UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 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): **November 1, 2019**

ATLANTIC POWER CORPORATION

(Exact name of registrant as specified in its charter)

British Columbia, Canada	**001-34691**	**55-0886410**
(State or other jurisdiction of incorporation or organization)	(Commission File Number)	(IRS Employer Identification No.)

3 Allied Drive, Suite 155 **Dedham, MA**	**02026**
(Address of principal executive offices)	(Zip Code)

(617) 977-2400
(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol	Name of Exchange on which registered
Common Shares, no par value, and the associated Rights to Purchase Common Shares	AT	The New York Stock Exchange

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 November 1, 2019, Atlantic Power Corporation (the "Company") held its third quarter 2019 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 third quarter 2019 financial results conference call and webcast.
99.2	Presentation prepared with respect to the Atlantic Power Corporation third quarter 2019 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:November 1, 2019

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

Exhibit 99.1

PREPARED REMARKS
Q3 2019
NOVEMBER 1, 2019

Ron Bialobrzeski — Atlantic Power Corporation — Director, Finance

Page 2: Cautionary Note Regarding Forward-Looking Statements

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

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

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

Pages 4-5: Q3 2019 Highlights and Cadillac

Let me begin with the fire at Cadillac, which occurred on September 22nd while the plant was being brought down for its annual fall outage. The most important fact is that no one was injured. We tell our people that safety is more important than money. We are still investigating the cause along with our insurers. At this time we believe that the fire probably resulted from a malfunction in the steam turbine, but we have more work to do before reaching any firm conclusions. We do know that the fire did not involve the fuel areas of the plant and was not related to anything specific to biomass plants.

Our assessment is that there was extensive damage to the steam turbine, generator and other components in that area of the plant. The turbine, generator and at least one transformer must be replaced. The boiler, cooling tower, fuel pile and fuel handling areas were not affected.

We are working hard to bring the plant back online. Our estimates of damages and schedules are not well defined as of yet, although we believe the repair and replacement costs will be substantially covered by insurance. Our preliminary estimate is an exposure of approximately $2.5 million to $3.0 million, representing our deductibles. Terry will address this in more detail. We expect the plant to be offline for an extended period, probably at least another nine months.

Although this incident does not appear to be the fault of any of our people or practices, we nevertheless want to use it as a rallying cry for our teams to put safety first and to shoot for perfection in our operations, recognizing — as Vince Lombardi used to say — we won't achieve perfection but we will catch excellence in that effort. Our plant managers are our most important employees, heading our most critical teams. They need to be outstanding servant leaders. Our commitment to servant leadership has always been strong and after the event at Cadillac we saw it in action, as our people rallied to do the right things before being asked. I want to thank all of our employees throughout the Company for the outstanding performance on September 22nd and in the weeks following.

Turning to the financial results, we had a good third quarter — exceeding our expectations — following a strong first half. As Terry will address, we are raising our 2019 guidance.

During the quarter, we also continued to meet our deleveraging objectives. We have paid the term loan down to $400 million (from $700 million at issuance in April 2016) and our leverage ratio is below four times. We expect our leverage ratio to show further improvement over the next few years, as we pay down debt more quickly than EBITDA may decline (due to the impact of Power Purchase Agreement, or PPA, expirations in 2022 and beyond). We do not have a specific leverage ratio target. We need to see how EBITDA settles out following the near-term PPA expirations, which will be a function of re-contracting outcomes.

We had a significant re-contracting success this quarter, executing a new ten-year contract for Williams Lake. The structure of the contract makes EBITDA and cash flow estimates more volatile, but after we have gotten further down the path in our fuel procurement strategy, we will provide guidance on our longer-term expectations. Based on our internal forecasts, which incorporate the materially higher fuel costs we are seeing in British Columbia, we believe that the new contract is significantly better from an intrinsic value per share standpoint than our earlier estimates, which were based on different re-contracting assumptions. This was a good result delivered by our commercial team.

This quarter also marked a return to growth for our Company. We acquired four contracted biomass plants for a total of $31.3 million. We are integrating the two we own outright into our fleet and already have identified some investments for next year that we expect will further improve returns. Our base case EBITDA for the plants is approximately $7 million to $9 million annually on average through 2027 and approximately $3 million annually on average from 2028 through 2043. The expected investment returns are attractive, particularly in a world of low returns. The acquisitions are accretive to our estimates of intrinsic value per share.

Looking ahead to the next five years, we expect strong operating cash flow with relatively modest exposure to PPA expirations prior to 2023. The majority of this cash flow will be applied to debt repayment, which will allow us to reduce our debt balance by approximately 50% by the end of 2023. We will have significant discretionary cash flow after debt repayment that we will look to allocate rationally, focused on price to value and intrinsic value per share. In 2020 we expect to continue pursuing additional external growth, but if we find little opportunity on that front, we can shift our focus to share buybacks. We have the liquidity and the temperament to move with speed and scale if the markets throw us any fat pitches. Our liquidity is strong at $181 million, relative to an enterprise value of $1.05 billion and an equity market capitalization of only $257 million.

As we firm up the EBITDA outlook for the next several years and as we continue to deliver on our deleveraging commitment, we expect the markets may begin to recognize the value in our shares that we believe exists today. In the meantime, we are well protected from a deflationary bust scenario in our sector (or more broadly across the economy) via the PPA cover on our assets. If, on the other hand, markets begin to gravitate toward hard assets because of inflation concerns, we have significant leverage to the upside as our valuation seems to embed poor re-contracting outcomes. This also may begin to be recognized.

Until then, we will continue to work to build value with a focus on frugality and intrinsic value per share. With strong liquidity, a strengthening balance sheet and excess capital to allocate, we can be patient and rational in buying or selling either our own securities or external assets. We have developed a good opportunity set and for patient and disciplined value investors, we like our position. We expect the markets to get more interesting sooner or later but we have good things to do while we are waiting.

Dan Rorabaugh — Atlantic Power Corporation — SVP Operations

Page 6: Q3 2019 Operational Performance

Safety

We had two recordable injuries in the third quarter, and seven in the first nine months of the year. As a result, our total recordable incident rate (TRIR) of 2.85 for the first nine months of 2019 was higher than the prior periods shown in the chart on page 6 of the presentation. Three of the incidents were lost time events. We take all injuries very seriously. As we discussed last quarter, we continue to take a more proactive approach on this critically important issue. We have monthly safety calls with plant management and safety specialists led by our VP of Safety. We have also increased the frequency of safety meetings and expanded safety-related communications throughout the company. Prior to the start of the fall outage season, we rolled out pre-outage safety training. We continue to make the safety of our employees our number one priority.

Generation

Turning to our operating results, generation increased 2.7% in the third quarter of 2019 compared to the 2018 period, primarily because of the acquisitions of Allendale and Dorchester and equity interests in Craven and Grayling, higher power prices in PJM (Morris), higher water flows at Curtis Palmer, and higher dispatch at Frederickson. Generation at Curtis Palmer increased 30% from the year-ago period, although it was 9% below the historical average. These increases were partially offset by lower generation at Williams Lake, due to voluntary curtailment resulting from lower wood fuel inventory, and at Manchief, due to lower dispatch.

Availability

Our availability factor in the third quarter of 2019 increased slightly to 95.1% from 94.3% in the third quarter of 2018. Cadillac, Morris and Piedmont improved as they had maintenance outages in the comparable 2018 period. These increases to availability were partially offset by decreases at Moresby Lake, due to a transformer failure (which we expect to replace later this fall), and Mamquam, due to a maintenance outage for a runner replacement.

Operations Update

Nipigon

In the third quarter, we upgraded Nipigon's gas turbine control system to improve reliability and also completed other work required by IESO market rules. Expenditures were modest and consistent with our plan. The operating performance of the plant under the long-term enhanced dispatch contract also has been consistent with our expectations.

Decommissioning of San Diego Sites

We have made progress addressing critical path issues with San Diego Gas & Electric and are now in the process of soliciting final bids from contractors for the demolition work at the three sites. We expect the majority of the work will be completed in the first half of 2020. Our current estimate is a total cost of $6.6 million, of which $852 thousand was spent in the third quarter and $1.5 million has been spent to date. We have realized a total of $1.8 million of salvage proceeds to date, most of it in January 2019. The net cash outlay is thus expected to be approximately $5 million, most of which will be spent in 2020. These estimates are subject to adjustment pending receipt of the final bids for the demolition work.

Cost Focus

During the quarter we continued to advance our program to improve our operation and maintenance performance. We rolled out Mainsaver (maintenance management system) to Allendale and Dorchester, which we acquired in July, and to Koma Kulshan, in which we acquired the remaining ownership interests in the third quarter of 2018. We will be rolling it out to Piedmont this quarter. We have an ongoing focus on optimizing the preventive maintenance programs for all sites. During the quarter, we reviewed and updated the maintenance plans for six sites.

Another area of focus is avoiding equipment issues that result in unplanned outages. To that end, we have installed predictive analytic software (PRiSM) at six plants over the past two years. To date, the system has had 21 good "catches" (potential equipment problems that were avoided). We plan to roll out PRiSM to Allendale and Dorchester in 2020.

