meeting of shareholders, provided that such shareholders represent at least 1% of the voting shares of a company or such shares have a fair market value of at least Cdn\$2,000. Such proposals must be sent to us in advance of any proposed meeting by delivering a timely written notice in proper form to our registered office. The notice must include information on the business the shareholder intends to bring before the

meeting. These provisions could have the effect of delaying until the next shareholder meeting shareholder actions that are favored by the holders of a majority of our outstanding voting securities; and

- Casual vacancies on our Board, 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, 2019, we had \$21.3 million of goodwill, which represented approximately 2% of our total assets on our consolidated balance sheets. Goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if an event or change in circumstance occurs that would more likely than not reduce the fair value of a reporting unit below its carrying value. We could be required to, and have in the past, evaluated the potential impairment of goodwill outside of the required annual evaluation process if we experience situations, including but not limited to, sustained declines in market capitalization, deterioration in general economic conditions or our operating or regulatory environment, increased competitive environment, an increase in fuel costs (particularly when we are unable to pass-through the impact to customers), significant changes in forecasted market prices for power, negative or declining cash flows, loss of a key contract or customer (particularly when we are unable to replace it on equally favorable terms), or our inability to renew certain of our PPAs following their expiration or termination. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. Additionally, goodwill may be impaired if any acquisitions we make do not perform as expected.

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

We have recorded \$55.0 million, nil and \$187.2 million of goodwill, long-lived asset and equity method investment impairments for the years ended December 31, 2019, 2018 and 2017, respectively. See Note 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, 2019.

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

Share Repurchase Program

On December 31, 2019, 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 Atlantic Power Preferred Equity Ltd. ("APPEL"), our wholly-owned subsidiary. The NCIBs expire on December 30, 2020 or such earlier date as the Company and/or APPEL complete their respective purchases pursuant to the new NCIBs. Under the NCIB, we may purchase up to a total of 10,578,799 common shares based on 10% of our public float as of December 17, 2019 and we are limited to daily purchases of 9,243 common shares per day with certain exceptions including block purchases and purchases on other approved exchanges. All purchases made under the NCIBs will be made through the facilities of the TSX or other Canadian designated exchanges and published marketplaces and in accordance with the rules of the TSX at market prices prevailing at the time of purchase. Common share purchases under the NCIBs may also be made on the New York Stock Exchange ("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, 2019, we have not made any repurchases under the new NCIBs.

This new NCIB replaced the prior NCIB that expired on December 30, 2019. Under the prior NCIB, we repurchased and cancelled 1,064,081 million common shares at a cost of \$2.5 million. The following table provides purchases of common equity securities by Atlantic Power Corporation and affiliated purchasers for the period of October 1, 2019 through December 31, 2019:

Purchase Period	Common Shares			Dollar Value of Maximum Number of Shares to be Purchased Under the Plan
	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares as Part of a Publicly Announced Purchase Plan	
10/1/2019 - 10/31/2019	50,829	\$ 2.27	50,829	
11/1/2019 - 11/30/2019	35,044	\$ 2.35	35,044	
12/1/2019 - 12/31/2019	618,444	\$ 2.35	618,444	\$0 ⁽¹⁾
Total	704,317		704,317	

⁽¹⁾ This plan expired on December 30, 2019, and has been replaced by the NCIB as noted above.

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.

Subsequent to December 31, 2019 and through February 26, 2020, we have repurchased and cancelled 1,742,919 common shares at a cost of \$4.1 million under the new NCIB.

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 106,932,375 on February 26, 2020.

Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2019 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	1,276,664	\$ —	—
Equity compensation plans not approved by security holders	179,968	—	89,984
Total	1,456,632	\$ —	89,984

(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(u), Equity compensation plans.

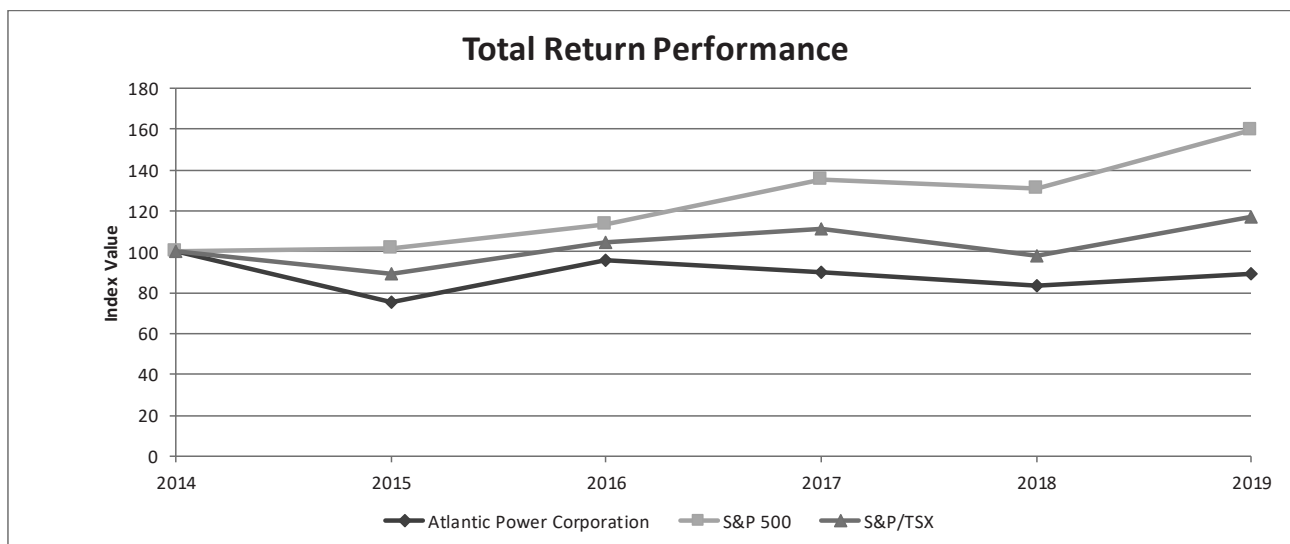
(2) The maximum aggregate number of common shares that may be issued under our Long-Term Incentive Plan upon redemption of notional shares is 6,000,000 and the maximum aggregate number of common shares that may be issued under our Transition Equity Grant Participation Agreement upon redemption of notional shares is 539,903. See Item 15. “Exhibits and Financial Statements Schedule”—Note 2(u), Equity compensation plans.

Performance Graph

The performance graph below compares the cumulative total shareholder return on our common shares for the period December 31, 2014 through December 31, 2019, with the cumulative total return of the Standard & Poor’s 500 Composite Stock Price Index, or S&P 500, and the Standard & Poor’s TSX Composite, or S&P/TSX.

The performance graph shown below is being furnished and compares each period assuming that a \$100 investment was made on December 31, 2014 in each of our common shares, the stocks included in the S&P 500 and the stocks included in the S&P/TSX, and that all dividends were reinvested.

Comparison of Cumulative Total Return



	Dec-2014	Dec-2015	Dec-2016	Dec-2017	Dec-2018	Dec-2019
AT	\$ 100.00	\$ 75.55	\$ 95.87	\$ 90.12	\$ 83.22	\$ 89.35
S&P	100.00	101.38	113.34	135.17	130.79	159.67
S&P / TSX	100.00	88.91	104.48	110.78	97.88	116.61

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected historical consolidated financial information for each of the periods indicated. The annual historical information for each of the years in the three-year period ended December 31, 2019 has been derived from our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

You should read the following selected consolidated financial data along with “Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations” and our consolidated financial statements and the accompanying notes, which describe the impact of material acquisitions and dispositions that occurred in the three-year period ended December 31, 2019.

(in millions of U.S. dollars, except as otherwise stated)	Year Ended December 31,				
	2019 ^(a)	2018 ^(a)	2017 ^(a)	2016 ^(a)	2015 ^{(a)(b)}
Project revenue	\$ 281.6	\$ 282.3	\$ 431.0	\$ 399.2	\$ 420.2
Project income (loss)	46.8	88.2	(47.4)	10.1	(41.4)
(Loss) income from continuing operations	(43.8)	37.2	(93.0)	(113.9)	(84.1)
Income from discontinued operations, net of tax	—	—	—	—	19.5
Net (loss) income attributable to Atlantic Power Corporation	(42.6)	36.8	(98.6)	(122.4)	(62.4)
Basic (loss) earnings per share					
(Loss) earnings per share from continuing operations attributable to Atlantic Power Corporation	\$ (0.39)	\$ 0.33	\$ (0.86)	\$ (1.02)	\$ (0.76)
Earnings per share from discontinued operations, net of tax	—	—	—	—	0.25
Net (loss) income attributable to Atlantic Power Corporation	\$ (0.39)	\$ 0.33	\$ (0.86)	\$ (1.02)	\$ (0.51)
Diluted (loss) earnings per share attributable to Atlantic Power Corporation ^(c)	\$ (0.39)	\$ 0.29	\$ (0.86)	\$ (1.02)	\$ (0.51)
Dividend declared per common share	\$ —	\$ —	\$ —	\$ —	\$ 0.09
Total assets	\$ 935.6	\$ 1,031.5	\$ 1,158.8	\$ 1,456.8	\$ 1,671.2
Total long-term liabilities	\$ 675.0	\$ 723.2	\$ 829.1	\$ 1,020.0	\$ 1,020.0

(a) Includes \$55.0 million, \$0, \$187.2 million, \$85.9 million and \$127.8 million of goodwill, long-lived asset and equity method investment impairments for the years ended December 31, 2019, 2018, 2017, 2016 and 2015, respectively.

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

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

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

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

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

The discussion and analysis below has been organized as follows:

- 1) 2019 Significant Activities and Recent Events
- 2) Performance Highlights and Overview of 2019 Results
- 3) Results of Operations by Segment
- 4) Project Operating Performance
- 5) Supplementary Non-GAAP Financial Information
- 6) Liquidity and Capital Resources
- 7) Critical Accounting Policies

2019 Significant Activities

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.

Debt reduction

During 2019, we made payments of \$72.3 million to reduce our corporate and consolidated project-level debt and repurchased \$18.5 million of convertible debentures prior to their December 2019 maturity. Our consolidated leverage ratio at year end 2019 was 3.8 times, an improvement from 4.5 times at year end 2018. 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%. An additional 0.25% step down in the interest rate margin will become effective should we achieve a Leverage Ratio (as defined in the Credit Agreement) of 2.75:1.00. 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.

Capital allocation

During 2019, we allocated capital to both external acquisitions and equity repurchases. We used \$28.5 million of our discretionary cash to close the acquisition of the Allendale and Dorchester biomass plants in South Carolina and equity investments in the Craven (North Carolina) and Grayling (Michigan) biomass plants. Including the \$2.6 million deposit on the South Carolina plants made in 2018 and transaction costs, the total investment in these four plants was \$31.3 million. We believe these acquisitions represent a meaningful addition to the level and length of our existing contracted cash flows. Together with the 2018 acquisition of the remaining ownership interests in our Koma Kulshan hydro project for \$13.6 million, as discussed in Note 3, *Acquisitions and divestments* to the consolidated financial statements, these were the first external investments that we have made during current management's tenure since 2015.

We also used \$10.5 million of our discretionary capital to repurchase and cancel common (\$2.5 million) and preferred (US\$8.0 million equivalent) shares at prices that we believe were attractive relative to our estimates of value during 2019. From 2015 through 2019, we repurchased a total of approximately 17.0 million common shares, representing an investment of \$38.8 million, and a total of nearly 1.6 million preferred shares, representing a total investment of Cdn\$24.7 million (US\$19.1 million equivalent). Common shares outstanding have been reduced approximately 11% during this period. The return on preferred share repurchases has averaged approximately 10% to 11%, including avoided tax-related obligations.

PPA renewals

In January 2019, Merck & Co., Inc. (“Merck”), the customer at our Kenilworth project, exercised its second extension option under the PPA, extending the expiration date from September 30, 2019 to September 30, 2020. In July 2019, Merck exercised the third and final one-year option under the PPA, extending its expiration date from September 30, 2020 to September 30, 2021.

In September 2019, we executed a new ten-year Energy Purchase Agreement with BC Hydro for our Williams Lake biomass plant in British Columbia, Canada that became effective October 1, 2019. Under the new contract, Williams Lake receives a fixed price per megawatt-hour for energy produced, up to the maximum level of generation permitted under the agreement. This price escalates annually with the British Columbia Consumer Price Index. The contract does not provide for a capacity payment and the energy payment structure does not include a fuel cost pass-through. Given the state of the timber market in British Columbia, the availability and cost of fuel will be the most significant variables determining the operational and financial performance of Williams Lake under the new contract.

Cost management

We cut our corporate overhead expense from approximately \$54 million in 2013 to \$24 million for 2019, which represents a cumulative reduction from 2013 of approximately 57%. We have maintained our corporate overhead in the \$24 million range for the past four years.

Recent Events

Cadillac Repair Update

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 local fire department and did not result in any injuries or known environmental violations. Although the plant incurred significant damage and is expected to be out of service for a lengthy period, we expect that the financial impact will be limited by our comprehensive insurance coverage.

During the third quarter, we recorded a \$25 million write-down of Cadillac’s property, plant and equipment and a \$0.3 million write-down of capital spares inventory. We also recorded a corresponding insurance receivable (\$24.2 million) as a component of other assets less the \$1.0 million property damage deductible, which was recorded as an insurance loss charged to other project income because we believe that it is probable we will receive insurance recoveries up to the replacement cost of the plant, less the deductible.

During the fourth quarter, we received \$11.3 million of insurance proceeds with respect to the fire at Cadillac, which were applied against the insurance receivable. During the three months ended December 31, 2019, we recorded a \$0.6 million write-down of fuel inventory, with a corresponding increase to the insurance receivable. As of December 31, 2019, the insurance receivable balance totaled \$13.5 million. Additionally, we estimate anticipated insurance recoveries related to business interruption losses of \$2.0 million for the three months ended December 31, 2019. 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. Anticipated reimbursements for business interruption losses were not recorded as of December 31, 2019 as all contingencies related to these claims had not been resolved as of

period end. We expect all contingencies related to business interruption losses to be resolved once final payment is received from the insurers, which is when we will recognize the reimbursements in earnings (loss). Capital spending through December 31, 2019 for repairs at Cadillac was \$5.1 million.

Chambers Impairment

We own a 40% limited partner interest in Chambers Cogeneration Limited Partnership. Chambers operates under a PPA that expires in March 2024. 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 projected 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 pre-impairment 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 project to be profitable in a merchant market. While declining power prices have been observed over the past several years, 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. Subsequent to recording the impairment, our remaining equity investment in Chambers is \$9.0 million.

Performance Highlights and Overview of 2019 Results

(in millions of U.S. dollars, except as otherwise stated)	Year Ended December 31,		
	2019	2018	2017
Project revenue	\$ 281.6	\$ 282.3	\$ 431.0
Project income (loss)	\$ 46.8	\$ 88.2	\$ (47.4)
Net (loss) income attributable to Atlantic Power Corporation	\$ (42.6)	\$ 36.8	\$ (98.6)
Net cash provided by operating activities	144.7	137.5	169.2
Net cash used in investing activities	(21.7)	(17.0)	(4.3)
Net cash used in financing activities	(110.8)	(135.0)	(178.9)
(Loss) earnings per share attributable to Atlantic Power Corporation—basic	\$ (0.39)	\$ 0.33	\$ (0.86)
(Loss) earnings per share attributable to Atlantic Power Corporation—diluted	(0.39)	0.29	(0.86)
Project Adjusted EBITDA ⁽¹⁾	\$ 196.1	\$ 185.1	\$ 288.8

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

Revenue decreased from \$282.3 million in the year ended December 31, 2018 to \$281.6 million in the year ended December 31, 2019, a decrease of \$0.7 million. The primary drivers of the decrease are as follows:

- *Williams Lake* – the extension of the energy purchase agreement at Williams Lake that became effective in April 2018 and expired in September 2019 provided lower pass-through of costs than the previous contract. The project entered into a new energy services agreement that became effective in October 2019, but the plant did not operate until late December, resulting in lower dispatch than in 2018. These factors resulted in a \$9.5 million decrease in project revenue;
- *San Diego projects* – the Naval Station, North Island and NTC projects ceased operations in February 2018. This resulted in a \$7.4 million decrease in project revenue;

- *Cadillac* – the project ceased operation after the fire in September 2019, resulting in \$5.6 million decrease in energy and capacity revenue; and
- *Morris* – there was a \$3.3 million decrease in project revenue at our Morris project due to lower fuel index prices than in 2018.

These decreases in project revenue were partially offset by:

- *Curtis Palmer* – higher water flows resulted in a \$12.0 million increase in revenue from 2018;
- *Allendale and Dorchester* – the Allendale and Dorchester projects were purchased on July 31, 2019 and contributed \$10.8 million of revenue in 2019; and
- *Tunis* – the project commenced its restart in October 2018 and contributed \$1.0 million of revenue in 2018 as compared to \$4.4 million of revenue in 2019, for an increase in project revenue of \$3.4 million.

Consolidated project income was \$46.8 million for the year ended December 31, 2019, a decrease of \$41.4 million from the prior year project income of \$88.2 million. The primary drivers of the decrease are as follows:

- *Impairment of equity investment and long-lived assets* – we recorded a \$49.2 million equity investment impairment at Chambers and a \$5.8 million long-lived asset impairment at Calstock in 2019;
- *Derivative instruments* – the change in fair value of our derivative instruments decreased \$11.1 million from 2018; and
- *Remeasurement gain* – we recorded a \$6.7 million gain in 2018 related to the remeasurement of our previous 50% equity ownership of Koma to fair value resulting from the acquisition of the remaining 50% in July of 2018.

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

- *Depreciation and amortization expense* – depreciation and amortization expense decreased by \$19.2 million from 2018 primarily due to a decrease of \$17.9 million at our Nipigon project resulting from the PPA intangible asset being fully amortized in 2018 and a \$2.6 million decrease at the San Diego projects, which ceased operations in February 2018; and
- *Operations and maintenance expenses* – operation and maintenance expenses decreased by \$8.0 million from 2018 primarily due to a decrease of \$7.1 million in maintenance expense at our Manchief project where a turbine overhaul was performed in 2018, a \$5.2 million decrease in operations and maintenance expenses at the San Diego projects, which ceased operations in February 2018, and a \$3.7 million decrease in maintenance expense at our Tunis project where costs were incurred in 2018 in preparation for the commencement of its commercial operation. These decreases were partially offset by \$4.8 million of increased operation and maintenance expenses at the Allendale and Dorchester projects, which were purchased on July 31, 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 59.

Factors and trends that may influence our results

The primary components of our financial results are (i) the financial performance of our projects, (ii) unrealized gains and losses associated with derivative instruments, (iii) interest expense and foreign exchange impacts on corporate-level debt, and (iv) impairment of goodwill, long-lived assets and equity method investments. We have

recorded net losses in four of the past five years, primarily as a result of non-cash losses associated with items (ii), (iii) and (iv) above, which are described in more detail in the following paragraphs.

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 May 2020 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 “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 and financial condition.”
- Our PPAs are generally structured to minimize our risk to fluctuations in commodity prices by passing the cost of fuel through to the utility and its customers, but some of our projects do have exposure to market power and fuel prices. See Item 1A. “Risk Factors—Risks Related to 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” and Item 7A. “Quantitative and Qualitative Disclosures About Market Risk” for additional details about our hedging arrangements.
- Our most significant exposure to market power prices exists at the Chambers and Morris projects. At Chambers, plant capacity is sold forward pursuant to the 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 and financial condition.

