PREPARED REMARKS
Q2 2018
AUGUST 3, 2018

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 quarterly report on Form 10-Q, 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

My remarks will include a summary of our second quarter 2018 financial results as well as recent operational and commercial developments. I will also revisit a couple of areas that I addressed in my letter to shareholders three months ago.

Page 4: Q2 2018 Highlights

As noted on page 4 of the presentation, second quarter results were modestly better than we had anticipated, as occurred in the first quarter as well. Although results for the first half reflect a significant decline from Power Purchase Agreement (PPA) expirations and the non-recurrence of the 2017 OEFC Settlement, as we expected, they are on track with our full year 2018 guidance.

During the second quarter we continued to use our strong operating cash flow to repay debt. We remain on track to repay a total of $100 million of debt this year. Our leverage ratio, which has been on a generally declining trend since 2013, increased this quarter to 3.8 times because of the significant decline in EBITDA that we are experiencing this year as a result of several PPA expirations and the non-recurrence of the OEFC Settlement. However, we expect our leverage ratio to begin declining again in 2019 as we continue to repay significant amounts of debt.

We’ve taken a balanced approach to capital allocation. From April through the end of July, we used $4.6 million of our discretionary cash to repurchase and cancel common and preferred shares. We will continue to do so when they are trading at attractive implied returns, as is currently the case. Although we often highlight the total amount of debt we have repaid (approximately $1.1 billion since 2013), I would note that we also have repurchased a total of $29.5 million in common shares since the spring of 2015 (and insiders have purchased another $4.9 million during this period).

In early July, we announced the acquisition of our partners' interests in the Koma Kulshan hydro facility for a total of $13.2 million, approximately 11 times estimated pro forma cash distributions. This is our first external growth investment following our three-year program to improve performance and strengthen our balance sheet. We closed this acquisition last Friday (July 27). Koma is our longest-dated PPA, with close to a 19-year remaining life.

At June 30, 2018, we had strong liquidity of $203 million, including approximately $42 million of discretionary cash. Although most of our operating cash flow is allocated to debt repayment, we intend to continue using our liquidity for share repurchases and additional growth investments, when they are accretive to intrinsic value per share.

In the area of operations, our Manchief plant completed its major gas turbine overhaul largely as expected. We completed the commissioning of our Tunis plant, though re-start has been delayed to October pending review by the Ontario Independent Electricity System Operator of the commissioning report. At Williams Lake, we've taken steps to reduce operation and maintenance costs to mitigate the impact of higher fuel costs. We are still awaiting regulatory approval (from the BCUC) of the short-term contract extension.

On the commercial front, we remain engaged with the Navy regarding site control for the Naval Station and North Island projects but continue to regard the probability of success as low. We are proceeding with plans to decommission all three sites, but have not yet finalized the cost or timing pending resolution with the Navy.

<u>Page 5: Mitigating the Financial Impact of PPA Expirations</u>

Turning to page 5, I'd like to discuss briefly how we think about the financial impact of PPA expirations over the next several years.

As I noted in my letter to shareholders earlier this year, if power prices remain at current levels (or decline further), the price we receive for power post-PPA would be materially below current contract levels. Some of our projects would not be re-contracted and we would consider mothballing or decommissioning them. The market is very focused on the EBITDA impact of these expirations. So are we, but there are mitigating elements when one considers the overall financial impact on Atlantic Power:

First, the timing of PPA expirations is lumpy. From year-end 2017 through April 1 of this year – a three-month period – six PPAs expired. The reduction to our 2018 results (relative to 2017) was about $83 million. In addition, 2018 results were reduced $29 million by the non-recurrence of the OEFC Settlement recorded in 2017. But between now and April 2022, we have only four PPAs scheduled to expire, which together generate annual EBITDA of approximately $15 million.

Second, we will achieve significant delevering during this period. Our existing projects generate significant cash flow that is in excess of their needs for maintenance, capex, interest and principal payments (on project debt), and working capital. The majority of that excess cash flow is distributed to the parent, and we use it to pay down the term loan. Over the next four years, we expect to reduce total debt by more than half, to slightly less than $400 million. This will result in significantly lower cash interest payments, which means that our operating cash flow will be reduced less than our EBITDA, and our leverage ratio will decline because debt repayment during this period has a more meaningful impact on the ratio than the decline in EBITDA from PPA expirations.

