
**UNITED STATES
SECURITIES AND EXCHANGE COMMISSION**

WASHINGTON, DC 20549

FORM 8-K

**CURRENT REPORT
Pursuant to Section 13 or 15(d) of the
Securities Exchange Act of 1934**

Date of report (Date of earliest event reported): **May 5, 2017**

ATLANTIC POWER CORPORATION

(Exact Name of Registrant as Specified in Charter)

British Columbia
(State or Other Jurisdiction
of Incorporation)

001-34691
(Commission
File Number)

55-0886410
(I.R.S. Employer
Identification No.)

**3 Allied Drive, Suite 220
Dedham, MA**
(Address of Principal Executive Offices)

02026
(Zip Code)

Registrant's Telephone Number, Including Area Code **(617) 977-2400**

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (*see* General Instruction A.2. below):

- ☐ Written communication pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- ☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- ☐ Pre-commencement communication pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- ☐ Pre-commencement communication pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

Indicate by check mark whether the registrant is an emerging growth company as defined in Rule 405 of the Securities Act of 1933 (17 CFR §230.405) or Rule 12b-2 of the Securities Exchange Act of 1934 (17 CFR §240.12b-2).

Emerging growth company ☐

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the Exchange Act. ☐

Item 2.02. Results of Operations and Financial Condition.

On May 5, 2017, Atlantic Power Corporation (the “Company”) held its first quarter 2017 financial results conference call and webcast. A copy of management’s prepared remarks and a copy of the related presentation are attached hereto as Exhibits 99.1 and 99.2, respectively, and are hereby incorporated by reference.

The information in Item 2.02, including Exhibits 99.1 and 99.2 is being furnished and shall not be deemed to be “filed” for purposes of Section 18 of the Securities Exchange Act of 1934 (the “Exchange Act”) or otherwise subject to the liability of that Section, nor shall such information be deemed to be incorporated by reference into any registration statement or other document filed under the Securities Act of 1933 or the Exchange Act, except as otherwise stated in that filing.

Item 9.01. Financial Statements and Exhibits

(d) *Exhibits*

Exhibit Number	Description
99.1	Atlantic Power Corporation’s management’s prepared remarks with respect to the Atlantic Power Corporation first quarter 2017 financial results conference call and webcast.
99.2	Presentation prepared with respect to the Atlantic Power Corporation first quarter 2017 financial results conference call and webcast.

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

Atlantic Power Corporation

Dated: May 5, 2017

By: /s/ TERRENCE RONAN
Name: Terrence Ronan
Title: *Chief Financial Officer*

EXHIBIT INDEX

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PREPARED REMARKS
Q1 2017
MAY 5, 2017

Ed Vamenta — Atlantic Power Corporation — Director, FP&A

Slide 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 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 we did an extensive business review on our fourth quarter and year-end 2016 financial results conference call just two months ago. The text of these remarks can be found on the Investors page of our website under “Presentations.”

Other members of the management team will address operational and financial results for the quarter, including an increase to our 2017 guidance, and an update on commercial activities and PPA renewal efforts, although there was not much new on that front. I’d like to focus my remarks on a few key developments since our March conference call:

Slide 5: Recent Developments

Settlement with OEFC re Global Adjustment revenues . In late April, we reached a settlement with the Ontario Electricity Financial Corporation (OEFC) regarding the amount of Global Adjustment revenues that we should have received for our Tunis, Kapuskasing and North Bay plants during the 2013-2017 period. The settlement calls for us to receive additional payments of Cdn\$36.1 million, including Cdn\$10.7 million received in the first quarter (but deferred for accounting purposes) and another Cdn\$20.3 million received earlier this week. The remaining amount will be collected over the balance of the year. In total, this

settlement will result in about US\$26 million of additional cash flow this year, which will benefit significantly our cash position at the parent.

Slide 6: Recent Developments (cont'd)

Term loan and revolver repricing . In mid-April, we executed a successful repricing of our \$615 million term loan and \$200 million revolving credit facility. As you may recall, we issued these instruments in April 2016 during challenging market conditions, and pricing was 500 over LIBOR. Since then, we have paid the term loan down to \$615 million from the original \$700 million size. Market conditions also have improved. On the repricing, we were able to reduce the spread by 75 basis points to LIBOR plus 425 basis points. This will result in \$2.4 million of cash interest savings this year and a higher amount next year, with total savings of approximately \$17 million over the remaining lives of the facilities, net of \$1.3 million of transaction costs.

Piedmont environmental permit . The amendment to Piedmont's Title V air permit issued by the Georgia environmental authorities in April establishes new fuelstock monitoring and recordkeeping requirements, which are not expected to require any significant changes to the way the plant is operated. The amended permit is subject to a public comment period and EPA review before becoming final. We expect that this process will be fully resolved within the next few months.

At that time or shortly thereafter, we expect to be in a position to conclude our evaluation of alternative paths to addressing the August 2018 debt maturity for

Piedmont (\$54 million), which include a potential sale process or continued ownership. I'll provide a bit more color on these alternatives:

Given our strengthened balance sheet and reductions in corporate overheads and interest expense, we are under no pressure to sell assets absent compelling terms. We believe that a sale of Piedmont would result in proceeds significantly in excess of the project-level debt and swap breakage costs. Because Piedmont is outside of the term loan structure, the excess proceeds would add to discretionary cash at the parent.

If we were to continue to own the asset, we would consider paying down the debt maturity out of liquidity, either in its entirety or in part in conjunction with a refinancing. The plant is now running well, after an initial period that required some additional investment by us to address operational issues. The PPA, which runs through December 2032, is with a strong counterparty with an A- credit rating. The remaining PPA term of more than 15 years is more than double our portfolio EBITDA-weighted average of approximately 6 years. Although the plant has never made cash distributions, it does generate approximately \$8 million of operating cash flow annually, which is currently all being applied to debt service. Reducing or eliminating the debt, which has an average rate of 8.47%, would make this cash flow available for distribution to the parent.

These are good options to be weighing. We will take a patient and disciplined approach in deciding what to do with this asset.

Slide 7: Q1 2017 Operational Performance

We had no recordable injuries in the first quarter, and none in the past seven months. We place the highest priority on maintaining a strong culture of safety and regulatory compliance.

Generation was lower in the first quarter than the year-ago period, primarily due to the fact that we placed Kapuskasing, Nipigon and North Bay into a non-operational state in the first quarter as a result of the revised contractual arrangements for these plants that we announced in January. Accordingly, generation in our Canada segment was substantially lower year-on-year; lower water flows at Mamquam were also a factor in the decreased generation. Availability in the Canada segment (which excludes the non-operational plants) declined primarily due to Mamquam. Generation in the East segment declined approximately 10% primarily because of reduced generation at Morris due to lower merchant demand, while generation in the West segment increased modestly because Naval Station had a major maintenance outage in the year-ago period that did not recur. Availability in our East segment was comparable to the year-ago period and availability in our West segment increased because of the non-recurrence of the Naval Station outage.

With respect to our hydro plants, water flows at Curtis Palmer this quarter were very similar to the first quarter of 2016. Last year, however, conditions deteriorated beginning in the second quarter and continued for most of the year. This year, the snowpack is greater and the lake is full as a result of rain mixed with snowpack. This should bode well for water flows going forward. I'd also mention that we had an increase in frazil ice this past winter, but we were able to use the

new spillway bladder that we installed last year to sluice ice and snow and to remove debris. As you may recall, this was one of our optimization projects. It increased our generation by more than 3,000 megawatt-hours. As a result, we have already recouped more than 50% of the installation cost.

Mamquam, which had a record year in 2016 in terms of water flows, was lower this quarter but has recovered some in April with increased precipitation. Snowpack is actually slightly higher than at this time last year.

Slide 8: Operations Update

With respect to Ontario, as we discussed last quarter, we have put our Kapuskasing, North Bay and Nipigon plants into a lay-up mode, or a non-operational status, based on revised contractual arrangements under which we will receive fixed monthly payments without any delivery obligations.

Our current plan is to return our Tunis project, also in Ontario, to service in 2018 under the 15-year PPA that was signed in December 2014. This will require an overhaul of the gas turbine and some maintenance work on other systems, which we expect to undertake in the latter part of 2017. We expect most of the cost, or approximately \$7 million, to be incurred and expensed this year. Although this represents our current thinking on timing, scope and cost, we remain in discussions with the relevant parties in Ontario, as discussed in our January 9, 2017 press release, on potential other initiatives that could be beneficial to ratepayers as well as to us. This could affect Tunis or our other Ontario projects.

We have several scheduled maintenance outages this year. Orlando just returned from its major turbine maintenance outage. At Morris, we began work in mid-April on the third and final combustion turbine upgrade, which is part of our optimization program, and expect to complete the upgrade in mid-May. During this period, Morris is continuing to run on the other two gas turbines. We began a major gas and steam turbine outage at Frederickson in late April. We also have a steam turbine overhaul under way at Kenilworth. Overall, though, we expect our maintenance costs in 2017 to be on a par with the 2016 level.

As we discussed last quarter, although we will continue to look for additional optimization projects, this year we have shifted our focus to two other areas where we expect the operations organization to have a leading role — engineering and operations support for PPA-related investments, such as the work at Tunis and possibly at other facilities to the extent that we are successful in extending PPAs elsewhere; and an aggressive initiative to analyze, identify and achieve cost savings. As part of this process we will be benchmarking our operation and maintenance costs as well as our efficiency, and evaluating many of our operational practices such as maintenance intervals and operations parameters with a view toward implementing best practices wherever feasible. We expect to have more to report on this later this year.

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

Slide 9: Commercial Update: PPA Renewal Status

Last quarter we provided an update on how we're approaching near-term PPA expirations in three key markets — Ontario, California and British Columbia. It has

been only two months since that conference call, and there is not anything substantive to report. However, I will briefly review where our PPA renewal efforts stand in each of those markets.

In Ontario, as previously mentioned, we reached an agreement with the relevant parties that produces benefits for all sides. As a result of this agreement, we put three of our gas plants into non-operational status. We do not expect either Kapuskasing or North Bay to return to service in the next couple of years, although they may return at a point in time when supply and demand conditions in the province become more favorable.

We continue to have discussions with the relevant parties in Ontario with respect to our plants on other potential initiatives that would produce ratepayer savings while also being beneficial for us. Specifically, this could include a more flexible operating arrangement for Nipigon after October 2018 (when the current enhanced dispatch agreement ends) through the expiration of its PPA in December 2022. We are also open to changes to the Tunis PPA, if they produce benefits for both sides.

