PREPARED REMARKS
Q1 2018
MAY 4, 2018

<u>Ron Bialobrzeski – Atlantic Power Corporation – Director, FP&A</u>

<u>Slide 2: Cautionary Note Regarding Forward-Looking Statements</u>

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 Slide 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 Slide 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 this quarter will be brief as it has been only two months since our last conference call, during which we provided an extensive review of the results of our restructuring activities, the status of our commercial initiatives on PPAs and growth, and our thoughts on capital allocation and the current state of the power markets. The text of these remarks can be found on the Investors page of our website under "Presentations." I also addressed these topics in my annual letter to our shareholders, included in our 2017 annual report, which can be found on the Media & Events page of our website under "Annual Reports."

Slide 4: Q1 2018 Highlights

Other members of the management team will address operational and financial results for the quarter in more detail, but I'd like to briefly highlight the results and recent developments:

- First quarter 2018 Project Adjusted EBITDA of $53.4 million and operating cash flow of $50.3 million keep us on track with our expectations for the full year.
- We repaid $32.4 million of debt during the quarter and are on track to repay $100 million for the full year. Our leverage ratio at March 31, 2018 was 3.2 times, although we expect it to increase by year-end due to lower levels of Project Adjusted EBITDA. However, we expect it to begin to decline again in 2019 and beyond as a result of continued debt repayment.

- We ended the quarter with $205 million of liquidity, including approximately $32 million of discretionary cash, after using $10.4 million in March to repurchase common and preferred shares at what we believe represented compelling price-to-value levels.

- We refinanced most of our 2019 convertible debentures during the quarter, and now have only $19 million (US$ equivalent) of convertible debentures maturing in 2019. The new issue ($89 million US$ equivalent) carries a 6.00% interest rate and has a 2025 maturity.

- In April, we executed a third re-pricing of our credit facilities, reducing the spread to 300 bp over LIBOR. Cumulative savings from these re-pricings relative to the original cost are $41 million through the maturity dates of the facilities.

- We've taken a disciplined approach to capital allocation. At present, we believe that internal opportunities look much more compelling than external. In March and April, we repurchased Cdn$5.1 million ($4 million US$ equivalent) of preferred shares at an implied cash return of 10 – 11%, reflecting the significant discount to par and the cash taxes we avoided. We also bought in a total of 3.5 million common shares at an average cost of $2.10 per share. Since 2015, we have invested a total of $27.2 million in common share repurchases, and during that time insiders have purchased $4.1 million, for a total investment in the shares of more than $31 million.

- The power markets remain challenging. On the commercial front, the contract for our Kenilworth project was extended one year by our customer, Merck. In San Diego, although we have executed new contracts for all three of our plants, they are conditioned upon us obtaining site control with the Navy, which appears unlikely.

- We expect to return our Tunis and Nipigon plants to service later this year; Tunis has a 15-year PPA and Nipigon has a long-term enhanced dispatch contract that runs through December 2022.

Dan Rorabaugh – Atlantic Power Corporation – SVP, Asset Management

Slide 5: Q1 2018 Operational Performance

Beginning with our safety record, we had no recordable injuries in the first quarter of 2018. For all of 2017, we had a total of three. We continue to place the highest priority on maintaining a strong culture of safety and regulatory compliance.

Turning to our operating results for the first quarter, generation declined 2.8% overall, driven primarily by declines at our San Diego projects, which we shut down on February 7 when our land use agreements with the U.S. Navy expired. Frederickson experienced lower dispatch due to mild temperatures. On the positive side, Manchief experienced higher dispatch, Morris and Chambers had higher dispatch due to cold temperatures, Orlando and Piedmont benefited from comparisons against the 2017 period, when they underwent maintenance outages, and Mamquam had higher water flows.

Our availability factor in the first quarter of 2018 improved to 98.3% from 96.4% in the year-ago period. The increase reflects maintenance outages at Mamquam and Piedmont in 2017, partially offset by a forced outage at Oxnard in 2018.

With respect to our hydro plants, generation at Curtis Palmer was approximately 10% higher than the historical average, but down approximately 2.5% from the first quarter of 2017, which was a very strong water year. Water flows at Mamquam were stronger than in 2017, which was close to an average year. Generation was 22.5% above the historical average and 18% better than the first quarter 2017 results.

