**PREPARED REMARKS**
**Q4 2018**
**MARCH 1, 2019**

**Ron Bialobrzeski – Atlantic Power Corporation – Director, Finance**

***Page 2: Cautionary Note Regarding Forward-Looking Statements***

Financial figures that are presented in this document and the presentation are stated in U.S. dollars and are approximate unless otherwise noted.

Management's prepared remarks presented in this document include forward-looking statements. As discussed on page 2 of the accompanying presentation, these statements are not guarantees of future performance and involve certain risks and uncertainties that are more fully described in our various securities filings. Actual results may differ materially from such forward-looking statements. Please see Atlantic Power Corporation's Safe Harbor statement, presented on page 2 of the accompanying presentation, which can be found in the Investor Relations section of our website.

In addition, the financial results in the Company's press release and the presentation include both GAAP and non-GAAP measures, including Project Adjusted EBITDA. For reconciliations of this measure to the most directly comparable GAAP financial measure to the extent that they are available without unreasonable effort, please refer to the press release, the Appendix of the presentation or our annual report on Form 10-K, all of which are available on our website.

For additional information, please refer to our most recent SEC filings, which can be accessed free of charge on our website, www.atlanticpower.com, and on EDGAR and SEDAR.

**James J. Moore, Jr. – Atlantic Power Corporation – President & CEO**

***Page 4: 2018 Highlights***

I will review the highlights of 2018 – our financial results and our operational and commercial initiatives. The rest of the team will provide more detail, and Terry Ronan will review our fourth quarter results. I'll also comment on our outlook and areas of focus for 2019.

**Financial results**. Our 2018 Project Adjusted EBITDA of $185.1 million was at the high end of our guidance range, and our operating cash flow of $137.5 million exceeded our estimate. We ended the year with liquidity of $191 million, including $39 million of discretionary cash.

**Balance sheet**. We repaid a total of $100.3 million of debt in 2018, using our strong operating cash flow from our existing businesses. We also re-priced our term loan two more times, reducing the spread by 75 basis points in 2018 and 225 basis points cumulatively since issuance. The combination of lower debt levels and a lower rate on the term loan is continuing to reduce our annual interest payments, which benefits our operating cash flow. We also further improved our debt maturity profile by refinancing most of our 2019 convertible debentures with a new 2025 convertible debenture, and we plan to redeem the remaining 2019s later this year.

**Capital allocation**. We have allocated most of our free cash flow (as it is typically defined) to debt reduction. But in 2018, we also allocated a meaningful portion of our discretionary cash to a combination of share repurchases and, for the first time in more than five years, external growth.

We invested $16.6 million in the repurchase of approximately 7.8 million shares at an average price of $2.13 per share. This reduced our share count by approximately 6.7%. We did so because we believed that our shares were trading below our estimates of intrinsic value per share. We also repurchased approximately 645 thousand preferred shares at a total cost of US$8.0 million equivalent, at an attractive after-tax yield of approximately 11%.

We also announced two acquisitions in 2018, both with long-dated PPAs that will add to Project Adjusted EBITDA and improve longer-term cash flows. In July, we consolidated our ownership of the Koma Kulshan hydro facility, which added 6 megawatts (MW), and in September, we agreed to acquire two biomass plants in South Carolina, which we expect will add 40 MW at closing later this year. As I indicated on our previous quarterly call, we think this investment represents a rare opportunity in the current market to earn attractive returns while adding to our PPA cover. These two acquisitions totaled $25.8 million, including the remaining $10.4 million for the South Carolina biomass plants that will be paid at closing.

**Costs**. In 2018, we maintained our overhead costs in line with 2016 and 2017 levels, approximately 55% below the 2013 peak level. Although the larger cost reduction opportunities are behind us, we continue to look for other pockets of potential savings. As noted on our previous quarterly call, in September, we moved to smaller headquarters space in our existing building, which will reduce our annual rent by approximately $245,000 or more than 40%.

**Operations**. We returned Tunis to commercial operation under a 15-year PPA in early October. We negotiated a Long-Term Enhanced Dispatch Contract for Nipigon that went into effect in November; this replaces the original PPA and runs through the same end date of 2022. We view the economics and risk profile of operating under the LTEDC as favorable versus the PPA. Separately, Dan Rorabaugh and the operations team continue to improve the efficiency of our operation and maintenance expenditures and practices.

**PPAs**. The re-contracting environment for gas plants remains challenging. Although we succeeded in obtaining new PPAs for two of our San Diego projects, we were not able to achieve site control with the Navy and are now in the process of decommissioning the sites. On the positive side, we agreed on a short-term extension at Williams Lake when that PPA expired last April, which we view as a bridge to a potential longer-term contract. Our customer at Kenilworth executed two successive one-year extensions of the PPA, which is now scheduled to expire in September 2020.

***Page 5: 2019 Outlook***

Our 2019 outlook with respect to each of these key areas is as follows:

**Project Adjusted EBITDA and Operating Cash Flow**. Our 2019 Project Adjusted EBITDA guidance of $175 million to $190 million is in line with the 2018 level, unlike last year when we experienced more than a $100 million decline versus 2017 that was PPA-related. Our expectations for operating cash flow reflect a modest decline in 2019, after adjusting for the working capital benefit related to PPA expirations that we realized in 2018.