In California, as discussed on the previous conference call, we have three plants in San Diego for which the utility customer under the PPAs is San Diego Gas & Electric (SDG&E). All three PPAs expire in December 2019. The plants are located on Navy or Marine Corps bases, and all three sell steam to the Navy or Marines under contracts that expire in February 2018, which is 22 months earlier than the PPA expiration dates. These contracts provide the plants with a right to use the property on which they are located. Neither the Navy nor the Marine

Corps plans to take steam from these plants after the existing agreements end. At that time, unless we are able to make alternate arrangements with the Navy and the Marines, our right to use the property would end and the PPAs with SDG&E could be terminated early, which could result in potential liabilities to us, subject to our ability to mitigate them, as well as a loss of EBITDA.

With this as background, we have been working concurrently with SDG&E (on new PPAs for two of the three plants) and the Navy (to ensure we have site control beyond February 2018). In mid-March, we responded to a solicitation by the Navy for proposals for energy security and resiliency at the bases on which the Naval Station and North Island plants are situated. The process laid out in the solicitation has three phases. Earlier this week, we learned that we have been selected to move to the next phase for both sites. We'll be submitting more detailed proposals by late May. In addition to the PPA discussions we are having with SDG&E, we are continuing to evaluate alternate contractual arrangements for the San Diego plants and Oxnard.

As we disclosed in our previous conference call, to the extent that we are successful in gaining site control and arranging new PPAs for one or more of the San Diego plants, we expect that there would be a substantial reduction in Project Adjusted EBITDA as compared to the current PPAs, given current market conditions. However, we think that even such a reduced level of EBITDA would provide an attractive return on the incremental investment needed to reconfigure and perform major maintenance on the facility. Also, a PPA of intermediate length could serve as a bridge to potentially better power market conditions down the road and preserve the long-term optionality of the plants.

Turning to our Williams Lake biomass plant in British Columbia, we are in discussions with BC Hydro on a potential short-term extension of the PPA, which expires next March. The focus has moved to a short-term extension because of the timing of BC Hydro's Integrated Resource Plan or IRP, which the utility is required to file in November 2018 but which is not expected to be finalized until sometime in 2019. A short-term extension could bridge the plant through the IRP process, which is expected to decide what role biomass will play in the utility's longer-term resource mix. If a short-term extension of the PPA is agreed to, we expect that Project Adjusted EBITDA under the new PPA would be substantially lower than under the existing PPA.

On previous conference calls we have discussed plans for a new fuel shredder at Williams Lake, which would allow the plant to burn a mix of up to 50% rail ties and other alternative fuels. This would allow the plant to remain a low-cost producer of energy and provide environmental disposal benefits to the region.

Last September we received an amended air permit from the Ministry of Environment that would allow us to make these changes in fuel mix by installing a new fuel shredder. Several appeals were filed with the Environmental Appeal Board with respect to the air permit amendment and the corresponding landfill permit amendment. The appeals of the landfill permit amendment have been dismissed. Recent indications are that an oral hearing on the remaining appeals will be held late this year or in the early part of 2018. A decision by the Board could occur in the first half of 2018. We believe that we have a strong position and that ultimately the permit will be upheld.

To be clear, however, the fuel shredder would not be required nor would it be economically feasible under a short-term extension of the PPA. We would proceed with this investment only if we were to reach agreement on a long-term extension of the PPA that provides us the ability to recover our investment in the new shredder and earn a reasonable return.

Terry Ronan — Atlantic Power Corporation — EVP & CFO

Before reviewing first quarter results, I'll address the Global Adjustment settlement with the OEFC that we reached in late April. As previously discussed, we expect to receive total payments of Cdn\$36.1 million or approximately US\$27 million. Approximately US\$20 million of the total relates to Kapuskasing and North Bay and the remaining US\$6 to US\$7 million is for Tunis and is related to operation of that plant in 2013 and 2014.

We received Cdn\$10.7 million or approximately US\$8 million of payments in the first quarter of 2017. At the time, we had not reached a settlement with the OEFC, so these amounts were recorded as deferred revenue and included as a current liability on the March 31st balance sheet. Accordingly, they did not benefit operating revenues, Net income or Project Adjusted EBITDA in the first quarter. They were included in Cash provided by operating activities and they are included in cash on the March 31st balance sheet. Having finalized a settlement in the second quarter, all contingent aspects of the gain have been addressed. Thus, we will record these payments as revenues in the second quarter, along with an additional Cdn\$20.3 million (or about US\$15 million) of payments that we received earlier this week. The remaining Cdn\$5.1 million relates to the enhanced

dispatch contracts at Kapuskasing and North Bay and will be received and recognized as revenue, when earned, over the balance of this year.

Slide 10: Q1 2017 Project Adjusted EBITDA bridge

We reported \$63.8 million of Project Adjusted EBITDA for the first quarter of 2017, an increase of \$1.3 million from the \$62.5 million reported for the comparable 2016 period. The slight increase was primarily attributable to the impact of the revised operational and contractual arrangements for Kapuskasing and North Bay as well as the expiration of an above-market gas contract for the two plants that expired at year-end 2016. The two plants had a combined increase in Project Adjusted EBITDA for the quarter of \$6.8 million. Orlando had a \$2.1 million increase in Project Adjusted EBITDA, mostly from the settlement of favorable fuel swaps. Unfavorable comparisons occurred at Morris, which decreased \$4.6 million due to several factors, including higher fuel prices, lower fuel optimization, the non-recurrence of a return on a construction project that we received in 2016, and a lower PJM capacity price. Mamquam decreased \$1.8 million due to lower water flows and Calstock decreased \$1.4 million due to lower waste heat and the expiration of a rate adder under the PPA.

Slide 11: Cash Flow Results and Uses of Cash

Cash provided by operating activities of \$34.1 million in the first quarter of 2017 increased \$4.7 million from the year-ago figure of \$29.4 million. The 2017 result benefited from the approximately \$8 million of Global Adjustment deferred revenues (included in cash flow) and a \$1.3 million increase in Project Adjusted EBITDA. These favorable variances were partially offset by decreases in cash provided by operating activities from Morris and Mamquam, for reasons

previously discussed, and a \$2.9 million increase in cash interest payments, which resulted from a higher term loan balance and higher spread on the loan relative to the first quarter of 2016.

During the quarter, we repaid \$25 million of our term loan and amortized \$2.3 million of project debt. We also made capital expenditures of approximately \$2 million and paid preferred dividends of \$2.1 million. These uses were funded from our operating cash flow.

Slide 12: Liquidity

At March 31, 2017, we had liquidity of \$214 million, including \$91.5 million of unrestricted cash. This is approximately \$10 million higher than the December 31st level of \$204 million, consisting of an approximate \$6 million increase in unrestricted cash and a \$4 million increase in revolver availability, which resulted from a reduction in letters of credit outstanding. Approximately \$66 million of the cash balance is at the parent; holding aside approximately \$10 million for working capital purposes, we had about \$56 million of discretionary cash at March 31st.

Slide 13: Progress on Debt Reduction and Leverage

Our March 31, 2017 consolidated debt was \$971 million. (Note, the debt totals shown on Slide 13 exclude unamortized discounts and deferred financing costs.) During the quarter, we repaid \$27 million of term loan and project debt, as previously discussed. Since year end 2013, we have reduced our consolidated debt by more than \$900 million as a result of amortization, discretionary repurchases and asset sales. During that same period, our leverage ratio declined from a peak of 9.5 times to 5.4 times at the end of March. Separately, debt at our equity-owned

projects has been reduced by more than \$90 million during this same period. (Note that our leverage ratio is based on gross debt rather than net, and Adjusted EBITDA, which is after corporate G&A costs.)

Slide 14: Debt Repayment Profile

Our progress to date in debt reduction and the refinancing of our term loan and revolver last year has improved our debt maturity profile considerably. Slide 14 is a schedule of expected debt repayment by year, including amortization, projected repayment of the term loan and bullet maturities. Of note:

- Approximately 57% of our debt is amortizing and the rest is bullet maturities. Compared to the profile of a few years ago, when our corporate debt consisted mostly of bullet maturities, this has reduced the amount of debt subject to refinancing risk.
- We are scheduled to repay another \$75 million of our term loan and \$9.5 million of project debt in the three remaining quarters of 2017, and expect to repay at least an additional \$40 million, for an expected total repayment this year in excess of \$150 million.
- Our next bullet maturity at the parent is not until June 2019, when the remaining \$42.5 million of Series C convertible debentures mature. The Series D convertible debentures (\$60.9 million U.S. dollar equivalent) mature in December of 2019. Both series of convertible debentures are callable at par two years prior to their maturity dates. At the project level, we have a bullet maturity of \$54 million at Piedmont in August 2018.

- Although not shown on this slide, our corporate revolver matures in April 2021. We currently do not have any borrowings under the revolver.

Slide 15: Projected Debt Balances

Between now and year-end 2020, we expect to repay approximately \$374 million of project and term loan debt, primarily from operating cash flow. This represents approximately 37% of our total debt.

As shown on Slide 15, this projected repayment would reduce our total debt to approximately \$640 million at year-end 2020. However, this assumes that we refinance Piedmont in 2018 and either refinance or use our revolver for the 2019 convertible debentures (that is, we are not assuming any reduction in debt for either). However, we expect that we would use some portion of our discretionary cash to address part of these maturities, which should further improve our debt levels during this period.

As previously discussed, we're evaluating different paths to address the Piedmont maturity, including a potential divestiture or a continued ownership where we reduce the debt at Piedmont by using cash, potentially but not necessarily in conjunction with a refinancing. We also have the option of including Piedmont in the term loan structure.

With respect to the convertible debentures, we have not made a decision with respect to addressing these maturities, but the alternatives include repurchases under our normal course issuer bid or NCIB, up to the 10% limit; calling one or both of the issues sometime between their June and December 2017 call dates and

their June and December 2019 maturity dates; or a refinancing prior to maturity. We have the option of using up to \$100 million under our corporate revolver to address the convertible debentures.

We expect this continued delevering to generate significant interest cost savings that benefit our cash flow. Repaying \$374 million of project and term loan debt during this period would result in an additional \$20 million of annualized interest cost savings by 2021. If we used cash to redeem all or part of the remaining convertible debentures, that would generate up to another \$6 million of annual interest cost savings. By reducing our cash interest payments, we can help to offset a portion of the impact on our cash flow from potential reductions to EBITDA resulting from PPA expirations during this period.

Delevering remains one of our most important financial goals. Although required debt amortization in 2017 is only \$112 million, which will be funded from our operating cash flow, we plan to allocate \$40 million or more of discretionary cash for additional debt reduction (which could include repurchasing or redeeming convertible debentures, further repayment of the term loan or repayment of the Piedmont project debt). This would bring total debt repayment in 2017 to \$150 million or more, and would reduce our year-end 2017 leverage ratio to below 4 times. Although we expect this ratio to increase modestly in 2018 due to lower expected Project Adjusted EBITDA, the magnitude of debt repayment during this period should move the ratio back in the range of 4 times by 2019.