Slide 6 Operations Update

Work to return our Tunis project to service is well under way, and we recently gave notice to the Ontario Independent Electricity System Operator of our planned July 1st restart date. The overhaul of the gas turbine is complete and it is in the process of being re-installed. The installation of a new, upgraded control system is also under way. Following completion of the installations, we will move to the testing phase. As we have indicated previously, we estimate the cost of the restart at approximately $5 to $6 million, all of which will be expensed, mostly in the first six months of this year.

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. Although we expect Tunis' Project Adjusted EBITDA to be negative in 2018 because of the restart costs, going forward we expect it to generate approximately US$2 million annually under the PPA.

We also plan to return Nipigon to service in November as a simple-cycle plant under the terms of its enhanced dispatch contract, 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 long-term enhanced dispatch contract are favorable versus the original PPA.

We don't expect Nipigon to require the amount of work or to incur significant costs to bring it back online as compared to Tunis, mainly because major equipment such as the gas turbine and generator do not require overhauls. The work we are doing at Nipigon, primarily upgrades to the gas turbine controls, is to enable remote simple-cycle operation. For Tunis, we have had to do overhauls of the major equipment and replace some obsolete control systems.

In terms of other maintenance work this year, we have two other outages currently under way. In mid-April, we began a major gas turbine outage at Manchief that will be about six weeks in duration. We had a similar outage in the spring of 2015, which was for the other gas turbine at Manchief. We also have a shorter and less significant gas turbine overhaul under way at Kenilworth, which began in early March and is expected to be completed in mid-June. However, the plant is operating on a leased engine while the work is being done, so we are continuing to sell power and steam to Merck and PJM. Later this year, we plan to replace the runners at both Mamquam units, which we will undertake beginning in August (usually a low rainfall period), and return them to service prior to the fall rains in October.

In previous quarters we've talked about our ongoing initiative to analyze, identify and achieve potential savings in our operation and maintenance costs. Last year we did internal benchmarking of our projects and we are close to retaining an outside consultant to undertake external benchmarking of our thermal (non-hydro) plants this year.

One of the steps we took in 2017 was to deploy Predictive Analytic (PRiSM) software at three plants (Curtis Palmer, Piedmont and Morris), which monitors equipment and systems, with a goal of improving reliability, reducing downtime and achieving fuel and operation and maintenance cost savings. We have already had visible results this year from installation of PRiSM at these plants. We expect to deploy this technology at two more sites this year, possibly three.

We will provide updates on our operating cost initiatives on future quarterly calls.

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

Slides 7-8: Commercial Update: PPA Renewal Status

Slides 7 and 8 provide an update on our commercial efforts with respect to those projects with PPAs or other contractual arrangements that either recently expired or will expire in 2019, specifically the San Diego projects, Williams Lake and Kenilworth.

San Diego Projects

As we disclosed on our previous quarterly conference call, our three projects in San Diego ceased operations on February 7, 2018 upon expiration of our land use agreements with the U.S. Navy. Without control of the sites on which the plants are located, we are not able to operate the plants. On March 1, the California

Public Utilities Commission approved the early termination of our PPAs with San Diego Gas & Electric (SDG&E) for all three projects. The 30-day appeal period for the CPUC decision has lapsed, so the risk of any potential liabilities arising from the early termination of the PPAs has been eliminated.

Last summer and fall, we executed new contracts with SDG&E for Naval Station and North Island that would commence in 2018 and one with Southern California Edison (SCE) for NTC (also known as MCRD), which would commence in 2019. The CPUC approved the two SDG&E contracts on March 1 and approval of the NTC contract is possible in the next few months. However, in order to perform under these contracts, we need permission from the Navy to remain on the sites for the entire contract term ("site control"). The new contracts with SDG&E and SCE require that site control be achieved by a certain date (in 2018). Although we have made proposals to the Navy that we believe would provide them benefits and allow us to remain on the sites, we have not been able to reach an agreement with the Navy on the commercial terms of such an arrangement. Thus, it is unlikely that we will be able to obtain site control and therefore unlikely that we will be able to resume operations at any of the three sites.

The original land use agreements with the Navy require us to decommission the sites once the agreements expire. We are proceeding with plans to decommission the three projects, and are in the process of defining the scope of work with the Navy. The project scope will drive the estimated cost and timing. We expect to have more to report on this issue later this year.