- 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"¹ 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. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our derivative instruments.

Interest expense and other costs associated with debt

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

Impairment

We test our 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 \$55.0 million, nil and \$187.1 million of impairments for the years ended December 31, 2019, 2018 and 2017, 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. 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. Our financial results for the year ended December 31, 2018 and 2017 have been revised to reflect these changes. All results of operations for the Solid Fuel, Natural Gas and Hydroelectric segments are recorded as a component of project income (loss). The segment classified as Corporate (formerly Un-Allocated Corporate) includes management fee revenue, operating expenses directly related to supporting our projects and mark-to-market adjustments of fuel and interest rate swaps. These items are recorded as a component of project income (loss). The Corporate segment also 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 other operating segments when determining project income (loss). Project income (loss) is the primary GAAP measure of our operating results and is discussed below by reportable segment followed by a discussion of Corporate items not included in project income (loss).

2019 compared to 2018

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

	Years Ended December 31,			
	2019	2018	\$ change	% change
Project revenue:				
Energy sales	\$ 138.0	\$ 130.9	\$ 7.1	5.4 %
Energy capacity revenue	125.4	97.9	27.5	28.1 %
Other	18.2	53.5	(35.3)	(66.0)%
	<u>281.6</u>	<u>282.3</u>	<u>(0.7)</u>	<u>(0.2)%</u>
Project expenses:				
Fuel	72.3	73.1	(0.8)	(1.1)%
Operations and maintenance	77.0	85.0	(8.0)	(9.4)%
Depreciation and amortization	64.5	83.7	(19.2)	(22.9)%
	<u>213.8</u>	<u>241.8</u>	<u>(28.0)</u>	<u>(11.6)%</u>
Project other income (expense):				
Change in fair value of derivative instruments	(8.9)	2.2	(11.1)	NM
Equity in (loss) earnings of unconsolidated affiliates	(3.0)	43.2	(46.2)	NM
Interest expense, net	(1.1)	(1.8)	0.7	(38.9)%
Impairment	(5.8)	—	(5.8)	NM
Insurance loss	(1.0)	—	(1.0)	NM
Other (expense) income, net	(1.2)	4.1	(5.3)	NM
	<u>(21.0)</u>	<u>47.7</u>	<u>(68.7)</u>	<u>NM</u>
Project income	<u>46.8</u>	<u>88.2</u>	<u>(41.4)</u>	<u>(46.9)%</u>
Administrative and other expenses:				
Administration	23.9	23.9	—	— %
Interest expense, net	44.0	52.7	(8.7)	(16.5)%
Foreign exchange loss (gain)	11.9	(22.8)	34.7	NM
Other expense (income), net	1.0	(3.0)	4.0	NM
	<u>80.8</u>	<u>50.8</u>	<u>30.0</u>	<u>59.1 %</u>
(Loss) income from operations before income taxes	(34.0)	37.4	(71.4)	NM
Income tax expense	9.8	0.2	9.6	NM
Net (loss) income	(43.8)	37.2	(81.0)	NM
Net (loss) income attributable to preferred shares of a subsidiary company	(1.2)	0.4	(1.6)	NM
Net (loss) income attributable to Atlantic Power Corporation	<u>\$ (42.6)</u>	<u>\$ 36.8</u>	<u>\$ (79.4)</u>	<u>NM</u>

Project (Loss) Income by Segment

	Year Ended December 31, 2019				Consolidated Total
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	
Project revenue:					
Energy sales	\$ 41.1	\$ 31.0	\$ 65.9	\$ —	\$ 138.0
Energy capacity revenue	38.7	86.7	—	—	125.4
Other	0.2	14.1	2.9	1.0	18.2
	<u>80.0</u>	<u>131.8</u>	<u>68.8</u>	<u>1.0</u>	<u>281.6</u>
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
	<u>76.8</u>	<u>102.8</u>	<u>32.8</u>	<u>1.4</u>	<u>213.8</u>
Project other income (expense):					
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)
	<u>(53.0)</u>	<u>39.5</u>	<u>—</u>	<u>(7.5)</u>	<u>(21.0)</u>
Project (loss) income	<u>\$ (49.8)</u>	<u>\$ 68.5</u>	<u>\$ 36.0</u>	<u>\$ (7.9)</u>	<u>\$ 46.8</u>

	Year Ended December 31, 2018				Consolidated Total
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	
Project revenue:					
Energy sales	\$ 37.4	\$ 38.3	\$ 55.2	\$ —	\$ 130.9
Energy capacity revenue	41.6	56.3	—	—	97.9
Other	4.8	44.6	3.1	1.0	53.5
	<u>83.8</u>	<u>139.2</u>	<u>58.3</u>	<u>1.0</u>	<u>282.3</u>
Project expenses:					
Fuel	24.1	49.0	—	—	73.1
Operations and maintenance	28.9	44.0	11.6	0.5	85.0
Depreciation and amortization	15.0	49.9	18.7	0.1	83.7
	<u>68.0</u>	<u>142.9</u>	<u>30.3</u>	<u>0.6</u>	<u>241.8</u>
Project other income (expense):					
Change in fair value of derivative instruments	—	3.2	—	(1.0)	2.2
Equity in earnings of unconsolidated affiliates	5.6	37.0	0.6	—	43.2
Interest expense, net	(1.7)	(0.1)	—	—	(1.8)
Other (expense) income, net	—	(3.1)	7.2	—	4.1
	<u>3.9</u>	<u>37.0</u>	<u>7.8</u>	<u>(1.0)</u>	<u>47.7</u>
Project income (loss)	<u>\$ 19.7</u>	<u>\$ 33.3</u>	<u>\$ 35.8</u>	<u>\$ (0.6)</u>	<u>\$ 88.2</u>

Discussion of project income (loss) by reportable segment:

Solid Fuel

Project income for 2019 decreased \$69.5 million from 2018 primarily due to:

- decreased project income of \$51.6 million at Chambers primarily due to a \$49.2 million impairment recorded in 2019;

- decreased project income of \$8.9 million at Williams Lake primarily due to the extension of the energy purchase agreement that became effective in April 2018 and expired in September 2019, which provided lower pass-through of costs than the previous contract. The project entered into a new energy purchase agreement that became effective in October 2019, but the plant did not operate until late December, resulting in lower dispatch than 2018;
- decreased project income of \$6.0 million at Calstock primarily due to a \$5.8 million long-lived asset impairment recorded in 2019; and
- decreased project income of \$4.3 million at Cadillac primarily due to the fire in September 2019, resulting in \$1.4 million of operating losses related to the 45-day business interruption insurance deductible and a \$1.0 million insurance loss for the property and casualty loss deductible.

Natural Gas

Project income for 2019 increased \$35.2 million from 2018 primarily due to:

- increased project income of \$16.9 million at Nipigon primarily due to a \$17.8 million decrease in amortization expense from accelerated amortization of the intangible PPA asset in 2018;
- increased project income of \$7.4 million at Manchief primarily due to a \$7.1 million decrease in maintenance expense from a turbine overhaul in 2018;
- increased project income of \$6.4 million at Tunis, primarily due to a \$3.7 million decrease in maintenance expense incurred in preparation for commencing operations in October 2018 and a \$3.4 million increase in project revenue;
- increased project income of \$6.3 million at our San Diego projects, which ceased operations in February 2018 and recorded higher asset retirement obligations in 2018; and
- increased project income of \$2.1 million at Frederickson primarily due to higher dispatch than 2018.

These increases were partially offset by:

- decreased project income of \$2.4 million at Orlando primarily due to a \$4.1 million decrease in the fair value of natural gas swaps, partially offset by a capacity rate escalation under the PPA; and
- decreased project income of \$1.9 million at Oxnard due to an increase in fuel pricing in 2019.

Hydroelectric

Project income for 2019 increased \$0.2 million from 2018 primarily due to:

- increased project income of \$11.5 million at Curtis Palmer primarily due to higher water flows than 2018.

This increase was partially offset by:

- decreased project income of \$7.9 million at Koma primarily due to a \$6.7 million gain in 2018 related to the remeasurement of our previous 50% equity ownership of Koma to fair value resulting from the acquisition of the remaining 50% in July of 2018; and
- decreased project income of \$2.2 million at Mamquam primarily due to lower water flows than 2018.

Corporate

Total project loss increased \$7.3 million from 2018 primarily due to a \$6.5 million decrease in fair value of interest rate swap agreements and settlements of forward gas contracts.

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 did not change materially from 2018.

Interest, net

Interest expense decreased \$8.7 million from \$52.7 million in 2018 to \$44.0 million in 2019 primarily due to lower outstanding debt balances than 2018, as well as a lower interest rate on our Term Loan.

Foreign exchange loss (gain)

Foreign exchange gain decreased by \$34.7 million from a \$22.8 million gain in 2018 to an \$11.9 million loss in 2019 due to the revaluation of instruments denominated in Canadian dollars (primarily our Medium Term Notes (“MTNs”) and convertible debentures). The Canadian dollar appreciated 4.8% against the U.S. dollar from December 31, 2018 to December 31, 2019, as compared to an 8.7% decrease in 2018.

Other expense (income), net

Other income, net decreased \$4.0 million in 2018 to other expense, net of \$1.0 million in 2019 primarily due to a \$5.0 million change in the fair value of the conversion option of the Series E Debentures.

Income tax expense

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 the Company’s 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.

2018 compared to 2017

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

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

Project Income (Loss) by Segment

	Year Ended December 31, 2018				Consolidated
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Total
Project revenue:					
Energy sales	\$ 37.4	\$ 38.3	\$ 55.2	\$ —	\$ 130.9
Energy capacity revenue	41.6	56.3	—	—	97.9
Other	4.8	44.6	3.1	1.0	53.5
	<u>83.8</u>	<u>139.2</u>	<u>58.3</u>	<u>1.0</u>	<u>282.3</u>
Project expenses:					
Fuel	24.1	49.0	—	—	73.1
Operations and maintenance	28.9	44.0	11.6	0.5	85.0
Depreciation and amortization	15.0	49.9	18.7	0.1	83.7
	<u>68.0</u>	<u>142.9</u>	<u>30.3</u>	<u>0.6</u>	<u>241.8</u>
Project other income (expense):					
Change in fair value of derivative instruments	—	3.2	—	(1.0)	2.2
Equity in earnings of unconsolidated affiliates	5.6	37.0	0.6	—	43.2
Interest expense, net	(1.7)	(0.1)	—	—	(1.8)
Other (expense) income, net	—	(3.1)	7.2	—	4.1
	<u>3.9</u>	<u>37.0</u>	<u>7.8</u>	<u>(1.0)</u>	<u>47.7</u>
Project income (loss)	<u>\$ 19.7</u>	<u>\$ 33.3</u>	<u>\$ 35.8</u>	<u>\$ (0.6)</u>	<u>\$ 88.2</u>

	Year Ended December 31, 2017				Consolidated
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Total
Project revenue:					
Energy sales	\$ 36.2	\$ 56.7	\$ 56.0	\$ —	\$ 148.9
Energy capacity revenue	41.6	64.2	—	—	105.8
Other	15.9	155.9	3.5	1.0	176.3
	<u>93.7</u>	<u>276.8</u>	<u>59.5</u>	<u>1.0</u>	<u>431.0</u>
Project expenses:					
Fuel	24.6	81.7	—	—	106.3
Operations and maintenance	29.2	45.6	13.3	(0.3)	87.8
Depreciation and amortization	21.6	73.7	17.4	0.4	113.1
	<u>75.4</u>	<u>201.0</u>	<u>30.7</u>	<u>0.1</u>	<u>307.2</u>
Project other income (expense):					
Change in fair value of derivative instruments	8.1	(7.9)	—	1.9	2.1
Equity in (loss) earnings of unconsolidated affiliates	(42.6)	(12.9)	0.7	—	(54.8)
Interest expense, net	(17.4)	(0.1)	—	—	(17.5)
Impairment	(29.1)	(57.3)	(14.7)	—	(101.1)
Other income, net	0.1	—	—	—	0.1
	<u>(80.9)</u>	<u>(78.2)</u>	<u>(14.0)</u>	<u>1.9</u>	<u>(171.2)</u>
Project (loss) income	<u>\$ (62.6)</u>	<u>\$ (2.4)</u>	<u>\$ 14.8</u>	<u>\$ 2.8</u>	<u>\$ (47.4)</u>

Discussion of project income (loss) by reportable segment:

Solid Fuel

Project income for 2018 increased \$82.3 million from 2017 primarily due to:

- increased project income of \$48.2 million at Chambers which recorded a \$47.1 million impairment in the year ended December 31, 2017;

- increased project income of \$27.4 million at Williams Lake primarily due to a \$29.1 million long-lived asset impairment recorded in 2017 and a \$6.7 million decrease in depreciation expense resulting from the long-lived asset impairment in 2017, partially offset by a \$10.7 million decrease in project revenue due to the terms of the energy purchase agreement extension that became effective in April 2018; and
- increased project income of \$7.9 million at Piedmont primarily due to \$7.1 million of lower interest expense and interest rate swap mark-to-market fair value adjustments resulting from the repayment of the project-level debt, in full, in 2017.

Natural Gas

Project income for 2018 increased \$35.7 million from 2017 primarily due to:

- decreased project loss of \$34.8 million at Frederickson which recorded a \$28.3 million impairment in 2017;
- decreased project loss of \$16.5 million, \$13.9 million and \$7.5 million at Naval Station, North Island and NTC primarily due to \$22.5 million, \$21.2 million and \$13.5 million of long-lived asset impairments recorded in 2017, respectively. These projects ceased operations in February 2018;
- increased project income of \$10.6 million at Selkirk primarily due to a \$10.6 million impairment recorded for the year ended December 31, 2017;
- increased project income of \$5.3 million at Orlando primarily due to higher generation and a higher capacity rate than 2017; and
- increased project income of \$5.7 million at Morris primarily due to higher energy and capacity revenues than 2017.

These increases were partially offset by:

- decreased project income of \$21.0 million at North Bay primarily due to \$37.2 million of revenue recorded related to the OEFC settlement and the expiration of the enhanced dispatch contract in 2017, partially offset by a \$13.5 million decrease in depreciation expense;
- decreased project income of \$20.4 million at Kapuskasing primarily due to \$39.0 million of revenue recorded related to the OEFC settlement and the expiration of the enhanced dispatch contract in 2017, partially offset by a \$16.3 million decrease in depreciation expense;
- decreased project income of \$9.4 million at Tunis primarily due to \$6.8 million of revenue recorded related to the OEFC settlement in 2017 and a \$3.3 million increase in maintenance expense in preparation of commencing operations in October 2018; and
- decreased project income of \$5.5 million at Manchief primarily due to a \$7.4 million increase in maintenance expense from a turbine overhaul completed in 2018.

Hydroelectric

Project income for 2018 increased \$21.0 million from 2017 primarily due to:

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

- increased project income of \$6.6 million at Koma Kulshan primarily due to a \$6.7 million gain in 2018 related to the remeasurement of our previous 50% equity ownership of Koma to fair value resulting from the acquisition of the remaining 50% in July of 2018.

Corporate

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

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 did not change materially from 2017.

Interest, net

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

Foreign exchange (gain) loss

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

Other income, net

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

Income tax expense

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

tax rates and \$1.1 million related to capital loss on intercompany notes.

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

(in Net GWh)	Year ended December 31,				
	2019	2018	2017	% change 2019 vs. 2018	% change 2018 vs. 2017
Segment					
Solid Fuel	1,439.2	1,517.6	1,527.1	(5.2)%	(0.6)%
Natural Gas	2,475.3	2,206.3	2,843.9	12.2 %	(22.4)%
Hydroelectric	673.2	637.7	643.7	5.6 %	(0.9)%
Total	4,587.7	4,361.6	5,014.7	5.2 %	(13.0)%

Year ended December 31, 2019 compared with Year ended December 31, 2018

Aggregate power generation for 2019 increased 5.2% from 2018 primarily due to:

- increased generation in the Natural Gas segment primarily due to a 317.9 net GWh increase in generation at Frederickson due to higher dispatch than 2018 and a 32.5 GWh increase in generation at Manchief due to higher dispatch than 2018, partially offset by a combined 95.5 net GWh decrease in generation at Naval Station, Naval Training Center and North Island, which ceased operations in February 2018; and
- increased generation in the Hydroelectric segment primarily due to an 88.4 net GWh increase in generation at Curtis Palmer due to higher water flows than 2018, partially offset by a 47.2 net GWh decrease in generation at Mamquam due to lower water flows than 2018.

These increases were partially offset by:

- decreased generation in the Solid Fuel segment primarily due to a 204.5 net GWh decrease in generation at Williams Lake due to lower wood fuel inventory and a 69.6 net GWh decrease at Cadillac due to the fire in September 2019, partially offset by a combined 223.1 net GWh increase in generation at Allendale, Dorchester, Craven and Grayling, which were acquired in 2019.

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

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

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

Availability

Segment	Year ended December 31,				
	2019	2018	2017	% change 2019 vs. 2018	% change 2018 vs. 2017
Solid Fuel	92.5 %	94.6 %	87.3 %	(2.2)%	8.4 %
Natural Gas	95.8 %	96.4 %	90.2 %	(0.6)%	6.9 %
Hydroelectric	92.6 %	97.3 %	93.7 %	(4.8)%	3.8 %
Weighted average	94.0 %	96.5 %	90.3 %	(2.6)%	6.9 %

Year ended December 31, 2019 compared with Year ended December 31, 2018

Weighted average availability for 2019 decreased to 94.0% from 96.5% in 2018 primarily due to:

- decreased availability in the Hydroelectric segment primarily due to a forced outage at Moresby Lake in 2019; and
- decreased availability in the Solid Fuel segment primarily due to the fire at Cadillac in September 2019.

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

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

- increased availability in the Solid Fuel segment primarily due to a shorter maintenance outage at Piedmont in 2018 than in 2017;
- increased availability in the Natural Gas segment primarily due to maintenance outages at Frederickson, Kenilworth and Orlando in 2017, partially offset by decreased availability at Manchief due to a maintenance outage in the 2018 period; and
- increased availability in the Hydroelectric segment primarily due to a maintenance outage at Mamquam in 2017.