**Balance sheet and credit profile**. We expect to repay $91 million of debt in 2019, including $5 million of debt at an equity-owned project, and at least $400 million in 2019 through 2023, reducing our debt outstanding by approximately half. At year end 2018, our consolidated leverage ratio was 4.5 times, which was up from the previous year due to lower 2018 EBITDA, but we expect it to improve in 2019 and beyond as debt repayment continues at a strong pace while PPA-related reductions in EBITDA are more moderate.

**Capital allocation**. As noted previously, we began 2019 with $39 million of discretionary cash. As Terry Ronan addresses in his prepared remarks, we believe that our liquidity and the cash flow generated by our existing assets are sufficient for us to continue paying down debt while also investing internally and externally in a disciplined manner. We have already allocated $7.0 million to share repurchases (mostly preferred shares; in January) and we will fund the remaining $10.4 million for the South Carolina biomass acquisition later this year. We continue to evaluate other potential acquisitions, and are hopeful that we will be successful on another this year.

**Costs**. 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.

**PPAs**. We have a weighted average remaining PPA life of approximately six years based on the expected 2019 EBITDA contribution of each project. Although this is shorter than we would like in this environment, during this period our PPAs will provide us with significant cash to allocate to debt repayment and other purposes. We believe that we can get to approximately net debt zero by 2025 if we execute on our debt reduction targets, and without aggressive assumptions regarding expiring PPAs. As I've noted before, at that time we'd have lower EBITDA but little (or no) net debt, hydro assets with long remaining physical and economic lives, cash flow from PPAs with remaining term, and potentially option value on some of the projects no longer under PPA.

Specific to 2019 and embedded in our guidance, there are fewer PPAs expiring in 2019 through 2021 than expired in 2017 and 2018. The four projects with expiring PPAs had a combined 2018 EBITDA of $17.6 million, though the 2019 number is considerably lower because of Williams

Lake. I point this out because the pattern of expirations is lumpy. Our EBITDA and cash flow is likely to be more stable during this three-year period.

**Dan Rorabaugh – Atlantic Power Corporation – SVP Operations**

Rather than focusing on fourth quarter operating results, since this is a year end review I'll address the full year results and then comment on a few data points specific to the fourth quarter.

***Page 6: FY 2018 Operational Performance***

Beginning on page 6 with our safety record, we had three recordable injuries in the fourth quarter and a total of four for the year. Although the three were relatively minor injuries and none resulted in lost time from work, they resulted in an increase in our recordable incident rate for 2018 to a level above the previous two years. We are committed to better performance, and we continue to place the highest priority on maintaining a strong culture of safety and regulatory compliance.

Turning to our operating results, generation declined 13.0% in 2018, primarily because of the San Diego projects, which were shut down on February 7, 2018 due to early termination of their PPAs. Frederickson declined due to milder temperatures and normal wind and hydro conditions, which reduced the need for gas generation relative to 2018. Generation at Curtis Palmer was down 14% from the year-ago period because 2017 benefited from above-average water flows, while 2018 was close to the long-term average. On the positive side, Manchief experienced higher dispatch and Mamquam generation increased 19% as a result of above-average water flows and the non-recurrence of a forced outage in 2017.

Our availability factor in 2018 increased to 96.5% from 90.3% in 2017. Frederickson, Kenilworth, Orlando and Mamquam all improved due to the non-recurrence of planned or forced outages in the prior period, and Piedmont had a shorter maintenance outage in 2018. Increases at these projects were partially offset by lower availability at Manchief due to the overhaul of one of its gas turbines in the second quarter of 2018. Although not a factor in the year-over-year comparison, Nipigon and Tunis were each 100% available under the terms of their respective contracts in the final months of 2018, which increased the weighted average availability of the fleet for the year.

***Page 7: Q4 2018 Operational Performance***

In the fourth quarter of 2018, as shown on page 7, generation declined 21.6% primarily due to the San Diego projects and Frederickson. Morris also declined due to lower PJM spot prices. On the positive side, Manchief had higher dispatch and Curtis Palmer benefited from increased water flows, which resulted in a 20% increase in generation from 2017 and 12% versus the long-term average. Although not as significant a factor overall, generation at Mamquam also benefited from higher water flows and increased 29% from 2017 and 36% versus the long-term average.

Availability improved slightly to 97.5% from 96.1% in the fourth quarter of 2017. The increase was primarily attributable to Kenilworth, which had a planned maintenance outage in the prior period, and Piedmont, which had an unplanned maintenance outage in the prior period. These positive comparisons were partially offset by lower availability at Oxnard due to unexpected repairs to the gas turbine.

***Page 8: Operations Update***

**Tunis**

We returned the Tunis plant to commercial operation in early October 2018 under a 15-year PPA with the Ontario Independent Electricity System Operator (IESO). The plant operates in dispatchable mode and receives capacity payments for being available and energy payments for those periods when it is required to produce power. Each day the project bids into the market based on its cost of production, but it has not been required to produce any power since returning to service. We expect its capacity factor to be low. Tunis is anticipated to generate approximately US$2 million to US$2.5 million of Project Adjusted EBITDA annually.