Next year we will undertake a benchmarking of our hydro and biomass plants, with a goal of driving further improvements to our cost structure as we add and integrate new assets into our fleet.

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

We are pleased with the progress we made this quarter on both our external growth and re-contracting efforts. My remarks today will focus primarily on our Williams Lake biomass plant in British Columbia. I will also review our re-contracting efforts at Oxnard and Calstock and provide an update on our recent biomass plant acquisitions. I'll close with a brief update on our Manchief transaction.

Page 7: Williams Lake *(British Columbia)*

The Company executed a new ten-year Energy Purchase Agreement (EPA) with BC Hydro for Williams Lake effective October 1, 2019, which replaces the short-term EPA that had been in place since April 2018 and which expired on September 30, 2019.

The EPA provides for a fixed price (escalating annually at British Columbia CPI) per megawatt-hour of energy produced, up to an annual limit of 388.4 gigawatt-hours (GWh) of generation (an implied average annual capacity factor of approximately 67%). The plant will not operate during the months of May, June, and July ("freshet", or the annual spring thaw that results in additional water flows for hydroelectric generating facilities), but will perform its annual maintenance during this period. The plant is required to operate in the November through February winter period, and is subject to performance penalties if it fails to meet minimum generation requirements in any one of those months (although in the 2019-2020 winter season, the plant will be required to operate only for the month of February).

The contract does not provide for a capacity payment and there is no fuel cost passthrough under the contract.

Conditions in the British Columbia timber market over the past couple of years have led to mill closings and production curtailments, which have adversely affected both the availability and cost of conventional fuel supplies. During the period that the plant was operating under the short-term EPA and prior to reaching agreement on a new long-term contract, we had been procuring fuel on a short-term basis only. In conjunction with negotiating a new contract for the plant, we updated our fuel supply forecasts to reflect costs that are materially higher than those experienced over the past few years.

Our focus now with the new ten-year EPA in place is on procuring fuel and rebuilding our fuel inventory through a variety of sources, including local mills and First Nations. In addition, to expedite and facilitate this effort, we are deploying a mobile shredder (chipper) that should provide access to new supplies of economic forest-based biomass and residue.

With minimal levels of fuel currently on site, our current expectation is that the plant will not operate in the fourth quarter. The EPA allows for lower generation levels in the 2019-2020 winter season so that we have time to rebuild inventory. We do not expect to incur any winter performance penalties if the plant returns to service and achieves the minimum required level of generation in February 2020.

As we have discussed on previous conference calls, we are permitted to burn rail ties up to an annual limit of 35% of the plant's fuel requirements. This would require installation of a new fuel shredder. With the execution of the new EPA, the economic evaluation of a shredder investment continues, taking into consideration the terms and conditions of the new EPA (including contract term), the significant capital investment required, and the availability and cost of conventional forest-based biomass fuel as compared to the cost of burning rail ties. Investment in a fuel shredder would need to meet our risk/return requirements. We expect to provide a further update on fuel supply and potential options for Williams Lake over the course of the next few quarters.

We plan to make significant maintenance investments in the plant consistent with our new ten-year EPA, including a cooling tower rebuild and generator rewind. We may undertake some maintenance this winter but we expect that most of the expenditures will be incurred in 2020 and 2021 during the May through July period when the plant is scheduled to be off-line. We plan to provide more color on the amount and timing of these expenditures on our fourth quarter conference call. We have also identified some potential optimization investments, but will not undertake these unless it is economic to do so. Based on our planned maintenance, which will be expensed, and our need to rebuild fuel inventories, we estimate that the plant will generate a breakeven or minimal level of EBITDA in 2020.

We intend to provide longer-term EBITDA guidance for the plant at a later date. We would note that, due to the absence of a fuel cost passthrough in the contract and considering conditions in the British Columbia timber market, Williams Lake is likely to experience greater variability to EBITDA and cash flow as compared to our other biomass plants.

Page 8: Re-contracting Updates

Oxnard (California)

The Oxnard PPA expires in May 2020. As we discussed last quarter, in June, the California Public Utilities Commission (CPUC) issued an order seeking comments on near-term reliability challenges and options for potential solutions, including the procurement of capacity from existing resources that are uncontracted after 2021. We believe the CPUC order highlights the need for reliable and firm capacity to enable the continued deployment of renewable generation in California.

In September, Southern California Edison (SCE), Oxnard's customer under its PPA, issued a 2019 System Reliability Request for Offers (RFO). The RFO is a dual-track solicitation that seeks to procure 1,745 MW of incremental system resource adequacy capacity to come online by August 1, 2021 ("Fast" Track) and in 2022 and beyond ("Standard" Track). SCE is seeking proposals for a variety of product offerings, including gas-fired generation capacity. Contract length would vary by type of product; for gas generation, the term would be three to five years. Bids are due in November with decisions by SCE expected in the first quarter of 2020. We plan to submit one or more bids for Oxnard in this RFO. We would note the process is a confidential one and thus we will be unable to comment on the status of our bids until a decision has been made public by SCE.

We are also pursuing in parallel with the RFO other potential paths to a new contract for Oxnard. Although we view these recent actions by the CPUC and SCE favorably, it is too early to know whether these developments will materially improve our re-contracting probability, which is currently low.

Calstock (Ontario)

The Calstock PPA, which expires in June 2020, is our most challenging re-contracting situation in the near term. As we have discussed on previous conference calls, under the current market structure in Ontario, there is no re-contracting mechanism or policy in place to compensate biomass plants for the non-power benefits provided. These benefits include providing an environmentally attractive alternative to landfilling wood waste, economic support for the local timber industry through the purchase of mill residuals, and material economic support to the local community of Hearst, Ontario. We have strong support from the local government, unions, various forestry organizations and Hearst area mills. We continue to remain engaged with the provincial government and are working hard to develop a re-contracting path for Calstock, but have no significant news to report at this time.

__Page 9: Biomass Acquisitions - Allendale and Dorchester__ *(South Carolina)*

Since closing the acquisition of the Allendale and Dorchester biomass plants at the end of July, we have been focused on integrating them into our fleet. Our integration efforts are on schedule and both plants have been performing in line with our expectations. Prior to closing the acquisition some small improvements were made that are already helping to reduce fuel burn modestly, and some others of a similar size are planned. We also have been evaluating a few optimization initiatives for both plants, primarily to improve boiler efficiency and optimize the fuel handling system. These modest investments, which we plan to make in 2020, are expected to improve plant efficiency (reducing fuel consumption and maintenance expense) and provide us access to additional supplies of lower-cost fuel (reducing unit fuel costs).

As we have noted previously, our base case forecast before any optimization initiatives is for the two plants to produce combined Project Adjusted EBITDA of approximately $3 million annually on average over the remaining term of their PPAs.

__Page 10: Biomass Acquisitions - Craven and Grayling__

In August, we closed the acquisition of a 50% interest in the 48 megawatt Craven County plant in North Carolina and a 30% interest in the 37 megawatt Grayling plant in Michigan. These plants are well managed and will continue to be operated by CMS Energy, a 50% owner in both plants. Results overall for the third quarter were in line with our expectations. We expect Craven and Grayling to generate a combined Project Adjusted EBITDA of approximately $4 million to $5 million annually on average over the remaining term of their PPAs. Craven and Grayling are accounted for under the equity method.

The acquisitions of the Allendale, Dorchester, Craven and Grayling plants increase our biomass presence to eight plants, including six plants that we operate. These acquisitions, funded from discretionary cash, are expected to meet our return target for external investments and be accretive to our estimates of intrinsic value per share.

Manchief Transaction

In May 2019, we announced an agreement to sell our Manchief plant to Public Service Co. of Colorado, the customer under the PPA, in May 2022 following the expiration of the PPA. The agreement is subject to regulatory approvals. In October, the Federal Energy Regulatory Commission approved the transaction. Also in October, the Colorado Public Utilities Commission established a schedule in Public Service Co. of Colorado's application for a Certificate of Public Convenience and Necessity for the acquisition of Manchief and related cost recovery. The schedule calls for testimony and responses in December followed by an evidentiary hearing in January. The statutory deadline for a Commission decision is in May 2020. We will provide an update on our fourth quarter conference call.

Terry Ronan — Atlantic Power Corporation — EVP & CFO

Slide 11: Accounting and Financial Impacts of Cadillac Event

Before reviewing the results of the third quarter, capital allocation and an update to our 2019 guidance, I will begin by addressing the financial impact of the Cadillac equipment malfunction and fire. We expect the impact to be relatively modest due to our insurance coverage.

We carry both property and business interruption insurance on all of our plants. The property insurance covers the cost of replacing the existing equipment, and carries a $1.0 million deductible. In the third quarter, we recorded a $25.0 million writedown of Cadillac property, plant and equipment and a $0.2 million writedown of capital spares inventory. We also recorded a corresponding insurance receivable of $24.2 million, which reflects the estimated replacement cost less the deductible. This estimate may change, as our assessment of the cost to repair or replace damaged equipment is still in progress. The deductible was recorded as an insurance loss, which reduced Project income (and therefore Net income), but did not affect Project Adjusted EBITDA. Going forward, the cost of repairs or replacement of equipment will be capitalized to property, plant and equipment (included in Investing Cash Flow) with no impact on Operating Cash Flow.