Supplementary Non-GAAP Financial Information

Project Adjusted EBITDA

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

	Year ended December 31,			\$ change	
	2019	2018	2017	2019	2018
Net (loss) income	\$ (43.8)	\$ 37.2	\$ (93.0)	\$ (81.0)	\$ 130.2
Income tax expense (benefit)	9.8	0.2	(58.1)	9.6	58.3
(Loss) income from operations before income taxes	(34.0)	37.4	(151.1)	(71.4)	188.5
Administration	23.9	23.9	23.6	—	0.3
Interest expense, net	44.0	52.7	64.2	(8.7)	(11.5)
Foreign exchange loss (gain)	11.9	(22.8)	16.3	34.7	(39.1)
Other expense (income), net	1.0	(3.0)	(0.4)	4.0	(2.6)
Project income (loss)	\$ 46.8	\$ 88.2	\$ (47.4)	\$ (41.4)	\$ 135.6
Reconciliation to Project Adjusted EBITDA					
Depreciation and amortization	80.7	99.7	133.2	(19.0)	(33.5)
Interest expense, net	2.5	3.4	19.2	(0.9)	(15.8)
Change in the fair value of derivative instruments	8.9	(2.2)	(2.1)	11.1	(0.1)
Impairment	55.0	—	187.1	55.0	(187.1)
Insurance loss	1.0	—	—	1.0	—
Other expense (income), net	1.2	(4.0)	(1.2)	5.2	(2.8)
Project Adjusted EBITDA	\$ 196.1	\$ 185.1	\$ 288.8	\$ 10.0	\$ (103.7)
Project Adjusted EBITDA by segment					
Solid Fuel	32.7	46.7	54.9	(14.0)	(8.2)
Natural Gas	108.2	90.4	185.3	17.8	(94.9)
Hydroelectric	55.5	47.5	47.2	8.0	0.3
Corporate	(0.3)	0.5	1.4	(0.8)	(0.9)
Total	\$ 196.1	\$ 185.1	\$ 288.8	\$ 11.0	\$ (103.7)

Solid Fuel

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

	Year ended December 31,				
	2019	2018	2017	% change 2019 vs. 2018	% change 2018 vs. 2017
Solid Fuel					
Project Adjusted EBITDA	\$ 32.7	\$ 46.7	\$ 54.9	(30)%	(15)%

Year ended December 31, 2019 compared with Year ended December 31, 2018

Project Adjusted EBITDA for 2019 decreased \$14.0 million or 30% from 2018 primarily due to decreases in Project Adjusted EBITDA of:

- \$9.0 million at Williams Lake primarily due to the extension of the energy purchase agreement that became effective in April 2018 and expired in September 2019, which provided lower pass-through of costs than the previous contract. The project also had lower generation than in 2018;
- \$4.0 million at Cadillac which has been non-operational since the fire in September 2019; and
- \$2.4 million at Chambers due to lower energy and steam demand, as well as lower prices on excess energy than in 2018.

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

- \$0.9 million at Grayling, which was acquired in August 2019; and
- \$0.9 million at Allendale, which was acquired in July 2019.

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

Project Adjusted EBITDA for 2018 decreased \$8.2 million or 15% from 2017 primarily due to decreases in Project Adjusted EBITDA of:

- \$8.4 million at Williams Lake due to lower gross margin under the extension of the energy purchase agreement that became effective in April 2018, partially offset by cost reductions.

Natural Gas

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

	Year ended December 31,				
	2019	2018	2017	% change 2019 vs 2018	% change 2018 vs 2017
Natural Gas					
Project Adjusted EBITDA	\$ 108.2	\$ 90.4	\$ 185.3	20 %	(51)%

Year ended December 31, 2019 compared with Year ended December 31, 2018

Project Adjusted EBITDA for 2019 increased by \$17.8 million or 20% from 2018 primarily due to increases in Project Adjusted EBITDA of:

- \$7.4 million at Manchief primarily due to a \$7.1 million decrease in maintenance expense from a turbine overhaul in 2018;
- \$7.1 million at Tunis, primarily due to a \$3.7 million decrease in maintenance expense incurred in preparation for commencing operations in October 2018 and a \$3.4 million increase in project revenue;
- \$2.1 million at Frederickson primarily due to higher dispatch than 2018;
- \$1.9 million at San Diego projects (which ceased operations in February 2018) due to losses incurred in the comparable 2018 period; and

- \$1.7 million at Orlando primarily due to a capacity rate escalation under the PPA.

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

- \$2.1 million at Oxnard due to an increase in fuel pricing and higher operating costs in 2019; and
- \$1.1 million at Morris mostly due to higher maintenance expenses in 2019.

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

Project Adjusted EBITDA for 2018 decreased by \$94.9 million or 51% from 2017 primarily due to decreases in Project Adjusted EBITDA of:

- \$36.7 million and \$34.5 million at Kapuskasing and North Bay, respectively, due to the expiration of the enhanced dispatch agreements in December 2017 and the OEFC settlement received in 2017;
- \$9.3 million, \$9.0 million and \$5.7 million at Naval Station, North Island and NTC, respectively, which ceased operations in February 2018;
- \$9.0 million at Tunis due to \$6.8 million of revenue recorded related to the OEFC settlement in 2017 and \$3.0 million of higher maintenance expense incurred during 2018; and
- \$5.5 million at Manchief due to a \$7.4 million increase in maintenance expense from a turbine overhaul, offset by a \$1.8 million increase in project revenue due to higher dispatch.

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

- \$7.4 million at Morris due to a higher capacity price, higher steam sales and ancillary revenue than 2017;
- \$3.0 million at Frederickson due to lower planned maintenance expense than 2017;
- \$2.8 million at Orlando due to higher availability and contractual capacity rates than 2017; and
- \$2.3 million at Nipigon due to a contractual rate increase and lower payroll expense than 2017.

Hydroelectric

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

	Year Ended December 31,				
	2019	2018	2017	% change 2019 vs. 2018	% change 2018 vs. 2017
Hydroelectric					
Project Adjusted EBITDA	\$ 55.5	\$ 47.5	\$ 47.2	17 %	1 %

Year ended December 31, 2019 compared with Year ended December 31, 2018

Project Adjusted EBITDA for 2019 increased by \$8.0 million or 17% from 2018 primarily due to an increase in Project Adjusted EBITDA of:

- \$11.5 million at Curtis Palmer primarily due to higher water flows than 2018.

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

- \$2.2 million at Mamquam primarily due to lower water flows than in 2018; and
- \$1.3 million at Moresby Lake primarily due to lower generation resulting from a transformer failure in 2019.

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

Project Adjusted EBITDA for 2018 increased by \$0.3 million or 1% from 2017 primarily due to an increase in Project Adjusted EBITDA of:

- \$3.3 million at Mamquam due to higher water flows and lower maintenance expense relative to 2017.

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

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

Corporate

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

	Year Ended December 31,				
	2019	2018	2017	% change 2019 vs. 2018	% change 2018 vs. 2017
Corporate					
Project Adjusted EBITDA	\$ (0.3)	\$ 0.5	\$ 1.4	NM	NM

Year ended December 31, 2019 compared with Year ended December 31, 2018

Project Adjusted EBITDA did not change materially from 2018.

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

- Project Adjusted EBITDA did not change materially from 2017.

Liquidity and Capital Resources

	December 31, 2019	December 31, 2018
Cash and cash equivalents	\$ 74.9	\$ 68.3
Restricted cash	7.7	2.1
Total	82.6	70.4
Revolving credit facility availability	121.7	123.1
Total liquidity	\$ 204.3	\$ 193.5

For the year ended December 31, 2019, our total liquidity increased \$10.8 million. Changes in cash and cash equivalent balances are further discussed hereinafter under the heading *Cash Flow Discussion*. Restricted cash increased \$5.6 million from 2018 primarily due to insurance proceeds received at Cadillac that are restricted for use in the reconstruction of the plant. 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 February 26, 2020.

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 May 2020 to November 2043. We currently have two projects with PPAs with expiration dates in 2020, Calstock 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 Economic and Financial Market Conditions—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing external growth opportunities or fund our operations.”

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 \$26.1 million of project capital expenditures and maintenance expenses (excluding \$5.1 million of Cadillac reconstruction costs) for the year ended December 31, 2019. In all cases, scheduled maintenance outages during the year ended December 31, 2019 occurred at such times that did not adversely impact the facilities’ availability requirements under their respective PPAs.

We expect to reinvest approximately \$36.8 million in 2020 in our portfolio (excluding reconstruction cost at Cadillac) 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 2020 level as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades. All remaining costs for the repair and reconstruction of our Cadillac plant are expected to be paid with insurance proceeds. Repair costs exceeded the \$1 million deductible in 2019. There may be timing differences between the period of when costs are accumulated and insurance proceeds are received.

Acquisitions

In August 2019, we acquired equity ownership interests in Craven and Grayling for \$18.7 million and in July 2019, we completed our acquisition of Dorchester and Allendale, paying the remaining \$10.0 million of the total \$12.6 million purchase price. The initial \$2.6 million deposit was made in 2018.

Debt Service and Redemptions

During the year ended December 31, 2019, we made \$70 million of principal payments on the Term Loan and \$2.3 million on Cadillac’s term loan. Additionally, in April 2019, we redeemed, in full, the aggregate principal amount

of Cdn\$24.7 million (\$18.5 million) of the outstanding Series D Debentures.

Debt Service Obligations - Corporate

The following table summarizes the maturities of our corporate debt at December 31, 2019:

	Maturity Date	Interest Rates	Remaining Principal Repayments	2020	2021	2022	2023	2024	Thereafter
Senior secured term loan facility ⁽¹⁾	April 2025	4.55% - 4.79%	\$ 380.0	\$ 72.5	\$ 93.0	\$ 106.0	\$ 60.0	\$ 36.0	\$ 12.5
MTNs	June 2036	5.95%	161.7	—	—	—	—	—	161.7
Convertible Debenture	January 2025	6.00%	88.5	—	—	—	—	—	88.5
Total Corporate Debt			<u>\$ 630.2</u>	<u>\$ 72.5</u>	<u>\$ 93.0</u>	<u>\$ 106.0</u>	<u>\$ 60.0</u>	<u>\$ 36.0</u>	<u>\$ 262.7</u>

⁽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 5.95% Medium Term Notes due June 23, 2036 (“MTNs”), letters of credit costs to meet the requirements of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by Atlantic Power Preferred Equity Ltd., a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of Term Loan outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Note that failing to meet the mandatory amortization requirements is not an event of default, but could result in APLP Holdings being unable to make distributions to Atlantic Power Corporation and Atlantic Power Preferred Equity Limited being unable to pay dividends to its shareholders. 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 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, 2019. 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, 2019. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

	<u>Maturity Date</u>	<u>Range of Interest Rates</u>	<u>Total Remaining Principal Repayments</u>	<u>2020</u>	<u>2021</u>	<u>2022</u>	<u>2023</u>	<u>2024</u>	<u>Thereafter</u>
Consolidated Projects:									
Cadillac	August 2025	6.26 % - 6.38 %	\$ 18.7	\$ 3.9	\$ 2.7	\$ 3.3	\$ 3.3	\$ 3.7	\$ 1.8
Total Consolidated Projects			18.7	3.9	2.7	3.3	3.3	3.7	1.8
Equity Method Projects:									
Chambers ⁽¹⁾	December 2023	5.00 %	38.5	7.8	8.8	10.1	11.8	—	—
Total Equity Method Projects			38.5	7.8	8.8	10.1	11.8	—	—
Total Project-Level Debt			<u>\$ 57.2</u>	<u>\$ 11.7</u>	<u>\$ 11.5</u>	<u>\$ 13.4</u>	<u>\$ 15.1</u>	<u>\$ 3.7</u>	<u>\$ 1.8</u>

⁽¹⁾ The above table does not include our \$1.1 million proportionate share of unamortized issuance premiums.

Repurchases of Securities

On December 31, 2018, we commenced a Normal Course Issuer Bid (“NCIB”) for each of our Series D and Series E Debentures, our common shares and for each series of the preferred shares of Atlantic Power Preferred Equity Ltd. (“APPEL”), our wholly-owned subsidiary. During the year ended December 31, 2019, we repurchased and canceled 1,064,081 common shares at a total cost of approximately \$2.5 million. Additionally, we repurchased and cancelled 427,500 shares of Series 1 Shares, 100,377 shares of Series 2 Shares and 148,311 shares of Series 3 Shares of APPEL at a total cost of \$8.0 million.

On December 31, 2019, 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, 2019, up to the following limits:

	<u>Maturity Date</u>	<u>Interest Rates</u>	<u>Limit on Purchase (Principal Amount) Total Limit</u>
Convertible Debenture	January 2025	6.00 %	Cdn\$ 11,500,000
			<u>Limit on Purchase (Number of Shares) Total Limit ⁽¹⁾</u>
Common Shares			10,578,799
Series 1 Preferred Shares			384,750
Series 2 Preferred Shares			223,072
Series 3 Preferred Shares			133,031

⁽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, 2020 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.

Subsequent to December 31, 2019 and through February 26, 2020, we have repurchased and cancelled 1,742,919 common shares at a cost of \$4.1 million under the new NCIB. We also repurchased and cancelled 247,894 Series 1 Shares at a cost of \$3.1 million.

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, 2019, there were 3,847,500 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 5.67% 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, 2019 to 5.83%. 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, the rate on the Series 3 Shares was reset to 5.83% and 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 per share, plus an amount equal to all accrued and unpaid dividends thereon. At December 31, 2019, there were 2,504,131 Series 2 Shares and 1,077,391 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 \$7.4 million and \$8.3 million on Series 1 Shares, Series 2 Shares and Series 3 Shares for the years ended December 31, 2019 and 2018, respectively.

Contributions to our pension plan

We expect to contribute \$0.4 million to our pension plan in 2020.

Cash Flow Discussion

2019 compared to 2018

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

	Year ended		Change
	December 31,		
	2019	2018	
Net cash provided by operating activities	\$ 144.7	\$ 137.5	\$ 7.2
Net cash used in investing activities	(21.7)	(17.0)	(4.7)
Net cash used in financing activities	(110.8)	(135.0)	24.2

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, 2019, the net increase in cash flows provided by operating activities of \$7.2 million was primarily the result of the following:

- *Hydrological conditions* – higher water flows at our Curtis Palmer project, partially offset by lower water flows at our Mamquam and Moresby Lake projects, had an \$8.0 million positive impact on cash flows provided by operating activities;
- *Major maintenance* – we performed a planned major maintenance outage at our Manchief project in 2018 and had no such outage in the year ended December 31, 2019, resulting in a \$7.4 million positive impact on cash flows from operations;
- *Tunis operations* – the Tunis project commenced commercial operations in October 2018 and recorded \$3.4 million of higher revenue in the year ended December 31, 2019. Additionally, Tunis incurred \$3.9 million of lower maintenance expense in 2019. In 2018, Tunis incurred \$5.0 million of non-recurring maintenance expense to prepare the project for commercial operations; and
- *Interest* – we made \$3.7 million of lower interest payments than 2018 due to lower outstanding debt balances and a lower interest rate on the Credit Facilities.

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

- *Contract extension* – the extension of the energy purchase agreement at Williams Lake that became effective in April 2018 and expired in September 2019 provided lower pass-through of costs than the previous contract. The project entered into a new energy purchase agreement that became effective in October 2019, but the plant did not operate until late December, resulting in lower dispatch than 2018. These factors resulted in a \$9.0 million negative impact on cash flows provided by operating activities;
- *Working capital* – changes in working capital resulted in a \$4.8 million decrease in cash flows from operating activities; and

- *Distributions from unconsolidated affiliates* – we received \$2.1 million of lower distributions from our unconsolidated affiliates.

Investing Activities

For the year ended December 31, 2019, the net increase in cash flows used in investing activities of \$4.7 million was primarily the result of the following:

- *Acquisitions* – we paid \$27.3 million net of cash received during 2019 for the completion of the acquisitions of Dorchester, Allendale and for the acquisition of equity interests in Craven and Grayling, as compared to \$15.4 million in 2018 for the step acquisition of Koma and the deposit paid for Dorchester and Allendale; and
- *Purchases of PP&E* – investments in capitalized plant additions were \$5.5 million higher than 2018, primarily due to \$5.1 million of capitalized additions at Cadillac, which is undergoing repairs related to the fire.

These increases were partially offset by the following:

- *Insurance recoveries* – we received \$11.3 million of property and casualty insurance recoveries related to the fire at Cadillac in the fourth quarter of 2019; and
- *Proceeds from asset sales* – we received \$1.6 million of cash proceeds from the sale of equipment at our San Diego projects in 2019.

Financing Activities

For the year ended December 31, 2019, the net decrease in cash flows used in financing activities of \$24.2 million was primarily the result of the following:

- *Convertible debenture redemptions* – we paid \$18.5 million to redeem and cancel the Series D Debentures in full during the year ended December 31, 2019. In 2018, we paid \$88.1 million to redeem and cancel the Series C Debentures, in full, and the Series D Debentures, in part, with proceeds from the issuance of the Series E Debentures;
- *Corporate and project-level debt repayments* – we made \$28.0 million less principal payments than 2018;
- *Common share repurchases* – we paid \$2.5 million in 2019 to repurchase and cancel common shares as compared to \$16.6 million in 2018; and
- *Deferred financing costs* – we incurred \$5.1 million of deferred financing costs related to the issuance of the Series E Debentures in 2018.

These decreases were partially offset by the following:

- *Convertible debenture issuance* – we received \$92.2 million from the issuance of the Series E Debentures in 2018.

2018 compared to 2017

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

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

Operating Activities

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

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

- *Contract expirations* – the expiration of the enhanced dispatch contracts at our North Bay and Kapuskasing projects on December 31, 2017, as well as operations ceasing at our San Diego projects in February 2018, had an approximate \$72 million impact on cash flows from operations;
- *OEFC Settlement* – we received approximately \$26.6 million related to our settlement with the OEFC for the year December 31, 2017 and did not receive any payments in 2018; and
- *Major maintenance* – a planned major maintenance outage at our Manchief project had a \$5.5 million impact on cash flows from operations. Additionally, costs incurred to prepare our Tunis project for commercial operations had a \$3.3 million impact on cash flows from operations.

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

- *Working capital* – changes in working capital resulted in a \$39.3 million increase in cash flows from operating activities primarily due to a \$20.6 million decrease in working capital at our Kapuskasing, North Bay and San Diego projects, which were not in operation at December 31, 2018 but were under contract in 2017;
- *Interest expense* – our interest payments were \$30.7 million lower than the comparable 2017 period due to lower interest rates and outstanding principal on our Term Loan, the repayment of the Epsilon Power Partners term facility, in full, in the second quarter of 2018 and the repayment of Piedmont's project-level debt, in full, in the fourth quarter of 2017; and
- *Distributions from unconsolidated affiliates* – we received \$14.3 million in higher distributions from our unconsolidated affiliates, primarily at our Orlando (\$6.6 million increase), Chambers (\$5.5 million increase) and Frederickson (\$2.0 million increase) projects.

Investing Activities

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

- *Acquisition of Koma Kulshan* – we paid \$12.8 million, net of cash received, to acquire an additional 0.25% ownership of Koma Kulshan in the second quarter of 2018 and the remaining 50% of Koma Kulshan in the third quarter of 2018; and
- *Deposit for acquisition* – we made a \$2.6 million down payment for the acquisition of two biomass plants in South Carolina, which closed on July 31, 2019; and
- *Proceeds from sale of equity investment* – in 2017, we received \$1.0 million from the sale of our 17.7% equity interest in Selkirk Cogen L.P.

These increases were partially offset by the following:

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

Financing Activities

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

- *Convertible debenture redemptions* – we paid \$88.1 million to redeem and cancel the Series C Debentures, in full, and the Series D Debentures, in part, with proceeds from the issuance of the Series E Debentures;
- *Common share repurchases* – we paid \$16.6 million in 2018 to repurchase and cancel common shares as compared to \$0.2 million in 2017;
- *Preferred share repurchases* – we paid \$8.0 million in 2018 to repurchase and cancel preferred shares as compared to \$3.1 million in 2017; and
- *Deferred financing costs* – we incurred \$5.1 million of deferred financing costs related to the issuance of the Series E Debentures in 2018.