**Nipigon**

The long-term enhanced dispatch contract (LTEDC) with the IESO went into effect for Nipigon on November 1, 2018. The LTEDC replaced the project's original PPA, which was terminated, but the contract expiration date of December 2022 remains the same. Similar to Tunis, Nipigon will operate as a flexible plant, running only when needed and when it is economic to operate. It receives monthly capacity-type payments, with adjustments for operational savings that will be shared with the IESO, and earns energy revenues for those periods when it operates. We expect the economics of the LTEDC to be favorable versus the original PPA, although fairly similar to results under the short-term enhanced dispatch contract that was in place from January 2017 through October 2018.

In contrast to Tunis, we did not need to perform any overhauls of Nipigon's major equipment prior to its return to service, although we plan to upgrade the plant's gas turbine control system, which will enable remote simple cycle operation, as well as undertake other component or system upgrades as necessary. We are planning to undertake this work in early summer pending IESO approval.

**Decommissioning of San Diego Sites**

We have made significant progress with the Navy regarding defining the scope of work to be performed in decommissioning each of the three San Diego plant sites, as required by our land use agreements. Although not yet finalized, we have agreement on most issues. Once an agreement is finalized, we expect to seek bids from contractors for the work, probably this spring. Based on current cost estimates, which could increase upon finalization of scope and receipt of final bids for the work, we estimate that the project will require a cash outlay of approximately $5 million, nearly all of which will be incurred this year, with expected completion of the work in the third quarter. To date, we have realized $1.7 million of salvage proceeds, most of which was received in January 2019. We also have repurposed assets elsewhere in the fleet where possible.

**Cost Focus**

As noted on our previous quarterly conference call, last year we undertook a benchmarking of our thermal (non-hydro) plants. This year an important area of focus for the operations team will be analyzing the findings and implementing the recommendations where feasible. For example, we'll be looking at equipment major maintenance intervals and standardization of O&M

practices. In addition, we'll be undertaking a benchmarking of our hydro projects this year. Two of the goals we see as most important are implementing best practices at all of our plants, and continuing to collect data to allow further improvements to our cost structure as we add and integrate new projects into our fleet.

**Joseph E. Cofelice – Atlantic Power Corporation – EVP Commercial Development**

***Page 9: Commercial Update***

As noted in our press release and previous disclosures, we have four projects with PPAs expiring in 2019 and 2020 – Williams Lake, Kenilworth, Oxnard and Calstock. Since our previous quarterly conference call there have been some positive re-contracting developments at Williams Lake and Kenilworth. I will review those as well as our current thoughts on the Ontario market and policy developments affecting the New York market. I'll conclude with a brief update on our pending acquisition and external growth strategy.

**Williams Lake**

As part of a comprehensive review of BC Hydro by British Columbia's Ministry of Energy, Mines and Petroleum Resources, in mid-February the BC government released a review of BC Hydro's purchase of power from Independent Power Producers (IPPs). Although the report is generally critical of past policies and their impact on ratepayers, its discussion of biomass has positive implications for the re-contracting outlook for Williams Lake. The report emphasizes the continued importance of biomass plants to the forestry sector, recognizes the broader benefits that these assets provide to the Province, and states that these benefits would be "nullified" if biomass projects were forced to immediately transition to market prices upon expiration of their PPAs. The report also recognizes that PPA renewals for biomass plants likely will have to be above the current market price for power, though lower than under the existing PPAs. Finally, the report states that the Ministry is in discussions with holders of PPAs that are expiring in the next few years. We can confirm that we have been actively involved in this process.

We appreciate the leadership shown by the BC government in recognizing the value and importance of biomass projects to the forestry industry and local communities, and for creating a path for further engagement regarding re-contracting. Our efforts to ensure a long-term future for Williams Lake have been strongly and actively supported by the local community, led by Mayor Cobb and MLA Barnett, and the Williams Lake Indian Band. We expect that discussions will commence with BC Hydro in the next few months regarding a potential PPA renewal for Williams Lake.

The project is currently operating under a short-term contract extension, which runs to June 30, 2019, or September 30, 2019 at BC Hydro's option. Our current expectation is that we will continue operating under this short-term extension while we engage with BC Hydro on a potential longer-term PPA renewal.

Separately, final submissions in the written hearing on the appeal of the amended air permit for Williams Lake were submitted by all parties last fall and we are awaiting a decision by the Environmental Appeal Board, which should occur in the next few months. We expect the permit to be upheld. As a reminder, the amended air permit would allow Williams Lake to burn a wider range of fuels, including rail ties (up to 50% of the mix), although this would require installation of a new fuel shredder. However, the project does not require a permit amendment or a new fuel shredder to continue burning its current mix of fuels. We would commit to investment in a new shredder only if supported by project economics under a new long-term contract with BC Hydro.

**Kenilworth**

In January 2019, Merck exercised the second of three one-year extension options, which extends the existing PPA through September 2020. We continue to work with Merck on further short-term PPA extensions as well as longer-term solutions.