Third, our refinancing risk is minimal. During this period we have only one bullet maturity – the $19 million (US$ equivalent) remaining on our Series D convertible debentures, in December 2019.

Fourth, as we've discussed in the past, we've reduced our corporate overhead costs by approximately 60% in the past five years. We continue to identify additional cost savings, though these are modest.

Certainly there is additional risk from PPAs expiring in 2022 and beyond. But even then, we expect to generate sufficient cash flow to continue reducing debt. By about 2025, we would expect to be approximately net debt-free.

Slide 6: Commercial Successes

Although my discussion has focused on the financial implications of not being successful in re-contracting PPAs over the medium term, I would emphasize that our Commercial team has had a number of successes over the past several years, as noted on page 6 of the presentation. These include:

- In **Ontario**, we agreed to revisions to our contracts that achieved benefits for us as well as the customer, negotiated a settlement with the OEFC that produced significant cash flow for us (about $29 million US$ equivalent), and negotiated a revised contractual arrangement for Nipigon (through 2022) that we believe will be beneficial. In addition, we obtained a new long-term PPA for Tunis (to 2033) in a very difficult power market, and expect to return the plant to service this October.

- In **San Diego**, we obtained new seven-year contracts for Naval Station and North Island that would have produced strong returns on the incremental required investment, though the projects are unlikely to return to service due to our inability to achieve site control with the Navy. Importantly, we were able to terminate the original PPAs ahead of schedule without incurring any financial penalties.

- We agreed on a short-term extension of the PPA for **Williams Lake**. Although the economics of the extension are marginal, the extension can serve as a bridge to a potential longer-term PPA. The extension is still subject to regulatory approval.

- We executed an 11-year extension at **Morris** to 2034 on terms comparable to the existing PPA.

- We achieved an operational turnaround at **Piedmont** and paid off the project's debt, leaving a debt-free plant that now distributes cash to the parent and has a PPA that runs through 2032.

- We consolidated ownership of **Koma Kulshan** at an attractive valuation and now own 100% of this small hydro plant with a PPA that runs through 2037.

Another topic that I covered in my letter to shareholders was the state of the power markets. In the past few months, there have been a few positive data points, although it's far too early and the examples too limited to call this a trend. Still, it is noteworthy that prices can go up as well as down. Specifically:

The May 2018 capacity auction in **PJM**, which set the capacity price for the June 2021- May 2022 delivery year, cleared at a higher price than expected, mostly because of a lower amount of cleared capacity, reflecting nuclear plant retirements and more modest new gas build than in years past. The price in the ComEd zone, where our Morris plant is located, increased to $195.55 per MW-day from $188.12 the previous year. In the non-constrained zones, the price increased to $140 from $76.53 the previous year.

In **California**, issues have emerged this summer due to gas pipeline outages and other factors that have reduced gas supply availability, low hydro reservoirs, plant retirements, the increasing penetration of renewables on the grid (which can result in higher volatility), and other factors. As a result, extremely high temperatures in southern California during late July have resulted in much higher spot prices for both gas and power.

In **Alberta** (where we do not have any plants), both spot and forward power prices have responded strongly to plant retirements and PPA terminations that have improved the supply/demand outlook as well as the release of details of the final capacity market design (to be implemented in 2021, with the initial auction expected in late 2019). The combination of lower gas prices in the region and higher power prices has benefited spark spreads (the margins realized by gas plants). Increased volatility has benefited gas peakers and plants such as hydro that provide ancillary services.

One example to the contrary is **ERCOT** (another market where we have no plants), where a heat wave in July resulted in new peak demand records being set. Spot prices reacted, though price spikes were relatively modest and short-lived, and forward prices actually declined.

Dan Rorabaugh – Atlantic Power Corporation – SVP, Asset Management

Page 7: Q2 2018 Operational Performance

Beginning with our safety record, we had one recordable injury in the second quarter of 2018 (following a first quarter in which we had none). We continue to place the highest priority on maintaining a strong culture of safety and regulatory compliance.

Turning to our operating results for the second quarter, generation declined 13.2% overall, driven primarily by declines at our San Diego projects, which we shut down on February 7, and at Curtis Palmer, which experienced significantly lower generation due to lower water flows than the year-ago period. On the positive side, Orlando benefited from a shorter spring maintenance outage this year as compared to 2017; Mamquam had significantly higher water flows than the year-ago period; Manchief experienced higher dispatch, notwithstanding being out for part of the quarter for its gas turbine overhaul; and Kenilworth had a maintenance outage in the 2017 period.