Williams Lake

As we disclosed in our previous quarterly call, in late December 2017 we reached an agreement with BC Hydro to amend and extend the contract for our Williams Lake biomass project in British Columbia. The short-term extension runs from April 2 of this year to June 30, 2019, or September 30, 2019 at the option of BC Hydro. The amended contract is subject to the approval of the BC Utilities Commission (BCUC), which in early April scheduled a written hearing process that commenced recently. The timing of a decision by the BCUC has not been determined. The contract amendment provides that if the BCUC has not approved the short-term extension within a specified timeframe, either party has the right to terminate the contract. This timeframe may be extended at BC Hydro's option.

As we noted on our previous quarterly conference call, the availability and price of fuel have been affected by recent wildfires in the region and other factors, and so are difficult to forecast beyond the very near term. Based on those near-term indications, we expect that the Project Adjusted EBITDA contribution under the short-term extension will be *de minimis*.

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

As background, the amended air permit allows us to burn a mix of up to 50% rail ties and other alternative fuels. However, we committed under the short-term extension with BC Hydro that we would not install a new fuel shredder (which would be necessary to burn the different mix) until we had reached an agreement with BC Hydro on a long-term contract for the project that would provide us a return of and on our incremental investment in the project. A key determining factor affecting the probability of a long-term contract is the outcome of BC Hydro's integrated resource plan (IRP), which will determine the long-term role of biomass in meeting the province's power needs. We expect the IRP process to take place sometime in 2019.

Kenilworth

In April 2018, Merck exercised the first of its three one-year renewal options at our Kenilworth project. The Energy Services Agreement (ESA) for Kenilworth was extended to September 30, 2019. The economic terms of the extension are substantially the same as previously. We have made proposals to Merck about the role we might play in meeting both its short- and long-term energy supply needs, and we expect such discussions to continue.

Other Commercial Initiatives

In addition to the initiatives mentioned above, 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. Our efforts include pursuing PPA extensions and restructurings for our existing assets and marketing our currently mothballed North Bay and Kapuskasing plants to potential industrial and commercial customers.

As previously reported, we are also pursuing the greenfield development of new combined heat and power (CHP) facilities for industrial customers, in response to a combination of high industrial power rates and low natural gas prices. Although these general market fundamentals support new CHP development, greenfield development is a long process and we do not expect to have much to report on this effort for some time.

As our CEO Jim Moore pointed out in his recent letter to shareholders, new power generation assets (renewable and new combined-cycle gas turbines, or CCGTs) continue to be added to the grid, increasing the oversupply of generation in a low growth market. In response to these market conditions, we continue to pursue potential acquisitions in the wholesale power market on an opportunistic basis, with a strong focus on out-of-favor assets with some PPA term and where we can also add operational and commercial value (such as biomass plants). In the first quarter of 2018, we added a new VP of Commercial Development to our team, enabling us to commit more resources to this effort. We are currently avoiding merchant generation opportunities with economics supported by optimistic or speculative forward pricing curves.

At this time we do not have anything more to report.

Terry Ronan – Atlantic Power Corporation – EVP & CFO

Slides 9-10: Q1 2018 Financial Highlights and Recent Developments

- Although Project Adjusted EBITDA of $53.4 million was $10.4 million below the year-ago level of $63.8 million, this result was better than expected. For the full year we still expect to be within our guidance range. Cash provided by operating activities increased $16.2 million to $50.3

million from $34.1 million, largely driven by favorable changes in working capital.

- During the first quarter we repaid $32.4 million of term loan and project debt, reducing our leverage ratio to 3.2 times, although we expect this ratio to increase over the remainder of the year, due to the year-over-year fall-off in Project Adjusted EBITDA. We ended the quarter with liquidity of $205.1 million, including approximately $32 million of discretionary cash.

- As reported on our year-end conference call, in January of this year we issued Cdn$115.0 million of 6.00% convertible debentures with a 2025 maturity, using the proceeds to redeem most of our 2019 convertible debentures. As a result, we have an improved debt maturity profile and minimal refinancing risk over the next five years.

- In April, we executed a third re-pricing of our term loan and revolver, reducing the spread another 50 bp to 300 bp over LIBOR. This will reduce our cash interest payments, before transaction costs, by $2.1 million in 2018 and by $8.5 million over the remaining terms of the facilities. Since the initial financing of the term loan and revolver in April 2016, we have reduced the spread by a total of 200 bp, which has resulted in $41.1 million of savings through the maturity dates of the facilities.

- We continue to manage our interest rate exposure. Most (81.5%) of our debt either carries a fixed rate or we have fixed the cost through interest rate swaps. Our exposure to a 100 bp change in LIBOR is approximately $600 thousand over the remainder of 2018 and approximately $450 thousand in 2019.