The business interruption insurance effectively (although not precisely) replaces the Project Adjusted EBITDA that Cadillac would generate if it were in operation. The insurance carries a 45-day deductible, which we estimate represents a reduction to Project Adjusted EBITDA of approximately $1.5 million to $2.0 million. The impact on operating cash flow is the same. As the incident that took the plant out of service occurred on Sept. 22, most of this impact will be in the fourth quarter. During this extended outage, we expect Cadillac will continue to meet its debt service obligations using the business interruption insurance. Cash that ordinarily would be distributed from the project will instead remain at the project until it returns to service, although this has no impact on operating cash flow as the results of the project are consolidated.

Page 12: Q3 2019 Financial Highlights

Financial results. In a continuation of the first half performance, both Project Adjusted EBITDA and cash provided by operating activities for the third quarter of 2019 exceeded our expectations, primarily due to the acquisitions and also to the avoidance of shutdown-related expenses at Williams Lake that we had previously budgeted. Water flows at Curtis Palmer were 9% below the historical average this quarter, so results for Curtis Palmer were slightly below our expectations, though still well above the dry level of 2018.

2019 guidance. Last quarter I indicated that we were trending toward the upper end of our guidance range. With three quarters of the year ahead of plan, we have increased our 2019 guidance for Project Adjusted EBITDA and narrowed the range, to $185 million - $195 million from $175 million - $190 million previously.

In addition to posting strong financial results this quarter, we also made progress on our balance sheet and our growth initiatives:

Balance sheet and maturity profile. We repaid $18.3 million of term loan and project debt during the third quarter. Our consolidated leverage ratio at September 30th was 3.7 times, which improved from last quarter as a result of debt repayment and increased EBITDA. We expect to repay approximately $15.8 million of consolidated debt during the fourth quarter, for a total of $86.6 million this year, and anticipate leverage at year end 2019 that is substantially in line with the September 30th ratio.

Capital allocation. During the third quarter of 2019, we used $28.5 million of our discretionary cash to close the acquisition of the Allendale and Dorchester biomass plants in South Carolina and minority interests in the Craven and Grayling biomass plants. Including the deposit on the South Carolina plants made in 2018 and transaction costs, the total investment in these four plants was $31.3 million. We also repurchased a modest amount of Series 2 preferred shares and a small amount of common shares at levels that we considered attractive.

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

Page 13: Q3 2019 Project Adjusted EBITDA bridge

Project Adjusted EBITDA for the third quarter of 2019 increased $3.5 million to $48.9 million from $45.4 million in the third quarter of 2018. Results exceeded our expectation for two primary reasons:

- We had a $1.7 million contribution by the four biomass plants we acquired in July and August (which were not included in our 2019 forecast); and
- We signed a new long-term contract for Williams Lake, which avoided $3.1 million of shutdown-related expenses that we had budgeted for the third quarter. Although Williams Lake EBITDA declined in the quarter (by $1.7 million), mostly because of voluntary curtailment due to low fuel inventory, the decline was smaller than expected.

Curtis Palmer EBITDA increased $1.5 million versus the third quarter of 2018, due to higher generation resulting from higher water flows (though generation was below the historical average for the quarter). Cadillac, Tunis and Frederickson also posted modest increases compared to the third quarter of 2018, mostly due to maintenance outages in the 2018 period; Frederickson also benefited from increased dispatch and Tunis from the new PPA that commenced in October 2018.

These positive comparisons were partially offset by Williams Lake, as previously noted, Oxnard ($1.6 million), due to gas turbine repairs, and Nipigon ($1.2 million), due to the control system upgrade.

Page 14: YTD 2019 Project Adjusted EBITDA bridge

For the first nine months of 2019, Project Adjusted EBITDA increased $14.7 million to $153.2 million from $138.5 million. Curtis Palmer accounted for $10.1 million of the increase, as higher water flows resulted in strong increases in generation (+25% vs. the historical average and +34% vs. the first nine months of 2018). Manchief and Tunis EBITDA increased $7.5 million and $6.6 million, respectively. Although most of the Manchief increase is attributable to the gas turbine overhaul in 2018, results were also driven by higher dispatch. Orlando and the acquired biomass plants also contributed to the EBITDA increases ($1.8 million and $1.7 million, respectively).

On the negative side, Williams Lake had a $6.6 million decrease in EBITDA due to the lower economics of the short-term contract extension that became effective in April 2019. Oxnard had a $2.9 million decrease in EBITDA due to gas turbine repairs and Chambers EBITDA decreased $2.8 million due to lower energy and steam demand as well as lower prices for excess energy.

Page 15: Operating Cash Flow and Uses of Cash

Third Quarter 2019

Cash provided by operating activities was $36.4 million in the third quarter of 2019, an increase of $16.9 million from $19.5 million in the third quarter of 2018. The increase was primarily attributable to the $3.5 million increase in Project Adjusted EBITDA, a $5.9 million increase in project distributions from unconsolidated affiliates, a $1.2 million reduction in cash interest payments and a $7.2 million favorable year-over-year change related to working capital. The increase in distributions from unconsolidated affiliates included a $3.8 million distribution from Orlando in September, which in 2018 was not received until early October.

During the third quarter, we used operating cash flow to repay $17.5 million of our term loan and to amortize $0.8 million of project debt. We also paid $1.8 million of dividends on our preferred shares and made $0.5 million of capital expenditures.

Nine Months Ended September 2019

Cash provided by operating activities for the first nine months of 2019 was $104.5 million, an increase of $6.7 million from $97.8 million in the comparable 2018 period. The increase was primarily due to the $14.7 million increase in Project Adjusted EBITDA as compared to the 2018 period, a $4.0 million increase in distributions from unconsolidated affiliates and a $3.3 million reduction in cash interest payments due to lower debt balances and a lower spread on our credit facilities. These positive variances were partially offset by a $17.3 million adverse change in cash flows attributable to changes in working capital, as the 2018 period included a $29.2 million release of working capital by Kapuskasing, North Bay and the three San Diego projects when they ceased operation.

In the first nine months of 2019, we used operating cash flow to repay $50.0 million of our term loan and to amortize $2.3 million of project debt. We also paid $5.5 million of preferred dividends and made $0.8 million of capital expenditures.

Page 16: Liquidity

During the quarter we generated discretionary cash flow (after debt repayment, preferred dividends and capital expenditures) of $15.8 million. We used this cash flow and a portion of cash on hand to fund the biomass acquisitions ($18.5 million for the Craven and Grayling interests and $10.0 million for Allendale and Dorchester) and modest repurchases of common and preferred shares. After this use of cash, we had

$31.2 million of unrestricted cash at the parent at September 30, 2019. After holding aside $7 million of this cash for working capital purposes, we had approximately $24 million of discretionary cash available for general corporate purposes.

Total liquidity at September 30, 2019 was $181.2 million, which included $58.1 million of unrestricted cash ($31.2 million at the parent and $26.9 million at the projects) and $123.1 million of availability under our revolver.

<u>Page 17: Debt Repayment Profile and Projected Debt Balances</u>

The charts on page 17 of the presentation show our expected debt repayment in 2019 through 2023 and the significant reduction in our debt levels during that period. Note that these charts include our $43 million share of project debt at Chambers, which is accounted for using the equity method. Repayment of that debt occurs at the project level before we receive cash distributions.

During the first nine months of this year, we repaid $50.0 million of term loan and $2.3 million of project debt and ended the third quarter with a consolidated leverage ratio of 3.7 times, which was slightly improved from the second quarter. In the fourth quarter, we expect to repay another $15.8 million of consolidated debt using our operating cash flow and $5.2 million of Chambers debt from project-level cash flow. We expect our year end 2019 ratio to be substantially in line with the September 30th level. However, we expect continuing repayment of debt and relatively stable levels of EBITDA to result in the leverage ratio continuing to move lower in 2020 and beyond.

Debt repayment during this period consists of term loan and project debt, which is typically amortized from operating cash flow. There are two bullet maturities during this period — our corporate revolver has an April 2022 maturity, but has no borrowings outstanding; and our term loan has an April 2023 maturity, with an expected remaining principal at that time of $111 million. Options that we will consider with respect to the $111 million include repayment at maturity using cash, an extension of the maturity date or a refinancing prior to maturity. Given the debt levels we foresee at that time, we believe that a refinancing is a feasible option. For purposes of the charts on this page, we have assumed a refinancing of the $111 million prior to maturity.

The bottom chart on page 17 of the presentation shows the impact of continued debt repayment on our debt balances, projected through year end 2023. Our debt level at September 30th, including our share of Chambers debt, was approximately $707 million. Assuming refinancing of the $111 million remaining principal prior to its April 2023 maturity, our projected debt level at year end 2023 would be reduced by approximately half to $362 million. Most of this reduction would occur by year end 2022.