Our availability factor in the second quarter of 2018 increased to 93.4% from 83.6% in the year-ago period. The increase reflects maintenance outages at Frederickson and Kenilworth in 2017; a forced outage at Mamquam in 2017, and a shorter spring outage this year at Orlando, partially offset by reduced availability at Manchief due to the gas turbine overhaul in 2018.

With respect to our hydro plants, generation at Curtis Palmer was approximately 28% below the second quarter of 2017 (which was a very strong water year) and 7% below the long-term average. Water flows at Mamquam have been well above the 2017 level (which was close to an average year) as well as above the long-term average. Generation at Mamquam was up 35% versus the second quarter of 2017 and up 22% compared to the long-term average.

Page 8: Operations Update

We have completed all significant work required to return our Tunis project to service. Capacity and environmental compliance testing is scheduled for later this month. The total cost of the re-start of approximately $5 million (US$ equivalent) was in line with our expectations. This cost, most of which was incurred in the first six months of 2018, was expensed. As we have indicated previously, we expect 2018 Project Adjusted EBITDA for Tunis to be negative due to the re-start expenses (its EBITDA for the first six months of 2018 was US$(4.1) million).

Last quarter we indicated that our planned re-start date for Tunis was July 1st. Subsequent to our conference call, we learned that because we had converted Tunis to operate in dispatchable mode (per the new PPA) and installed a new control system for the project, the Ontario Independent Electricity System Operator (IESO) requires a commissioning report to be filed as part of the registration process. The independent engineer for the project filed the commissioning report with the IESO on July 30. The timeline for IESO review is typically about 60 days. If the IESO does not raise any significant issues with the report that we must address, we should be able to commence operation of the project under the PPA in October.

Once returned to service, Tunis will operate as a simple-cycle plant under a 15-year PPA under which it will receive capacity payments for being available and will bid into the market based on its cost of production. We expect it to generate approximately US$2 million of Project Adjusted EBITDA annually.

As discussed last quarter, we also plan to return Nipigon to service as a simple-cycle plant under the terms of its long-term enhanced dispatch contract (LTEDC), which runs through December 2022. Nipigon will operate as a flexible plant, running only when needed and when it is economic to operate. It will receive monthly capacity-type payments and earn energy revenues for those periods when it operates. The economics of the LTEDC are favorable versus the original PPA.

We do not need to perform any overhauls of Nipigon's major equipment prior to its return to service. We plan to upgrade the plant's gas turbine control system in 2019, which will enable remote simple cycle operation. We do not expect to be required to file a commissioning report with the IESO for Nipigon. Thus, we continue to expect that the project will operate under the LTEDC beginning in November of this year.

In terms of other significant maintenance work this year, we completed the major gas turbine outage at Manchief in late May. The gas turbine overhaul at

Kenilworth is expected to be completed in early September, though the plant continues to operate on a leased engine while the work is being done, selling power and steam to Merck under the PPA and fulfilling its obligations to PJM. Some of the Kenilworth maintenance expense that we had expected to incur in the second quarter has been shifted into the third. During the quarter, we completed routine annual maintenance at Frederickson, Morris and Piedmont. Lastly, the runner replacement at Mamquam that had been planned for late summer has been deferred to the first quarter of 2019 due to third-party engineering availability.

A few other areas of focus for the Operations team:

First, following the acquisition of Koma Kulshan on July 27, we have assumed operation of the project from Covanta. The employees at Koma are now Atlantic Power employees. We expect this transition to be seamless.

Second, in order to mitigate the impact of higher fuel costs and the less favorable PPA terms at Williams Lake, in the second quarter we took steps to reduce operation and maintenance expense at the project. We also have made shorter-term fuel supply arrangements which, although not covering 100% of our expected needs, give us a bit more visibility on cost. We still expect that under the short-term contract extension, Williams Lake will be a marginal contributor to Project Adjusted EBITDA.

Third, as we have discussed on previous quarterly calls, we are proceeding with plans to decommission the three San Diego plant sites. We expect to have more to report on our third quarter call.