- Lastly, in March and April we repurchased and canceled approximately 3.5 million common shares at an average price of $2.10 per share, 237,500 shares of our preferred Series 1 and 83,095 shares of our preferred Series 3, at a total cost of $11.4 million. These repurchases were done under our normal course issuer bid (NCIB). We used a portion of our discretionary cash to fund these purchases.

Slide 11: Q1 2018 Project Adjusted EBITDA bridge

First quarter 2018 Project Adjusted EBITDA results of $53.4 million decreased $10.4 million from $63.8 million in the first quarter of 2017. The decline was expected and primarily attributable to the expirations of five PPAs since December. The primary factors affecting the results were:

PPA expirations. The Kapuskasing and North Bay contracts expired on December 31, 2017 and were not renewed, as expected. Together these accounted for $14.9 million of the decline in Project Adjusted EBITDA from the first quarter of 2017. Our three projects in San Diego ceased operations in early February, as previously discussed. This resulted in a $2.7 million reduction in Project Adjusted EBITDA from the first quarter of 2017.

Tunis restart expenses. Maintenance costs associated with the restart of Tunis, which are being expensed, resulted in a $2.6 million reduction in Project Adjusted EBITDA from that project relative to the year-ago quarter.

On the positive side:

- **Morris** had a $3.6 million increase in Project Adjusted EBITDA in the first quarter of 2018. This was attributable to higher generation levels and higher power prices due to extremely cold temperatures in January, a higher capacity price in PJM this year, and higher steam and ancillary service revenue. Kenilworth and Chambers also benefited from the temperature impact on generation and prices in PJM, though to a much lesser degree.
- **Nipigon** had a $1.7 million increase in Project Adjusted EBITDA due to a higher capacity rate under its existing contract;
- **Williams Lake** had a $1.0 million increase in Project Adjusted EBITDA due to higher contractual firm energy revenues;
- **Mamquam** had a $0.9 million increase in Project Adjusted EBITDA due to higher water flows than the year-ago period; and
- A $0.7 million benefit to Project Adjusted EBITDA from the November 2017 sale of **Selkirk**, which posted a loss in the first quarter of 2017.

Slide 12: Cash Flow Results and Uses of Cash

For the quarter, cash provided by operating activities totaled $50.3 million, an increase of $16.2 million from $34.1 million in the first quarter of 2017. The $50.3 million included a $20.9 million benefit to cash flow from changes in working capital, including an $18.3 million decrease in working capital at Kapuskasing, North Bay, Nipigon and the three San Diego projects. The PPAs for five of those projects expired in late 2017 and early 2018. Operating cash flow also benefited from a $4.5 million reduction in cash interest payments resulting from debt repayment and a lower spread on the Company's credit facilities. These two positive factors were partially offset by the impact on operating cash flow of the $10.4 million decline in Project Adjusted EBITDA, primarily at those projects for which the PPAs expired in late 2017 and early 2018.

During the quarter, we used operating cash flow to repay $30 million of our term loan and to amortize $2.4 million of project debt. We also made $1.1 million of capital expenditures and paid $2.2 million of preferred dividends.

Slide 13: Liquidity

At March 31, 2018, we had liquidity of $205.1 million, including $82.6 million of unrestricted cash, which was approximately $3.9 million higher than the December 31st level of $78.7 million. Approximately $39.2 million of the March 31st cash balance was at the parent, which was $10.5 million lower than the December 31st level of $49.7 million. Holding aside approximately $7 million for working capital purposes, we had about $32 million of discretionary cash at March 31.

The reduction in parent cash from the year-end 2017 level was primarily attributable to the use of $10.4 million of cash during the quarter for preferred and common share repurchases under the NCIB, as previously discussed.

As shown in Slide 13, we do not currently have any borrowings under the revolver, but we do use it for letters of credit. Availability under the revolver increased $3 million to $122.5 million at March 31, 2018.

Slide 14: Debt Repayment Profile

We expect to repay a substantial amount of debt over the next several years, as shown on Slide 14. Most of this will be in the form of amortization of our term loan and project debt, which will be repaid from operating cash flow. Relatively little is in the form of bullet maturities, so we consider our refinancing risk during this period to be modest.

In March 2018, we redeemed all of our Series C convertible debentures and most of our Series D convertible debentures. The remaining $19 million (US$ equivalent) of the Series D debentures, which mature in December 2019, are the only bullet maturity we have in the next four years. 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.