**Ontario**

Due to an unfavorable supply/demand balance in the Ontario wholesale power market, we continue with our efforts to market the North Bay and Kapuskasing power plants (not currently in operation) to potential industrial customers. These efforts have been adversely affected by low and volatile cryptocurrency pricing. We have nothing new to report at this time.

The Calstock biomass plant is a major focus of our re-contracting effort in Ontario for 2019. The PPA expires in June 2020 and current wholesale power prices are insufficient to support biomass plant operations. As we have in British Columbia, we will continue to work with government and other stakeholders to promote a fair valuation for the broader benefits (e.g., support of forestry and local communities) provided by biomass plants.

**Curtis Palmer**

Policy developments in New York appear to be generally favorable for renewable resources such as our Curtis Palmer hydro facility. In 2016, the state announced a goal of achieving 50% of electricity generation from renewable resources by 2030. More recently, last December the New York Independent System Operator (NYISO) issued a carbon pricing proposal. It is a complex proposal and the outlook for adoption and implementation is unclear. However, it is indicative of the aggressive approach the state is taking on this issue. We view this as having positive implications for the longer-term outlook for Curtis Palmer, where we currently have considerable PPA term remaining. If enacted in close to its current form, the policy could result in a value uplift in the post-PPA period. We will continue to monitor this process and are prepared to take advantage of any potential re-contracting opportunities that may emerge. We would note that the FERC license for Curtis Palmer does not expire until April 2040.

**South Carolina Biomass Acquisition**

In September 2018, we announced an agreement to acquire two contracted 20 megawatt biomass plants (Allendale and Dorchester) located in South Carolina from EDF Renewables for $13 million. All of the output from both plants is sold to Santee Cooper, a state-owned utility, under two PPAs that run to 2043. We remain on track to close this acquisition late in the third quarter or the fourth quarter of 2019. The long period to closing is to allow EDF Renewables to restructure the ownership of the plants, which can occur only after the end of the relevant tax credit recapture periods. We are using this time to ensure a smooth transition once the acquisition closes, and to be in a position to quickly implement initiatives similar to those we have undertaken at our own biomass projects over the past few years.

**Other Commercial Initiatives**

As we have discussed on previous quarterly calls, we remain focused on re-contracting of our existing assets, optimizing the value of our sites, and seeking new investment opportunities that meet our return requirements. Although we are generally agnostic when it comes to power generation technologies, we continue to believe that investing in operating biomass projects offers a more favorable risk/return profile than other wholesale power generation asset classes. It is also an asset class where we possess a competitive advantage due to our considerable operating expertise. Following on our agreement to acquire two South Carolina plants from EDF, we continue to pursue the acquisition of other biomass projects in operation. We hope to have more to say on this effort in the near future.

**Terry Ronan – Atlantic Power Corporation – EVP & CFO**

***Page 10: 2018 Financial Highlights***

Page 10 summarizes the financial highlights of 2018:

**Financial results**. Project Adjusted EBITDA of $185.1 million was at the high end of our guidance range of $170 million to $185 million. Morris exceeded our expectations (higher ancillary services revenues), as did Kenilworth (higher PJM pricing) and Manchief (higher dispatch). Cash provided by operating activities of $137.5 million benefited from the release of $21 million of working capital from projects at which the PPAs expired in 2017 and early 2018. We had anticipated this but our estimate of $95 million to $110 million had assumed working capital to be nil.

**Balance sheet and maturity profile**. We repaid a total of $100.3 million of term loan and project debt in 2018, as expected. We ended the year with a consolidated leverage ratio of 4.5 times, unchanged from the Sept. 30, 2018 level (although higher than the 3.3 times of 2017 due to lower Project Adjusted EBITDA in 2018). We reduced the spread on our credit facilities twice during the year to the current level of 275 basis points over LIBOR. In the first quarter of 2018, we addressed the majority of our 2019 convertible debenture maturities and now have Cdn$24.7 million (US$18.1 million equivalent) remaining, which we intend to redeem at or prior to the December 2019 maturity. We ended the year with liquidity of $191 million.

**Capital allocation**. During 2018, we used a portion of our discretionary cash to repurchase common shares when they were trading at a discount to our estimates of intrinsic value per share. We also repurchased preferred shares at after-tax cash yields (including tax savings) of approximately 11%. We made one external acquisition and announced another that is scheduled to close later this year. Each of these will add to our capacity, Project Adjusted EBITDA and average contract life.

I'll review each of these highlights in more detail on the following pages.