These decreases were partially offset by the following:

- *Convertible debenture issuance* – we received \$92.2 million from the issuance of the Series E Debentures; and
- *Corporate and project-level debt repayments* – we made \$65.6 million of lower principal payments than 2017 primarily due to the \$54.6 million payment to retire Piedmont's non-recourse project-level debt in 2017.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations as of December 31, 2019:

	Payment Due by Period				Total
	Less than 1 year	1-3 Years	3-5 Years	Thereafter	
Long-term debt including estimated interest ⁽¹⁾	\$ 106.5	\$ 253.5	\$ 138.2	\$ 386.0	\$ 884.2
Operating leases	1.2	1.5	0.6	—	3.3
Finance leases	0.1	0.2	—	—	0.3
Operations and maintenance commitments	0.4	0.6	—	—	1.0
Fuel purchase and transportation obligations	5.0	10.2	—	—	15.2
Other liabilities	3.1	—	—	2.7	5.8
Total contractual obligations	<u>\$ 116.3</u>	<u>\$ 266.0</u>	<u>\$ 138.8</u>	<u>\$ 388.7</u>	<u>\$ 909.8</u>

⁽¹⁾ Debt represents our proportionate share of project long-term debt and corporate-level debt. Project debt is non-recourse to us and is generally amortized during the term of the respective revenue-generating contracts of the projects. The range of interest rates on long-term consolidated project debt at December 31, 2019 was 4.55% to 6.38%.

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.

Off-Balance Sheet Arrangements

As of December 31, 2019, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

Critical Accounting Policies and Estimates

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

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

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

Long-lived asset impairment

Long-lived assets, such as property, plant and equipment, and other intangible assets subject to depreciation and amortization, are reviewed for impairment 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 Business and Our Projects—Impairment of goodwill or long-lived assets or equity method investments could have a material adverse effect on our business, results of operations and financial condition".

We recorded a \$5.8 million long-lived asset impairment at Calstock in the year ended December 31, 2019. We did not record any long-lived asset impairments in 2018. Previously, we recorded long-lived asset impairments of \$29.1 million, \$22.5 million, \$21.2 million and \$13.5 million, respectively, at our Williams Lake, Naval Station, North Island and Naval Training Center reporting units in the year ended December 31, 2017. 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.

We recorded equity method investment impairments of \$49.2 million at our Chambers project in the year ended December 31, 2019. We did not record any equity method investment impairments in 2018. We previously recorded equity method investment impairments of \$47.1 million, \$28.3 million and \$10.1 million, respectively, at our Chambers, Frederickson and Selkirk projects in the year ended December 31, 2017. See Item 15 — Note 6, *Equity method investments in unconsolidated affiliates* for discussion of these impairments.

Goodwill

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

We apply a standard that provides an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of a reporting unit is less than its carrying amount. These factors include an assessment of macroeconomic and industry conditions, market events and circumstances as well as the overall financial performance of our reporting units. For our 2019 test, we elected to not perform a qualitative assessment at any of our three of our reporting units, given the passage of time since a quantitative test had been performed for each reporting unit.

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 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.

We did not record any goodwill impairments in 2019 or 2018. We previously recorded a goodwill impairment of \$14.7 million at our Curtis Palmer reporting unit in the year ended December 31, 2017. 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.

Acquired assets

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

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.

During the three months ended December 31, 2019 and for the full year 2019, we received \$11.3 million of insurance proceeds, which were applied against the Cadillac insurance receivable of \$24.2 million. Additionally, we estimate anticipated insurance recoveries related to business interruption losses of \$2.0 million for the three months ended December 31, 2019. Anticipated reimbursements for business interruption losses were not recorded as of December 31, 2019 as all contingencies related to these claims had not been resolved as of period end. We expect all contingencies related to business interruption losses to be resolved once final payment is received from the insurers, which is when we will recognize the reimbursements in earnings (loss).

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, 2019, we have recorded a valuation allowance of \$145.4 million.

Recent Accounting Developments

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

Fuel Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity, natural gas, biomass and coal prices. See “Item 1A. Risk Factors—Risks Related to Our Business and Our Projects—Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the results of the operations of the projects.” We often employ (i) tolling structures, whereby an offtaker is responsible for fuel procurement, (ii) long-term fuel contracts, where we lock in a set quantity of fuel at a predetermined price, or (iii) pass-through arrangements, whereby the cost of fuel is borne by the ultimate offtaker. The combination of long-term energy sales and fuel purchase agreements is generally designed to mitigate the impacts to cash flows of changes in commodity prices by passing through changes in fuel prices to the buyer of the energy.

Natural Gas

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

Our 50%-owned Orlando project is exposed to changes in natural gas prices. We have entered into various natural gas swaps to effectively fix the price of 16.3 million MMBtu of future natural gas purchases at Orlando, which is approximately 100% of our projected gas consumption through 2023. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at December 31, 2019. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations. Because we have fixed the price of approximately 100% of our projected gas consumption, Orlando is not exposed to changes in the price of natural gas through 2023.

Biomass

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

Our Calstock project has six fuel suppliers, three of which provide up to 65% of its fuel requirements and are under contract to provide fuel, with a tipping fee through the end of the PPA in May 2020. We are exposed to the remaining 35% of the project's estimated fuel requirements. A 10% per Ton change from our budgeted wood waste costs at Calstock would have an estimated \$0.2 million impact on forecasted cash distributions in 2020 based on planned operations.

None of our other biomass projects have long-term biomass fuel contracts. A 10% per Ton change from our budgeted wood waste cost based on planned operations would have the following approximate impact on forecasted cash distributions in 2020 for each of these biomass plants:

- Allendale - \$0.6 million
- Cadillac - \$0.03 million
- Craven - \$0.6 million
- Dorchester - \$0.6 million
- Grayling - \$0.2 million
- Piedmont - \$1.2 million
- Williams Lake - \$1.1 million

Coal

Our 40%-owned Chambers project is exposed to changes in coal prices. For 2020, we forecasted an average coal price of \$98 per Ton. A 10% change from our forecasted price would impact cash distributions in 2020 from Chambers by an estimated \$1.3 million based on planned operations.

Electricity Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity prices at projects that operate with PPAs that are based on spot market pricing or at projects that operate without a PPA. Our most significant exposure to market power prices is at the Chambers and Morris projects.

At our 40%-owned Chambers project, plant capacity is sold forward pursuant to the PPA with our utility customer. However, the project is economically dispatched, which impacts variable operating margins. For example, during periods of low demand and low spot electricity prices, the project is dispatched less, which reduces the project's operating margin. In addition, the utility customer has the right to sell a portion of the output into the spot market if it is economical to do so, and the Chambers project shares in the profit from these sales. This also adds some variability to the project's financial results. In 2020, projected cash distributions from Chambers would change by approximately \$0.8 million per 10% change in the PJM-East spot price of electricity.

At Morris, a portion of the capacity is contracted with the industrial customer through 2034. The remaining capacity has been sold forward into the PJM capacity market through annual auctions covering the period through May 2022. The capacity revenues from these auctions generally represent the majority of the operating margin of the uncontracted portion of the project. Energy associated with the capacity sold forward into the PJM market is generally dispatched by PJM when economic to do so or when needed for other reasons. The project can also offer ancillary services to the grid. The sale of energy and ancillary services from the uncontracted portion of the project is not at a fixed price or margin and therefore can add variability to the project's financial results. In 2020, projected cash distributions from Morris would change by approximately \$0.4 million per 10% change in the spot price of electricity based on the forecasted level of approximately 200,000 MWh of grid sales and all other variables being held constant.

When a PPA expires or is terminated, it is possible that the price received by the project for power under subsequent arrangements may be reduced and in some cases, significantly. Our projects may not be able to secure a new agreement and could be exposed to sell power at spot market price. See Item 1A. "Risk Factors—Risk Related to Our Business and Our Projects—The expiration or termination of our PPAs could have a material adverse impact on our business, results of operations and financial condition." It is possible that subsequent PPAs or the spot market may not be available at prices that permit the operation of the project on a profitable basis. If this occurs, the affected project may temporarily or permanently cease operations.

Foreign Currency Exchange Risk

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

The following table contains the components of recorded foreign exchange (gain) loss for the years ended December 31, 2019, 2018, and 2017:

	Year Ended December 31,		
	2019	2018	2017
Unrealized foreign exchange loss (gain):			
Convertible debentures, corporate debt, and other	\$ 12.1	\$ (22.2)	\$ 15.1
Foreign currency forwards	—	0.1	0.1
	12.1	(22.1)	15.2
Realized foreign exchange (gain) loss	(0.2)	(0.7)	1.1
	<u>\$ 11.9</u>	<u>\$ (22.8)</u>	<u>\$ 16.3</u>

A 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar would have an approximate impact of \$25 million on the carrying value of our corporate debt and convertible debentures denominated in Canadian dollars at December 31, 2019.

Interest Rate Risk

Changes in interest rates impact cash payments that are required on our debt instruments as approximately 98% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at variable rates or is not financially hedged through the use of interest rate swaps. After considering the impact of interest rate swaps described below, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest expense at equity investments, by approximately \$0.2 million at December 31, 2019.

The Partnership

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, 2019, these agreements totaled \$370.6 million notional amount of the remaining \$380.0 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 Term Loan bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 2.75%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00%, resulting in a minimum of a 3.75% all-in rate on the Term Loan for the non-swapped portion of the remaining principal amount. The weighted average rate of these swap agreements is 2.00%, resulting in an all-in rate of approximately 4.75% for \$370.6 million of the Term Loan. In February 2020, APLP Holdings entered into additional interest rate swap agreements. For the period beginning March 31, 2020 through December 31, 2021, we mitigated exposure to changes in interest rates a one-month LIBOR fixed rate of 1.39%. The notional amount of these interest rate swap agreements range between \$9.4 million and \$45.0 million and are sized to the targeted debt balance payments over that period.

In February 2020, 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) replacement. Subsequent to the expiration of the outstanding interest rate swap agreements on March 31, 2022, we are exposed to changes in interest at the Adjusted Eurodollar Rate or its replacement through the maturity date of the Term Loan.

Cadillac

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

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

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

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

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

None.

ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

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

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

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

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-14(f) under the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2019 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, 2019 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, 2019 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, 2019 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

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

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

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

ITEM 11. EXECUTIVE COMPENSATION

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

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

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

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

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

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

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

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

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

(a)(2) Financial Statement Schedules

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

(a)(3) Exhibits

EXHIBIT INDEX

Exhibit No.	Description
2.1	Plan of Arrangement of Atlantic Power Corporation, dated as of November 24, 2005
2.2	Arrangement Agreement, dated as of June 20, 2011, among Capital Power Income L.P., CPI Income Services Ltd., CPI Investments Inc. and Atlantic Power Corporation
3.1	Articles of Continuance of Atlantic Power Corporation, dated as of June 29, 2010
4.1	Form of common share certificate
4.2	Trust Indenture, dated as of October 11, 2006 between Atlantic Power Corporation and Computershare Trust Company of Canada
4.3	First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Secured Debentures, dated November 27, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada
4.4	Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 17, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada
4.5	Form of First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, between Atlantic Power Corporation and Computershare Trust Company of Canada
4.6	Second Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated July 5, 2012, between Atlantic Power Corporation and Computershare Trust Company of Canada
4.7	Third Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated August 17, 2012, between Atlantic Power Corporation and Computershare Trust Company of Canada
4.8	Fourth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of November 29, 2012, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A.
4.9	Fifth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 11, 2012, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A.
4.10	Sixth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of March 22, 2013, among Atlantic Power Corporation and Computershare Trust Company of Canada

Exhibit No.	Description
4.11	Seventh Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of January 29, 2018, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A.
4.12	Indenture, dated as of November 4, 2011, by and among Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association
4.13	First Supplemental Indenture, dated as of November 5, 2011, by and among the New Guarantors signatory thereto, Atlantic Power Corporation, the Existing Guarantors named therein and Wilmington Trust, National Association
4.14	Second Supplemental Indenture, dated as of November 5, 2011, by and among Curtis Palmer LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association
4.15	Third Supplemental Indenture, dated as of February 22, 2012, by and among Atlantic Oklahoma Wind, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association
4.16	Fourth Supplemental Indenture, dated as of August 3, 2012, by and among Atlantic Rockland Holdings, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association
4.17	Fifth Supplemental Indenture, dated as of November 29, 2012, by and among Atlantic Ridgeline Holdings, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association
4.18	Sixth Supplemental Indenture, dated as of January 29, 2013, by and among the New Guarantors named therein, Atlantic Power Corporation, the Existing Guarantors named therein and Wilmington Trust, National Association
4.19	Registration Rights Agreement, dated as of November 4, 2011, by and among, Atlantic Power Corporation, the Guarantors listed on Schedule A thereto and Morgan Stanley & Co. LLC and TD Securities (USA) LLC, as representatives of the several Initial Purchasers
4.20	Shareholder Rights Plan Agreement, dated effective as of February 28, 2013, between Atlantic Power Corporation and Computershare Investor Services, Inc., which includes the Form of Right Certificate as Exhibit A
4.21	Advance Notice Policy, dated April 1, 2013
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
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

Exhibit No.	Description
10.5	Modification and Joinder Agreement, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Ridgeline Energy LLC, PAH RAH Holding Company LLC, Ridgeline Eastern Energy LLC, Ridgeline Energy Solar LLC, Lewis Ranch Wind Project LLC, Hurricane Wind LLC, Ridgeline Power Services LLC, Ridgeline Energy Holdings, Inc., Ridgeline Alternative Energy LLC, Frontier Solar LLC, PAH RAH Project Company LLC, Monticello Hills Wind LLC, Dry Lots Wind LLC, Smokey Avenue Wind LLC, Saunders Bros. Transportation Corporation, Bruce Hill Wind LLC, South Mountain Wind LLC, Great Basin Solar Ranch LLC, Goshen Wind Holdings LLC, Meadow Creek Holdings LLC, Ridgeline Holdings Junior Inc., Rockland Wind Ridgeline Holdings LLC, Meadow Creek Intermediate Holdings LLC and the other Subsidiaries party thereto in favor of Bank of Montreal, as Administrative Agent
10.6+	Employment Agreement, dated April 15, 2013, between Atlantic Power Corporation and Terrence Ronan
10.7+	Addendum to Executive Employment Agreements of each of Terrence Ronan and Edward Hall, dated August 30, 2013
10.8+	Deferred Share Unit Plan, dated as of April 24, 2007 of Atlantic Power Corporation
10.9+	Third Amended and Restated Long-Term Incentive Plan
10.10+	Fourth Amended and Restated Long-Term Incentive Plan
10.11+	Fifth Amended and Restated Long-Term Incentive Plan
10.12+	Amendment No. 1 to the Fifth Amended and Restated Long-Term Incentive Plan of the Company
10.13	Termination of the Operating Agreement of Canadian Hills Wind, LLC, dated as of December 28, 2012
10.14	Purchase and sale agreement, dated as of January 30, 2013 among Quantum Lake LP, LLC, Quantum Lake GP, LLC, Quantum Pasco LP, LLC, Quantum Pasco GP, LLC, Quantum Auburndale LP, LLC and Quantum Auburndale GP, LLC (as Buyers) and Lake Investment, LP, NCP Lake Power, LLC, Teton New Lake, LLC, NCP Dadee Power, LLC, Dade Investment, LP, Auburndale, LLC and Auburndale GP, LLC (as Sellers)
10.15	Agreement dated November 24, 2014, by and among Clinton Group and the Company
10.16+	Employment Agreement among the Company, Atlantic Power Services, LLC and James J. Moore, Jr., dated January 22, 2015
10.17+	Transition Equity Grant Participation Agreement between Atlantic Power Services, LLC and James J. Moore, Jr., dated January 22, 2015
10.18	Membership Interest Purchase Agreement by and between Atlantic Power Transmission, Inc. and Terraform AP Acquisition Holdings, LLC dated as of March 31, 2015
10.19	Guaranty Agreement by Atlantic Power Corporation in favor of Terraform AP Acquisition Holdings, LLC, dated as of March 31, 2015
10.20	Agreement dated May 21, 2015, by and among Mangrove Partners and the Company
10.21	Amendment No.1 to Membership Interest Purchase Agreement, dated June 3, 2015
10.22+	Employment Agreement among the Company, Atlantic Power Services, LLC and Joseph E. Cofelice, dated September 15, 2015
10.23	Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners
10.24	Securities Pledge Agreement, dated as of April 13, 2016, among Atlantic Power Corporation, Atlantic Power GP II, Inc. and Goldman Sachs Lending Partners LLC as Collateral Agent

Exhibit No.	Description
10.25	Amendment dated April 17, 2017 to the Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners
10.26	Second Amendment dated October 18, 2017 to the Credit and Guaranty Agreement, dated as of April 13, 2016, among APLP Holdings Limited Partnership, as Borrower, Atlantic Power Corporation, as guarantor, Certain Subsidiaries of APLP Holdings Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of America, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC as Administrative Agent and Collateral Agent, and Goldman Sachs Lending Partners LLC, Merrill Lynch, Pierce, Fenner & Smith Incorporated, RBC Capital Markets, The Bank of Tokyo-Mitsubishi UFJ, Ltd., Wells Fargo Securities, LLC, and Industrial and Commercial Bank of China, in their respective capacities as Joint Lead Arrangers and Joint Bookrunners
10.27	Amendment to Employment Agreement, by and among Atlantic Power Services, LLC, the Company and Joseph Cofelice, dated as of February 27, 2018
10.28	Amendment No. 2 to the Fifth Amended and Restated Long-Term Incentive Plan of the Company
10.29+	Sixth Amended and Restated Long-Term Incentive Plan
10.30+	Amendment to Transition Equity Grant Participation Agreement between Atlantic Power Services, LLC and James J. Moore, Jr., dated as of January 23, 2019
10.31+	Form of Legacy Award Amendment
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 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.
16.1	Letter from KPMG LLP, Chartered Accountants, to the Securities and Exchange Commission, dated August 10, 2010
21.1*	Subsidiaries of Atlantic Power Corporation
23.1*	Consent of KPMG LLP
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a- 14(a)/15d-14(a) under the Exchange Act

Exhibit No.	Description
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, 2019 formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Shareholders' Equity, (iv) the Consolidated Statements of Cash Flows, and (v) related notes to these financial statements

+ Indicates management contract or compensatory plan or arrangement.

* Filed herewith.

** Furnished herewith.

(b) Exhibits:

See Item 15(a)(3) above.

(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: February 27, 2020

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.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ JAMES J. MOORE, JR.</u> James J. Moore, Jr.	President, Chief Executive Officer and Director (principal executive officer)	February 27, 2020
<u>/s/ TERRENCE RONAN</u> Terrence Ronan	Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)	February 27, 2020
<u>/s/ KEVIN HOWELL</u> Kevin Howell	Chairman of the Board, Director	February 27, 2020
<u>/s/ R. FOSTER DUNCAN</u> R. Foster Duncan	Director	February 27, 2020
<u>/s/ DANIELLE S. MOTTOR</u> Danielle S. Mottor	Director	February 27, 2020
<u>/s/ GILBERT S. PALTER</u> Gilbert S. Palter	Director	February 27, 2020

Atlantic Power Corporation

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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, 2019 and 2018, the related consolidated statements of operations, comprehensive (loss) income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes, (and financial statement schedules I to II) (collectively, the consolidated financial statements). In our opinion, the consolidated financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2019 and 2018, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2019, 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, 2019, based on criteria established in *Internal Control – Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated February 27, 2020 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.