Slide 16: 2017 Guidance: Project Adjusted EBITDA bridge vs. 2016 actual

The Company has not provided guidance for Project income or Net income because of the difficulty of making accurate forecasts and projections without unreasonable efforts with respect to certain highly variable components of these comparable GAAP metrics, including changes in the fair value of derivative instruments and foreign exchange gains or losses. These factors, which generally do not affect cash flow, are not included in Project Adjusted EBITDA.

As disclosed in our May 4, 2017 press release, we have increased our 2017 guidance for Project Adjusted EBITDA to a range of \$250 to \$265 million from a range of \$225 to \$240 million. The \$25 million increase in guidance is attributable to the Global Adjustment revenues, which we indicated last quarter were not included in our initial 2017 guidance.

We have provided an additional disclosure on this slide in response to questions that we have received. The most important contributor to the higher Project Adjusted EBITDA in 2017 relative to the \$202 million recorded in 2016 is the impact of the revised contractual and operational status of our Kapuskasing and North Bay plants in Ontario and the expiration of an above-market contract to supply gas to these plants, all of which occurred at year-end 2016, and the collection of Global Adjustment revenues for these plants under the OEFC settlement.

On Slide 16, we have provided a bridge of the 2016 Project Adjusted EBITDA for these two plants (\$10 million) to the estimated 2017 level that is embedded in our guidance (approximately \$67 million, including \$20 million of Global Adjustment

payments), implying an increase of \$57 million in 2017. Essentially, this increase accounts for all of the \$55 million increase in total Company Project Adjusted EBITDA from \$202 million in 2016 to \$257.5 million in 2017 (based on the guidance midpoint). Although there are other variables in 2017, as shown in the bridge and discussed below, they are essentially offsetting. Absent the significant increase from these two plants, which is mostly attributable to non-recurring or expiring factors, 2017 results would be more in line with 2016.

As shown on the bridge, the other factors affecting our 2017 guidance are less significant but include:

- Forecasted return to average water flows, which would result in increased EBITDA from Curtis Palmer, partially offset by a decrease from Mamquam;
- Full year return on optimization investments, including the final turbine upgrade at Morris to be completed this spring;
- Lower maintenance expense and higher revenues at Morris, which had an extended scheduled outage in 2016;
- Maintenance expense required to prepare Tunis for a return to service in 2018 under the terms of the PPA, and
- Maintenance expense at Frederickson related to a scheduled major gas and steam turbine outage.

Slide 17: 2017 Guidance: Project Adjusted EBITDA bridge to Cash Provided by Operating Activities

Slide 17 provides a bridge of our 2017 Project Adjusted EBITDA guidance range of \$250 to \$265 million to an estimate of Cash provided by operating activities, which we have updated to a range of \$155 to \$170 million, consistent with the

increase to Project Adjusted EBITDA guidance. For purposes of this bridge, the impact of changes in working capital on cash flow is assumed to be nil. Our assumptions with regard to corporate overheads, cash interest payments and cash taxes are unchanged, although the recent repricing of our term loan should yield modest savings this year, net of the \$1.3 million of transaction costs that will be recorded in the second quarter.

Planned uses of operating cash flow in 2017 include \$100 million amortization of our term loan; \$12 million of project debt amortization; \$5 million of capital expenditures, mostly consisting of the Morris turbine upgrade and a few other small projects; and \$9 million of preferred dividend payments. We expect to have significant free cash flow remaining after these uses that would be available for discretionary purposes. As previously noted, we plan to allocate \$40 million or more of our estimated discretionary cash to additional debt reduction in 2017.

2018 Outlook

As previously discussed, our 2017 guidance represents a significant increase from our 2016 results, on the order of \$55 million based on the guidance midpoint. This increase is primarily attributable to the contribution by Kapuskasing and North Bay, which will not continue in 2018 because of the expiration of the enhanced dispatch contracts at year-end 2017 and the non-recurring nature of the Global Adjustment payments received in 2017. The additional cash flows from these plants are very beneficial and will add to our cash balance and debt repayment capacity in 2017. However, we do not expect either of these plants to generate EBITDA in 2018.

We are not providing 2018 guidance at this time. However, we would note that the roll-off of Kapuskasing and North Bay would put our 2018 results at about the level of 2016 (\$202 million). Other factors likely to affect results include the expiration or potential expiration of PPAs for the San Diego plants and Williams Lake in the early part of 2018, as previously disclosed. In comparing 2018 to 2016, we would expect there to be a much smaller reduction associated with PPA expirations than with the roll-off of Kapuskasing and North Bay. This reduction could be partially offset by increases elsewhere in the portfolio. From a cash flow standpoint, we would expect the impact of lower Project Adjusted EBITDA to be mitigated (although not completely offset) by reductions in cash interest payments resulting from repayment of \$150 million or more of debt in 2017 and approximately \$100 million of term loan and project debt in 2018.

James J. Moore, Jr. - Atlantic Power Corporation — President & CEO

Slide 18: Concluding Remarks

The IPP sector in the United States is in a period of distress with low power prices owing to weak demand, public policy (at least in some of the states in which we operate) that is supportive of intermittent power generation while not adequately compensating reliable generation sources, state-level efforts to avoid nuclear retirements, and low interest rates coupled with tax incentives creating new supply in already oversupplied markets. Many of the same factors are at play in Canada.

The good news for Atlantic Power is that our efforts to reduce debt, cut interest expenses, cut corporate overhead and extend debt maturities have put us in a position to act deliberately and with patience. Compared to 2013, our interest payments and overheads are \$91 million lower, which is significant against a

Project Adjusted EBITDA this year of \$250 to \$265 million, and even more significant if the EBITDA related to our Ontario plants that will not continue next year is excluded.

We have improved liquidity of \$214 million, including \$122.5 million available under our \$200 million revolver, and \$91.5 million of unrestricted cash, including approximately \$66 million at the parent level. We also have a growing ability to access capital markets, as evidenced by the successful term loan repricing we just completed.

We have good options for allocating our cash flow and using our liquidity, including: maintaining ownership of Piedmont with its 15-year remaining PPA life and A- credit offtaker by paying down or paying off the 2018 maturity; redeeming the 2019 convertible debentures; making capital investments in certain plants related to PPA renewal efforts; developing new projects for industrial customers, and repurchasing shares when our share price is lower than our estimate of intrinsic value per share, as is currently the case.

Although we cannot control power prices or public policy, we believe our two-year turnaround effort has put us in a better position to both endure the downturn, protecting as much value as we can in this market environment, while also looking to grow intrinsic value per share over time through rational capital allocation. If we get a stronger power market environment at some point in the future, our low corporate overheads and reduced interest expense will provide us with enhanced cash flows that will be divided by a lower share count.

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

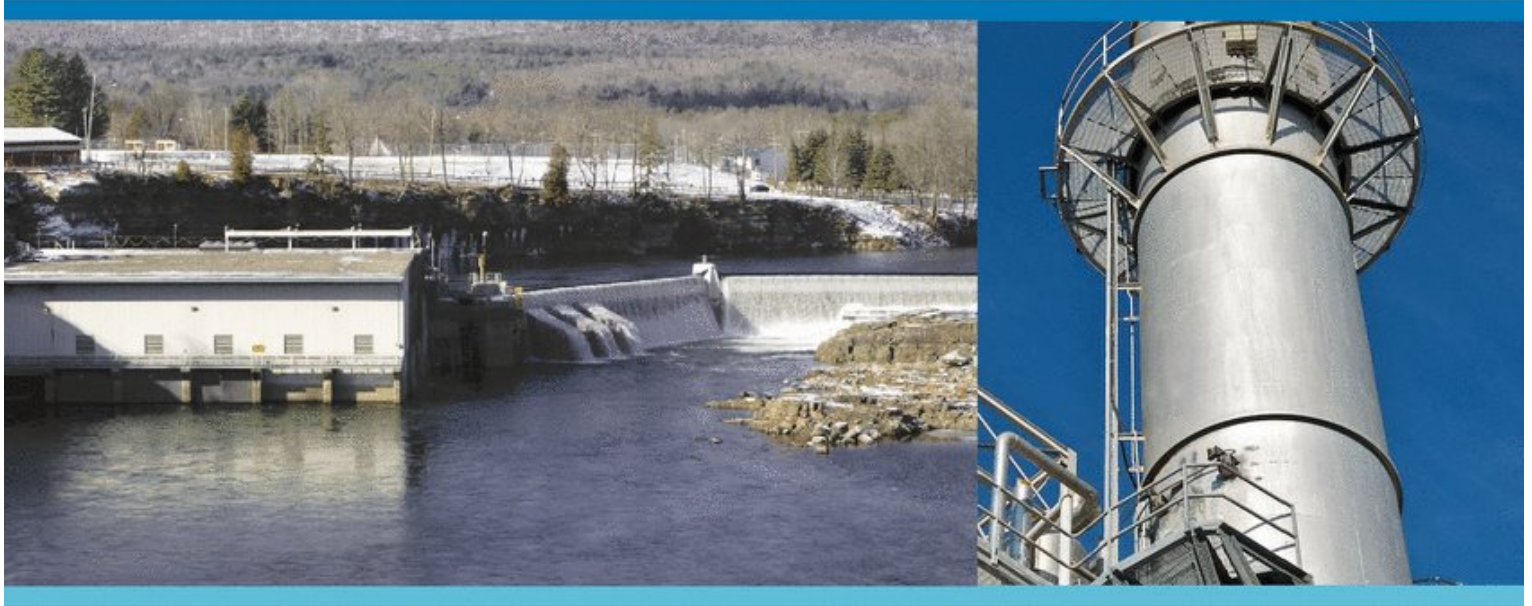
(in millions of U.S. dollars, except as otherwise stated)

Unaudited

	Three months ended March 31	
	2017	2016
Net loss attributable to Atlantic Power Corporation	\$ (2.7)	\$ (14.9)
Net income attributable to preferred share dividends of a subsidiary company	2.1	2.0
Net loss	\$ (0.6)	\$ (12.9)
Income tax benefit	(0.3)	1.6
Loss from operations before income taxes	(0.9)	(11.3)
Administration	6.4	6.1
Interest expense, net	17.3	16.6
Foreign exchange loss	2.5	19.8
Other income, net	—	(2.5)
Project income	\$ 25.3	\$ 28.7
Reconciliation to Project Adjusted EBITDA		
Depreciation and amortization	\$ 34.9	\$ 29.9
Interest expense, net	2.4	2.5
Change in the fair value of derivative instruments	1.2	1.2
Other expense	—	0.2
Project Adjusted EBITDA	\$ 63.8	\$ 62.5



AtlanticPower
Corporation



Q1 2017 Financial Results Conference Call

May 5, 2017

Cautionary Note Regarding Forward-Looking Statements

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

Forward-looking statements can generally be identified by the use of words such as "should," "intend," "may," "expect," "believe," "anticipate," "estimate," "continue," "plan," "project," "will," "could," "would," "target," "potential" and other similar expressions. In addition, any statements that refer to expectations, projections or other characterizations of future events or circumstances are forward-looking statements. Although Atlantic Power Corporation ("AT", "Atlantic Power" or the "Company") believes that the expectations reflected in such forward-looking statements are reasonable, such statements involve risks and uncertainties and should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. Please refer to the factors discussed under "Risk Factors" and "Forward-Looking Information" in the Company's periodic reports as filed with the Securities and Exchange Commission from time to time for a detailed discussion of the risks and uncertainties affecting the Company, including, without limitation, the outcome or impact of the Company's business strategy to increase the intrinsic value of the Company on a per-share basis through disciplined management of its balance sheet and cost structure and investment of its discretionary cash in a combination of organic and external growth projects, acquisitions, and repurchases of debt and equity securities; the Company's ability to enter into new PPAs on favorable terms or at all after the expiration of existing agreements, and the outcome or impact on the Company's business of any such actions. Although the forward-looking statements contained in this news release are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. These forward-looking statements are made as of the date of this news release and, except as expressly required by applicable law, the Company assumes no obligation to update or revise them to reflect new events or circumstances. The Company's ability to achieve its longer-term goals, including those described in this news release, is based on significant assumptions relating to and including, among other things, the general conditions of the markets in which it operates, revenues, internal and external growth opportunities, its ability to sell assets at favorable prices or at all and general financial market and interest rate conditions. The Company's actual results may differ, possibly materially and adversely, from these goals.