***Page 11: Q4 2018 Project Adjusted EBITDA bridge***

In the fourth quarter of 2018, Project Adjusted EBITDA declined to $46.6 million from $62.1 million in the fourth quarter of 2017. The decline was expected and primarily attributable to PPA expirations and lower-priced extensions since year end 2017. Curtis Palmer benefited from above-average water flows and thus EBITDA for the quarter exceeded our expectations. Key drivers (as shown in the bridge on page 11) included the following:

**PPA expirations**. The Kapuskasing and North Bay contracts expired on Dec. 31, 2017 and were not renewed. Both projects had received OEFC Settlement revenues in 2017 that did not recur. Together these accounted for $17.1 million of the decline in Project Adjusted EBITDA from the fourth quarter of 2017. Our three projects in San Diego ceased operations in early February 2018 and the PPAs were terminated effective March 1, 2018, which resulted in a $2.3 million reduction in Project Adjusted EBITDA from the fourth quarter of 2017. The Williams Lake PPA, which was scheduled to expire on April 1, 2018, was amended and extended for a short period on less favorable terms, resulting in a $1.6 million reduction to Project Adjusted EBITDA. In total, PPA expirations and lower-priced extensions accounted for $21 million of the $15.5 million decline in Project Adjusted EBITDA for the quarter.

**Oxnard**. Higher maintenance expense due to required repairs to the gas turbine reduced Project Adjusted EBITDA by $1.2 million.

**Other**. Other projects, primarily Calstock and Nipigon, accounted for another $1.6 million of the decline.

On the positive side:

**Curtis Palmer**. Water flows were above the long-term average as well as above the 2017 level, which resulted in increased generation for Curtis Palmer (+12% vs. long-term average and +20% vs. Q4 2017) and a $3.6 million increase in Project Adjusted EBITDA from the year-ago level.

**Tunis**. The Tunis project was returned to commercial operation under a 15-year PPA in October 2018. Project Adjusted EBITDA increased $1.8 million primarily due to the non-recurrence of start-up maintenance expense in the fourth quarter of 2017.

**Other**. Morris benefited from a higher PJM capacity price and higher steam sales, and Mamquam benefited from favorable water flows (+36% vs. long-term average and +29% vs. Q4 2017). The combined impact of these and other projects was $2.9 million.

***Page 12: Full Year 2018 Project Adjusted EBITDA bridge***

2018 Project Adjusted EBITDA of $185.1 million decreased $103.7 million from the 2017 level of $288.8 million. Results were better than expected mostly due to higher contributions by Morris, Kenilworth and Manchief, as previously noted. Relative to 2017, the PPA expirations and non-recurrence of the OEFC Settlement accounted for approximately $104 million, or effectively the entire decline. Results also were affected by re-start expenses at Tunis incurred in the first half of 2018 and the non-recurrence of the OEFC Settlement ($9.0 million) and a gas turbine maintenance outage at Manchief in the second quarter of 2018 ($5.5 million). Notwithstanding the strong water flows in the fourth quarter, Curtis Palmer had lower Project Adjusted EBITDA for the year ($2.8 million) because of lower generation earlier in the year. Projects that contributed positively to the comparison included Morris, Mamquam, Frederickson, Orlando and other projects, as indicated in the bridge on page 12.

***Page 13: Operating Cash Flow and Uses of Cash***

Page 13 reviews cash provided by operating activities for the fourth quarter and full year 2018 and a comparison to the 2017 comparable periods.

**Fourth Quarter 2018**

Cash provided by operating activities totaled $39.7 million in the fourth quarter, an increase of $9.2 million from $30.5 million in the fourth quarter of 2017. Although Project Adjusted EBITDA declined $15.5 million, the impact of this decline on cash flow was more than offset by lower cash interest payments ($16.8 million) and increased distributions from unconsolidated affiliates ($7.9 million). The decrease in cash interest payments was attributable to the non-recurrence of the Piedmont swap termination cost in the fourth quarter of 2017 ($9.4 million), the reduction in the term loan balance as a result of continued repayments, the reduction in the spread on the credit facilities, the repayment of Piedmont project debt in full in October 2017, and the shift in timing of interest payments on the Series E convertible debenture (January, whereas interest on the Series C and Series D convertible debentures was paid in December). Distributions from unconsolidated affiliates in the fourth quarter of 2018 included the September distribution from Orlando ($3.6 million), which was not received until October.

During the quarter, we used operating cash flow to repay $20 million of our term loan and to amortize $0.8 million of project debt. We also paid $2.0 million of dividends on our preferred shares.

**Full Year 2018**

Cash provided by operating activities for 2018 of $137.5 million declined $31.7 million from $169.2 million in 2017. Although Project Adjusted EBITDA declined $103.7 million, the reduction in operating cash flow was significantly less due to $39.3 million of favorable changes in working capital (as compared to the prior year), including $20.6 million related to PPA expirations and plant shutdowns (Kapuskasing, North Bay and the three San Diego projects); a $30.7 million reduction in cash interest payments resulting from debt repayment, a lower spread on our credit facilities and the non-recurrence of the Piedmont swap termination cost, and a $14.3 million increase in distributions from unconsolidated affiliates.

Recall that our operating cash flow estimate for 2018 of $95 million to $110 million assumed zero contribution from working capital changes. Adjusting for this working capital benefit, actual results were $14 million better than the midpoint of our estimate, and were attributable to better performance at several projects, lower cash interest payments as a result of the timing of convertible debenture interest payments and re-pricing the interest rate spread on the term loan.

In 2018, we used operating cash flow to repay $90 million of our term loan and to amortize $10.3 million of project debt. We also paid $8.3 million of dividends on our preferred shares and made $1.8 million of capital expenditures.