/s/ KPMG LLP

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

New York, New York

February 27, 2020

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, 2019, 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, 2019, 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, 2019 and 2018, the related consolidated statements of operations, comprehensive (loss) income, shareholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2019, and the related notes, (and financial statement schedules I to II) (collectively, the consolidated financial statements) and our report dated February 27, 2020 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

February 27, 2020

ATLANTIC POWER CORPORATION
CONSOLIDATED BALANCE SHEETS
(in millions of U.S. dollars)

	December 31,	
	2019	2018
Assets		
Current assets:		
Cash and cash equivalents	\$ 74.9	\$ 68.3
Restricted cash	7.7	2.1
Accounts receivable	30.4	35.7
Insurance recovery receivable (Note 23)	13.5	—
Current portion of derivative instruments asset (Notes 14 and 15)	0.7	4.2
Inventory (Note 7)	18.6	15.8
Prepayments	3.8	4.0
Income taxes receivable (Note 16)	1.8	0.3
Lease receivable (Note 24)	0.9	—
Other current assets	0.4	5.9
Total current assets	152.7	136.3
Property, plant, and equipment, net (Note 8)	502.1	549.5
Equity investments in unconsolidated affiliates (Note 6)	96.6	140.8
Power purchase agreements and intangible assets, net (Note 10)	144.3	170.1
Goodwill (Note 9)	21.3	21.3
Derivative instruments asset (Notes 14 and 15)	—	0.3
Operating lease right-of-use assets (Note 24)	6.3	—
Deferred income taxes (Note 16)	10.4	7.0
Other assets	1.9	6.2
Total assets	<u>\$ 935.6</u>	<u>\$ 1,031.5</u>
Liabilities		
Current liabilities:		
Accounts payable	\$ 8.9	\$ 2.5
Accrued interest	2.6	2.3
Other accrued liabilities	20.8	20.2
Current portion of long-term debt (Note 12)	76.4	68.1
Current portion of derivative instruments liability (Notes 14 and 15)	12.0	4.5
Convertible debentures (Note 13)	—	18.1
Operating lease liabilities (Note 24)	2.0	—
Other current liabilities	0.2	0.2
Total current liabilities	122.9	115.9
Long-term debt, net of unamortized discount and deferred financing costs (Note 12)	473.5	540.7
Convertible debentures, net of discount and unamortized deferred financing costs (Note 13)	81.1	75.7
Derivative instruments liability (Notes 14 and 15)	15.9	15.4
Deferred income taxes (Note 16)	23.7	16.0
Power purchase agreements and intangible liabilities, net (Note 10)	19.8	21.2
Asset retirement obligations, net (Note 11)	51.5	49.2
Operating lease liabilities (Note 24)	4.8	—
Other long-term liabilities (Note 11)	4.7	5.0
Total liabilities	797.9	839.1
Equity		
Common shares, no par value, unlimited authorized shares; 108,675,294 and 108,341,738 issued and outstanding at December 31, 2019 and December 31, 2018 (Note 19)	1,259.9	1,260.9
Accumulated other comprehensive loss (Note 5)	(140.7)	(146.2)
Retained deficit	(1,164.2)	(1,121.6)
Total Atlantic Power Corporation shareholders' equity	(45.0)	(6.9)
Preferred shares issued by a subsidiary company (Note 20)	182.7	199.3
Total equity	137.7	192.4
Total liabilities and equity	<u>\$ 935.6</u>	<u>\$ 1,031.5</u>

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,		
	2019	2018	2017
Project revenue:			
Energy sales (Note 4)	\$ 138.0	\$ 130.9	\$ 148.9
Energy capacity revenue (Note 4)	125.4	97.9	105.8
Other (Note 4)	18.2	53.5	176.3
	<u>281.6</u>	<u>282.3</u>	<u>431.0</u>
Project expenses:			
Fuel	72.3	73.1	106.3
Operations and maintenance	77.0	85.0	87.8
Depreciation and amortization	64.5	83.7	113.1
	<u>213.8</u>	<u>241.8</u>	<u>307.2</u>
Project other income (loss):			
Change in fair value of derivative instruments (Notes 14 and 15)	(8.9)	2.2	2.1
Equity in (loss) earnings of unconsolidated affiliates (Note 6)	(3.0)	43.2	(54.8)
Interest, net	(1.1)	(1.8)	(17.5)
Impairment (Note 9)	(5.8)	—	(101.1)
Insurance loss (Note 23)	(1.0)	—	—
Other (expense) income, net	(1.2)	4.1	0.1
	<u>(21.0)</u>	<u>47.7</u>	<u>(171.2)</u>
Project income (loss)	46.8	88.2	(47.4)
Administrative and other expenses:			
Administration	23.9	23.9	23.6
Interest expense, net	44.0	52.7	64.2
Foreign exchange loss (gain)	11.9	(22.8)	16.3
Other expense (income), net (Note 14)	1.0	(3.0)	(0.4)
	<u>80.8</u>	<u>50.8</u>	<u>103.7</u>
(Loss) income from operations before income taxes	(34.0)	37.4	(151.1)
Income tax expense (Note 16)	9.8	0.2	(58.1)
Net (loss) income	(43.8)	37.2	(93.0)
Net (loss) income attributable to preferred shares of a subsidiary company (Note 20)	(1.2)	0.4	5.6
Net (loss) income attributable to Atlantic Power Corporation	<u>\$ (42.6)</u>	<u>\$ 36.8</u>	<u>\$ (98.6)</u>
Net (loss) earnings per share attributable to Atlantic Power Corporation shareholders: (Note 21)			
Basic	\$ (0.39)	\$ 0.33	\$ (0.86)
Diluted	<u>(0.39)</u>	<u>0.29</u>	<u>(0.86)</u>
Weighted average number of common shares outstanding: (Note 21)			
Basic	109.3	112.0	115.1
Diluted	109.3	141.8	115.1

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION
CONSOLIDATED STATEMENTS OF COMPREHENSIVE (LOSS) INCOME

(in millions of U.S. dollars)

	Year Ended December 31,		
	2019	2018	2017
Net (loss) income	\$ (43.8)	\$ 37.2	\$ (93.0)
Other comprehensive income, net of tax:			
Unrealized (loss) gain on hedging activities	\$ (0.3)	\$ 0.4	\$ (0.1)
Net amount reclassified to earnings	0.3	0.1	0.5
Net realized and unrealized gain on derivatives	—	0.5	0.4
Defined benefit plan, net of tax	(0.3)	0.2	(0.7)
Foreign currency translation adjustments	5.8	(12.1)	14.0
Other comprehensive income (loss), net of tax	5.5	(11.4)	13.7
Comprehensive (loss) income	(38.3)	25.8	(79.3)
Less: Comprehensive (loss) income attributable to preferred shares of a subsidiary company	(1.2)	0.4	5.6
Comprehensive (loss) income attributable to Atlantic Power Corporation	\$ (37.1)	\$ 25.4	\$ (84.9)

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	Preferred Shares of a Subsidiary Company	Total Shareholders' Equity
Balance at January 1, 2017	114.6	\$ 1,272.9	\$ (1,059.8)	\$ (148.5)	\$ 221.3	\$ 285.9
Net (loss) income	—	—	(98.6)	—	5.6	(93.0)
Share-based compensation	0.7	2.1	—	—	—	2.1
Common share repurchases	(0.1)	(0.2)	—	—	—	(0.2)
Preferred share repurchases	—	—	—	—	(3.1)	(3.1)
Dividends on preferred shares of a subsidiary company - Series 1 (Cdn\$1.212500 per share)	—	—	—	—	(4.6)	(4.6)
Dividends on preferred shares of a subsidiary company - Series 2 (Cdn\$1.392500 per share)	—	—	—	—	(2.5)	(2.5)
Dividends on preferred shares of a subsidiary company - Series 3 (Cdn\$1.182500 per share)	—	—	—	—	(1.5)	(1.5)
Realized and unrealized gain on hedging activities, net of tax of \$0.3 million	—	—	—	0.4	—	0.4
Foreign currency translation adjustments	—	—	—	14.0	—	14.0
Defined benefit plan, net of tax of \$0.3 million	—	—	—	(0.7)	—	(0.7)
Balance at December 31, 2017	115.2	\$ 1,274.8	\$ (1,158.4)	\$ (134.8)	\$ 215.2	\$ 196.8
Net income	—	—	36.8	—	0.4	37.2
Share-based compensation	0.9	2.7	—	—	—	2.7
Common share repurchases	(7.8)	(16.6)	—	—	—	(16.6)
Preferred share repurchases	—	—	—	—	(8.0)	(8.0)
Dividends on preferred shares of a subsidiary company - Series 1 (Cdn\$1.212500 per share)	—	—	—	—	(4.2)	(4.2)
Dividends on preferred shares of a subsidiary company - Series 2 (Cdn\$1.392500 per share)	—	—	—	—	(2.5)	(2.5)
Dividends on preferred shares of a subsidiary company - Series 3 (Cdn\$1.327539 per share)	—	—	—	—	(1.6)	(1.6)
Realized and unrealized gain on hedging activities, net of tax of \$0.1 million	—	—	—	0.5	—	0.5
Foreign currency translation adjustments	—	—	—	(12.1)	—	(12.1)
Defined benefit plan, net of tax of \$0.1 million	—	—	—	0.2	—	0.2
Balance as of December 31, 2018	108.3	\$ 1,260.9	\$ (1,121.6)	\$ (146.2)	\$ 199.3	\$ 192.4
Net loss	—	—	(42.6)	—	(1.2)	(43.8)
Share-based compensation	1.4	1.5	—	—	—	1.5
Common share repurchases	(1.1)	(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
Defined benefit plan, net of tax of \$0.1 million	—	—	—	(0.3)	—	(0.3)
Balance as of December 31, 2019	108.6	\$ 1,259.9	\$ (1,164.2)	\$ (140.7)	\$ 182.7	\$ 137.7

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,		
	2019	2018	2017
Cash provided by operating activities:			
Net (loss) income	\$ (43.8)	\$ 37.2	\$ (93.0)
Adjustments to reconcile net (loss) income to net cash provided by operating activities:			
Depreciation and amortization	64.4	83.7	113.1
(Gain) loss on disposal of fixed assets and inventory	(0.9)	(0.4)	0.1
Asset retirement obligations	1.4	3.5	—
Gain on step acquisition of equity investment	—	(7.2)	—
Share-based compensation	1.5	2.7	2.1
Impairment	5.8	—	101.1
Insurance loss	1.0	—	—
Equity in loss (earnings) from unconsolidated affiliates	3.0	(43.2)	54.8
Distributions from unconsolidated affiliates	59.5	61.6	47.3
Unrealized foreign exchange loss (gain)	12.2	(22.0)	15.2
Change in fair value of derivative instruments	10.7	(5.5)	(2.1)
Amortization of debt discount, deferred financing costs and operating lease right-of-use assets	8.6	9.4	10.8
Deferred income taxes	4.8	(3.6)	(62.2)
Change in other operating balances			
Accounts receivable	8.2	18.8	(15.4)
Inventory	(1.8)	1.6	(1.6)
Prepayments and other assets	3.9	8.7	0.4
Accounts payable	5.1	(1.2)	(0.9)
Accruals and other liabilities	1.1	(6.6)	(0.5)
Cash provided by operating activities	144.7	137.5	169.2
Cash used in investing activities:			
Investment in unconsolidated affiliate	(18.7)	—	—
Insurance proceeds	11.3	—	—
Cash paid for acquisition, net of cash received	(8.6)	(12.8)	—
Deposit for acquisition	—	(2.6)	—
Proceeds from sales of assets and equity investments, net	1.6	0.2	1.0
Purchase of property, plant and equipment	(7.3)	(1.8)	(5.3)
Cash used in investing activities:	(21.7)	(17.0)	(4.3)
Cash used in financing activities:			
Proceeds from convertible debenture issuance	—	92.2	—
Repayment of convertible debentures	(18.5)	(88.1)	—
Common share repurchases	(2.5)	(16.6)	(0.2)
Preferred share repurchases	(8.0)	(8.0)	(3.1)
Repayment of corporate and project-level debt	(72.3)	(100.3)	(165.9)
Cash payments for vested LTIP units, including amounts withheld for taxes	(2.1)	(0.8)	(0.7)
Deferred financing costs	—	(5.1)	(0.3)
Dividends paid to preferred shareholders	(7.4)	(8.3)	(8.7)
Cash used in financing activities:	(110.8)	(135.0)	(178.9)
Net increase (decrease) in cash, restricted cash and cash equivalents	12.2	(14.5)	(14.0)
Cash, restricted cash and cash equivalents at beginning of period	70.4	84.9	98.9
Cash, restricted cash and cash equivalents at end of period	\$ 82.6	\$ 70.4	\$ 84.9
Supplemental cash flow information			
Interest paid	\$ 37.6	\$ 41.3	\$ 72.0
Income taxes paid, net	\$ 2.3	\$ 3.1	\$ 4.4
Accruals for construction in progress	\$ 0.3	\$ (1.5)	\$ 1.2

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(in millions of U.S. dollars, except per-share amounts)

1. Nature of business

General

Atlantic Power is an independent power producer that owns power generation assets in 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, 2019, 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 Toronto Stock Exchange under the symbol “ATP” and on the New York Stock Exchange 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.

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

(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, 2019 and 2018, 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 \$8.5 million and \$11.8 million at December 31, 2019 and 2018, respectively. Interest expense from the amortization of deferred financing costs for the years ended December 31, 2019, 2018, and 2017 was \$3.2 million, \$5.1 million, and \$6.3 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.

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

(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

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

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 as of November 30, 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 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

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

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 (loss) income (“OCL”) until the hedged transactions occur and are recognized in earnings. The ineffective portion of the cash flow hedge, if any, is immediately recognized in earnings.

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

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

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

(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 May 2020 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.

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

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

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.

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

(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 units granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional units granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Unvested notional units are entitled to receive dividends, if paid, equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date.

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

(t) Asset retirement obligations:

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

(u) 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 (loss) income. In addition, we also recognize on an after-tax basis, as a component of other comprehensive (loss) income, 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.

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

(v) Business combinations:

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

(w) Concentration of credit risk:

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

(x) Use of estimates:

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

(y) Recently adopted and issued accounting standards:

Accounting Standards Adopted in 2019

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

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expedient that permits us to retain our existing lease assessment and classification. The Company has elected not to apply the recognition requirements to short-term leases and not to separate non-lease components from associated lease components, for all classes of underlying assets. In July 2018, the FASB issued further authoritative guidance to provide an additional transition method to adopt the new lease requirements by allowing entities to initially apply the requirements by recognizing a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption. We elected this transition method.

As the result of our adoption of the guidance, we recorded \$6.4 million and \$7.2 million of right-of-use assets and lease liabilities, respectively, in the consolidated balance sheets on January 1, 2019. We have no transitional adjustments to our opening retained earnings or our consolidated statements of operations. See Note 16, Leases for further information.

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

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

Accounting Standards Not Yet Adopted

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 is 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. The impact of adoption will require additional disclosures commencing with our March 31, 2020 quarterly report on Form 10-Q; however, there is no anticipated material impact on our consolidated financial statements.

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

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

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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 are effective for fiscal years ending after December 15, 2020, for public business entities and early adoption is permitted for all entities. We are currently evaluating the impact that adoption will have on our disclosures.

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. 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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

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	<u>\$</u>	<u>12.6</u>

⁽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,

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2019 to December 31, 2019.

2018 Acquisitions

(a) Koma Kulshan Associates

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

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

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

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

The fair values of the assets acquired and liabilities assumed, as well as the fair value of our previous 50% equity interest in Koma, were estimated by applying an income approach using the discounted cash flow method. These measurements were based on significant inputs not observable in the market and thus represent a level 3 fair value measurement. The primary considerations and assumptions that affected the discounted cash flows included the operational characteristics and financial forecasts of the acquired facility, remaining useful life and a discount rate based on the weighted average cost of capital adjusted for the risk and characteristics of the project. We recognized a \$7.2 million gain recorded in other income in the consolidated statements of operations for the year ended December 31, 2018 as a result of remeasuring our previous 50% equity interest in Koma immediately before the business combination to fair value. The \$24.8 million of intangible assets recorded will be amortized straight-line through the remaining life of

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
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Koma's PPA, which expires on March 31, 2037. Additionally, we recorded \$0.5 million of deferred tax liabilities and deferred tax expense related to the step acquisition of Koma Kulshan.

Koma contributed \$1.1 million of revenue and net income of \$0.0 million (excluding the \$7.2 million gain recognized from the step acquisition) to the consolidated statements of operations for the period from July 27, 2018 to December 31, 2018. The impact to pro forma results of operations was not significant to the years ended December 31, 2019, 2018 and 2017.

2017 Divestment

(a) Selkirk Project

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

4. Revenue from contracts

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

	Year Ended December 31, 2019				Consolidated Total
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	
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

	Year Ended December 31, 2018				Consolidated Total
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	
Project revenue:					
Energy sales	\$ 37.4	\$ 38.3	\$ 55.2	\$ —	\$ 130.9
Energy capacity revenue	41.6	56.3	—	—	97.9
Steam energy and capacity revenue	0.1	15.6	—	—	15.7
Waste heat revenue	0.2	—	—	—	0.2
Enhanced dispatch contracts	—	23.9	—	—	23.9
Ancillary and transmission services	4.5	5.4	3.1	—	13.0
Asset management and operation	—	—	—	1.0	1.0
Miscellaneous revenue	—	(0.3)	—	—	(0.3)
	83.8	139.2	58.3	1.0	282.3

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
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Contract balances

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

	December 31, 2019	December 31, 2018
Accounts receivables	\$ 30.4	\$ 35.7
Contract liabilities	0.3	0.1

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. Contract liabilities as of December 31, 2018 include a \$0.1 million steam sale credit at the San Diego plants.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
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5. Changes in accumulated other comprehensive income by component

The changes in accumulated OCI by component are as follows:

	Year Ended December 31,		
	2019	2018	2017
Foreign currency translation			
Balance at beginning of period	\$ (146.4)	\$ (134.3)	\$ (148.3)
Other comprehensive income (loss):			
Foreign currency translation adjustments ⁽¹⁾	5.8	(12.1)	14.0
Balance at end of period	<u>\$ (140.6)</u>	<u>\$ (146.4)</u>	<u>\$ (134.3)</u>
Pension			
Balance at beginning and end of period	\$ (1.4)	\$ (1.6)	\$ (0.9)
Other comprehensive loss:			
Settlement	0.3	—	—
Curtailement gain	—	—	(1.6)
Tax (expense) benefit	(0.1)	—	0.4
Total Other comprehensive income (loss) before reclassifications, net of tax	0.2	—	(1.2)
Total amount reclassified from accumulated other comprehensive income, net of tax	(0.5)	0.2	0.5
Total other comprehensive (loss) income	<u>(0.3)</u>	<u>0.2</u>	<u>(0.7)</u>
Balance at end of period	<u>\$ (1.7)</u>	<u>\$ (1.4)</u>	<u>\$ (1.6)</u>
Cash flow hedges			
Balance at beginning of period	\$ 1.6	\$ 1.1	\$ 0.7
Other comprehensive income (loss):			
Net change from periodic revaluations	(0.5)	0.5	(0.2)
Tax benefit (expense)	0.2	(0.1)	0.1
Total Other comprehensive (loss) income before reclassifications, net of tax	(0.3)	0.4	(0.1)
Net amount reclassified to earnings:			
Interest rate swaps ⁽²⁾	0.4	0.2	0.9
Tax expense	(0.1)	(0.1)	(0.4)
Total amount reclassified from accumulated other comprehensive income, net of tax	0.3	0.1	0.5
Total other comprehensive income	<u>—</u>	<u>0.5</u>	<u>0.4</u>
Balance at end of period	<u>\$ 1.6</u>	<u>\$ 1.6</u>	<u>\$ 1.1</u>

⁽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.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
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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, 2019	Carrying value as of December 31,	
		2019	2018
Frederickson ⁽¹⁾	50.2 %	\$ 65.2	\$ 72.0
Orlando Cogen, LP	50.0 %	3.6	4.5
Chambers Cogen, LP	40.0 %	9.0	64.3
Craven County Wood Energy, LP ⁽²⁾	50.0 %	9.5	—
Grayling Generating Station, LP ⁽²⁾	30.0 %	9.3	—
Total		<u>\$ 96.6</u>	<u>\$ 140.8</u>

- ⁽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,		
	2019	2018	2017
Frederickson	\$ 9.1	\$ 6.9	\$ (27.9)
Orlando Cogen, LP	33.0	30.1	25.6
Koma Kulshan Associates ⁽¹⁾	—	0.6	0.7
Chambers Cogen, LP	(46.0)	5.6	(42.6)
Selkirk Cogen Partners, LP ⁽²⁾	—	—	(10.6)
Craven County Wood Energy, LP ⁽³⁾	0.1	—	—
Grayling Generating Station, LP ⁽³⁾	0.8	—	—
Total (loss) earnings of unconsolidated affiliates	(3.0)	43.2	(54.8)
Distributions from equity method investments	(59.5)	(61.6)	(47.3)
Deficit in earnings of equity method investments, net of distributions	<u>\$ (62.5)</u>	<u>\$ (18.4)</u>	<u>\$ (102.1)</u>

- ⁽¹⁾ In July 2018, we purchased the remaining 50% partnership interest in Koma and consolidated the project in our financial statements. See Note 3 *Acquisitions and divestments*.
- ⁽²⁾ In November 2017, we sold our 17.7% interest in Selkirk.
- ⁽³⁾ In May 2019, we acquired the equity ownership interests held by AltaGas in Craven and Grayling. See Note 3 *Acquisitions and divestments*.