Fourth, as part of our ongoing initiative to analyze, identify and achieve potential savings in our operation and maintenance costs, we recently retained a consulting firm to perform external benchmarking of our thermal (non-hydro) plants. We expect an initial report this fall, which will look at not only cost structure but also staffing levels, maintenance intervals and other variables. As a sign of the importance of this effort, we have assigned responsibility for the overall program to one of our vice presidents. He has worked on both the operations and commercial teams and will be solely focused on this critical effort. We will provide updates on our operating cost initiatives on future quarterly calls.

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

Page 9: Commercial Update

I'll provide an update on the San Diego projects and Williams Lake. There have not been any developments at Kenilworth since our previous quarterly call, when we announced that the customer (Merck) had exercised its option for a one-year extension of the PPA (to September 2019).

San Diego Projects

As previously reported, our three projects in San Diego have not operated since February 7, 2018, when our land use agreements with the U.S. Navy expired. The PPAs with San Diego Gas & Electric (SDG&E) were terminated effective March 1, 2018. Although we signed new seven-year power contracts with SDG&E for Naval Station and North Island that were approved by the California Public Utilities Commission (CPUC) earlier this year, those contracts are conditioned upon us reaching an agreement with the Navy that would allow us to remain on base in order to operate the projects ("site control").

Since the early part of this year, we have been engaged in discussions with the Navy on potential paths to site control at Naval Station and North Island. To date we have not reached an agreement. In order to continue these discussions with the Navy, in July we amended the two power contracts with SDG&E to provide an extension of the date by which we would have to achieve site control. Those amendments are subject to CPUC approval. We view the probability of reaching an agreement for either site as low, so although discussions with the Navy are ongoing, we are continuing to make preparations to decommission both sites. Decommissioning is required by the land use agreements with the Navy.

Separately, last year we executed a power contract with Southern California Edison (SCE) for our NTC project. However, we have been unsuccessful in re-engaging with the Navy regarding site control for NTC. Also, in July 2018, the CPUC rejected the SCE contract for NTC. Therefore, we intend to proceed with the decommissioning of NTC.

Williams Lake

As disclosed previously, Williams Lake is operating under a short-term extension of the contract with BC Hydro that runs to June 30, 2019, or September 30, 2019 at BC Hydro's option. The amended contract is subject to the approval of the BC Utilities Commission (BCUC). The written hearing process before the BCUC commenced in early April and the schedule was recently extended. Although the timing of a decision by the BCUC has not been determined, it is unlikely to be before September. If the BCUC has not approved the short-term extension by September 17, 2018, either party has the right to terminate the contract. This timeframe may be extended at BC Hydro's option.

Separately, written hearings on the appeal of the amended air permit for Williams Lake, which we received in September 2016, continue before the Environmental Appeal Board. We expect the permit to be upheld when this matter is decided, probably in the fourth quarter of this year.

Other Commercial Initiatives

Our commercial team is broadly focused on maximizing the value of our existing assets and sites, as well as pursuing growth opportunities where economically feasible. Although in the past few years our efforts have been focused primarily on PPA extensions and restructurings, we are also, for example, marketing our currently mothballed North Bay and Kapuskasing plants to potential industrial and commercial customers. We believe that current policy and market trends will increase the demand for fully depreciated flexible and reliable peaking generation. Therefore, we view our mothballed gas plants as having potential future value as peaking plants. That is why we are working to preserve optionality at those sites.

We are also in the process of evaluating all our project sites (e.g., land availability, interconnection capacity, and market conditions) for potential competitive advantages for energy storage applications. Although the probability of success is low in any utility request for new PPA proposals, we will participate on an opportunistic basis when the competitive situation warrants. Although confidentiality provisions prevent disclosing project specifics, we submitted our first energy storage bid in the second quarter.

We continue to pursue potential acquisitions on an opportunistic basis, focusing on risk/return as opposed to specific asset classes. On our previous call, we discussed our external growth focus on out-of-favor assets with PPA terms, such as biomass plants. Although we have nothing to report at this time, we believe this focus is more likely to yield opportunities that meet our risk/return targets.

Although we continue to pursue the development of greenfield combined heat and power (CHP) projects, and believe that market fundamentals (e.g., high industrial rates and low natural gas prices) support the development of new CHP projects, greenfield development is a long process and we have recently shifted development resources to potentially nearer-term and higher-probability biomass and energy storage initiatives.