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

Interest Costs

We continue to manage our exposure to increases in market interest rates. At September 30, 2019, approximately 94% of our debt carried either a fixed rate or a variable rate that has been fixed through interest rate swaps. Through December 2019, approximately 94.5% of our debt is either fixed rate or swapped, and through December 2021, approximately 97% on average. Our exposure to a 100 basis point change in LIBOR is $353 thousand over the next 12 months.

Page 18: 2019 Project Adjusted EBITDA Guidance

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.

We have increased our 2019 Project Adjusted EBITDA guidance and narrowed the range, to $185 million to $195 million, from $175 million to $190 million previously. As indicated on page 18 of the presentation, the primary drivers of the increased guidance are:

- Curtis Palmer, which has benefited from higher water flows and generation levels relative to historical averages;
- The biomass plant acquisitions (for a partial year);
- Williams Lake (avoided expenses due to new contract); and
- Higher dispatch at Manchief.

These positive variances were partially offset by lower than expected results at Oxnard (gas turbine repairs), Cadillac (impact of business interruption insurance deductible related to the extended outage, approximately $1.5 million to $2.0 million), and more modest shortfalls at a couple of other projects.

Although we are not providing quarterly guidance, we would note that our revised full year guidance implies a decline in Project Adjusted EBITDA for the fourth quarter of 2019 from the $46.3 million recorded in the comparable 2018 period. The significant drivers of this expected decrease are Curtis Palmer, which had a strong fourth quarter in 2018 (generation 12% above the historical average), Williams Lake (no generation expected in the fourth quarter of 2019) and Cadillac (impact of business interruption insurance deductible). We expect these decreases to be partially offset by increases from the biomass acquisitions, Nipigon and Oxnard.

<u>Page 19: 2019 Cash provided by operating activities and planned capital allocation</u>

Our estimate of 2019 cash provided by operating activities is now a range of $115 million to $125 million, as shown on page 19 of the presentation. This is up from $100 million to $115 million previously. The increase to our estimate is attributable to our higher Project Adjusted EBITDA guidance and the delay in a majority of the San Diego decommissioning outlays to 2020.

As is our practice, for purposes of this estimate we have assumed that the impact of changes in working capital on cash flow is nil. Year to date, changes in working capital have had a $5 million benefit to operating cash flow.

Our principal planned uses of operating cash flow in 2019 include $65 million amortization of our term loan, $3.1 million of project debt amortization, approximately $8 million of dividends on our preferred shares, and $1.1 million of capital expenditures. This year, our expected term loan and project debt repayments are approximately $32 million lower than in 2018 while EBITDA is expected to be generally in line with or slightly higher than the 2018 level. Thus, we have had a higher level of discretionary cash flow this year.

<u>Capital Allocation</u>

As shown on page 19 of the presentation, through September, we have allocated $8.8 million to the repurchase of preferred and common shares under the NCIB and $18.5 million (US$ equivalent) to the redemption of the Series D convertible debentures ($18.9 million including accrued interest). As previously noted, we also used $28.5 million to fund the closing of the acquisitions of the Allendale and Dorchester biomass plants and equity interests in the Craven and Grayling biomass plants.

NCIB Update

The NCIB repurchases during the third quarter were modest. In July, we repurchased and canceled 12,000 shares of the Cumulative Rate Reset Preferred, Series 2, at Cdn$18.30 per share, for a total cost of Cdn$220 thousand (US$168 thousand equivalent). Earlier this year, we reached the 10% limit on repurchases of Series 1 and Series 3 preferred shares under our NCIB. To date, we have repurchased approximately 43% of the 10% limit on the Series 2. During the quarter, we also repurchased and canceled 2,067 common shares at an average price of $2.27 per share. In addition, in October (fourth quarter), we repurchased another 50,829 common shares at an average price of $2.27 per share.

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, impairment charges, insurance loss (gain), other (income) expenses 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 and to Net income (loss) on a consolidated basis is provided in Table 1 below.

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

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Net income (loss) attributable to Atlantic Power Corporation	**$ 12.6**	**$ (3.2)**	**$ 22.7**	**$ 12.1**
Net income (loss) attributable to preferred share dividends of a subsidiary company	1.7	(1.5)	(3.1)	(1.6)
Net income (loss)	**$ 14.3**	**$ (4.7)**	**$ 19.6**	**$ 10.5**
Income tax expense	0.2	3.6	2.4	7.7
Income (loss) from operations before income taxes	14.5	(1.1)	22.0	18.2
Administration	5.5	5.7	17.3	17.9
Interest expense, net	10.9	14.6	33.0	40.7
Foreign exchange (gain) loss	(2.8)	4.5	7.1	(9.1)
Other (income) expense, net	(0.2)	2.5	0.7	0.3
Project income	**$ 27.9**	**$ 26.2**	**$ 80.1**	**$ 68.0**
Reconciliation to Project Adjusted EBITDA				
Depreciation and amortization	$ 20.2	$ 25.0	$ 60.6	$ 78.0
Interest expense, net	0.8	(0.6)	2.0	2.7
Change in the fair value of derivative instruments	(1.0)	—	8.3	(3.5)
Insurance loss	1.0	—	1.0	—
Other (income) expense, net	—	(5.2)	1.2	(6.7)
Project Adjusted EBITDA	**$ 48.9**	**$ 45.4**	**$ 153.2**	**$ 138.5**

Exhibit 99.2

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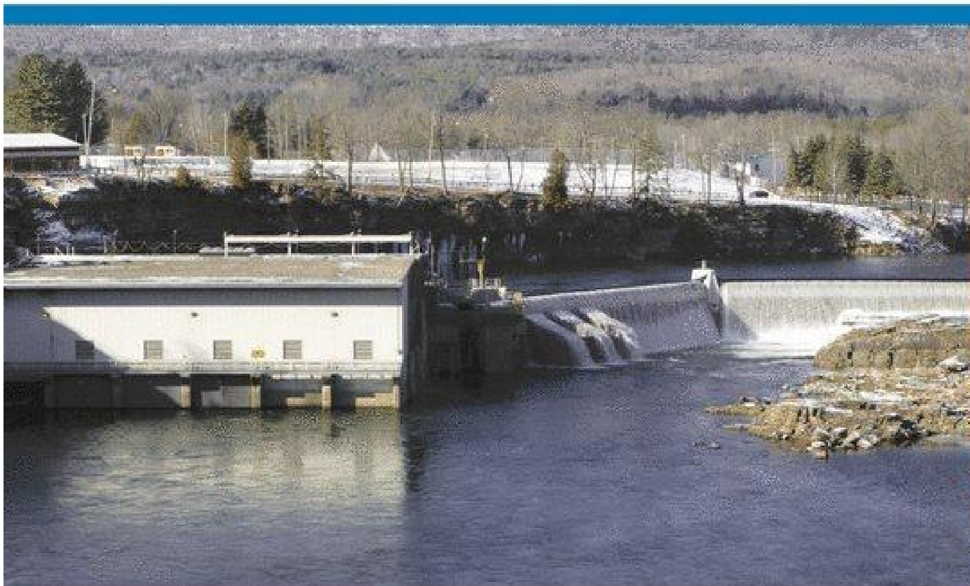
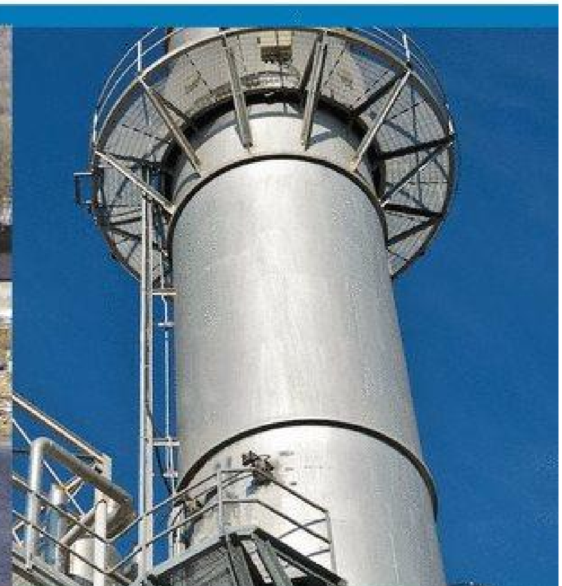




Q3 2019 Financial Results Supplementary Presentation

November 1, 2019

AtlanticPower Corporation

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 presentation 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 presentation 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 presentation, 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 and amortization, impairment charges, insurance loss (gain), other (income) expenses, and changes in the fair value of derivative instruments. Management uses Project Adjusted EBITDA at the project level to provide comparative information about project performance and believes such information is helpful to investors. A reconciliation of Project Adjusted EBITDA to Project income (loss) and to Net income (loss) on a consolidated basis is provided on page 38.

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 (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.

Reference to "Cdn$" and "Canadian dollars" are to the lawful currency of Canada and references to "$", "US$" and "U.S. dollars" are to the lawful currency of the United States. All dollar amounts herein are in U.S. dollars, unless otherwise indicated.