Disclaimer – Non-GAAP Measures

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) by segment and on a consolidated basis is provided on slide 34.

Cash Distributions from Projects is the amount of cash distributed by the projects to the Company out of available project cash flow after all project-level operating costs, interest payments, principal repayment, capital expenditures and working capital requirements. It is not a non-GAAP measure. Project Adjusted EBITDA, a non-GAAP measure, is the most comparable measure, but it is before debt service, capital expenditures and working capital requirements. The Company has provided a bridge of Project Adjusted EBITDA to Cash Distributions from Projects on slide 32.

All amounts in this presentation are in US\$ and approximate unless otherwise stated.

Agenda

- CEO: Q1 2017 Highlights and Recent Developments
- Operations Review
- Commercial Review / PPAs
- Q1 2017 Financial Results
- Balance Sheet and Liquidity Update
- 2017 Guidance
- CEO: Concluding Remarks
- Q&A

Q1 2017 Highlights

- Solid start to the year
 - Plant operations as expected
 - Spring maintenance outages on track
 - No safety issues
 - Hydro conditions at Curtis Palmer looking better
- Financial results in line with expectations
 - Project Adjusted EBITDA of \$63.8 million vs. \$62.5 million
 - o Did not include any benefit from Global Adjustment payments (OEFC)
 - Cash provided by operating activities of \$34.1 million vs. \$29.4 million
 - o Included about \$8 million of Global Adjustment payments
- Debt reduction on track
 - Repaid \$27.3 million of term loan and project debt in Q1
 - Expect to repay \$150 million or more of debt this year
- Improved liquidity
 - \$214 million at March 31 vs. \$204 million at December 31, 2016
 - Includes \$91.5 million of unrestricted cash (including \$66 million at the parent)
- Increased 2017 guidance by \$25 million for Global Adjustment payments
 - Now \$250 to \$265 million

Developments Since Q4 / YE 2016 Call

OEFC Settlement Regarding Global Adjustment Dispute

- In April, finalized settlement for Cdn\$36.1 million (approximately US\$26 million)
- Represents revenues that we should have received in April 2013 through the current year for Kapuskasing, North Bay and Tunis plants
- Received Cdn\$10.7 million in Q1 2017 and another Cdn\$20.3 million in early May (Q2)
- Q1 2017 amount recorded as deferred revenue; benefited cash flow but not included in Q1 2017 Project Adjusted EBITDA of \$63.8 million
 - Q1 and May 2017 payments will be recorded in Q2 2017 EBITDA
- Expect to receive another Cdn\$5.1 million over the balance of the year
- Adds significantly (~ US\$18 million) to our cash at the parent (\$66 million)

Developments Since Q4 / YE 2016 Call (continued)

Term Loan / Revolver Repricing

- In April, successfully repriced \$615 million term loan and \$200 million revolver
- Reduced spread by 75 bp to LIBOR + 4.25%
- Results in interest cost savings, net of transaction fees, of \$2.4 million in 2017 and \$17 million over remaining lives of facilities

Piedmont

- Resolution of required amendment to air permit expected in next couple of months
- Evaluating options for 2018 debt maturity
 - Sale process – expect would result in proceeds in excess of project debt
 - Continue to own – pay down or refinance 8.5% debt
- Disciplined approach: we believe both are good options

Q1 2017 Operational Performance:

Lower generation primarily due to curtailment of the Ontario gas plants

Safety: Total Recordable Incident Rate



(1) 2014 BLS data, generation companies = 1.1
(2) 2015 BLS data, generation companies = 1.4

Availability (weighted average)

	Q1 2017	Q1 2016
East U.S.	98.8%	99.0%
West U.S.	94.7%	89.6%
Canada	91.4%	99.5%
Total	96.8%	96.6%

Availability factor in line:

- + Naval Station is favorable due to major outage in prior period
- Mamquam is unfavorable due to planned outage in current period

Aggregate Power Generation Q1 2017 vs. Q1 2016 (thousands, Net MWh)



Generation is down:

- Kapuskasing/Nipigon/North Bay are not in operation for 2017 under the enhanced dispatch contracts with the IESO
- Mamquam lower water flows (compared to record levels in 2016)
- Morris merchant generation down due to mild weather and low PJM demand
- + Naval Station favorable due to major outage in prior period

Operations Update

Ontario Plants

- Kapuskasing, Nipigon and North Bay in non-operational state
- Plan to return Tunis to service in 2018
 - Work to be done in latter part of 2017
- Still in discussions with relevant parties in Ontario on potential initiatives that could affect Tunis and/or Nipigon

Scheduled Maintenance Outages

- Morris – Work on completing third and final combustion turbine upgrade (optimization project); currently under way; plant continuing to operate on two previously upgraded turbines
- Frederickson – Major outage for gas and steam turbines began in late April
- Kenilworth – Steam turbine overhaul, but plant continues to operate on gas turbine
- Orlando – Major turbine maintenance completed

Cost Reduction Initiatives

- Analysis and benchmarking of operation and maintenance costs under way
- Goal – improved efficiency and operational performance
- Expect to have more to say in 2H 2017

Commercial Update: PPA Renewal Status

Ontario

- Continuing discussions with relevant parties on potential initiatives for Nipigon and Tunis that would be mutually beneficial

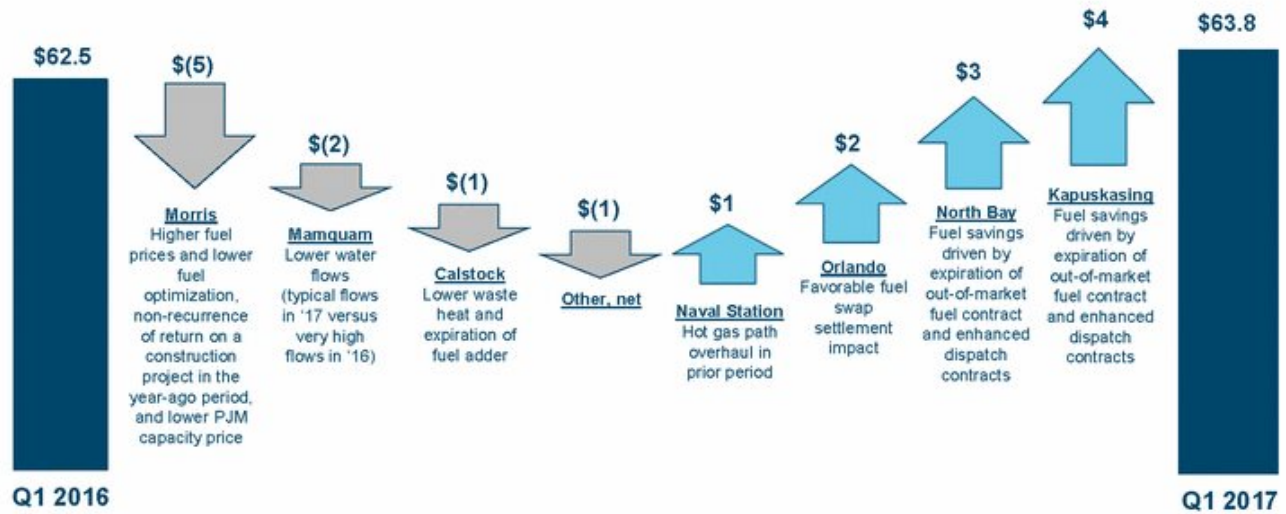
San Diego Plants

- Three plants – PPAs with San Diego Gas & Electric (SDG&E) expire Dec. 2019, but Navy steam contracts / leases expire Feb. 2018
- Continuing discussions with SDG&E for PPAs at two of three plants
- Also considering other contracting options for Oxnard and San Diego plants
- Navy issued solicitation for energy resiliency proposals for Naval Station and North Island
 - We responded in mid-March
 - Notified early May that we have been selected to move into second phase for both

Williams Lake

- Discussions with BC Hydro continuing on potential extension of existing PPA (expires March 2018)
 - Focus is on a short-term extension that would bridge to outcome of Integrated Resource Plan (2019)
 - Would not require investment in a new fuel shredder
 - Would result in significantly lower Project Adjusted EBITDA compared to existing PPA
- Regarding appeal of amended air permit for new shredder
 - Some of the appeals were dismissed by Environmental Appeal Board
 - Oral hearing likely in toward year-end or early 2018
 - Final decision could be in first-half 2018

Q1 2017 Project Adjusted EBITDA (\$ millions)



Q1 2017 Cash Flow Results (\$ millions)

<i>Unaudited</i>	Three months ended March 31,		
	2017	2016	Change
Cash provided by operating activities	\$34.1	\$29.4	\$4.7
Significant uses of cash provided by operating activities:			
Term loan repayments ⁽¹⁾	(25.0)	(25.3)	0.3
Project debt amortization	(2.3)	(2.1)	(0.2)
Capital expenditures	(2.0)	(0.7)	(1.3)
Preferred dividends	(2.1)	(2.0)	(0.1)

Primary drivers:

- Deferred revenues under OEFC Settlement +7.9
- Kap/N.Bay/Nipigon revised contracts +6.6
- Lower results at Morris and Mamquam (6.4)
- Higher cash interest payments (2.9)

⁽¹⁾ Includes 1% mandatory annual amortization and targeted debt repayments.