**Additional Capital Allocation**

During 2018, we used a portion of our discretionary cash to fund growth initiatives as well as to repurchase common and preferred shares under our normal course issuer bid, or NCIB, as follows:

**Acquisitions**. In June and July of 2018, we closed the acquisition of our partners' interests in our Koma Kulshan hydro project (adding 6 MW to our capacity) and bought out the O&M contract, using $12.8 million of our discretionary cash (net of cash acquired). With this acquisition we consolidated our ownership of Koma at an attractive valuation level; the acquisition also adds to the stability of our cash flows as the project has a PPA that runs to 2037.

In September, we used $2.6 million of cash to make a deposit in conjunction with our agreement to acquire two contracted biomass plants in South Carolina (each 20 MW) for $13 million. Closing of this acquisition is not expected until late third quarter or fourth quarter 2019. As with Koma Kulshan, these facilities have long-dated PPAs expiring in 2043.

**NCIB**. In the fourth quarter of 2018, we repurchased and canceled nearly 2 million common shares at an average price of $2.15/share (total investment of $4.3 million). For the year, we repurchased and canceled approximately 7.8 million common shares at an average price of $2.13/share (total investment of $16.6 million). We also repurchased and canceled approximately 645 thousand preferred shares at a total cost of Cdn$10.3 million (US$8.0 million equivalent). In December 2018, we put a new NCIB in place that allows us to repurchase up to 10% of our common shares, preferred shares and Series D and Series E convertible debentures, subject to certain limitations.

***Page 14: Liquidity***

As shown on page 14, at Dec. 31, 2018, we had liquidity of $191.4 million, including $68.3 million of unrestricted cash. Liquidity increased by approximately $11 million from the Sept. 30, 2018 level, which was due to an increase of $10.7 million in our unrestricted cash balance. Our revolver availability was essentially unchanged at $123.1 million. During the quarter we generated discretionary cash flow (after debt repayment, preferred dividends and capital expenditures) of approximately $17 million, of which we used $4.3 million for the repurchase of common shares. After holding aside $7 million for working capital purposes, we had about $39 million of discretionary cash at Dec. 31.

***Page 15: Debt Repayment Profile***

As previously reported, in the first quarter of 2018, we issued a Cdn$115 million Series E convertible debenture with a 6.00% coupon and a January 2025 maturity date, and used the net proceeds to redeem in full the Series C convertible debentures maturing in June 2019 and to partially redeem the Series D convertible debentures maturing in December 2019. We have Cdn$24.7 million of Series D convertible debentures remaining (US$18.1 million equivalent), which we plan to redeem at or prior to the maturity date. We have no other bullet maturities in 2019, 2020 or 2021.

As shown on page 15, we expect to repay a significant amount of debt over the next five years. Other than the Series D maturity in 2019, the repayments through 2023 consist of term loan and project debt, which is typically amortized from operating cash flow. There are two other bullet maturities during this period – our corporate revolver has an April 2022 maturity, but has no borrowings outstanding; and our term loan has an April 2023 maturity, with an expected remaining principal at that time of $125 million. Options available to us with respect to the $125 million include repayment at maturity using cash, an extension of the maturity date or a refinancing prior to maturity. Given the debt levels we foresee at that time, we believe that a refinancing is a feasible option. For purposes of this chart and the following one on page 16, we have assumed a refinancing of the $125 million prior to maturity.

***Page 16: Projected Debt Balances***

During the fourth quarter of 2018, we repaid $20 million of term loan and $0.8 million of project debt; for the full year, we repaid $90 million of term loan and $10.3 million of project debt. We ended the year with a consolidated leverage ratio of 4.5 times, unchanged from the Sept. 30th level. As we noted in our third quarter 2018 financial results, our leverage ratio has increased due to the decline in 2018 Project Adjusted EBITDA, notwithstanding debt repayment of $100 million. We expect our consolidated leverage ratio to decline to approximately 4 times by year end 2019 as we repay another $86 million of consolidated debt this year (as shown on page 22), move below four times in 2020 and to continue to decline thereafter.

Page 16 shows the impact of continued debt repayment on our debt balances, projected through year end 2023. Reflecting the five-year repayment total of $401 million discussed on page 15, which assumes refinancing of the $125 million remaining principal prior to its April 2023 maturity, our projected debt balance at year end 2023 would be $369 million, which would consist of the Cdn$210 million (US$154 million equivalent) Medium-Term Notes (with a 2036 maturity), the Cdn$115 million (US$84 million equivalent) Series E convertible debenture (2025 maturity), and $5 million of Cadillac project debt (also a 2025 maturity).

We expect that this substantial debt repayment over the next several years will generate significant interest cost savings that would mitigate a portion of the impact of lower Project Adjusted EBITDA (from PPA expirations, or extensions on less favorable terms) on our operating cash flow.

**Interest Costs**

As previously reported, in October 2018 we executed a fourth re-pricing of our term loan and revolver, reducing the spread another 25 basis points, to 275 basis points over LIBOR. This was the second reduction in the spread in 2018, with the earlier one a 50 basis point reduction in April. The spread on the facilities when originally issued in April 2016 was LIBOR plus 500.