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Distributions from equity method investments exceeded (loss) earnings of equity method investments for the years ended December 31, 2019, 2018 and 2017, 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, 2019, 2018 and 2017, and operating results for the years ended December 31, 2019, 2018 and 2017, respectively, for our proportional ownership interest in equity method investments:

	2019	2018	2017
Assets			
Current assets			
Frederickson	\$ 2.1	\$ 2.5	\$ 1.9
Orlando Cogen, LP	7.8	7.7	9.2
Koma Kulshan Associates ⁽¹⁾	—	—	0.5
Chambers Cogen, LP	14.4	15.6	17.3
Craven County Wood Energy, LP ⁽²⁾	4.4	—	—
Grayling Generating Station, LP ⁽²⁾	3.3	—	—
Non-current assets			
Frederickson	63.9	70.0	76.2
Orlando Cogen, LP	6.1	7.1	8.1
Koma Kulshan Associates ⁽¹⁾	—	—	4.7
Chambers Cogen, LP	56.5	117.4	130.9
Craven County Wood Energy, LP ⁽²⁾	5.8	—	—
Grayling Generating Station, LP ⁽²⁾	6.8	—	—
	<u>\$ 171.1</u>	<u>\$ 220.3</u>	<u>\$ 248.8</u>
Liabilities			
Current liabilities			
Frederickson	\$ 0.3	\$ —	\$ 0.4
Orlando Cogen, LP	10.2	10.3	10.3
Koma Kulshan Associates ⁽¹⁾	—	—	0.1
Chambers Cogen, LP	13.7	9.2	3.7
Craven County Wood Energy, LP ⁽²⁾	0.8	—	—
Grayling Generating Station, LP ⁽²⁾	0.5	—	—
Non-current liabilities			
Frederickson	0.5	0.5	0.4
Orlando Cogen, LP	—	—	—
Koma Kulshan Associates ⁽¹⁾	—	—	0.2
Chambers Cogen, LP	48.2	59.5	70.0
Craven County Wood Energy, LP ⁽²⁾	—	—	—
Grayling Generating Station, LP ⁽²⁾	0.3	—	—
	<u>\$ 74.5</u>	<u>\$ 79.5</u>	<u>\$ 85.1</u>

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

⁽²⁾ In May 2019, we acquired the equity ownership interests held by AltaGas in Craven and Grayling. See Note 3 *Acquisitions and divestments*.

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Operating results	2019	2018	2017
Revenue			
Frederickson	\$ 36.0	\$ 21.0	\$ 21.6
Orlando Cogen, LP	61.5	60.2	55.0
Koma Kulshan Associates ⁽¹⁾	—	1.2	1.8
Chambers Cogen, LP	39.4	43.3	43.8
Selkirk Cogen Partners, LP ⁽²⁾	—	—	1.8
Craven County Wood Energy, LP ⁽³⁾	4.9	—	—
Grayling Generating Station, LP ⁽³⁾	2.2	—	—
	<u>144.0</u>	<u>125.7</u>	<u>124.0</u>
Project expenses			
Frederickson	26.9	14.1	21.0
Orlando Cogen, LP	28.5	30.1	29.4
Koma Kulshan Associates ⁽¹⁾	—	0.6	1.1
Chambers Cogen, LP	34.6	36.1	37.5
Selkirk Cogen Partners, LP ⁽²⁾	—	—	2.8
Craven County Wood Energy, LP ⁽³⁾	4.7	—	—
Grayling Generating Station, LP ⁽³⁾	1.8	—	—
	<u>96.5</u>	<u>80.9</u>	<u>91.8</u>
Project other expenses			
Frederickson	—	—	(28.4)
Orlando Cogen, LP	—	—	—
Koma Kulshan Associates ⁽¹⁾	—	—	—
Chambers Cogen, LP	(50.9)	(1.6)	(48.9)
Selkirk Cogen Partners, LP ⁽²⁾	—	—	(9.7)
Craven County Wood Energy, LP ⁽³⁾	—	—	—
Grayling Generating Station, LP ⁽³⁾	0.4	—	—
	<u>(50.5)</u>	<u>(1.6)</u>	<u>(87.0)</u>
Net income (loss)			
Frederickson	9.1	6.9	(27.8)
Orlando Cogen, LP	33.0	30.1	25.6
Koma Kulshan Associates ⁽¹⁾	—	0.6	0.7
Chambers Cogen, LP	(46.1)	5.6	(42.6)
Selkirk Cogen Partners, LP ⁽²⁾	—	—	(10.7)
Craven County Wood Energy, LP ⁽³⁾	0.2	—	—
Grayling Generating Station, LP ⁽³⁾	0.8	—	—
Equity in (loss) earnings of unconsolidated affiliates	<u>\$ (3.0)</u>	<u>\$ 43.2</u>	<u>\$ (54.8)</u>

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

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

⁽³⁾ 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. We recorded investment impairments of \$47.1 million, \$28.3 million and \$10.6 million, respectively, at our Chambers, Frederickson and Selkirk projects in the year ended December 31, 2017. These impairments are a component of the operating results in the table above. There were no impairment triggers during 2018 and accordingly

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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.

2017 – Event-driven test in the fourth quarter

Frederickson

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

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

When determining if the decrease in fair value estimated in our 2017 test was other than temporary, we considered the likelihood that future conditions would change such that the power prices currently observed in the forward pricing models would become more favorable over time. Frederickson operates in a region with large, planned coal facility retirements and strong population growth. However, it was our assessment that natural gas prices were

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likely to remain low when considering the current and expected future supply of shale gas and that these factors would negatively impact future merchant pricing. Based on these factors, we determined that the decline in the fair value of our equity investment in Frederickson was other than temporary. We recorded a \$28.3 million impairment in earnings from unconsolidated affiliates in the consolidated statements of operations for the year ended December 31, 2017.

2017 – Event-driven test in the second quarter

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

Selkirk

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

Chambers

Prior to our impairment analysis, Chambers was recorded as a \$124 million component of our equity investments in unconsolidated affiliates on the consolidated balance sheets.

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

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

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

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7. Inventory

Inventory consists of the following:

	December 31,	
	2019	2018
Parts and other consumables	\$ 12.2	\$ 9.6
Fuel	6.4	6.2
Total inventory	<u>\$ 18.6</u>	<u>\$ 15.8</u>

8. Property, plant and equipment, net

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

	December 31, 2019	December 31, 2018	Depreciable Lives
Land	\$ 6.4	\$ 5.3	
Office equipment, machinery and other	6.5	6.0	3 - 10 years
Leasehold improvements	2.1	2.1	7 - 15 years
Asset retirement obligation	23.4	24.1	1 - 43 years
Plant in service	848.1	874.4	1 - 45 years
Construction in progress	7.2	—	
	<u>893.7</u>	<u>911.9</u>	
Less accumulated depreciation	(391.6)	(362.4)	
Total property, plant and equipment, net	<u>\$ 502.1</u>	<u>\$ 549.5</u>	

Depreciation expense of \$37.6 million, \$40.0 million and \$83.3 million, was recorded for the years ended December 31, 2019, 2018 and 2017, respectively.

As described below, we recorded \$4.0 million and \$67.6 million of long-lived asset impairments to property, plant and equipment in the years ended December 31, 2019 and 2017, respectively, with a corresponding charge to Impairment in the statement of operations. No long-lived asset impairments to property, plant and equipment were recorded in the year ended December 31, 2018.

2019 – Event-driven test performed in fourth quarter

Calstock – Long-lived assets

Calstock operates under a PPA that expires in June 2020. The near-term expiration of the PPA resulted in a triggering event to test for long-lived asset impairment. We performed the test as of December 31, 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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
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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.

2018 – Event-driven test performed in fourth quarter

Williams Lake – Long-lived assets

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

Because of the uncertainty of our ability to recontract the project, we performed a probability-based approach when determining the weighted average fair value of Williams Lake. This approach considered the cash flows remaining under the current contract assuming a September 30, 2019 expiration date, as well as a modeled hypothetical long-term extension. In February 2019, the office of the Minister of Energy, Mines and Petroleum Resources in British Columbia made recommendations that the government could direct BC Hydro to pursue renewal transactions for existing biomass plants with expiring contracts. We considered these factors when creating our modeled hypothetical long-term extension. This model incorporates significant judgments and estimates by management when determining outcome likelihood, as well as long-term extension economics. Williams Lake has approximately 20 years of remaining useful life. We believe that Williams Lake provides value to British Columbia based on its positioning as a renewable resource, its synergy with the local forestry industry and its lower \$/KW cost than new biomass construction.

Upon testing Williams Lake for long-lived asset impairment, the estimated weighted-average undiscounted cash flows exceeded the carrying value of the asset group. Accordingly, no long-lived asset impairment was recorded at December 31, 2018. We subsequently executed a new ten-year Energy Purchase Agreement with BC Hydro for Williams Lake, which became effective October 1, 2019.

2017 – Event-driven test performed in fourth quarter

Williams Lake – Long-lived assets

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
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of the extension were known at December 31, 2017. Williams Lake's asset group for testing of long-lived assets totaled \$40.0 million consisting of \$39.4 million in PPE, net and a \$0.6 million intangible PPA asset.

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

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

2017 – Event-driven test performed in third quarter

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

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

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

We were unable to extend our land use license agreements through the end of our PPAs and ceased operations at these plants on February 7, 2018. The San Diego Projects are components of our Natural Gas segment.

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9. Goodwill

The following table presents goodwill by reportable segment for the years ended December 31, 2019 and 2018:

	Segment	2019	2018
Curtis Palmer	Hydroelectric	\$ 14.4	\$ 14.4
Morris	Natural Gas	3.3	3.3
Nipigon	Natural Gas	3.6	3.6
Total		<u>\$ 21.3</u>	<u>\$ 21.3</u>

Goodwill Impairment Testing

We perform our annual goodwill impairment test as of November 30 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.

Based on the results of the annual goodwill impairment tests for years ended December 31, 2019 and 2018, 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.

For the year ended December 31, 2019, we performed a quantitative test at each reporting unit. For the year ended December 31, 2018, we performed a quantitative test at our Curtis Palmer reporting unit and qualitative assessments at our Morris and Nipigon reporting units. Curtis Palmer's fair value exceeded its carrying value by approximately \$8.3 million or 9% at November 30, 2018.

In the fourth quarter of 2017, based on the results of the annual quantitative goodwill impairment test, management determined that the fair value of the Curtis Palmer reporting unit was below its respective carrying value, including goodwill. Accordingly, we recorded a \$14.7 million goodwill impairment at Curtis Palmer during the year ended December 31, 2017. Subsequent to the impairment, Curtis Palmer has \$14.4 million of goodwill remaining at December 31, 2017. As a hydro facility, Curtis Palmer has substantial useful life beyond the expiration of its PPA in 2027. Estimates of fair value beyond the end of its PPA expiration utilize merchant pricing assumptions and are sensitive to changes in forward power prices. These forward prices declined significantly from those observed in our 2016 test, resulting in a reduction of the fair value from our impairment test performed in the fourth quarter of 2016.

The other remaining reporting units with goodwill recorded, Nipigon (\$3.6 million of goodwill at December 31, 2017) and Morris (\$3.3 million of goodwill at December 31, 2017), had fair values that exceeded their carrying values by approximately \$111.7 million or 118% and accordingly, no goodwill impairment was recorded as of December 31, 2017.

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

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

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
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The following tables summarize the components of our intangible assets and other liabilities subject to amortization at December 31, 2019 and 2018:

Assets

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

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

Liabilities

	<u>Power Purchase and Fuel Supply Agreement Liabilities, Net</u>		
	<u>Power Purchase Agreements</u>	<u>Fuel Supply Agreements</u>	<u>Total</u>
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	<u>\$ (13.7)</u>	<u>\$ (6.1)</u>	<u>\$ (19.8)</u>

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

The following table presents amortization expense of intangible assets for the years ended December 31, 2019, 2018 and 2017:

	<u>2019</u>	<u>2018</u>	<u>2017</u>
PPAs	\$ 26.4	\$ 43.4	\$ 36.5
Fuel supply agreements	(0.4)	(0.4)	(0.4)
Total amortization	<u>\$ 26.0</u>	<u>\$ 43.0</u>	<u>\$ 36.1</u>

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
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The following table presents estimated future amortization expense for the next five years:

<u>Year Ended December 31,</u>	
2020	\$ 22.1
2021	20.2
2022	15.9
2023	12.6
2024	12.6

The weighted average remaining amortization period related to our intangible assets and liabilities was 8.6 years as of December 31, 2019.

11. Other long-term liabilities

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

	<u>2019</u>	<u>2018</u>
Long-term contract liability	\$ 0.2	\$ —
Net pension liability	1.2	1.2
Accrued LTIP and director share units	1.6	1.4
Other	1.7	2.4
	<u>\$ 4.7</u>	<u>\$ 5.0</u>

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

	<u>2019</u>	<u>2018</u>
Asset retirement obligations beginning of year	\$ 49.2	\$ 45.3
Accretion and change in estimate of asset retirement obligation	2.3	4.3
Acquisition	—	1.8
Costs incurred	(1.0)	(0.5)
Translation adjustments	1.0	(1.7)
Asset retirement obligations, end of year	<u>\$ 51.5</u>	<u>\$ 49.2</u>

In the third quarter of 2017, we performed an event-driven long-lived asset impairment test at our Naval Station, North Island and Naval Training Center projects. See Note 8, *Property, plant and equipment* for discussion of the facts and circumstances resulting in the impairment. At the time of the assessment, we had not completed our process for estimating decommissioning costs at those facilities. In the fourth quarter of 2017, based on information provided by third parties, we determined that the estimated costs to remove the facilities and return the land to the conditions required under their respective land rights agreements was approximately \$1.7 million. Prior to adjustment, we had recorded asset retirement obligations for Naval Station, North Island and Naval Training Center of \$6.7 million. These retirement obligations were based on estimates made at the time of their acquisition in November 2011, as well as engineering studies performed at the inception of these projects. These asset retirement obligations were accreted based on inflation and discount rates. As a result of the change in estimate for decommissioning costs, we recorded a \$5.0 million decrease to amortization expense in the fourth quarter of 2017. These projects ceased operations in February 2018. Subsequent to their shutdown, we have been actively planning the decommissioning of these facilities. Although the process is not final, changes to both the scope and cost of decommissioning these facilities resulted in a change of estimate of the asset retirement obligation. We increased the asset retirement obligation by \$1.4 million and \$3.5 million and recorded a corresponding decommissioning loss in the consolidated statements of operations for the years ended December 31,

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2019 and 2018, respectively.

12. Long-term debt

Long-term debt consists of the following:

	December 31, 2019	December 31, 2018	Interest Rate
Recourse Debt:			
Senior secured term loan facility, due 2025 ⁽¹⁾	\$ 380.0	\$ 450.0	LIBOR ⁽²⁾ plus 2.75 %
Senior unsecured notes, due June 2036 (Cdn\$210.0)	161.7	154.0	5.95 %
Non-Recourse Debt:			
Cadillac term loan, due 2025 ⁽³⁾	18.7	21.0	LIBOR plus 1.61 %
Less: unamortized discount	(5.8)	(9.0)	
Less: unamortized deferred financing costs	(4.7)	(7.2)	
Less: current maturities	(76.4)	(68.1)	
Total long-term debt	<u>\$ 473.5</u>	<u>\$ 540.7</u>	

Current maturities consist of the following:

	December 31, 2019	December 31, 2018	Interest Rate
Current Maturities:			
Senior secured term loan facility, due 2025 ⁽¹⁾	\$ 72.5	\$ 65.0	LIBOR ⁽²⁾ plus 2.75 %
Cadillac term loan, due 2025 ⁽³⁾	3.9	3.1	LIBOR plus 1.61 %
Total current maturities	<u>\$ 76.4</u>	<u>\$ 68.1</u>	

⁽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 \$370.6 million of the \$380.0 million remaining aggregate borrowings under our Term Loan at December 31, 2019. 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.

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

2020	\$ 76.4
2021	95.7
2022	109.3
2023	63.3
2024	39.7
Thereafter	176.0
	<u>\$ 560.4</u>

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, 2019, \$380.0 million of the Term Loan is outstanding and letters of credit in an aggregate face amount of \$78.3 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 \$380 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. The Revolver will mature in April 2022. 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.

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

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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) ranging from 5.00:1.00 at December 2019 to 4.25:1.00 from June 30, 2020, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 3.25:1.00 at December 31, 2019 to 4.00:1.00 from June 30, 2022. At December 31, 2019, 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 Atlantic Power Preferred Equity Ltd., a

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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

Atlantic Power Limited Partnership (the “Partnership”), a wholly-owned subsidiary acquired on November 5, 2011, has outstanding Cdn\$210.0 million (\$161.7 million as of December 31, 2019) 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, 2019, we were in compliance with these covenants. The MTNs are guaranteed by Atlantic Power Corporation and Atlantic Power Preferred Equity Ltd., an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership.

Non-Recourse Debt

Project-level debt at our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue-generating contracts of the projects. The loans have certain financial covenants that must be met in order to distribute available cash. At December 31, 2019, 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, 2019	December 31, 2018
6.00% Debentures due January 2025 (Series E) (Cdn \$115.0 million)	\$ 88.5	\$ 84.3
6.00% Debentures due December 2019 (Series D) (Cdn \$24.7 million)	—	18.1
Less: Unamortized deferred financing costs	(3.8)	(4.6)
Less: Unamortized discount	(3.6)	(4.0)
Total current and long-term convertible debentures	<u>\$ 81.1</u>	<u>\$ 93.8</u>

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.

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Series E Debentures

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

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

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

Series 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 \$3.2 million and \$1.2 million at December 31, 2019 and December 31, 2018, 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*.

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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,			
	2019		2018	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Cash and cash equivalents	\$ 74.9	\$ 74.9	\$ 68.3	\$ 68.3
Restricted cash	7.7	7.7	2.1	2.1
Derivative assets current	0.7	0.7	4.2	4.2
Derivative assets non-current	—	—	0.3	0.3
Derivative liabilities current	12.0	12.0	4.5	4.5
Derivative liabilities non-current	15.9	15.9	15.4	15.4
Long-term debt, including current portion	560.4	589.5	625.0	607.6
Convertible debentures	88.5	93.0	102.4	101.8

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.