Liquidity (\$ millions)

<i>Unaudited</i>	12/31/16	3/31/17
Revolver capacity	\$200.0	\$200.0
Letters of credit outstanding	(81.5)	(77.5)
Unused borrowing capacity	118.5	122.5
Unrestricted cash	85.6	91.5
Total Liquidity	\$204.1	\$214.0

Note: Liquidity does not include restricted cash of \$10.0 million at March 31, 2017 and \$13.3 million at December 31, 2016.

\$4 reduction in LCs (debt service LC)

Includes ~ \$66 at APC (parent); balance is at the plants or other subsidiaries
 (10) Need for working capital purposes
 ~ 56 Discretionary cash available

Progress on Debt Reduction and Leverage (\$ millions)

(Unaudited)

		<u>Leverage ⁽¹⁾</u>
12/31/2013 consolidated debt	\$1,876	9.5x
12/31/2014 consolidated debt	1,755	6.9x
12/31/2015 consolidated debt	1,019	5.7x
3/31/2016 consolidated debt	994	5.6x
Term loan refinancing:		
Issuance of new term loan (April)	700	
Repayment of previous term loan (April)	(448)	
3/31/16 consolidated debt – pro forma	1,246	7.1x
Changes Q2-Q4 2016:		
Redemption of 2017 convertible debentures (May)	(110)	
Repurchase of 2019 convertible debentures (July)	(63)	
Amortization of new term loan (Q2 – Q4)	(60)	
Amortization of project debt (Q2 – Q4)	(9)	
Incremental F/X impact (unrealized gain) (Q2 – Q4)	(7)	
12/31/16 consolidated debt	997	5.6x
Changes Q1 2017:		
Amortization of new term loan	(25)	
Amortization of project debt	(2)	
Incremental F/X impact (unrealized loss)	2	
3/31/17 consolidated debt	971	5.4x

Net increase in debt \$252

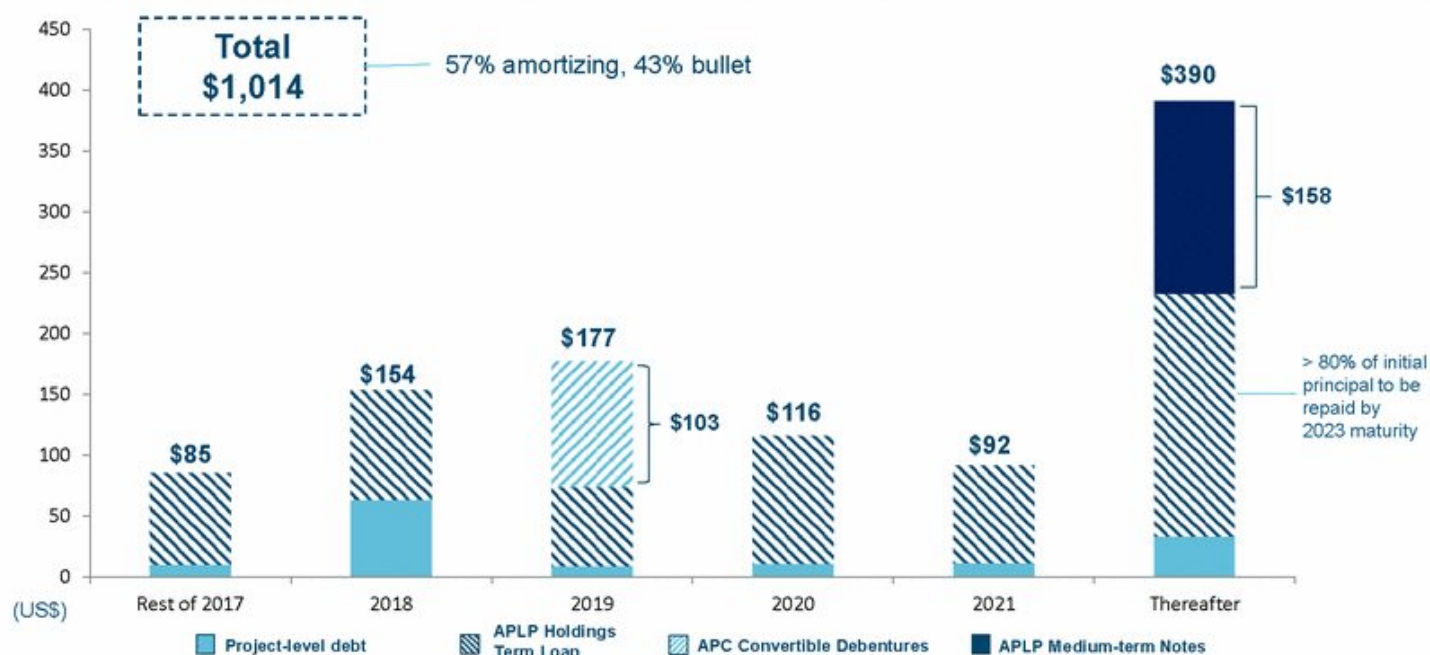
By year end 2016, had paid down all but \$10 of \$252 increase

Total net reduction in consolidated debt of approximately \$905 million since YE 2013; in addition, debt at equity-owned projects has been reduced by approximately \$89 million.

Note: Consolidated debt excludes unamortized discounts and deferred financing costs
⁽¹⁾ Consolidated gross debt to trailing 12-month Adjusted EBITDA (after Corporate G&A)

Debt Repayment Profile at March 31, 2017 (\$ millions)

Includes Company's share of debt at equity-owned projects

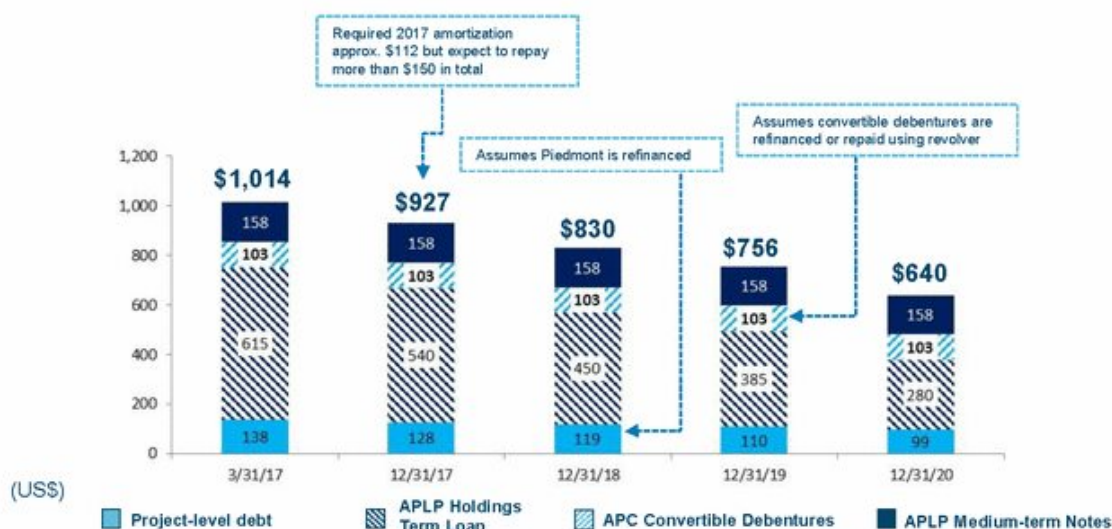


- Project-level non-recourse debt totaling \$138, including \$43 at Chambers (equity method); includes Piedmont bullet maturity of \$54.1 (2018); remainder amortizes over the life of the project PPAs
- \$615 amortizing term loan (maturing in April 2023), which has 1% annual amortization and mandatory prepayment via the greater of a 50% sweep or such other amount that is required to achieve a specified targeted debt balance (combined annual average of ~ \$82)
- \$103 (US\$ equivalent) of convertible debentures (maturing in June and December 2019)
- \$158 APLP Medium-term Notes due in 2036

Note: C\$ denominated debt was converted to US\$ using US\$ to C\$ exchange rate of 1.3299.

Projected Debt Balances through 2020 (\$ millions)

Includes Company's share of debt at equity-owned projects



Q1 2017 – Year-end 2020:

- Term loan – Repay \$335, ending balance \$280 – annual interest cost savings \$18 by 2021
- Project debt (proportional) – Repay \$39, ending balance \$99 – annual interest cost savings \$2
- Assumes Piedmont (\$54) is refinanced at maturity in 2018 – if repaid, would have annual interest cost savings of ~ \$5
- Assumes 2019 convertible debentures (\$103) are refinanced or repaid using revolver (no change in debt)
 - If redeemed or repurchased using cash, annual interest savings of up to \$6 in 2020

Cumulative Paydown of Debt Drives Interest Cost Savings

Note: C\$ denominated debt was converted to US\$ using US\$ to C\$ exchange rate of 1:1.3299.

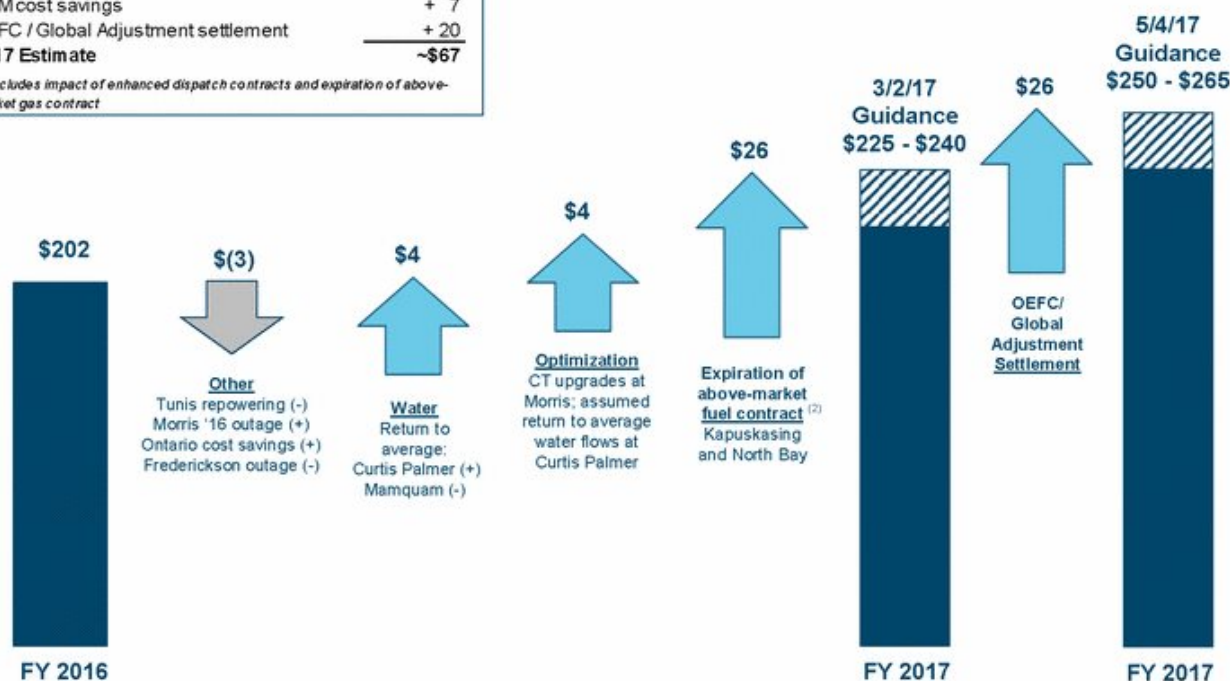
2017 Project Adjusted EBITDA Guidance (\$ millions)