Interest cost savings attributable to these two re-pricings (before associated transaction costs) are estimated to be $3.6 million in 2019. The savings from all four re-pricings are estimated to be $44.4 million from the time of re-pricing through the maturity dates of the facilities.

We also continue to manage our exposure to increases in market interest rates. At Dec. 31, 2018, approximately 96% of our debt carried either a fixed rate or a variable rate that has been fixed through interest rate swaps. Through December 2019, approximately 92% of our debt is either fixed rate or swapped, and through June 2020, approximately 83%. Our exposure to a 100 basis point change in LIBOR is $285 thousand in 2019.

***Page 17: 2019 Guidance***

**Project Adjusted EBITDA**

We have 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. These factors, which generally do not affect cash flow, are not included in Project Adjusted EBITDA.

Our 2019 Project Adjusted EBITDA guidance is $175 million to $190 million. The midpoint of this range is in line with our 2018 Project Adjusted EBITDA of $185.1 million. As shown on page 17, the most significant expected changes in 2019 relative to 2018 are:

**Williams Lake**. We're projecting an approximate $11 million reduction in Project Adjusted EBITDA due to the lower margins under the short-term PPA extension. Recall that for the first three months of 2018, the project was still operating under the original PPA. The short-term PPA is scheduled to expire on June 30 of this year, or September 30 at the customer's option. Our guidance does not assume a new contract, although we expect to engage in discussions with BC Hydro in the next couple of months.

**Tunis**. We're projecting an approximate $6 million increase in Project Adjusted EBITDA this year. Recall that in 2018, we incurred $4 million of maintenance expense prior to re-start of the project under the new PPA in October. On previous calls we had indicated an expected run-rate

EBITDA under the PPA and we believe that $2 million to $2.5 million remains a reasonable estimate.

**Manchief**. We did a major overhaul of one of the gas turbines in 2018, although the impact was partially offset by higher dispatch for the year. We are projecting an increase of $5 million in Project Adjusted EBITDA this year.

**Other**. There are several other small year-over-year changes that are close to offsetting. To the positive, Frederickson should benefit from lower maintenance expense this year. The San Diego projects had negative EBITDA in 2018 but this should be reduced and ultimately go to zero once the decommissioning is completed. We expect modestly negative comparisons at Mamquam (above-average water flows in 2018), Morris (maintenance expense) and Chambers.

One other note with respect to our 2019 Project Adjusted EBITDA guidance. Although at the midpoint it is in line with 2018, we expect variability with respect to quarterly comparisons. As noted, in the first quarter of last year, Williams Lake was under its original PPA. Because of that and a couple of other more modest factors, we expect first quarter 2019 results to be lower than the year-ago period. However, we expect second quarter 2019 results to be higher than a year ago, because the Manchief gas turbine outage occurred in the second quarter of 2018.

***Page 18: 2019 Cash provided by operating activities and planned capital allocation***

Based on our Project Adjusted EBITDA guidance, we estimate 2019 cash provided by operating activities in the range of $100 million to $115 million, as shown on page 18. As is our practice, this estimate assumes the impact of changes in working capital on cash flow is nil. Keep in mind that 2018 operating cash flow of $137.5 million included a $21 million benefit driven by the release of working capital from projects at which PPAs expired in 2017 and 2018. Adjusting for that factor, the expected decline in 2019 operating cash flow, about $9 million at the midpoint of our estimate, is modest and is primarily attributable to $5.2 million of project debt amortization at our Chambers equity method project after none in 2018, and $5 million of expected outlays for decommissioning of the San Diego projects.

Our principal planned uses of operating cash flow in 2019 include $65 million amortization of our term loan; $3.1 million of project debt amortization; $8 million of dividends on our preferred shares; and an estimated $1.2 million of capital expenditures.

I would note that although we expect our operating cash flow for 2019 to be approximately $30 million lower (at the midpoint of our estimate) than in 2018, the impact on our discretionary cash flow is mitigated by $32 million of lower term loan and project debt repayments. We expect to have discretionary cash flow available for other purposes, which could include share repurchases, our pending acquisition and the remaining Series D convertible debentures.

The acquisition of the South Carolina biomass plants is expected to close late in the third quarter or the fourth quarter of this year. We made a deposit of $2.6 million in September 2018 and expect to pay the remaining $10.4 million at closing. As noted previously, we plan to redeem the remaining Cdn$24.7 million (US$18.1 million equivalent) of the Series D at or prior to maturity in December. We have the option of using our revolver for either of these outlays rather than cash.

In January of this year, we used cash to repurchase 44 thousand common shares ($0.1 million) and 604 thousand preferred shares (Cdn$9.2 million, or US$6.9 million equivalent). With these repurchases, we have reached the 10% limit on the Series 1 and Series 3 preferred shares under the current NCIB.

Any additional investments or acquisitions or security repurchases would represent additional uses of cash this year.