Terry Ronan – Atlantic Power Corporation – EVP & CFO

Pages 10-11: Q2 2018 Financial Highlights

- Project Adjusted EBITDA of $39.8 million declined $45.6 million from the year-ago level of $85.4 million, primarily because of PPA expirations in 2018 and the OEFC Settlement recorded in 2017. However, results were better than expected, due to stronger results at Morris, Mamquam and Kenilworth, partially offset by below-average water flows at Curtis Palmer. Relative to our plan, we also benefited from a shift in the timing of maintenance expense at several projects from the first half of the year to the second. As we catch up with these planned maintenance expenses, and despite the three-month delay at Tunis relative to our previous July 1st assumption, our full year results are projected to remain within our guidance range of $170 to $185 million.

- Cash provided by operating activities decreased $23.5 million to $28.1 million from $51.6 million. Although the decline in Project Adjusted EBITDA had a negative impact on cash flow, the effects were partially offset by lower cash interest payments and favorable changes in working capital, mostly related to PPA expirations and plant shutdowns. Our 2018 estimate of cash provided by operating activities of $95 to $110 million assumes the impact of changes in working capital is nil, but it is more likely to be a positive for the full year.

- During the second quarter we repaid $26.4 million of term loan and project debt. The decline in Project Adjusted EBITDA resulted in an increase in our leverage ratio to 3.8 times. We ended the quarter with liquidity of $203.4 million, including approximately $42 million of discretionary cash.

- We continue to manage our interest rate exposure. At June 30, 2018, approximately 96% of our debt carried either a fixed rate or a variable rate which has been fixed through interest rate swaps. Our exposure to a 100 bp change in LIBOR is approximately $300 thousand over the remainder of 2018 and approximately $450 thousand in 2019.

- Lastly, in the second quarter, we repurchased and canceled approximately 1.3 million common shares at an average price of $2.14 per share and 40,000 shares of our preferred Series 3, at a total cost of $3.4 million. In July, we repurchased and canceled 0.3 million common shares at an average price of $2.14 per share, 5,000 shares of our preferred Series 2 and 41,965 shares of our preferred Series 3, at a total cost of $1.2 million. These repurchases were done under our normal course issuer bid (NCIB). We used a portion of our discretionary cash to fund these purchases.

Page 12: Q2 2018 Project Adjusted EBITDA bridge

Second quarter 2018 Project Adjusted EBITDA results of $39.8 million decreased $45.6 million from $85.4 million in the second quarter of 2017. The decline was expected and primarily attributable to the expirations of six PPAs since December (Kapuskasing, North Bay, Naval Station, North Island, NTC and Williams Lake) and the non-recurrence of the OEFC Settlement (most of which was recorded in the second quarter of 2017). The most significant factors affecting the results were:

PPA expirations. The Kapuskasing and North Bay contracts expired on December 31, 2017 and were not renewed, as expected. Also, both projects received OEFC Settlement revenues in 2017 that did not recur. Together these accounted for $28.1 million of the decline in Project Adjusted EBITDA from the second quarter of 2017. Our three projects in San Diego ceased operations in early February and the PPAs were terminated effective March 1st, which resulted in a $7.7 million reduction in Project Adjusted EBITDA from the second quarter of 2017. The Williams Lake PPA, which was scheduled to expire on April 1, was amended and extended for a short period on less favorable terms; this resulted in a $2.8 million reduction to Project Adjusted EBITDA.

Tunis. Maintenance costs associated with the re-start of Tunis, which are being expensed, and the non-recurrence of OEFC Settlement revenue recorded in the second quarter of 2017 resulted in an $8.1 million reduction in Project Adjusted EBITDA relative to the year-ago quarter.

Manchief. Maintenance expenses of $7.4 million associated with the overhaul of the gas turbine during the quarter resulted in a decline in Project Adjusted EBITDA of $7.2 million from the year-ago period.

Curtis Palmer. Water flows that were well below year-ago levels resulted in reduced generation for Curtis Palmer and a $3.5 million reduction to Project Adjusted EBITDA from the year-ago level.

On the positive side:

Frederickson benefited from lower maintenance expense than in the 2017 period, when it had a major maintenance outage; Project Adjusted EBITDA was $3.0 million higher than the year-ago period.

Orlando benefited from improved availability due to a shorter maintenance outage than in the year-ago period, and to higher contractual capacity rates; Project Adjusted EBITDA increased $2.0 million.

Morris had a $1.7 million increase in Project Adjusted EBITDA, which resulted from a higher capacity price in PJM this year.