Guidance revised to \$250 to \$265 (had been \$225 to \$240)

Kapuskasing & North Bay

2016 Project Adjusted EBITDA	\$10
Gross margin ⁽¹⁾	+ 30
O&M cost savings	+ 7
OEFC / Global Adjustment settlement	+ 20
2017 Estimate	~\$67

⁽¹⁾ Includes impact of enhanced dispatch contracts and expiration of above-market gas contract



Key drivers include: Kapuskasing & North Bay (see above), higher Optimization returns and assumed average water flows at Curtis Palmer (+) and Mamquam (-)

The Company has not provided guidance for Project income or Net income because of the difficulty of making accurate forecasts and projections without unreasonable efforts with respect to certain highly variable components of these comparable GAAP metrics, including changes in the fair value of derivative instruments and foreign exchange gains or losses. These factors, which generally do not affect cash flow, are not included in Project Adjusted EBITDA.

Bridge of 2017 Project Adjusted EBITDA Guidance to Cash Provided by Operating Activities (\$ millions)

2017 Project Adjusted EBITDA Guidance⁽¹⁾	\$250 - \$265
Adjustment for equity method projects ⁽²⁾	(1)
Corporate G&A expense	(22)
Cash interest payments	(67)
Cash taxes	(4)
Other	-
Cash provided by operating activities	\$155 - \$170

Note: For purposes of providing a reconciliation of Project Adjusted EBITDA guidance, impact on Cash provided by operating activities of changes in working capital is assumed to be nil.

2017 expected uses of cash provided by operating activities:	
Term loan repayments ⁽³⁾	\$100
Project debt amortization	12
Capital expenditures	5
Preferred dividend payments	9

⁽¹⁾ Initially provided May 4, 2017.

⁽²⁾ Represents difference between Project Adjusted EBITDA and cash distribution from equity method projects.

⁽³⁾ Includes 1% mandatory annual amortization and targeted debt repayments.

CEO: Concluding Remarks

- Atlantic Power in much better position than three years ago
 - Lower interest expense and corporate overheads (down \$91 million)
 - Significant compared to Project Adjusted EBITDA of \$250 to \$265 million
 - Much lower debt balance; improved liquidity (\$214 million)
- Good options for allocating cash flow and using liquidity
 - Retain ownership of Piedmont / pay down project-level debt
 - Redeem 2019 convertible debentures
 - Develop new projects for industrial customers
 - Repurchase shares when trading at a discount to our estimates of intrinsic value

Appendix

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Capitalization (\$ millions)

	December 31, 2016		March 31, 2017	
Long-term debt, incl. current portion ⁽¹⁾				
APLP Medium-Term Notes ⁽²⁾	\$156		\$158	
Revolving credit facility	-		-	
Term Loan	640		615	
Project-level debt (non-recourse)	97		95	
Convertible debentures	103		103	
Total long-term debt, incl. current portion	\$996	78%	\$971	77%
Preferred shares	221	17%	221	18%
Common equity ⁽³⁾	65	5%	63	5%
Total shareholders equity	286	22%	284	23%
Total capitalization	\$1,282	100%	\$1,255	100%
⁽¹⁾ Debt balances are shown before unamortized discount and unamortized deferred financing costs ⁽²⁾ Period-over-period change due to F/X impacts ⁽³⁾ Common equity includes other comprehensive income and retained deficit Note: Table is presented on a consolidated basis and excludes equity method projects.				

Capital Summary at March 31, 2017 (\$ millions)

Atlantic Power Corporation			
	Maturity	Actual	
		Amount	Interest Rate
Convertible Debentures (ATP.DB.U)	6/2019	\$42.5	5.75%
Convertible Debentures (ATP.DB.D)	12/2019	\$60.9 (C\$81.0)	6.0%
APLP Holdings Limited Partnership			
	Maturity	Actual	
		Amount	Interest Rate
Revolving Credit Facility	4/2021	\$0	LIBOR + 5.00% ⁽¹⁾
Term Loan	4/2023	\$614.9	6.00%-6.12% ⁽²⁾⁽³⁾
Atlantic Power Limited Partnership			
	Maturity	Actual	
		Amount	Interest Rate
Medium-term Notes	6/2036	\$157.9 (C\$210)	5.95%
Preferred shares (AZP.PR.A)	N/A	\$93.1 (C\$125)	4.85%
Preferred shares (AZP.PR.B)	N/A	\$45.5 (C\$58.5)	5.57%
Preferred shares (AZP.PR.C)	N/A	\$31.0 (C\$41.5)	4.68% ⁽⁴⁾
Atlantic Power Transmission & Atlantic Power Generation			
	Maturity	Amount	Interest
Project-level Debt (consolidated)	Various	\$94.8	4.20%-8.47%
Project-level Debt (equity method)	Various	\$42.9	4.50%-5.00%

⁽¹⁾ As of April 17, 2017, the spread is reduced to 3.75%. ⁽²⁾ Includes impact of interest rate swaps. ⁽³⁾ As of April 17, 2017, the interest rate is 5.25%-5.37%. ⁽⁴⁾ Set on December 1, 2016 for March 31, 2017 dividend payment. Will be reset quarterly based on sum of the Canadian Government 90-day Treasury Bill yield (using the three-month average result plus 4.18%). Note: C\$ denominated debt was converted to US\$ using US\$ to C\$ exchange rate of \$1.3299.

APLP Holdings Term Loan Cash Sweep Calculation

APLP Holdings Adjusted EBITDA

(note: excludes Piedmont; is after majority of Atlantic Power G&A expense)

Less:

Capital expenditures

Cash taxes

= Cash flow available for debt service

Less:

APLP Holdings consolidated cash interest
(revolver, term loan, MTNs, EPP, Cadillac)

= Cash flow available for cash sweep

Calculate 50% of cash flow available for sweep

Compare 50% cash flow sweep to amount required to achieve targeted debt balance

Must repay greater of 50% or the amount required to achieve targeted debt balance for that quarter

If targeted debt balance is > 50% of cash flow sweep:

- Repay amount required to achieve target, up to 100% of cash flow available from sweep
- Remaining amount, if any, to Company

If targeted debt balance is < 50% of cash flow sweep:

- Repay 50% minimum
- Remaining 50% to Company

Expect cash sweep to average 65% to 70% over the life of the loan, though higher in early years, and with considerable variability from year to year

Expect > 80% of principal to be repaid by maturity through mandatory and targeted repayments

Notes:

The cash sweep calculation occurs at each quarter-end. Targeted debt balances are specified in the credit agreement for each quarter through maturity.

APLP Holdings Credit Facilities – Financial Covenants

Fiscal Quarter	Leverage Ratio	Interest Coverage Ratio
3/31/2017	6.00:1.00	2.75:1.00
6/30/2017	5.50:1.00	3.00:1.00
9/30/2017	5.50:1.00	3.00:1.00
12/31/2017	5.50:1.00	3.00:1.00
3/31/2018	5.50:1.00	3.00:1.00
6/30/2018	5.00:1.00	3.00:1.00
9/30/2018	5.00:1.00	3.00:1.00
12/31/2018	5.00:1.00	3.00:1.00
3/31/2019	5.00:1.00	3.00:1.00
6/30/2019	5.00:1.00	3.25:1.00
9/30/2019	5.00:1.00	3.25:1.00
12/31/2019	5.00:1.00	3.25:1.00
3/31/2020	5.00:1.00	3.25:1.00
6/30/2020	4.25:1.00	3.5:1.00
9/30/2020	4.25:1.00	3.5:1.00
12/31/2020	4.25:1.00	3.5:1.00
3/31/2021	4.25:1.00	3.5:1.00
6/30/2021	4.25:1.00	3.75:1.00
9/30/2021	4.25:1.00	3.75:1.00
12/31/2021	4.25:1.00	3.75:1.00
3/31/2022	4.25:1.00	3.75:1.00
6/30/2022	4.25:1.00	4.00:1.00
9/30/2022	4.25:1.00	4.00:1.00
12/31/2022	4.25:1.00	4.00:1.00
3/31/2023	4.25:1.00	4.00:1.00

Leverage ratio:

Consolidated debt to Adjusted EBITDA, calculated for the trailing four quarters.

Consolidated debt includes both long-term debt and the current portion of long-term debt at APLP Holdings, specifically the amount outstanding under the term loan and the amount borrowed under the revolver, if any, the Medium Term Notes, and consolidated project debt (Epsilon Power Partners and Cadillac).

Adjusted EBITDA is calculated as the Consolidated Net Income of APLP Holdings plus the sum of consolidated interest expense, tax expense, depreciation and amortization expense, and other non-cash charges, minus non-cash gains. The Consolidated Net Income includes an allocation of the majority of Atlantic Power G&A expense. It also excludes earnings attributable to equity-owned projects but includes cash distributions received from those projects.

Interest Coverage ratio:

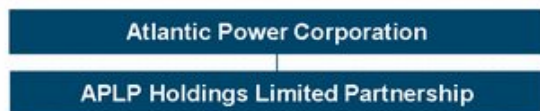
Adjusted EBITDA to consolidated cash interest payments, calculated for the trailing four quarters.

Adjusted EBITDA is defined above.

Consolidated cash interest payments include interest payments on the debt included in the Consolidated debt ratio defined above.

Note, the project debt, Project Adjusted EBITDA and cash interest expense for Piedmont are not included in the calculation of these ratios because the project is not included in the collateral package for the credit facilities.