***Page 19: Tax Update***

Page 19 contains a schedule of our net operating losses ("NOLs") by their expiration dates as well as some disclosures about the impact of U.S. tax legislation, updated from our comments on this topic a year ago. We have not been a significant cash taxpayer because of our NOL position; the $3.1 million of cash taxes that we paid in 2018 are mostly related to withholding taxes associated with the payment of dividends on the preferred shares in Canada. We do not anticipate becoming a federal cash taxpayer in either the U.S. or Canada in 2018 or 2019.

With regard to specific provisions of the new tax legislation, we expect that we will save a modest amount of cash taxes with the repeal of the corporate AMT. In addition, based on our understanding that net business interest deductions in excess of 30% of EBITDA would be disallowed under the new tax law, we believe that approximately $38.9 million of interest expense will be disallowed in 2018. This estimate is increased from the disclosure we provided a year ago. However, the interest expense deduction limitation is allowed to be carried forward indefinitely and we anticipate it will be deductible in future periods, as indicated on page [x].

In 2018, we experienced a material increase in our income tax expense of $58.3 million. This increase is primarily related to the impact of the reduction in the U.S. corporate tax rate from 35% to 21%, which results in a reduction in our U.S. deferred tax assets (primarily U.S. net operating losses) and, in turn, an increase in our U.S. tax expense.

During 2018, we recorded a reduction of $6.6 million to our existing U.S. Valuation Allowances ("VA"). Based on initiatives recently completed and various analyses, management determined that sufficient deferred tax liabilities were likely to reverse in a timely manner against certain deferred tax assets, resulting in a reduction of our VA in the United States.

**Other Updates**

There are two other items addressed in the 10-K that I will elaborate on:

**Decommissioning Cost Accrual**

As indicated by Dan Rorabaugh in his prepared remarks, we expect to receive and finalize bids for decommissioning the San Diego projects this spring. Based on preliminary estimates, we recorded an additional $3.5 million of decommissioning expense in the fourth quarter of 2018, which is included in Project income (loss) but not included in Project Adjusted EBITDA. We estimate there will be approximately $5 million of cash outlays associated with this project, the majority of which will be incurred in 2019. Our estimates of expense and cash requirements are subject to change pending finalization of scope with the Navy and receipt of final bids for the work. We have received $1.7 million of salvage proceeds to date, most of it in January.

**Impairment Analysis**

At Dec. 31, 2018, we had $21.3 million of goodwill at Curtis Palmer ($14.4 million), Morris ($3.3 million) and Nipigon ($3.6 million). As is our annual practice, we reviewed goodwill for potential impairment in the fourth quarter and determined that no impairment was required.

We also conducted an event-driven review of our long-lived assets at Williams Lake. The short-term extension of the PPA at Williams Lake expires on June 30, 2019, or September 30, 2019 at the customer's option. Our practice is to review long-lived assets within six months of the earliest expected PPA expiration date. At Dec. 31, 2018, Williams Lake's long-lived assets totaled $11.4 million. Based on our analysis, we determined that no impairment was required. You will recall that in 2017, we had recorded a partial impairment of property, plant and equipment and a full impairment of intangibles at Williams Lake.

## Non-GAAP Disclosures

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, 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 Table 1 below.

**Atlantic Power Corporation**
**Table 1 – Reconciliation of Net Income (loss) to Project Adjusted EBITDA**
**(in millions of U.S. dollars)**
**Unaudited**

| | Three months ended December 31, | | Twelve months ended December 31, | |
|---|---|---|---|---|
| | **2018** | **2017** | **2018** | **2017** |
| **Net income (loss) attributable to Atlantic Power Corporation** | **$24.7** | **($41.1)** | **$36.8** | **($98.6)** |
| Net income attributable to preferred share dividends of a subsidiary company | 2.0 | 2.2 | 0.4 | 5.6 |
| **Net income (loss)** | **$26.7** | **($38.9)** | **$37.2** | **($93.0)** |
| Income tax (benefit) expense | (7.5) | (19.7) | 0.2 | (58.1) |
| Income (loss) before income taxes | 19.2 | (58.6) | 37.4 | (151.1) |
| Administration | 5.9 | 6.0 | 23.9 | 23.6 |
| Interest expense, net | 12.0 | 14.7 | 52.7 | 64.2 |
| Foreign exchange (gain) loss | (13.7) | (1.4) | (22.8) | 16.3 |
| Other income, net | (3.4) | (0.4) | (3.0) | (0.4) |
| **Project income (loss)** | **$20.1** | **($39.7)** | **$88.2** | **($47.4)** |
| | | | | |
| **Reconciliation to Project Adjusted EBITDA** | | | | |
| Depreciation and amortization | $21.8 | $27.6 | $99.7 | $133.2 |
| Interest expense, net | 0.8 | 11.2 | 3.4 | 19.2 |
| Change in the fair value of derivative instruments | 1.3 | (8.0) | (2.2) | (2.1) |
| Impairment | - | 72.1 | - | 187.1 |
| Other (expense) income, net | 2.5 | (1.1) | (4.0) | (1.2) |
| **Project Adjusted EBITDA** | **$46.6** | **$62.1** | **$185.1** | **$288.8** |