Mamquam had a $1.6 million increase in Project Adjusted EBITDA due to higher water flows and lower maintenance expense than the year-ago period.

Page 13: YTD June 2018 Project Adjusted EBITDA bridge

Project Adjusted EBITDA for the six months ended June 2018 of $93.2 million decreased $56.1 million from $149.3 million for the six months ended June 2017. The decline was expected and driven by many of the same factors affecting the second quarter 2018 comparison, primarily PPA expirations, the non-recurrence of the OEFC Settlement, Tunis re-start expenses, the Manchief gas turbine overhaul, and lower water flows at Curtis Palmer. Projects that contributed positively to the comparison included Morris, Frederickson, Orlando and Mamquam, mostly for the same reasons as in the second quarter, and Nipigon, which benefited from a contractual rate increase.

Page 14: Cash Flow Results and Uses of Cash

Second Quarter 2018

Cash provided by operating activities totaled $28.1 million in the second quarter, a decrease of $23.5 million from $51.6 million in the second quarter of 2017. Although the $45.6 million decline in Project Adjusted EBITDA had a negative impact on operating cash flow, this was partially offset by a $13.8 million benefit to cash flow from changes in working capital and an $8.7 million reduction in cash interest payments resulting from debt repayment and a lower spread on our credit facilities. The favorable change in working capital was mostly attributable to a decrease in working capital at projects no longer in operation due to PPA expirations.

During the quarter, we used operating cash flow to repay $20 million of our term loan and to amortize $6.4 million of project debt, including repayment in full of the $5.6 million of debt remaining at Epsilon Power Partners (EPP), ahead of its scheduled amortization later in 2018 and early 2019. We also paid $2.1 million of preferred dividends.

Year-to-date June 2018

Cash provided by operating activities for the six months ended June 2018 of $78.4 million declined $7.3 million from $85.7 million in the comparable 2017 period. Although Project Adjusted EBITDA declined $56.1 million, the reduction in operating cash flow was significantly less due to $34.7 million of favorable changes in working capital, including $17.7 million related to PPA expirations and plant shutdowns (Kapuskasing, North Bay and the three San Diego projects), and a $13.2 million reduction in cash interest payments resulting from debt repayment and a lower spread on our credit facilities.

In the first six months of 2018, we used operating cash flow to repay $50 million of our term loan and to amortize $8.8 million of project debt. We also paid $4.3 million of preferred dividends.

Page 15: Liquidity

At June 30, 2018, we had liquidity of $203.4 million, including $80.8 million of unrestricted cash. These figures were only slightly lower than the March 31st balances of $205.1 million and $82.6 million, respectively. Approximately $49.2 million of the June 30th cash balance was at the parent, which was $10 million higher than the March 31st level. The increase resulted from a release of cash by the projects due to lower working capital needs (at projects no longer in operation). Holding aside approximately $7 million for working capital purposes, we had about $42 million of discretionary cash at June 30.

In the second quarter, we used $3.4 million of discretionary cash for common and preferred share repurchases and another $1.1 million to make an additional equity investment in Koma Kulshan.

As shown on page 15, we do not currently have any borrowings under the revolver, but we do use it for letters of credit. Availability under the revolver was $122.6 million at June 30th, virtually unchanged from the March 31st level.

Although not depicted in this liquidity presentation because it occurred subsequent to quarter-end, I would note that on July 27, we used $12.1 million of discretionary cash to fund the acquisition of Covanta's interest in Koma Kulshan and to buy out the operation and maintenance contract.

Page 16: Debt Repayment Profile

We expect to repay a substantial amount of debt over the next several years, as shown on page 16. Through year-end 2022, we expect to amortize approximately $411 million of our term loan and project debt, predominantly from operating cash flow. During this period, we have only one bullet maturity– the remaining $19 million (US$ equivalent) of the Series D debentures, which mature in December 2019. We can redeem the Series D convertible debentures at par at or before their maturity date, or repurchase a portion of them up to a 10% limit under our NCIB.

With respect to the second half of 2018 specifically, we plan to repay $40 million of our term loan ($20 million in each of the third and fourth quarters) and amortize $1.5 million of project debt (at Cadillac). This would bring debt repayment for the year to a total of $100 million.