Power Projects



Atlantic Power Limited Partnership					
Project	Location	Type	Economic Interest	Net MW	Contract Expiry
Calstock	Ontario	Biomass	100%	35	6/2020
Kapuskasing	Ontario	Nat. Gas	100%	40	12/2017
Mamquam	B.C.	Hydro	100%	50	9/2027
Morseby Lake	B.C.	Hydro	100%	6	8/2022
Nipigon	Ontario	Nat. Gas	100%	40	12/2022
North Bay	Ontario	Nat. Gas	100%	40	12/2017
Tunis	Ontario	Nat. Gas	100%	40	11/2032 ⁽²⁾
Williams Lake	B.C.	Biomass	100%	66	3/2018
Curtis Palmer	New York	Hydro	100%	60	12/2027
Kenilworth	New Jersey	Nat. Gas	100%	29	9/2018
Morris	Illinois	Nat. Gas	100%	177	12/2034
Frederickson	Washington	Nat. Gas	50.15%	125	8/2022
Manchief	Colorado	Nat. Gas	100%	300	4/2022
Naval Station	California	Nat. Gas	100%	47	12/2019 ⁽³⁾
Naval Training	California	Nat. Gas	100%	25	12/2019 ⁽³⁾
North Island	California	Nat. Gas	100%	40	12/2019 ⁽³⁾
Oxnard	California	Nat. Gas	100%	49	5/2020

Atlantic Power Transmission & Atlantic Power Generation					
Project	Location	Type	Economic Interest	Net MW	Contract Expiry
Cadillac	Michigan	Biomass	100%	40	12/2028
Chambers	New Jersey	Coal	40%	105	12/2024
Orlando	Florida	Nat. Gas	50%	65	12/2023
Piedmont ⁽¹⁾	Georgia	Biomass	100%	55	12/2032
Selkirk	New York	Nat. Gas	17.7%	61	Merchant
Koma Kulshan	Washington	Hydro	49.8%	6	12/2037

-  Canada
-  East U.S.
-  West U.S.

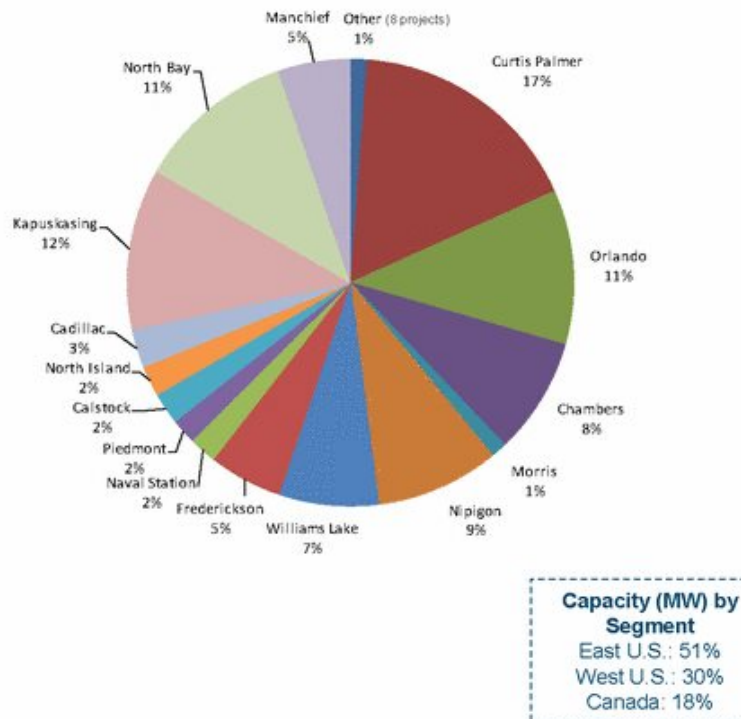
⁽¹⁾ Excluded from the APLP Holdings collateral package

⁽²⁾ 15-year contract commences between Nov. 2017 and Jun. 2019

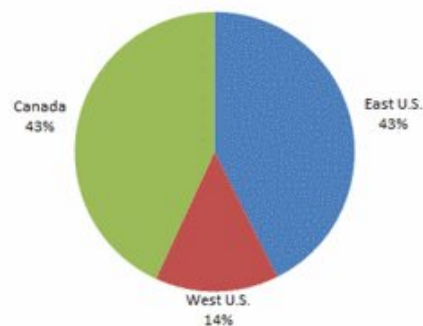
⁽³⁾ May terminate earlier if land use agreements with U.S. Navy expiring in Feb. 2018 are not extended

Earnings and Cash Flow Diversification by Project

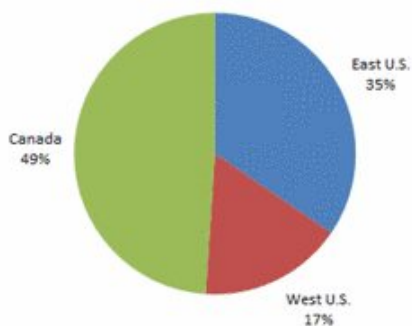
No single project contributed more than 17% to Project Adjusted EBITDA for the three months ended March 31, 2017 ⁽¹⁾



Three months ended March 31, 2017 Project Adjusted EBITDA by Segment ⁽¹⁾



Three months ended March 31, 2017 Cash Distributions from Projects by Segment ⁽²⁾



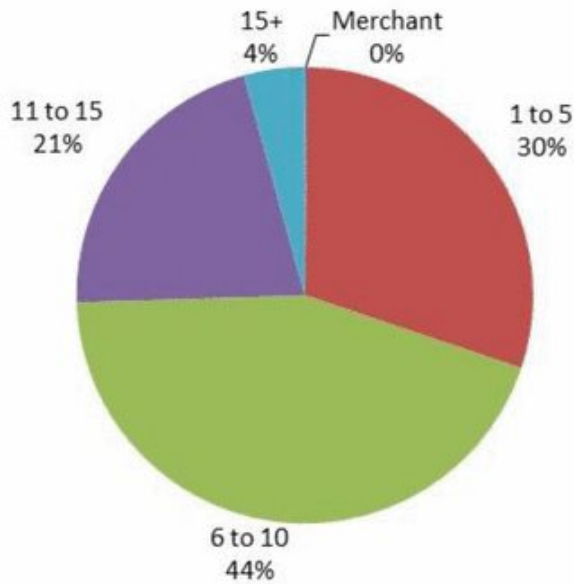
⁽¹⁾ Based on \$63.8 million in Project Adjusted EBITDA for the three months ended March 31, 2017. Un-allocated corporate segment is included in "Other" category for project percentage allocation and allocated equally among segments for three months ended March 31, 2017 Project Adjusted EBITDA by Segment.

⁽²⁾ Based on \$47.3 million in Cash Distributions from Projects for the three months ended March 31, 2017.

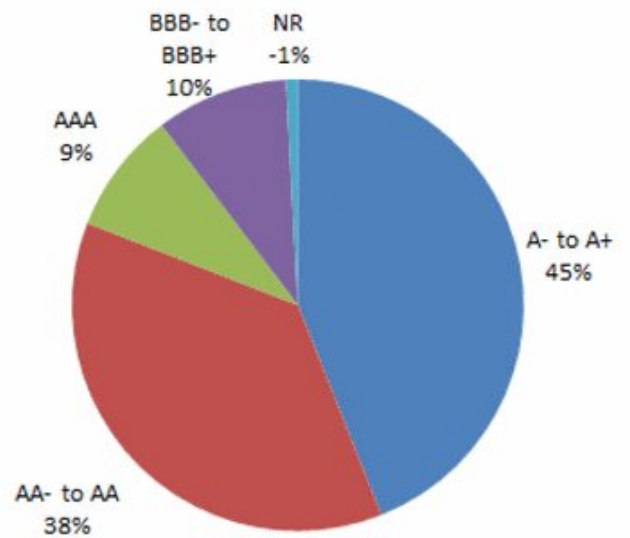
Majority of Cash Flows Covered by Contracts with More Than 5 Years Remaining

Contracted projects have an average remaining PPA life of 5.8 years ⁽¹⁾

PPA Length (years) ⁽¹⁾



Pro Forma Offtaker Credit Rating ⁽¹⁾



70% of estimated 2017 Project Adjusted EBITDA generated from PPAs that expire beyond the next five years

⁽¹⁾ Weighted by FY 2017 Project Adjusted EBITDA estimate (excluding contribution of OEFC / Global Adjustment payments).

Results Summary, Q1 2017 vs Q1 2016 (\$ millions)

(Unaudited)

Summary of Financial and Operating Results

	Three months ended March 31	
	2017	2016
Financial Results		
Project revenue	\$98.4	\$106.4
Project income	25.3	28.7
Net loss attributable to Atlantic Power Corp.	(2.7)	(14.9)
Cash provided by operating activities	34.1	29.4
Project Adjusted EBITDA	63.8	62.5
Operating Results		
Aggregate power generation (thousands of Net MWh)	1,158.7	1,586.9
Weighted average availability	96.8%	96.6%

Segment Results

	Three months ended March 31	
	2017	2016
Project income (loss)		
East U.S.	\$12.9	\$16.1
West U.S.	(0.7)	(2.4)
Canada	10.9	16.4
Un-allocated Corporate	2.2	(1.4)
Total	25.3	28.7
Project Adjusted EBITDA		
East U.S.	\$27.2	\$30.3
West U.S.	9.1	7.5
Canada	27.5	24.8
Un-allocated Corporate	-	(0.1)
Total	63.8	62.5

G&A and Development Expenses (\$ millions)

	2013 Actual	2014 Actual	2015 Actual	2016 Actual
Development ⁽¹⁾	\$7.2	\$3.7	\$1.1	n/a ⁽¹⁾
Project G&A and Other	11.4	3.8	1.5	0.2
Corporate G&A ⁽²⁾	35.2	37.9	29.4	22.6
Total Overhead	\$53.8	\$45.4	\$31.9	\$22.8

Included in Project Adj. EBITDA

"Administration" expense on Income Statement; not included in Project Adj. EBITDA

Project G&A and other:

- Operations & Asset Management
- Environmental, Health & Safety
- Project Accounting

Corporate G&A:

- Executive & Financial Management
- Treasury, Tax, Legal, HR, IT, Commercial activities
- Corporate Accounting
- Office & administrative costs
- Public company costs
- One-time costs (mostly severance)

2016 level represents a 57% reduction from 2013

(1) Includes approximately \$3 million annual contractual obligation related to Ridgeline acquisition that terminated in the first quarter of 2015. For 2016 and beyond, all Development spend will be recorded in Corporate G&A.

(2) Includes \$6 severance in 2014; approximately \$4 severance and \$2 restructuring in 2015

Net Operating Loss Carryforwards (NOLs) (\$ millions)

As of December 31, 2016, we had NOLs scheduled to expire per the schedule below that we can utilize to offset future taxable income:

2027	\$43.2
2028	93.0
2029	70.8
2030	25.8
2031	13.4
2032	19.0
2033	137.7
2034	167.0
2035	17.0
2036	32.1
Total	\$619.0

- NOLs represent approximately \$216 million in potential future tax savings
- Although we expect these NOLs will be available to us as a future benefit:
 - Some of the NOLs are subject to limitations on their use.
 - Concurrent with closing the term loan refinancing, we implemented a tax restructure by moving APG and APT underneath USGP to form one consolidated tax group. We believe this structure will allow the Company to operate in the most tax-efficient manner going forward.