Q3 2019 Supplementary Presentation

- Highlights
- Operations Review
- Commercial Update
- Financial Results
- Liquidity and Debt Repayment Profile
- 2019 Guidance
- Appendix

Q3 2019 Highlights

- Results for the third quarter exceeded our expectations
  - Continuation of the first-half 2019 trend
  - Raising 2019 guidance for Project Adjusted EBITDA
- Executed new ten-year contract for Williams Lake
  - Good outcome in difficult power market
  - Expect it to be significantly accretive to our estimates of intrinsic value
- Closed acquisitions of four biomass plants for approximately $31 million
  - Combined EBITDA of approximately $7 million to $9 million annually on average through 2027
  - Attractive acquisition multiples; accretive to our estimates of intrinsic value
- Cadillac equipment failure and extended outage
  - Only significant negative development of the quarter
  - No injuries; not a biomass issue; financial impact limited
- Anticipating significant operating cash flow in 2020-2024
  - Debt reduction and improvement in leverage ratio continuing
  - Meaningful discretionary cash flow available for disciplined capital allocation

Cadillac Equipment Malfunction and Fire

- Significant equipment malfunction sparked a fire at the plant on September 22, 2019
    - Plant was in process of being brought down for its fall outage
    - No injuries
    - Still investigating the cause, but believe it began with a malfunction in steam turbine which sparked fire
- Extensive damage to steam turbine, generator and other components in that area of the plant
    - Turbine, generator, and at least one transformer must be replaced
    - Boiler, cooling tower, fuel pile and fuel handling areas were not affected – not a biomass issue
- Plant expected to be offline for an extended period
    - Current estimate (subject to change) at least another nine months
- Expect financial impact to be mostly covered by insurance
    - Preliminary estimate of exposure: Deductibles of ~$2.5 million to $3.0 million (all in 2019)

Q3 2019 Operational Performance:

Higher generation due to acquisitions and higher dispatch at Frederickson

Safety: Total Recordable Incident Rate

TRIR, generation companies (Bureau of Labor Statistics): FY 2015 1.4, FY 2016 1.0, FY 2017 1.5

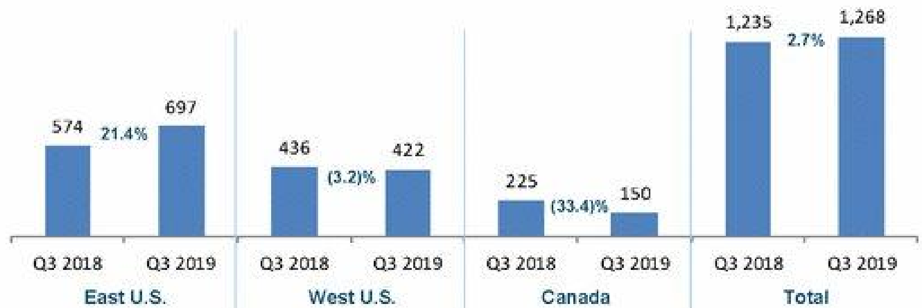
Availability

	Q3 2019	Q3 2018
East U.S.	98.8%	94.0%
West U.S.	97.8%	97.8%
Canada	79.9%	90.2%
Total	**95.1%**	**94.3%**

Higher availability factor:

+ Cadillac extended outage in prior period
+ Morris fall outage taken in prior period
+ Piedmont 100% availability in period
- Moresby Lake transformer failure
- Mamquam runner replacement

Aggregate Power Generation Q3 2019 vs. Q3 2018 (Net GWh)



Generation drivers:

+ Acquisitions of Allendale, Dorchester, Craven and Grayling
+ Frederickson higher dispatch
+ Morris higher PJM pricing
+ Curtis Palmer higher water flows
- Williams Lake voluntary curtailment
- Manchief lower dispatch

Hydro generation

Curtis Palmer	Mamquam
+30% vs Q3 2018	- 8% vs Q3 2018
- 9% vs long-term avg.	- 9% vs long-term avg.

New Contract for Williams Lake

- New ten-year Energy Purchase Agreement (EPA) with BC Hydro effective October 1, 2019
- Fixed price per megawatt-hour for energy produced (annual CPI escalator)
- Annual generation limit of 388.5 gigawatt-hours
  - The plant will not operate during the months of May, June and July ("freshet")
  - Required to operate in November through February (this winter – February only required month)
- No capacity payment or fuel cost pass-through
- Fuel availability and cost are significant variables
  - Adversely affected by current state of BC timber market
  - Near-term focus is on building fuel inventory; making progress since EPA signed
- Required maintenance consistent with new ten-year contract
  - Cooling tower rebuild and generator rewind; will be expensed
  - Expect to undertake beginning in Q4 2019; majority in 2020 and 2021 (freshet months)
- Continuing to evaluate potential investment in fuel shredder to burn rail ties
  - Reviewing expected capital cost, economics of investment and risks
  - Compare returns to conventional supply options
- Expect to provide update on fuel supply outlook and potential options over next few quarters
- EBITDA outlook
  - Expect EBITDA loss in Q4 2019 (no operation)
  - Expect breakeven or minimal EBITDA in 2020 (maintenance; still negotiating with fuel suppliers)
  - Will provide longer-term EBITDA guidance at a later date

Recontracting Updates

Oxnard (California)

- PPA expires in May 2020
- In September, Southern California Edison (SCE) issued an RFO for 1,745 MW of incremental system resource adequacy capacity to come online by August 2021 or 2022 and later
- Bids are due in November with decisions expected in Q1 2020
- Plan to submit one or more bids for Oxnard in this RFO
- Also pursuing other potential paths to a new contract

Calstock (Ontario)

- PPA expires in June 2020; most challenging near-term expiration
- Engaged with the provincial government
  - No mechanism in place in Ontario to compensate biomass for non-power benefits
- Have strong support from local government, various forestry organizations, unions and Hearst area mills

Biomass Acquisitions – Allendale and Dorchester (South Carolina)

- Acquired July 31, 2019
- Paid $10.0 million at closing, including closing adjustments; total investment $12.6 million
- 20 MW each; Allendale in service since November 2013 and Dorchester since October 2013
  - 30-year PPAs with South Carolina Public Service Authority
- Fuel a mix of mill and harvesting residues
- Expect base case Project Adjusted EBITDA on a combined basis of approximately $3 million annually on average
- Integration efforts on schedule; plants have been performing in line with expectations
- Evaluating modest optimization investments for 2020 to improve boiler efficiency and plant reliability, reduce maintenance costs and increase access to a wider range of fuels at lower cost

Allendale

Dorchester

Biomass Acquisitions – Craven and Grayling

- Acquired August 31, 2019
  - 50% interest in 48 MW Craven County plant in North Carolina; in service since October 1990
  - 30% interest in 37 MW Grayling plant in Michigan; in service since June 1992
- Total cost $18.7 million, including $0.2 million of previously expensed transaction costs
- PPAs run through December 31, 2027 (Craven – Duke Energy; Grayling – Consumers/CMS Energy)
- Plants are well managed; operated by CMS Energy, a 50% owner in both plants
- Results overall for the third quarter were in line with expectations
- Expect Project Adjusted EBITDA on a combined basis of approximately $4 million to $5 million annually on average over the remaining term of the PPAs
- Projects are accounted for using the equity method


Craven


Grayling

Accounting and Financial Impacts of Cadillac Event

- Carry both property and business interruption insurance on all of our plants
- Property insurance covers cost of replacing equipment
  - Carries $1.0 million deductible
- Q3 2019 financial statements:
  - Recorded a $25.2 million write down for Cadillac PP&E and capital spares inventory
  - Recorded a corresponding $24.2 million insurance receivable
    - Both are based on current assessment of damage and cost to repair or replace; subject to change
  - Deductible recorded as insurance loss of $1.0 million
    - Reduced Project income and Net income – but does not affect Project Adjusted EBITDA
- Business interruption insurance effectively replaces lost EBITDA
  - Carries 45-day deductible
  - Estimated lost EBITDA and reduction to operating cash flow during deductible period: ~ $1.5 million - $2.0 million (majority in Q4 2019)

Q3 2019 Financial Highlights

Financial Results	• Project Adjusted EBITDA of $48.9 million, up from $45.4 million in Q3 2018 • Results exceeded expectations, mostly due to biomass plant acquisitions and avoided shutdown expenses at Williams Lake • Cash provided by operating activities of $36.4 million, up from $19.5 million in Q3 2018
2019 Outlook	• Increased 2019 Project Adjusted EBITDA(1) guidance to range of $185 million to $195 million • Estimating 2019 cash provided by operating activities(2) of $115 million to $125 million
Balance Sheet	• Repaid $18.3 million of term loan and project debt • Consolidated leverage ratio of 3.7 times, improved from 4.0 times last quarter • Expect to repay approximately $15.8 million in fourth quarter (leverage ratio to remain below 4.0 times)
Capital Allocation	• On July 31, completed acquisition of two contracted biomass plants from EDF Renewables; $10.0 million paid at closing (incl. closing adjustments), plus $2.6 million deposit paid in Sept. 2018 • On August 13, completed acquisition of minority interests in two contracted biomass plants from AltaGas for $18.7 million (including $0.2 million of transaction costs) • Invested C$220 thousand in repurchase of Series 2 preferred shares under NCIB

Q3 and YTD 2019 results exceeded expectations

Significant progress on growth initiatives and debt repayment

(1) 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 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.
(2) Assumes for this purpose that changes in working capital are nil.