Page 17: Projected Debt Balances

Page 17 shows the impact of continued debt repayment on our debt balances, projected through year end 2023. At June 30, 2018, we had debt of $821 million, including our share of debt at Chambers, which is an equity-owned project. Assuming that we amortized the term loan per the targeted debt reduction schedule through year-end 2022 and repaid the remaining $125 million of principal at its maturity in April 2023, our projected debt balance at year-end 2023 of $252 million would consist of the $160 million (US$ equivalent) Medium-Term Notes (with a 2036 maturity), the $87 million (US$ equivalent) Series E convertible debenture (2025 maturity), and $5 million of project debt. However, there are alternative paths we could follow with respect to the final balance on the term loan, including refinancing it prior to its maturity date, extending the maturity date or (as page 17 contemplates), paying off the remaining principal with cash in 2023.

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

Page 18: 2018 Guidance: Project Adjusted EBITDA bridge vs. 2017 actual

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.

Although the format of the bridge on page 18 is slightly different from previous quarters, there has been no change to our 2018 Project Adjusted EBITDA guidance of $170 to $185 million. As we have noted in the past, approximately $112 million of the decline versus the $288.8 million we reported for 2017 is attributable to PPA expirations, the 2017 OEFC Settlement and Tunis re-start expenses. Although there are other puts and takes, as shown on page 18, they are largely offsetting. As noted earlier, although first half 2018 results were better than our expectations, we expect to give this back in the second half, mostly due to a shift in the timing of maintenance expense and the delay in the Tunis re-start under the new PPA.

Page 19: Bridge of 2018 EBITDA Guidance to Cash provided by operating activities

Based on our 2018 Project Adjusted EBITDA guidance range of $170 to $185 million, we estimate 2018 cash provided by operating activities in the range of $95 to $110 million. This estimate assumes the impact of changes in working capital on cash flow is nil, but given the reduction in working capital attributable to projects no longer in operation (relative to 2017), changes in working capital are more likely to have a positive impact on the 2018 GAAP result.

Our principal planned uses of operating cash flow in 2018 include $90 million amortization of our term loan; $10 million of project debt amortization; $1.4 million of capital expenditures; and $8 million of preferred dividend payments. As previously noted, our repurchases under the NCIB and our acquisition of Koma Kulshan have been funded from our discretionary cash balances.

As previously indicated, our leverage ratio at June 30, 2018 was 3.8 times. Notwithstanding planned debt repayment of $100 million this year, we expect this ratio to increase to the high four times range by year-end 2018, because of the significant expected reduction in 2018 Project Adjusted EBITDA. However, as we continue to repay significant amounts of debt (as shown on page 16), our leverage ratio should begin declining again in 2019. We expect the ratio to move below four times by the end of 2020.

San Diego decommissioning cost estimate

As noted, we are preparing to decommission the three San Diego projects, as required by our land use agreements with the Navy. We have developed a range of cost estimates for each project as well as estimates of expected salvage value. We expect to refine those estimates once the scope of work has been determined together with the Navy. As disclosed previously, we have accrued $1.7 million of decommissioning expense for these projects. If the final cost exceeds our accrual, which is possible, the additional expense would reduce net income, but would not be included in Project Adjusted EBITDA. We expect to provide an update with our third quarter results.

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 June 30,		Six months ended June 30,	
	2018	**2017**	**2018**	**2017**
Net (loss) income attributable to Atlantic Power Corporation	**($0.6)**	**($21.9)**	**$15.2**	**($24.6)**
Net income (loss) attributable to preferred share dividends of a subsidiary company	1.6	2.1	(0.1)	4.3
Net income (loss)	**$1.0**	**($19.8)**	$15.1	($20.3)
Income tax expense (benefit)	0.9	(22.3)	4.2	(22.6)
Income (loss) from operations before income taxes	1.9	(42.1)	19.3	(42.9)
Administration	6.2	5.7	12.2	12.1
Interest expense, net	11.1	18.4	26.1	35.7
Foreign exchange (gain) loss	(5.4)	5.9	(13.6)	8.3
Other income, net	(0.2)	-	(2.2)	-
Project income (loss)	$13.6	($12.1)	$41.8	$13.2
Reconciliation to Project Adjusted EBITDA				
Depreciation and amortization	$25.1	$34.7	$53.1	$69.3
Interest expense, net	0.9	2.5	1.9	5.3
Change in the fair value of derivative instruments	0.2	2.6	(3.6)	3.8
Impairment	-	57.7	-	57.7
Project Adjusted EBITDA	$39.8	$85.4	$93.2	$149.3