Project Income (Loss) by Project (\$ millions)

		Three months ended	
		March 31	
		2017	2016
East U.S.	Accounting		
Cadillac	Consolidated	\$0.6	\$0.7
Curtis Palmer	Consolidated	7.0	7.0
Kenilworth	Consolidated	0.1	(0.1)
Morris	Consolidated	0.2	3.8
Piedmont	Consolidated	(1.9)	(5.0)
Chambers	Equity method	2.5	3.4
Orlando	Equity method	5.1	6.6
Selkirk	Equity method	(0.7)	(0.3)
Total		12.9	16.1
West U.S.			
Manchief	Consolidated	0.6	0.5
Naval Station	Consolidated	(0.3)	(1.3)
Naval Training Center	Consolidated	(0.3)	(0.2)
North Island	Consolidated	0.3	(0.5)
Oxnard	Consolidated	(1.9)	(1.7)
Frederickson	Equity method	0.9	0.6
Koma Kulshan	Equity method	-	0.2
Total		(0.7)	(2.4)
Canada			
Calstock	Consolidated	0.9	2.3
Kapuskasing	Consolidated	3.1	3.6
Mamquam	Consolidated	0.4	2.3
Nipigon	Consolidated	0.5	0.8
North Bay	Consolidated	3.5	4.1
William's Lake	Consolidated	2.5	3.0
Other	Consolidated	-	0.3
Total		10.9	16.4
Totals			
Consolidated projects		15.3	19.6
Equity method projects		7.8	10.5
Un-allocated corporate		2.2	(1.4)
Total Project Income		\$25.3	\$28.7

Project Adjusted EBITDA by Project (\$ millions)

Unaudited

		Three months ended March 31	
		2017	2016
East U.S.	Accounting		
Cadillac	Consolidated	\$1.8	\$2.1
Curtis Palmer	Consolidated	10.9	10.9
Kenilworth	Consolidated	0.8	0.5
Morris	Consolidated	0.7	5.4
Piedmont	Consolidated	1.2	0.6
Chambers	Equity method	5.4	6.1
Orlando	Equity method	7.1	5.1
Selkirk	Equity method	(0.7)	(0.3)
Total		27.2	30.3
West U.S.			
Manchief	Consolidated	3.3	3.3
Naval Station	Consolidated	1.3	0.3
Naval Training Center	Consolidated	0.4	0.6
North Island	Consolidated	1.4	0.7
Oxnard	Consolidated	(0.9)	(0.6)
Frederickson	Equity method	3.4	3.0
Koma Kulshan	Equity method	0.1	0.3
Total		9.1	7.5
Canada			
Calstock	Consolidated	1.5	2.8
Kapuskasing	Consolidated	7.4	3.8
Mamquam	Consolidated	0.8	2.6
Nipigon	Consolidated	5.7	5.8
North Bay	Consolidated	7.3	4.2
Williams Lake	Consolidated	4.6	5.1
Other ⁽¹⁾	Consolidated	0.2	0.5
Total		27.5	24.8
Totals			
Consolidated projects		48.5	48.5
Equity method projects		15.3	14.2
Un-allocated corporate		0.0	(0.1)
Total Project Adjusted EBITDA		\$63.8	\$62.5

Unaudited

		Three months ended March 31	
		2017	2016
Total Project Adjusted EBITDA		\$63.8	\$62.5
Other project expense		(\$0.0)	\$0.2
Interest expense, net		2.4	2.5
Depreciation and amortization		34.9	29.9
Change in fair value of derivative instruments		1.2	1.2
Project income		\$25.3	\$28.7
Other income, net		-	(2.5)
Foreign exchange loss		2.5	19.8
Interest expense, net		17.3	16.6
Administration		6.4	6.1
Loss from operations before income taxes		(0.9)	(11.3)
Income tax (benefit) expense		(0.3)	1.6
Net loss		(\$0.6)	(\$12.9)

⁽¹⁾ Includes Tunis and Moresby Lake

Cash Distributions from Projects, Q1 2017 vs Q1 2016 (\$ millions)

Three months ended March 31, 2017 (Unaudited)

Segment	Project Adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Other, including changes in working capital	Cash Distributions from Projects
East U.S.						
Consolidated	\$15.4	(\$2.3)	(\$2.1)	(\$1.2)	(\$0.1)	\$9.7
Equity method	11.8	-	(0.5)	(0.0)	(4.6)	6.7
Total	27.2	(2.3)	(2.5)	(1.2)	(4.7)	16.4
West U.S.						
Consolidated	5.6	-	-	(0.0)	0.0	5.6
Equity method	3.5	-	-	-	(1.3)	2.2
Total	9.1	-	-	(0.0)	(1.3)	7.8
Canada						
Consolidated	27.5	(0.0)	(0.0)	(0.3)	(4.1)	23.1
Equity method	-	-	-	-	-	-
Total	27.5	(0.0)	(0.0)	(0.3)	(4.1)	23.1
Total consolidated	48.5	(2.4)	(2.1)	(1.5)	(4.2)	38.4
Total equity method	15.3	-	(0.5)	(0.0)	(5.9)	8.9
Un-allocated corporate	0.0	-	-	(0.0)	0.0	(0.0)
Total	\$63.8	(\$2.4)	(\$2.5)	(\$1.5)	(\$10.1)	\$47.3

Three months ended March 31, 2016 (Unaudited)

Segment	Project Adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Other, including changes in working capital	Cash Distributions from Projects
East U.S.						
Consolidated	\$19.4	(\$0.6)	(\$1.9)	\$4.0	\$3.2	\$24.1
Equity method	10.9	(1.5)	(0.6)	(0.0)	(3.5)	5.2
Total	30.3	(2.1)	(2.5)	4.0	(0.3)	29.3
West U.S.						
Consolidated	4.2	-	-	-	1.3	5.4
Equity method	3.3	-	-	(0.0)	(0.6)	2.7
Total	7.5	-	-	(0.0)	0.6	8.1
Canada						
Consolidated	24.8	-	(0.0)	(0.3)	(6.3)	18.2
Equity method	-	-	-	-	-	-
Total	24.8	-	(0.0)	(0.3)	(6.3)	18.2
Total consolidated	48.5	(0.6)	(1.9)	3.7	(1.8)	47.8
Total equity method	14.2	(1.5)	(0.6)	(0.0)	(4.2)	7.9
Un-allocated corporate	(0.1)	-	-	0.3	(0.2)	(0.0)
Total	\$62.5	(\$2.1)	(\$2.5)	\$4.0	(\$6.1)	\$55.7

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 and amortization (including non-cash impairment charges) and changes in the fair value of derivative instruments. Management uses Project Adjusted EBITDA at the project level to provide comparative information about project performance and believes such information is helpful to investors. A reconciliation of Project Adjusted EBITDA to Project income (loss) and to Net income (loss) by segment and on a consolidated basis is provided on slide 34.

Cash Distributions from Projects is the amount of cash distributed by the projects to the Company out of available project cash flow after all project-level operating costs, interest payments, principal repayment, capital expenditures and working capital requirements. It is not a non-GAAP measure. Project Adjusted EBITDA, a non-GAAP measure, is the most comparable measure, but it is before debt service, capital expenditures and working capital requirements. The Company has provided a bridge of Project Adjusted EBITDA to Cash Distributions from Projects on slide 32.

Investors are cautioned that the Company may calculate these measures in a manner that is different from other companies.

Unaudited

	Three months ended March 31	
	2017	2016
Net loss attributable to Atlantic Power Corporation	(\$2.7)	(\$14.9)
Net income attributable to preferred share dividends of a subsidiary company	2.1	2.0
Net loss	(\$0.6)	(\$12.9)
Income tax benefit	(0.3)	1.6
Loss from operations before income taxes	(0.9)	(11.3)
Administration	6.4	6.1
Interest expense, net	17.3	16.6
Foreign exchange loss	2.5	19.8
Other income, net	-	(2.5)
Project income	\$25.3	\$28.7
Reconciliation to Project Adjusted EBITDA		
Depreciation and amortization	\$34.9	\$29.9
Interest expense, net	2.4	2.5
Change in the fair value of derivative instruments	1.2	1.2
Other expense	-	0.2
Project Adjusted EBITDA	\$63.8	\$62.5

Reconciliation of Net Income (Loss) to Project Adjusted EBITDA by Segment, Q1 2017 vs Q1 2016 (\$ millions)

Three months ended March 31, 2017 (unaudited)

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net (loss) income attributable to Atlantic Power Corporation	\$12.9	(\$0.7)	\$10.9	(\$25.8)	(\$2.7)
Net income attributable to preferred share dividends of a subsidiary company	-	-	-	2.1	2.1
Net (loss) income	12.9	(0.7)	10.9	(23.7)	(0.6)
Income tax (benefit) expense	-	-	-	(0.3)	(0.3)
Income (loss) from operations before income taxes	12.9	(0.7)	10.9	(24.0)	(0.9)
Administration	-	-	-	6.4	6.4
Interest expense, net	-	-	-	17.3	17.3
Foreign exchange loss	-	-	-	2.5	2.5
Other income, net	-	-	-	-	-
Project income (loss)	12.9	(0.7)	10.9	2.2	25.3
Change in fair value of derivative instruments	0.2	-	3.3	(2.3)	1.2
Depreciation and amortization	11.5	10.0	13.3	0.1	34.9
Interest expense, net	2.6	(0.2)	-	-	2.4
Other project expense	-	-	-	-	-
Project Adjusted EBITDA	\$27.2	\$9.1	\$27.5	\$-	\$63.8

Three months ended March 31, 2016 (unaudited)

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Net (loss) income attributable to Atlantic Power Corporation	\$16.1	(\$2.4)	\$16.4	(\$45.0)	(\$14.9)
Net income attributable to preferred share dividends of a subsidiary company	-	-	-	2.0	2.0
Net (loss) income	16.1	(2.4)	16.4	(43.0)	(12.9)
Income tax (benefit) expense	-	-	-	1.6	1.6
Income (loss) from operations before income taxes	16.1	(2.4)	16.4	(41.4)	(11.3)
Administration	-	-	-	6.1	6.1
Interest expense, net	-	-	-	16.6	16.6
Foreign exchange loss	-	-	-	19.8	19.8
Other income, net	-	-	-	(2.5)	(2.5)
Project income (loss)	16.1	(2.4)	16.4	(1.4)	28.7
Change in fair value of derivative instruments	0.7	-	(0.4)	0.9	1.2
Depreciation and amortization	11.0	9.9	8.8	0.2	29.9
Interest expense, net	2.5	-	-	-	2.5
Other project expense	-	-	-	0.2	0.2
Project Adjusted EBITDA	\$30.3	\$7.5	\$24.8	(\$0.1)	\$62.5