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Q3 2019 Project Adjusted EBITDA(1) (bridge vs 2018)

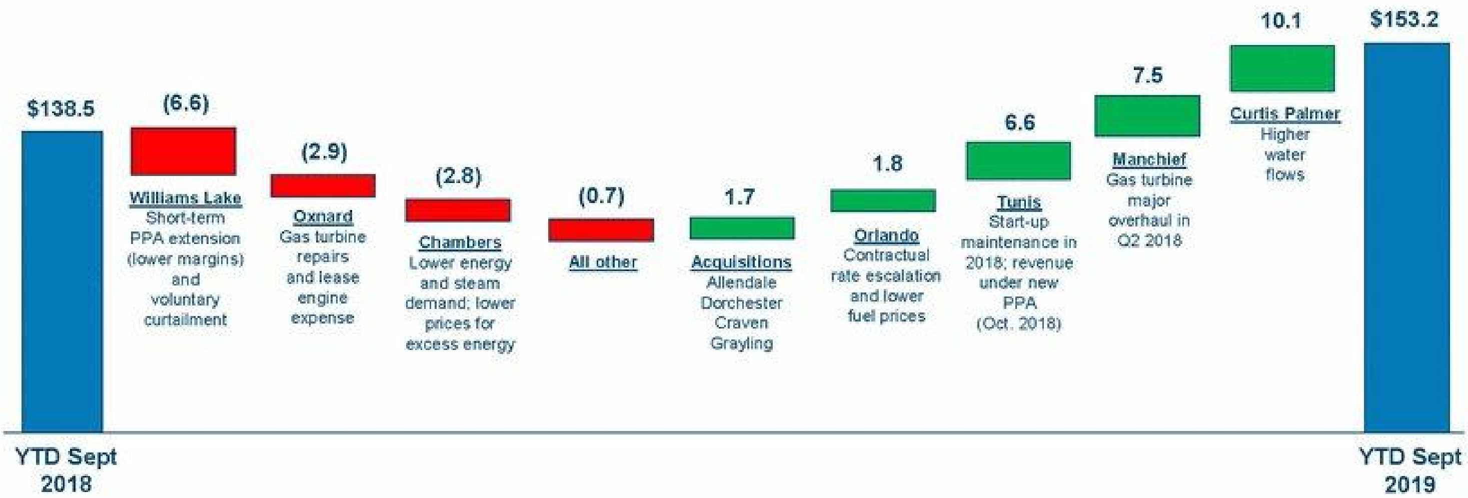
($ millions)

Biomass acquisitions and higher water flows at Curtis Palmer drove the increase, partially offset by voluntary curtailment at Williams Lake

(1) See Appendix for discussion of non-GAAP disclosures.

YTD 2019 Project Adjusted EBITDA[(1)] (bridge vs 2018)

($ millions)



Higher water flows at Curtis Palmer drove strong YTD results

Manchief and Tunis also significant contributors

Williams Lake decrease due to lower margins under short-term contract and voluntary curtailment

(1) See Appendix for discussion of non-GAAP disclosures.

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Q3 2019 Cash Flow Results

($ millions)

Unaudited	Three months ended September 30, 2019	2018	Change
Cash provided by operating activities	$36.4	$19.5	$16.9
Recurring uses of cash provided by operating activities:			
Term loan repayments [1]	(17.5)	(20.0)	2.5
Project debt amortization	(0.8)	(0.8)	-
Capital expenditures	(0.5)	(0.1)	(0.4)
Preferred dividends	(1.8)	(2.1)	0.3

- $3.5 million increase in Project Adjusted EBITDA
- $5.9 million increase in distributions from unconsolidated affiliates ($3.8 million due to timing)
- $1.2 million reduction in cash interest payments due to lower debt balances
- $7.2 million favorable year-over-year change in working capital

Unaudited	Nine months ended September 30, 2019	2018	Change
Cash provided by operating activities	$104.5	$97.8	$6.7
Recurring uses of cash provided by operating activities:			
Term loan repayments [1]	(50.0)	(70.0)	20.0
Project debt amortization	(2.3)	(9.5)	7.2
Capital expenditures	(0.8)	(1.4)	0.6
Preferred dividends	(5.5)	(6.3)	0.8

- $14.7 million increase in Project Adjusted EBITDA
- $4.0 million increase in distributions from unconsolidated affiliates
- $3.3 million reduction in cash interest payments due to lower debt balances and lower spread
- ($17.3) million adverse impact from changes in working capital
    - 2018 period included $29.2 million release of working capital by the San Diego projects, Kapuskasing and North Bay due to PPA expirations

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

Liquidity

($ millions)

	Sep 30, 2019	Jun 30, 2019
Cash and cash equivalents, parent	$31.2	$45.6
Cash and cash equivalents, projects	26.9	25.8
Total cash and cash equivalents	**58.1**	**71.4**
Revolving credit facility	200.0	200.0
Letters of credit outstanding	(76.9)	(77.0)
Availability under revolving credit facility	**123.1**	**123.0**
Total Liquidity	**$181.2**	**$194.4**
Excludes restricted cash of:	$1.7	$1.4
Consolidated debt (1)	**$664.2**	**$685.4**
Leverage ratio (2)	**3.7**	**4.0**

Includes approx. $24 million available for discretionary purposes

Q3 2019 change: ($13.3) million

$15.8 million discretionary cash flow after debt repayment, preferred dividends and capex

($18.5) million for minority interests in Craven and Grayling

($10.0) million to acquire Allendale and Dorchester

(1) Before unamortized discount and unamortized deferred financing costs
(2) Consolidated debt to trailing 12-month Adjusted EBITDA (after Corporate G&A)

Debt Repayment and Projected Debt Balances through 2023 (1)

($ millions)

Debt Repayment

Projected Debt Balances

- Term loan – Remaining $111 million principal; assumed to be refinanced prior to April 2023 maturity
  - Alternatives include repayment at maturity or extension of maturity date
- Includes $14 million amortization of term loan in Q1 2023

- Expect to reduce our debt by approximately half by YE 2023
- Expect the majority of the debt will be repaid from operating cash flows
- Expect to result in lower cash interest payments and lower leverage ratios

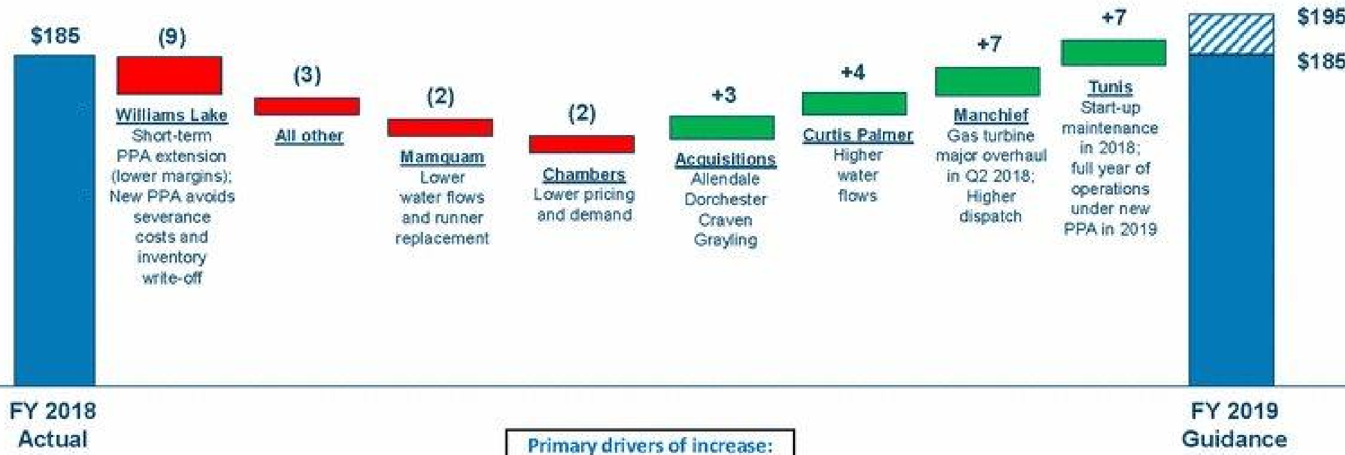
(1) Includes Company's proportional share of debt at Chambers of $43 million, which is not consolidated because the project is 40% owned. Note: C$ denominated debt was converted to US$ using US$ to C$ exchange rate of $1.3249.

2019 Project Adjusted EBITDA[1] Guidance (bridge vs 2018)

($ millions)

Increasing guidance to range of $185 million to $195 million

Previously $175 million to $190 million



Primary drivers of increase:	
Curtis Palmer	+4
Acquisitions	+3
Williams Lake	+2
All other	(2)
Total change	**+7**

(1) 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. See Appendix for discussion of non-GAAP disclosures.