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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, 2019 and December 31, 2018. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

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

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, 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. As of December 31, 2018, the credit valuation adjustments resulted in a \$1.0 million net increase in fair value, which consists of a \$0.1 million pre-tax gain in other comprehensive income and a \$0.9 million gain in change in fair value of derivative instruments.

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.

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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, 2019, 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 <u>December 31, 2019</u>
Beginning balance of liability at January 1, 2019	\$ 1.2
Total unrealized loss	1.8
Currency transaction loss	0.2
Ending balance of liability at December 31, 2019	\$ 3.2

15. Accounting for derivative instruments and hedging activities

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. We have one contract designated as a cash flow hedge, and we defer the effective portion of the change in fair value of the derivatives in accumulated other comprehensive (loss) income, 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 April 23, 2019, 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 2020 through February 2020. 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.

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Natural gas swaps

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

We have entered into various natural gas swaps to effectively fix the price of 16.3 million MMBtu of future natural gas purchases at our Orlando project, which is approximately 100% of our share of the expected natural gas purchases in 2020 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, 2019. 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, 2019, these agreements totaled \$370.6 million notional amount of the remaining \$380.0 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 Term Loan bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 2.75%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00%, resulting in a minimum of a 3.75% all-in rate on the Term Loan for the non-swapped portion of the remaining principal amount. The weighted average rate of these swap agreements is 2.00%, resulting in an all-in rate of approximately 4.75% for \$370.6 million of the Term Loan. In February 2020, APLP Holdings entered into additional interest rate swap agreements. For the period beginning March 31, 2020 through December 31, 2021, we mitigated exposure to changes in interest rates a one-month LIBOR fixed rate of 1.39%. The notional amount of these interest rate swap agreements range between \$9.4 million and \$45.0 million and are sized to the targeted debt balance payments over that period.

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

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, 2019, we have no foreign currency forward contracts.

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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, 2019 and December 31, 2018:

	Units	December 31, 2019	December 31, 2018
Natural gas swaps	Natural Gas (MMbtu)	16.3	16.3
Gas purchase agreements	Natural Gas (Gigajoules)	6.4	9.0
Interest rate swaps	Interest (US\$)	468.4	616.6

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, 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	<u>\$ 0.7</u>	<u>\$ 27.9</u>

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	December 31, 2018	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	\$ —	\$ 0.4
Interest rate swaps long-term	—	1.0
Total derivative instruments designated as cash flow hedges	—	1.4
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current	4.2	—
Interest rate swaps long-term	0.3	—
Natural gas swaps current	—	0.1
Natural gas swaps long-term	—	1.4
Gas purchase agreements current	—	2.8
Gas purchase agreements long-term	—	13.0
Convertible debenture conversion option	—	1.2
Total derivative instruments not designated as cash flow hedges	4.5	18.5
Total derivative instruments	<u>\$ 4.5</u>	<u>\$ 19.9</u>

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:

	Interest Rate Swaps	
Year Ended December 31, 2019		
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
Settlements expected to be recognized from OCI in expense in the next 12 months, net of \$0.1 million of tax	\$	0.3
Year Ended December 31, 2018		
Accumulated OCI balance at January 1, 2018	\$	1.1
Change in fair value of cash flow hedges		0.4
Realized from OCI during the period		0.1
Accumulated OCI balance at December 31, 2018	<u>\$</u>	<u>1.6</u>

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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,		
		2019	2018	2017
Gas purchase agreements	Fuel	\$ 8.2	\$ 4.1	\$ 7.5
Natural gas swaps	Fuel	0.9	0.3	0.4
Interest rate swaps	Interest, net	(3.2)	(3.3)	0.9

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 (loss) gain recognized in income	Year ended December 31,		
		2019	2018	2017
Natural gas swaps	Change in fair value of derivatives	\$ (4.6)	\$ (0.5)	\$ (1.8)
Gas purchase agreements	Change in fair value of derivatives	3.2	3.7	(5.0)
Interest rate swaps	Change in fair value of derivatives	(7.5)	(1.0)	8.9
		(8.9)	2.2	2.1
Convertible debenture conversion option	Other expense (income), net	1.8	(1.2)	—
Foreign currency forwards	Foreign exchange loss	\$ —	\$ 0.1	\$ —

16. Income tax expense

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

	Year Ended December 31,		
	2019	2018	2017
Current income tax expense	\$ 4.9	\$ 3.8	\$ 4.1
Deferred income tax expense (benefit)	4.9	(3.6)	(62.2)
Total income tax expense (benefit), net	\$ 9.8	\$ 0.2	\$ (58.1)

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The following is a reconciliation of the income taxes calculated at the Canadian enacted statutory rate of 27% for the years ended December 31, 2019, 2018 and 2017, respectively, to the provision for income taxes in the consolidated statements of operations:

	Year Ended December 31,		
	2019	2018	2017
Computed income tax (benefit) expense at Canadian statutory rate	(9.2)	10.1	(39.3)
Increases (decreases) resulting from:			
Operating in countries with different income tax rates	0.1	0.1	(20.1)
Change in valuation allowance	(9.1)	10.2	(59.4)
	5.7	(6.7)	(34.6)
	(3.4)	3.5	(94.0)
Dividend withholding tax and other cash taxes	1.3	0.5	0.2
Foreign exchange	1.7	—	(2.4)
Changes in tax rates	2.2	(3.3)	(1.5)
Remeasurement of deferred tax assets and liabilities	—	—	28.5
Capital gain (loss) on intercompany notes	0.1	(1.1)	(0.1)
Impairments	7.7	—	9.9
Other	0.2	0.6	1.3
	13.2	(3.3)	35.9
Income tax expense (benefit)	<u>\$ 9.8</u>	<u>\$ 0.2</u>	<u>\$ (58.1)</u>

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The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2019 and 2018 are presented below:

	<u>2019</u>	<u>2018</u>
Deferred tax assets:		
Loss carryforwards	\$ 135.9	\$ 163.3
Capital loss carryforwards	35.8	34.4
Interest expense limitation carryforwards	9.7	10.9
Finance and share issuance costs	0.1	0.5
Tax Credits	1.4	1.4
Stock-based compensation	2.4	2.9
Derivative contracts	5.7	3.2
Other long-term notes	—	1.5
Other	0.9	—
Total deferred tax assets	<u>191.9</u>	<u>218.1</u>
Less: Valuation allowance	<u>(145.4)</u>	<u>(139.7)</u>
	46.5	78.4
Deferred tax liabilities:		
Intangible assets	(21.9)	(30.0)
Property, plant and equipment	(31.2)	(41.9)
Basis difference in joint ventures	(5.4)	(15.5)
Other long-term investments	(1.3)	—
Total deferred tax liabilities	<u>(59.8)</u>	<u>(87.4)</u>
Net deferred tax liability	<u>(13.3)</u>	<u>(9.0)</u>
Net deferred tax (liability) asset by jurisdiction		
U.S. Federal and State	\$ (23.7)	\$ (16.0)
Canada	10.4	7.0
Net deferred tax liability	<u>(13.3)</u>	<u>(9.0)</u>

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.

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

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During the preparation of our 2019 consolidated financial statements, we identified an immaterial error in our previously issued financial statements relating to the presentation of deferred taxes in accordance with ASC 740 - Income Taxes. Under this guidance, entities are prohibited from offsetting deferred tax liabilities from one jurisdiction against deferred tax assets of another jurisdiction. At December 31, 2018, we recorded deferred tax assets in Canada of \$7.0 million and deferred tax liabilities of \$16.0 million in the U.S. Prior to the correction, we presented a net deferred tax liability of \$9.0 million. The prior period balance sheet has been revised to correct this error. This reclassification did not impact the consolidated statement of operations or consolidated statement of cash flows.

Valuation allowances are reserves that have been recorded to offset some or all of its deferred tax assets. The amount of the allowances recorded have been based on that portion of the tax assets for which evidence suggests it is more likely than not that a tax benefit will not be realized. As of December 31, 2019, we have recorded a valuation allowance of \$145.4 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, 2019, we had the following net operating loss carryforwards that are scheduled to expire in the following years:

	<u>U.S.</u>	<u>Canada</u>	<u>Total</u>
2029	\$ -	\$ 27.3	\$ 27.3
2030	41.1	-	41.1
2031	25.8	-	25.8
2032	13.4	5.8	19.2
2033	20.6	23.5	44.1
2034	122.3	9.1	131.4
2035	154.1	-	154.1
2036	17.0	20.3	37.3
2037	16.7	8.9	25.6
2038	-	10.1	10.1
2039	-	6.9	6.9
	<u>\$ 411.0</u>	<u>\$ 111.9</u>	<u>\$ 522.9</u>

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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, 2019, 2018 and 2017:

	Notional Shares	Grant Date Weighted-Average Fair Value per Notional Share
Outstanding at December 31, 2016	2,101,118	\$ 2.08
Granted	1,817,463	2.38
Vested and redeemed	(1,009,780)	2.22
Forfeitures	(24,227)	2.32
Outstanding at December 31, 2017	2,884,574	2.22
Granted	2,483,237	2.02
Vested and redeemed	(1,388,671)	2.22
Forfeitures	(26,939)	2.09
Outstanding at December 31, 2018	3,952,201	2.09
Granted	1,724,081	2.72
Vested and redeemed	(2,071,335)	2.10
Forfeitures	(26,855)	2.17
Outstanding at December 31, 2019	<u>3,578,092</u>	<u>\$ 2.38</u>

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 \$8.5 million, \$8.3 million and \$6.4 million for the years ended December 31, 2019, 2018 and 2017. The weighted average remaining vesting term for outstanding notional shares was 1.7 years at December 31, 2019. Approximately \$3.6 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 \$4.9 million, \$3.6 million and \$3.4 million for the years ended December 31, 2019, 2018 and 2017, respectively. Cash payments made for vested notional shares were \$2.1 million, \$0.9 million and \$0.7 million for the years ended December 31, 2019, 2018 and 2017, respectively.

Transition Equity Participation Agreement

We also have 269,952 transition notional shares outstanding at December 31, 2019 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

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without cause, resigns for good reason, 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 \$0.4 million to the pension plan in 2020.

The net annual periodic pension cost related to the pension plan for the years ended December 31, 2019, 2018 and 2017 includes the following components:

	<u>2019</u>	<u>2018</u>	<u>2017</u>
Service cost benefits earned	\$ 0.3	\$ 0.3	\$ 0.5
Interest cost on benefit obligation	0.5	0.5	0.6
Expected return on plan assets	(0.7)	(0.7)	(0.9)
Settlements	0.3	—	—
Net period benefit cost	<u>\$ 0.4</u>	<u>\$ 0.1</u>	<u>\$ 0.2</u>

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

	<u>2019</u>	<u>2018</u>
Projected benefit obligation at January 1	\$ (13.2)	\$ (15.8)
Service cost	(0.3)	(0.3)
Interest cost	(0.5)	(0.5)
Actuarial (gain) loss	(2.0)	1.4
Employee contributions	(0.1)	(0.1)
Benefits paid	0.2	0.8
Settlements	2.4	—
Foreign currency adjustment	(0.6)	1.3
Projected benefit obligation at December 31	<u>(14.1)</u>	<u>(13.2)</u>
Fair value of plan assets at January 1	\$ 12.0	\$ 13.9
Actual return on plan assets	2.0	(0.4)
Employer contributions	0.8	0.4
Employee contributions	0.1	0.1
Benefits paid	(0.2)	(0.8)
Settlements	(2.4)	—
Foreign currency adjustment	0.6	(1.2)
Fair value of plan assets at December 31	<u>12.9</u>	<u>12.0</u>
Funded status at December 31-excess of obligation over assets	<u>\$ (1.2)</u>	<u>\$ (1.2)</u>

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

	<u>2019</u>	<u>2018</u>
Non-current liabilities	\$ 1.2	\$ 1.2

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

	<u>2019</u>	<u>2018</u>
Unrecognized (gain) loss	\$ (1.7)	\$ 1.4

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

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

	<u>2019</u>	<u>2018</u>
Projected benefit obligation	\$ 14.1	\$ 13.2
Accumulated benefit obligation	12.9	12.2
Fair value of plan assets	12.9	12.0

The market-related value of the pension plan's assets is the fair value of the assets. Plan assets are invested in a common collective trust which totaled \$12.9 million and \$12.0 million for the years ended December 31, 2019 and 2018, 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:

	<u>2019</u>	<u>2018</u>
Weighted-Average Assumptions		
Discount rate	3.25 %	4.0 %
Rate of compensation increase	2.0 %	2.0 %

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

	<u>2019</u>	<u>2018</u>	<u>2017</u>
Weighted-Average Assumptions			
Discount rate	4.0 %	3.5 %	4.0 %
Rate of return on plan assets	5.8 %	5.8 %	5.8 %
Rate of compensation increase	2.0 %	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, 2019, 2018 and 2017, 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

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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:

	<u>2019</u>	<u>2018</u>
Canadian equity	30 %	29 %
U.S. equity	14 %	14 %
International equity	14 %	13 %
Canadian fixed income	39 %	41 %
Real estate equities	3 %	3 %
	<u>100 %</u>	<u>100 %</u>

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,	
2020	Cdn\$ 0.4
2021	0.5
2022	0.6
2023	0.7
2024	0.8
2025-2029	4.7

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 \$1.3 million, \$1.4 million, and \$1.2 million for the years ended December 31, 2019, 2018 and 2017, respectively.

19. Common shares

Our common shares have no par value and unlimited authorization. We had 108,675,294 and 108,341,738 common shares issued and outstanding at December 31, 2019 and December 31, 2018, respectively.

Stock Repurchase Program

During the year ended December 31, 2019, we repurchased and canceled 1,064,081 common shares at a total cost of approximately \$2.5 million under an NCIB that expired on December 30, 2019. In the year ended December 31, 2018, we repurchased and canceled 7,772,971 common shares at a total cost of approximately \$16.6 million.

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On December 31, 2019, 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, 2020 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 10,578,799 common shares based on 10% of our public float as of December 17, 2019 and we are limited to daily purchases of 9,243 common shares per day with certain exceptions including block purchases and purchases on other approved exchanges. All purchases made under the NCIBs will be made through the facilities of the TSX or other Canadian designated exchanges and published marketplaces and in accordance with the rules of the TSX at market prices prevailing at the time of purchase. Common share purchases under the NCIBs may also be made on the New York Stock Exchange in compliance with Rule 10b-18 under the 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.

Subsequent to December 31, 2019 and through February 26, 2020, we have repurchased and cancelled 1,742,919 common shares at a cost of \$4.1 million under the new NCIB.

Shelf Registration

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

20. Preferred shares issued by a subsidiary company

In 2007, a subsidiary acquired in our acquisition of the Partnership issued 5.0 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the “Series 1 Shares”) priced at Cdn\$25.00 per share. Cumulative dividends are payable on a quarterly basis. 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, 2019, there were 3,847,500 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 5.67% and holders of the Series 2 Shares converted 23,618 Series 2 Shares into Series 3 Shares.

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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, 2019 to 5.83%. 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, the rate on the Series 3 Shares was reset to 5.83% and 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 per share, plus an amount equal to all accrued and unpaid dividends thereon. At December 31, 2019, there were 2,504,131 Series 2 Shares and 1,077,391 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, 2 and 3 Shares are accounted for as a non-controlling interest on our consolidated balance sheets and consolidated statements of operations. The subsidiary company paid aggregate dividends of \$7.4 million, \$8.3 million and \$8.7 million for the years ended December 31, 2019, 2018 and 2017, respectively. In 2019, we repurchased and cancelled 427,500 of the Series 1 Shares, 100,377 of the Series 2 Shares and 148,311 Series 3 Shares, respectively for a total cost of \$8.0 million. We also repurchased and cancelled preferred shares at a cost of \$8.0 million and \$3.1 million in the years ended December 31, 2018 and 2017, respectively. As a result of the repurchases, losses of \$8.6 million, \$7.9 million and \$3.0 million were attributed to the preferred shares of a subsidiary company in the Consolidated Statements of Operations for the years ended December 31, 2019, 2018 and 2017, respectively.

Subsequent to December 31, 2019 and through February 26, 2020, we repurchased and cancelled 247,894 Series 1 Shares at a cost of \$3.1 million.

21. Basic and diluted (loss) earnings per share

Basic (loss) earnings per share is calculated by dividing net (loss) income 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 (loss) earnings per share is computed in a manner consistent with that of basic (loss) earnings 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 (loss) earnings 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 (loss) earnings per share. However, these instruments are included in the denominator, when dilutive, for purposes of computing diluted (loss) earnings per share under the treasury stock method.

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The following table sets forth the diluted net (loss) income and potentially dilutive shares utilized in the per share calculation for the years ended December 31, 2019, 2018 and 2017:

Basic	2019	2018	2017
Numerator:			
(Loss) income attributable to Atlantic Power Corporation	\$ (42.6)	\$ 36.8	\$ (98.6)
Denominator:			
Weighted average basic shares outstanding	109.3	112.0	115.1
Basic (loss) earnings per share attributable to Atlantic Power Corporation	<u>\$ (0.39)</u>	<u>\$ 0.33</u>	<u>\$ (0.86)</u>
Diluted			
Numerator:			
Net (loss) income attributable to Atlantic Power Corporation	(42.6)	36.8	(98.6)
Add: convertible debenture interest expense	—	4.7	—
	<u>(42.6)</u>	<u>41.5</u>	<u>(98.6)</u>
Denominator:			
Weighted average basic shares outstanding	109.3	112.0	115.1
Convertible debentures	—	27.8	—
Share-based compensation	—	2.0	—
	<u>109.3</u>	<u>141.8</u>	<u>115.1</u>
Diluted (loss) earnings per share attributable to Atlantic Power Corporation	<u><u>(0.39)</u></u>	<u><u>0.29</u></u>	<u><u>(0.86)</u></u>

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

	2019	2018	2017
Share-based compensation	1.5	—	1.6
Convertible debentures	27.8	—	8.1
Total	<u>29.3</u>	<u>—</u>	<u>9.7</u>

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 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. Our financial results for the years ended December 31, 2018 and 2017 have been revised to reflect these changes in operating segments. The segment classified as Corporate (formerly Un-Allocated Corporate) includes activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects and intercompany eliminations. These costs are not allocated to the operating segments when determining segment profit or loss.

We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project (loss) 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 use Project Adjusted EBITDA to provide comparative information about segment performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. Our equity investments in unconsolidated affiliates are presented on a proportionally consolidated basis in Project Adjusted EBITDA and in the reconciliation of Project Adjusted EBITDA to project (loss) income.