We expect to amortize approximately $437 million of our term loan and project debt through year-end 2022. With respect to 2018 specifically, we plan to repay $90 million of our term loan (including $30 million already repaid in the first quarter) and amortize $10 million of project debt (including $2.4 million repaid in the first quarter).

Slide 15: Projected Debt Balances

Slide 15 shows the impact of continued debt repayment on our debt balances, projected through year end 2023. At March 31, 2018, we had debt of $853 million, including our share of debt at equity-owned projects (Chambers). 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 $255 million would consist of the $163 million (US$ equivalent) Medium-Term Notes (with a 2036 maturity), the $89 million (US$ equivalent) Series E convertible debenture (2025 maturity), and $6 million of project debt. However, there are alternative paths we could follow with respect to the term loan, including refinancing it prior to its maturity date, extending the maturity date or (as Slide 15 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.

Slide 16: 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.

As noted earlier, we are reaffirming our 2018 Project Adjusted EBITDA guidance of $170 to $185 million. This represents a reduction of approximately $111 million (based on the guidance midpoint) versus the $288.8 million we reported for 2017. Slide 16, which depicts the significant drivers of this reduction, is unchanged from our fourth quarter and year-end 2017 presentation.

Q2 2018 Outlook

Although Project Adjusted EBITDA declined only $10.4 million in the first quarter of 2018 versus the year-ago level, we expect to see a more significant reduction in the second quarter resulting from these year-over-year changes. There are several reasons for this:

Ontario: The first quarter of 2017 did not include any EBITDA from the OEFC settlement (which benefited Kapuskasing, North Bay and Tunis). The second quarter of 2017 included $25 million of EBITDA from the OEFC settlement. As a result, these three projects had Project Adjusted EBITDA on a combined basis of approximately $34 million in the second quarter of 2017. This year, Kapuskasing and North Bay will not contribute to EBITDA, and we expect that Tunis will be negative in the second quarter due to restart expenses.

San Diego: The three San Diego projects operated for part of the first quarter but will not operate during the second quarter of this year. In the second quarter of 2017, they generated a combined EBITDA of approximately $6 million.

Williams Lake: The project transitioned to a short-term extension of its PPA effective April 2, 2018, and we expect the EBITDA contribution under the extension will be *de minimis*. In the second quarter of 2017, Williams Lake generated approximately $3 million of EBITDA.

Manchief: As noted on Slide 16, we expect a $7 million reduction in the EBITDA contribution from Manchief this year due to a major gas turbine outage. The outage is currently under way and we expect to see this impact in the second quarter.

Certainly, as in any quarter, there will be other puts and takes, but we expect these to be much more modest assuming normal water conditions and other factors.

Slide 17: 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. Relative to our fourth quarter and year-end 2017 presentation, we now expect that cash interest payments in 2018 will be approximately $45 million, or $2 million lower than previously, due to the April 2018 re-pricing of our credit facilities.

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 have been funded from our discretionary cash balances.

One last comment with regard to the 2018 outlook, and that concerns our leverage ratio. As previously indicated, at March 31, 2018, our leverage ratio was 3.2 times. Notwithstanding planned debt repayment of $100 million this year, we expect our year-end 2018 leverage ratio to move back into the high four times range, because of the significant expected reduction in 2018 Project Adjusted EBITDA. However, the planned continued significant repayment of debt in 2019 and beyond puts us back on a path to lower leverage ratios. We expect the ratio to decline below four times by the end of 2020.

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 loss on a consolidated basis is provided in Table 1 below.

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

	Three months ended March 31,	
	2018	**2017**
Net income (loss) attributable to Atlantic Power Corporation	**$15.9**	**($2.7)**
Net (loss) income attributable to preferred share dividends of a subsidiary company	(1.7)	2.1
Net income (loss) attributable to Atlantic Power Corporation	**$14.2**	**($0.6)**
Income tax expense (benefit)	3.2	(0.3)
Income (loss) from operations before income taxes	17.4	(0.9)
Administration	6.0	6.4
Interest expense, net	15.1	17.3
Foreign exchange (gain) loss	(8.2)	2.5
Other income, net	(2.0)	-
Project income	**$28.3**	**$25.3**
Reconciliation to Project Adjusted EBITDA		
Depreciation and amortization	$27.9	$34.9
Interest expense, net	1.0	2.4
Change in the fair value of derivative instruments	(3.8)	1.2
Project Adjusted EBITDA	**$53.4**	**$63.8**