Bridge of 2019 Project Adjusted EBITDA Guidance to Cash Provided by Operating Activities

($ millions)

	Updated Guidance as of 10/31/19	Initial Guidance as of 2/28/19
Project Adjusted EBITDA	**$185 - $195**	**$175 - $190**
Adjustment for equity method projects (1)	(5)	(5)
Corporate G&A expense	(22)	(22)
Cash interest payments	(39)	(39)
Cash taxes	(2)	(4)
Decommissioning (San Diego projects)	(1)	(5)
Other (including changes in working capital)	-	-
Cash provided by operating activities	**$115 - $125**	**$100 - $115**

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.

Planned Uses of Cash Provided by Operating Activities:

• Term loan repayments	$65.0
• Project debt amortization	3.1
• Preferred dividends	8.0
• Capital expenditures	1.1

Capital Allocation YTD Sep 2019:

• NCIB repurchases (2)	$8.8
• Redemption of Series D	18.5
• Acquisitions (3)	28.5

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.

(1) Represents difference between Project Adjusted EBITDA and cash distribution from equity method projects; in 2019, the $(5) million reflects debt amortization at Chambers of $5.2 million. (2) 2019 YTD repurchases include $8.0 million of preferred shares and $0.8 million of common shares. (3) Includes the $10.0 million for the South Carolina biomass acquisition paid at closing July 31, 2019 and $18.5 million for the AltaGas biomass acquisition that closed August 13, 2019.

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Power Projects and PPA Expiration Dates

Year	Project	Location	Type	Economic Interest	Net MW	Contract Expiry
2020	Oxnard	California	Nat. Gas	100%	49	5/2020 (1)
	Calstock	Ontario	Biomass	100%	35	6/2020
2021	Kenilworth	New Jersey	Nat. Gas	100%	29	9/2021
2022	Manchief	Colorado	Nat. Gas	100%	300	4/2022 (2)
	Moresby Lake	B.C.	Hydro	100%	6	8/2022
	Frederickson	Washington	Nat. Gas	50.15%	125	8/2022
	Nipigon	Ontario	Nat. Gas	100%	40	12/2022
2023	Orlando	Florida	Nat. Gas	50%	65	12/2023
2024	Chambers	New Jersey	Coal	40%	105	3/2024
2025 - 2029	Mamquam	B.C.	Hydro	100%	50	9/2027 (3)
	Curtis Palmer	New York	Hydro	100%	60	12/2027 (4)
	Craven	North Carolina	Biomass	50%	24	12/2027
	Grayling	Michigan	Biomass	30%	11	12/2027
	Cadillac	Michigan	Biomass	100%	40	6/2028
	Williams Lake	B.C.	Biomass	100%	66	10/2029
2032 - 2043	Piedmont	Georgia	Biomass	100%	55	9/2032
	Tunis	Ontario	Nat. Gas	100%	37	10/2033
	Morris	Illinois	Nat. Gas	100%	77 (5)	12/2034 (6)
	Koma Kulshan	Washington	Hydro	100%	13	3/2037
	Dorchester	South Carolina	Biomass	100%	20	10/2043
	Allendale	South Carolina	Biomass	100%	20	11/2043

(1) Oxnard's steam sales agreement expires in Feb. 2020. (2) Public Service Co. of Colorado has executed an agreement to purchase Manchief after the expiration of the PPA in May 2022, subject to regulatory approval. (3) BC Hydro has an option to purchase Mamquam that is exercisable in Nov. 2021. (4) Expires at the earlier of Dec. 2027 or the provision of 10,000 GWh of generation. Based on cumulative generation to date, we expect the PPA to expire prior to Dec. 2027. (5) Equistar has right to take up to 77 MW but on average takes approx. 50 MW. Balance of 177 MW of capacity is sold to PJM. (6) Equistar has an option to purchase Morris exercisable in Dec. 2020 and Dec. 2027.

YTD 2019 Operational Performance:

Higher generation due to higher dispatch at Frederickson

Safety: Total Recordable Incident Rate

TRIR, generation companies (Bureau of Labor Statistics): FY 2015 1.4, FY 2016 1.0, FY 2017 1.5

Availability

	YTD 2019	YTD 2018
East U.S.	98.0%	95.8%
West U.S.	94.6%	94.6%
Canada	90.1%	95.4%
Total	**95.8%**	**95.4%**

Availability factor in line with prior period:

- \+ Manchief overhaul in prior period
- \+ Kenilworth overhaul in prior period
- \+ Piedmont fewer forced outage hours
- \- Moresby Lake transformer failure
- \- Mamquam seal repair and runner replacement

Aggregate Power Generation YTD 2019 vs. YTD 2018 (Net GWh)

Generation driven by:

- \+ Frederickson higher dispatch
- \+ Acquisitions of Allendale, Dorchester, Craven and Grayling
- \+ Curtis Palmer higher water flows
- \- San Diego PPA expirations (Feb. 2018)
- \- Williams Lake voluntary curtailment
- \- Chambers lower energy prices
- \- Mamquam lower water flows

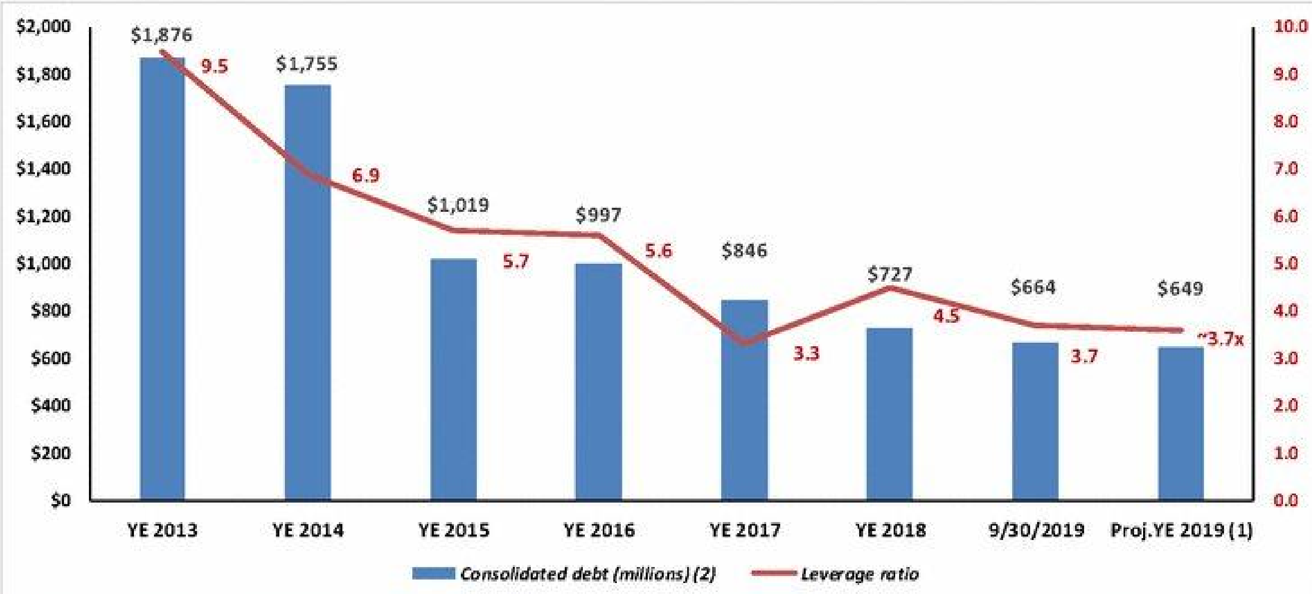
YTD Hydro generation

Curtis Palmer	Mamquam
+34% vs Sep YTD 2018	-13% vs Sep YTD 2018
+25% vs long-term avg.	In line with long-term avg.