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

	<u>Solid Fuel</u>	<u>Natural Gas</u>	<u>Hydroelectric</u>	<u>Corporate</u>	<u>Consolidated</u>
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	<u>\$ (49.8)</u>	<u>\$ 68.5</u>	<u>\$ 36.0</u>	<u>\$ (98.5)</u>	<u>\$ (43.8)</u>
Year Ended December 31, 2018					
Project revenues	\$ 83.8	\$ 139.2	\$ 58.3	\$ 1.0	\$ 282.3
Segment assets	258.3	280.8	404.5	87.9	1,031.5
Goodwill	—	6.9	14.4	—	21.3
Capital expenditures	1.3	—	0.2	0.3	1.8
Project Adjusted EBITDA	\$ 46.7	\$ 90.4	\$ 47.5	\$ 0.5	\$ 185.1
Change in fair value of derivative instruments	—	(3.2)	—	1.0	(2.2)
Depreciation and amortization	23.7	57.0	18.9	0.1	99.7
Interest, net	3.3	0.1	—	—	3.4
Other project expense (income)	—	3.2	(7.2)	—	(4.0)
Project income (loss)	19.7	33.3	35.8	(0.6)	88.2
Administration	—	—	—	23.9	23.9
Interest expense, net	—	—	—	52.7	52.7
Foreign exchange gain	—	—	—	(22.8)	(22.8)
Other income, net	—	—	—	(3.0)	(3.0)
Net income (loss) before income taxes	19.7	33.3	35.8	(51.4)	37.4
Income tax expense	—	—	—	0.2	0.2
Net income (loss)	<u>\$ 19.7</u>	<u>\$ 33.3</u>	<u>\$ 35.8</u>	<u>\$ (51.6)</u>	<u>\$ 37.2</u>

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Consolidated
Year Ended December 31, 2017					
Project revenues	\$ 93.7	\$ 276.8	\$ 59.5	\$ 1.0	\$ 431.0
Segment assets	284.2	369.0	408.8	96.8	1,158.8
Goodwill	—	6.9	14.4	—	21.3
Capital expenditures	4.7	—	0.8	—	5.5
Project Adjusted EBITDA	\$ 54.9	\$ 185.3	\$ 47.2	\$ 1.4	\$ 288.8
Change in fair value of derivative instruments	(8.1)	7.9	—	(1.9)	(2.1)
Depreciation and amortization	30.4	84.5	17.7	0.6	133.2
Interest, net	19.1	0.1	—	—	19.2
Impairment	76.2	96.2	14.7	—	187.1
Other project (income) expense	(0.1)	(1.0)	—	(0.1)	(1.2)
Project (loss) income	(62.6)	\$ (2.4)	\$ 14.8	\$ 2.8	(47.4)
Administration	—	—	—	23.6	23.6
Interest, net	—	—	—	64.2	64.2
Foreign exchange loss	—	—	—	16.3	16.3
Other income, net	—	—	—	(0.4)	(0.4)
Net (loss) income before income taxes	(62.6)	(2.4)	14.8	(100.9)	(151.1)
Income tax benefit	—	—	—	(58.1)	(58.1)
Net (loss) income	\$ (62.6)	\$ (2.4)	\$ 14.8	\$ (42.8)	\$ (93.0)

The table below provides information, by country, about our consolidated operations for each of the years ended December 31, 2019, 2018 and 2017 and Property, Plant and Equipment, PPAs and other Intangible and total assets as of December 31, 2019 and 2018, 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		
	2019	2018	2017
United States	\$ 208.4	\$ 203.4	\$ 262.4
Canada	73.2	78.9	168.6
Total	\$ 281.6	\$ 282.3	\$ 431.0

	Property, Plant and Equipment, net of accumulated depreciation		PPAs and other intangible assets, net of accumulated amortization		Total assets	
	2019	2018	2019	2018	2019	2018
United States	\$ 353.9	\$ 396.5	\$ 142.8	\$ 165.9	\$ 762.3	\$ 842.2
Canada	148.2	153.0	1.5	4.2	173.3	189.3
Total	\$ 502.1	\$ 549.5	\$ 144.3	\$ 170.1	\$ 935.6	\$ 1,031.5

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. Niagara Mohawk, Atlantic City Electric, BC Hydro, Georgia Power Company and IESO provided 15.1%, 12.6%, 12.5%, 10.9% and 10.8%, respectively, of total consolidated revenues for the year ended December 31, 2018. IESO, Niagara Mohawk, San Diego Gas & Electric and BC Hydro provided 20.3%, 10.7%, 10.6% and 10.3%, respectively, of total consolidated revenues for the year ended December 31, 2017. IESO purchased electricity from the Calstock,

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

Nipigon and Tunis projects and previously purchased electricity from our North Bay and Kapuskasing projects in the Natural Gas segment. Niagara Mohawk purchases electricity from the Curtis Palmer project in the Hydroelectric segment and BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the Hydroelectric and Solid Fuel segments. Georgia Power Company purchases electricity from the Piedmont project in the Solid Fuel segment. Atlantic City Electric purchases electricity from the Chambers project in the Solid Fuel segment. San Diego Gas & Electric previously purchased electricity from our Naval Station, Naval Training Center and North Island projects in the Natural Gas 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, 2019, our commitments under this agreement are estimated as follows:

2020	\$ 0.4
2021	0.4
2022	0.2
2023	—
2024	—
Thereafter	—
	<u>\$ 1.0</u>

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, 2019, our commitments under such outstanding agreements are estimated as follows:

2020	\$ 5.0
2021	5.0
2022	5.2
2023	—
2024	—
Thereafter	—
	<u>\$ 15.2</u>

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

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. Cadillac is expected to be offline for an extended period. Our insurance provides coverage for 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. Our 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. At this time, we are unable to determine the Cadillac plant's expected return to service date. The business interruption deductible under the policies insuring the Cadillac assets is 45 days of lost production, which had an approximate \$1.4 million impact to cash flows from operations in 2019.

Impact

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 is probable that insurance proceeds will be received in order to repair the facility, we applied accounting for gains and losses on involuntary conversions. Based on loss estimates and expenses incurred through third quarter of 2019, we recorded a \$25 million write-down of Cadillac's property, plant and equipment and a \$0.3 million write-down of capital spares inventory in the three months ended September 30, 2019. This was our best estimate at the time the loss was incurred, but may be subject to future adjustments based on actual experience of replacement cost. We also recorded a corresponding insurance receivable (\$24.2 million), a component of other current assets, less the \$1.0 million property damage deductible, which was recorded as a charge to other project income, because we believe that it is probable we will receive insurance recoveries up to our estimated plant write-down. As the plant is repaired, any costs incurred will be capitalized to property, plant

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

and equipment. As of December 31, 2019, we have recorded \$5.1 million in capital additions related to repairs at Cadillac. Insurance proceeds in excess of the net book value of the property, plant and equipment write-down, if any, would be recorded as a gain in the period those proceeds are received.

During the three months ended December 31, 2019 and for the full year 2019, we received \$11.3 million of insurance proceeds with respect to the fire at Cadillac, which were applied against the September 30, 2019 insurance receivable of \$24.2 million. During the three months ended December 31, 2019, we recorded a \$0.6 million write-down of fuel inventory, with a corresponding increase to the insurance receivable. As of December 31, 2019, the insurance receivable balance totals \$13.5 million. Additionally, we estimate anticipated insurance recoveries related to business interruption losses of \$2.0 million for the three months ended December 31, 2019. 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. Anticipated reimbursements for business interruption losses were not recorded as of December 31, 2019 as all contingencies related to these claims had not been resolved as of period end. We expect all contingencies related to business interruption losses to be resolved once final payment is received from the insurers, which is when we will recognize the reimbursements in earnings. The Cadillac biomass plant is a component of our Solid Fuel segment.

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, 2019.

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 is 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, 2019
Lease cost: ⁽¹⁾	
Operating lease cost	\$ 1.9
Short-term lease cost	0.1
Sublease income	(1.2)
Total lease cost	\$ 0.8

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

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

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

	<u>Lease Payments</u>	<u>Income from subleasing</u>	<u>Net lease payments</u>
2020	\$ 2.3	\$ (1.1)	\$ 1.2
2021	2.0	(1.1)	0.9
2022	1.7	(1.1)	0.6
2023	1.2	(0.7)	0.5
2024	0.1	—	0.1
Thereafter	—	—	—
Total operating lease payments	<u>\$ 7.3</u>	<u>\$ (4.0)</u>	<u>\$ 3.3</u>
Less: present value discount	<u>(0.5)</u>		
Total operating lease liabilities	<u>\$ 6.8</u>		

	<u>Lease Payments</u>
2020	\$ 0.1
2021	0.1
2022	0.1
Thereafter	—
Total finance lease payments	<u>\$ 0.3</u>
Less: amount representing interest	<u>(0.1)</u>
Total finance lease liabilities	<u>\$ 0.2</u>

Other Information:

Cash paid for amounts included in the measurement of lease liabilities ⁽¹⁾:

Operating cash flows from operating leases	\$ 0.8
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⁽¹⁾ Cash flows from finance leases are immaterial to the Company

Lease assets obtained in exchange for new lease liabilities (non-cash):

Operating	\$ 1.6
Finance	0.2

Weighted average remaining lease term (in years):

Operating leases	3.5
Finance leases	2.4

Weighted average discount rate - operating leases	3.92 %
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Weighted average discount rate - finance leases	4.06 %
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ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

The following table presents future minimum lease payments under operating leases, which at inception had a non-cancelable term of more than one year, as previously reported.

	<u>Lease Payments</u>	<u>Income from subleasing</u>	<u>Net lease payments</u>
2019	\$ 1.7	\$ (1.1)	\$ 0.6
2020	1.4	(1.1)	0.3
2021	1.4	(1.1)	0.3
2022	1.4	(1.1)	0.3
2023	0.8	(0.7)	0.1
Thereafter	—	—	—
	<u>\$ 6.7</u>	<u>(5.1)</u>	<u>\$ 1.6</u>

We have no lease transactions with related parties. We did not utilize practical expedients for separating lease components for all operating leases that we lease.

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 (loss) income over the lease term. We elected the practical expedient that permits us to retain our existing lease assessment and classification.

As of December 31, 2019, we have twelve PPAs accounted for as operating leases and one PPA accounted as a direct financing lease 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 eight months to twenty-four years. At December 31, 2019, a net investment in lease of \$0.9 million is recorded in current assets on the consolidated balance sheets for our direct financing lease. 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,	
	<u>2019</u>	<u>2018</u>
Solid Fuel	\$ 79.1	\$ 83.8
Natural Gas	24.4	20.8
Hydroelectric	68.8	58.3
	<u>\$ 172.3</u>	<u>\$ 162.9</u>

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.

ATLANTIC POWER CORPORATION
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (continued)
(in millions of U.S. dollars, except per-share amounts)

25. Unaudited selected quarterly financial data

Unaudited selected quarterly financial data are as follows:

	Quarter Ended				Total
	2019				
	December 31,	September 30,	June 30,	March 31,	
Project revenue	\$ 66.2	\$ 71.1	\$ 71.3	\$ 73.0	\$ 281.6
Project (loss) income	(33.4)	27.9	21.7	30.6	46.8
Net (loss) income	(63.4)	14.3	2.9	2.4	(43.8)
Net (loss) income attributable to Atlantic Power Corporation	(65.3)	12.6	1.2	8.9	(42.6)
(Loss) income per share attributable to Atlantic Power Corporation	\$ (0.60)	\$ 0.12	\$ 0.01	\$ 0.08	\$ (0.39)
Weighted average number of common shares outstanding-basic	109.3	109.4	109.7	108.9	109.3
Diluted (loss) income per share attributable to Atlantic Power Corporation	\$ (0.60)	\$ 0.10	\$ 0.01	\$ 0.07	\$ (0.39)
Weighted average number of common shares outstanding-diluted	109.3	137.8	110.2	138.6	109.3

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

ATLANTIC POWER CORPORATION
SCHEDULE I—CONDENSED BALANCE SHEETS (PARENT COMPANY ONLY)

(in millions of U.S. dollars)

	December 31,	
	2019	2018
Assets		
Current assets:		
Cash and cash equivalents	\$ 43.2	\$ 42.4
Prepayments and other current assets	0.8	3.3
Total current assets	44.0	45.7
Investment in and advances to / from subsidiaries	0.3	51.6
Total assets	<u>\$ 44.3</u>	<u>\$ 97.3</u>
Liabilities		
Current liabilities:		
Accounts payable and accrued liabilities	\$ 3.6	\$ 3.4
Derivative liability	3.2	1.2
Convertible debentures	—	18.1
Total current liabilities	6.8	22.7
Convertible debentures	81.1	80.4
Other long-term liabilities	1.4	1.1
Total liabilities	89.3	104.2
Shareholders' equity	(45.0)	(6.9)
Total liabilities and shareholders' equity	<u>\$ 44.3</u>	<u>\$ 97.3</u>

See accompanying notes to condensed financial statements.

ATLANTIC POWER CORPORATION
SCHEDULE I—CONDENSED STATEMENTS OF OPERATIONS (PARENT COMPANY ONLY)
(in millions of U.S. dollars)

	<u>Year Ended December 31,</u>		
	<u>2019</u>	<u>2018</u>	<u>2017</u>
Administrative and other expenses:			
Administrative expense	\$ 4.6	\$ 5.0	\$ 5.4
Interest expense, net	10.0	13.5	11.6
Foreign exchange loss (gain)	4.3	(9.4)	4.0
Other expense (income)	2.0	(3.1)	0.2
Loss from parent company	(20.9)	(6.0)	(21.2)
Equity (loss) earnings of subsidiaries, net of income tax benefit	(22.9)	43.2	(71.8)
Net (loss) income	<u>\$ (43.8)</u>	<u>\$ 37.2</u>	<u>\$ (93.0)</u>

See accompanying notes to condensed financial statements.

ATLANTIC POWER CORPORATION

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

(in millions of U.S. dollars)

	Years Ended December 31,		
	2019	2018	2017
Cash provided by operating activities:			
Net (loss) income	\$ (43.8)	\$ 37.2	\$ (93.0)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Non-cash losses (earnings) from subsidiaries, net of taxes	22.9	(43.2)	71.8
Dividends received from subsidiaries	68.5	39.0	67.9
Unrealized foreign exchange loss (gain)	4.3	(9.4)	4.0
Change in fair value of convertible debenture conversion option derivative	1.8	(3.2)	—
Amortization of debt discount and deferred financing costs	0.7	2.6	—
Change in other operating balances			
Accounts receivable	(9.0)	7.4	(1.1)
Prepayments and other assets	2.5	1.0	1.4
Accounts payable and accrued liabilities	1.4	0.8	0.5
Cash provided by operating activities	49.3	32.2	51.5
Cash used in investing activities:			
Advances to / from investments in subsidiaries	(27.5)	2.4	(57.8)
Cash paid for acquisition	—	(13.6)	—
Deposit for acquisition	—	(2.6)	—
Cash used in investing activities	(27.5)	(13.8)	(57.8)
Cash used in financing activities:			
Common share repurchases	(2.5)	(16.6)	(0.2)
Repayment of convertible debentures	(18.5)	(88.1)	—
Deferred financing costs	—	(5.1)	—
Proceeds from convertible debenture issuance	—	92.2	—
Repayment of intercompany note	—	(0.2)	(0.9)
Cash used in financing activities	(21.0)	(17.8)	(1.1)
Net increase (decrease) in cash and cash equivalents	0.8	0.6	(7.4)
Cash, restricted cash and cash equivalents at beginning of period	42.4	41.8	49.2
Cash, restricted cash and cash equivalents at end of period	\$ 43.2	\$ 42.4	\$ 41.8
Supplemental cash flow information			
Interest paid	\$ 5.2	\$ 4.7	\$ 6.2

See accompanying notes to condensed financial statements

ATLANTIC POWER CORPORATION

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

(in millions of U.S. dollars)

1. Nature of business

Atlantic Power Corporation (the “Parent Company”) is a holding company that conducts substantially all of its business through its subsidiaries. As specified in certain of its subsidiaries’ credit agreements, there are restrictions on the Parent Company’s ability to obtain funds from certain of its subsidiaries through dividends (refer to Note 11, “Long-term debt”, to the consolidated financial statements). As of December 31, 2019, total Atlantic Power Corporation shareholders’ deficit was \$45.0 million and approximately \$5.3 million of net assets at certain subsidiaries constituted restricted net assets as defined in Rule 4-08(e)(3) of Regulation S-X. The restricted net assets of these subsidiaries exceeded our consolidated net assets, thus requiring this Schedule I, “Condensed Financial Information of the Registrant.” Accordingly, the balance sheets as of December 31, 2019 and 2018, and the statements of operations and cash flows for the years ended December 31, 2019, 2018 and 2017, have been presented on a “Parent-only” basis. In these statements, the Parent Company’s investments in its consolidated subsidiaries are presented under the equity method of accounting. We had no undistributed earnings from our unconsolidated investments for the years ended December 31, 2019, 2018 and 2017, respectively.

As disclosed in Note 12 of the consolidated financial statements, APLP Holdings may be restricted from making dividend payments or other distributions to Atlantic Power Corporation, and APLP and its subsidiaries may be prohibited from making dividends or distributions to Atlantic Power Preferred Equity Limited shareholders in the event of a covenant default or if APLP Holdings fails to achieve a target principal amount on the Term Loan that declines quarterly based on a predetermined specified schedule. APLP Holdings has made principal payments to meet the targeted debt balance requirement as of December 31, 2019 and is not prohibited from making dividends to the Parent Company. The consolidated equity of APLP Holdings was approximately \$4.9 million at December 31, 2019 and includes the subsidiaries with restricted net assets of \$5.3 million at December 31, 2019 disclosed above.

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

2. Dividends received

The Parent Company received dividends of \$68.5 million, \$39.0 million and \$67.9 million in 2019, 2018 and 2017, respectively, from its consolidated and unconsolidated subsidiaries.

ATLANTIC POWER CORPORATION
SCHEDULE II—VALUATION AND QUALIFYING ACCOUNTS
FOR THE YEARS ENDED DECEMBER 31, 2019, 2018 and 2017

(in millions of U.S. dollars)

	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
Income tax valuation allowance, deducted from deferred tax assets:					
Year ended December 31, 2019	\$ 139.7	\$ 5.7	\$ —	\$ —	\$ 145.4
Year ended December 31, 2018	\$ 151.4	\$ (11.7)	\$ —	\$ —	\$ 139.7
Year ended December 31, 2017	\$ 186.0	(34.6)	\$ —	\$ —	\$ 151.4

CERTIFICATION

I, James J. Moore, 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 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 accounting 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: February 27, 2020

/s/ JAMES J. MOORE, JR.

James J. Moore, Jr.
President and Chief Executive Officer
(Principal Executive Officer)

CERTIFICATION

I, Terrence Ronan, 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 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 accounting 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: February 27, 2020

/s/ TERRENCE RONAN

Terrence Ronan
Chief Financial Officer
(Principal Financial Officer)

**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 ended December 31, 2019 (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: February 27, 2020

/s/ JAMES J. MOORE, JR.

James J. Moore, Jr.

President and Chief Executive Officer

**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, 2019 (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.

Date: February 27, 2020

/s/ TERRENCE RONAN

Terrence Ronan
Chief Financial Officer
(Principal Financial Officer)

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CORPORATE INFORMATION

Corporate Headquarters

3 Allied Drive, Suite 155
Dedham, MA 02026
Tel: 617.977.2400

www.atlanticpower.com

Transfer Agent

Computershare Investor Services, Inc.
100 University Avenue, 8th Floor
Toronto, ON M5J 2Y1 CANADA

Legal Counsel

Goodmans LLP
Bay Adelaide Centre
333 Bay Street, Suite 3400
Toronto, ON M5H 2S7 CANADA

Cleary Gottlieb
One Liberty Plaza
New York, NY 10006 USA

Auditor

KPMG LLP
345 Park Avenue
New York, NY 10154 USA

Annual Meeting

The Annual Meeting of Shareholders will be held on June 17, 2020.

Stock Exchange Information

TSX Ticker Symbol: ATP
NYSE Ticker Symbol: AT

Investor Information

Individual shareholders, security analysts, portfolio managers and other institutional investors seeking information about the company should contact Atlantic Power Corporation Investor Relations at 617.977.2700 or by email at info@atlanticpower.com.



AtlanticPower
Corporation