Strengthening Balance Sheet

($ millions)

Approximately $1.2 billion net reduction in consolidated debt since YE 2013

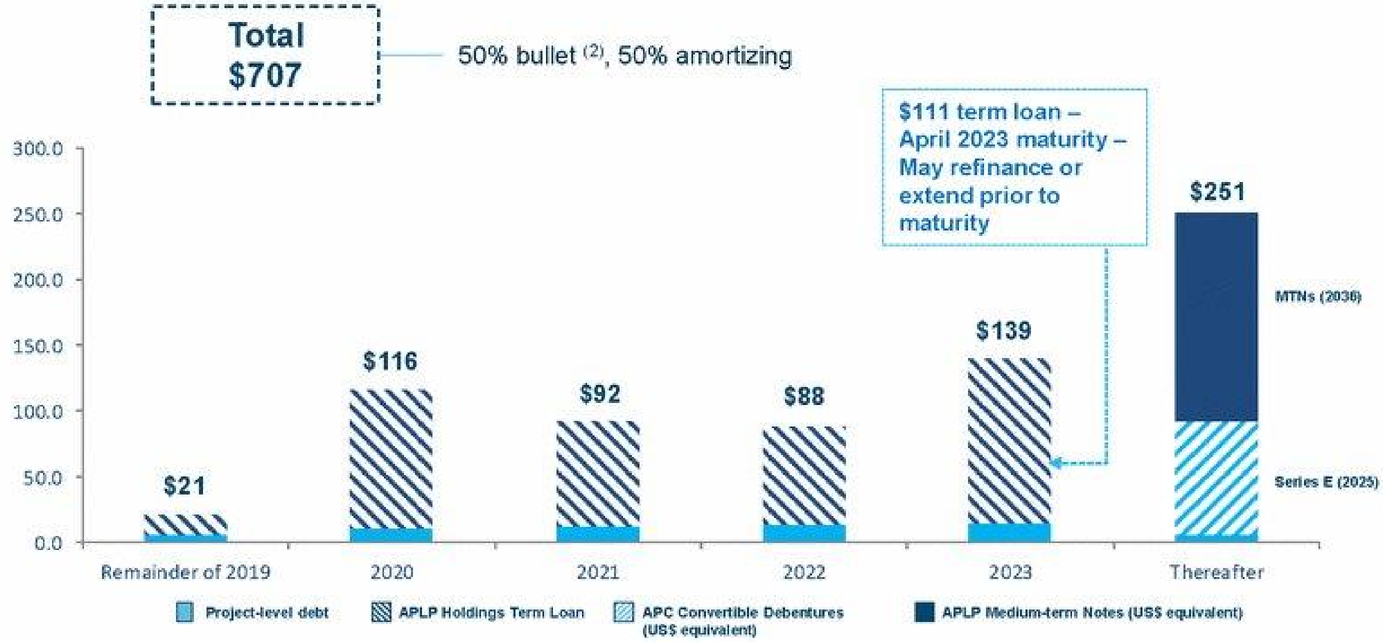


- Expect to repay another ~$15.8 million of consolidated debt by YE 2019, for a total of approximately $86.6 million in 2019
- Leverage ratio expected to be substantially unchanged at approximately 3.7 times by YE 2019

(1) Reflects $86 million of debt repayments in 2019 (2) Excludes unamortized discounts and deferred financing costs.

Debt Repayment Profile at September 30, 2019 (1)

($ millions)



- **Project-level non-recourse debt:** $62, including $43 at Chambers (equity method); amortizes over the life of the project PPAs (through 2025)
- **APLP Holdings Term Loan:** $400; 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 average annual repayment through 2022 of ~ $87)
- **APC Convertible Debentures:** $87 (US$ equivalent) of Series E convertible debentures (maturing Jan. 2025)
- **APLP Medium-Term Notes:** $159 (US$ equivalent) due in June 2036

(1)) Includes Company's proportional share of debt at Chambers of $43 million, which is not consolidated because the project is 40% owned. (2) Bullet percentage includes remaining term loan balance at maturity in April 2023 of $111 million, medium term notes and Series E convertible debentures. Note: C$ denominated debt was converted to US$ using US$ to C$ exchange rate of 1.3249

Projected Debt Balances through 2023 (1)

($ millions)

Expected Debt Repayment (September 30, 2019 – Year End 2023):

- **APLP Holdings Term Loan:** Amortize $289; $111 remaining balance due at maturity in April 2023, assumed to be refinanced prior to that date (2)
- **Project Debt:** Amortize $56, ending balance $6 (Cadillac)
- **APC Convertible Debentures:** No repayment required prior to 2025 maturity
- **Total Repayment through 2023:** $345 (49% of total)

(1)) Includes Company's proportional share of debt at Chambers of $43 million, which is not consolidated because the project is 40% owned (2) Alternatives include extension of maturity date or repayment at maturity. Note: C$ denominated debt was converted to US$ using US$ to C$ exchange rate of 1.3249.

Reducing Cash Interest Payments and Corporate Overhead

($ millions)

Approximate 70% reduction from 2013 level

Reduction has been driven by debt repayment as well as re-pricings of our term loan and revolver

Approximate 60% reduction from 2013 level

(1) Includes consolidated debt only

Capitalization

($ millions)

	Sep. 30, 2019		Jun. 30, 2019	
Long-term debt, incl. current portion (1)				
APLP Medium-Term Notes (2)	$158.6		$160.5	
Revolving credit facility	-		-	
Term Loan	400.0		417.5	
Project-level debt (non-recourse)	18.8		19.5	
Convertible debentures (2)	86.8		87.9	
Total long-term debt, incl. current portion	**$664.2**	**77%**	**$685.4**	**80%**
Preferred shares (3)	182.7	21%	182.9	21%
Common equity (4)	19.3	2%	7.9	1%
Total shareholders equity	**$202.0**	**23%**	**$190.8**	**22%**
Total capitalization	**$866.2**	**100%**	**$876.2**	**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) Par value of preferred shares was approximately $140 million and $142 million at September 30, 2019 and June 30, 2019, respectively.
(4) 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 September 30, 2019

($ millions)

Atlantic Power Corporation			
	Maturity	Amount Outstanding	Interest Rate
Convertible Debentures (ATP.DB.E)	1/2025	$86.8 (C$115.0)	6.00%
APLP Holdings Limited Partnership			
	Maturity	Amount	Interest Rate
Revolving Credit Facility	4/2022	$0	LIBOR + 2.75%
Term Loan	4/2023	$400.0	4.15%-4.79% (1)
Atlantic Power Limited Partnership			
	Maturity	Amount	Interest Rate
Medium-term Notes	6/2036	$158.6 (C$210)	5.95%
Preferred shares (AZP.PR.A)	N/A	$72.6 (C$96.2)	4.85%
Preferred shares (AZP.PR.B)	N/A	$42.1 (C$55.8)	5.57%
Preferred shares (AZP.PR.C)	N/A	$25.5 (C$33.7)	5.84% (2)
Atlantic Power Transmission & Atlantic Power Generation			
	Maturity	Amount	Interest
Project-level Debt (Cadillac - consolidated)	8/2025	$18.7	6.26%-6.38%
Project-level Debt (Chambers - equity method)	12/2019, 12/2023	$42.9	4.50%-5.00%

(1) Weighted average rate at Sep. 30, 2019 of approximately 4.20%. Range and weighted average include impact of interest rate swaps (2) Set on Aug 30, 2019 for Dec. 31, 2019 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 $1.3249.

APLP Holdings Term Loan Cash Sweep Calculation

APLP Holdings Adjusted EBITDA
(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, 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
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**	**3.50:1.00**
9/30/2020	4.25:1.00	3.50:1.00
12/31/2020	4.25:1.00	3.50:1.00
3/31/2021	4.25:1.00	3.50:1.00
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

<u>Leverage ratio</u>:

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 (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.

<u>Interest Coverage ratio</u>:

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.

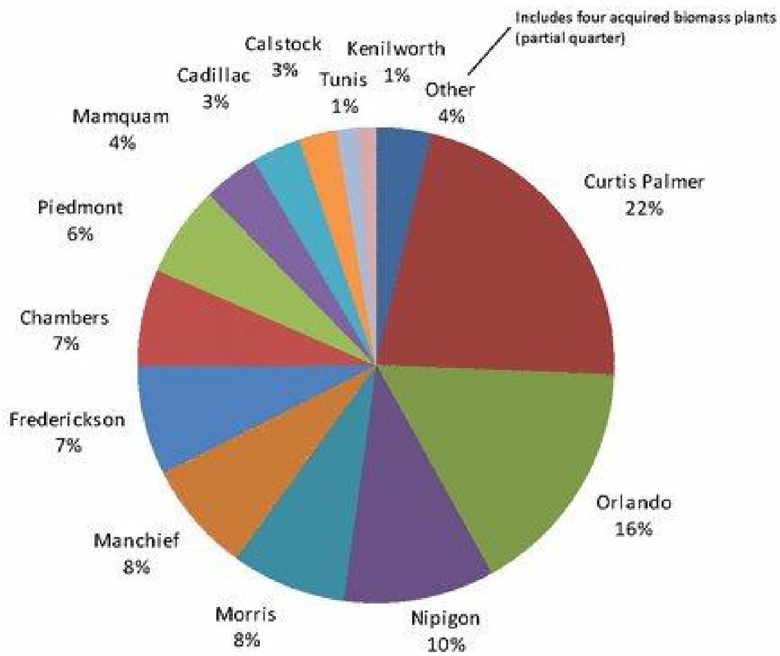
Note, the project debt, Project Adjusted EBITDA and cash interest expense for Piedmont are not included in the calculation of these ratios because the project is not included in the collateral package for the credit facilities.

AtlanticPower Corporation

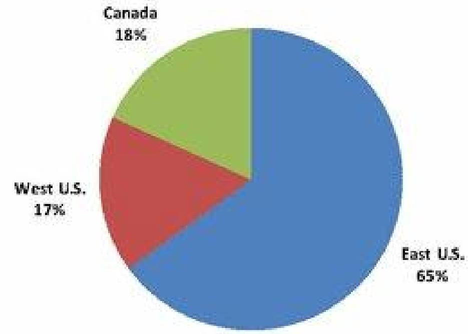
Project Adjusted EBITDA and Cash Flow Diversification by Project

Nine months ended September 30, 2019

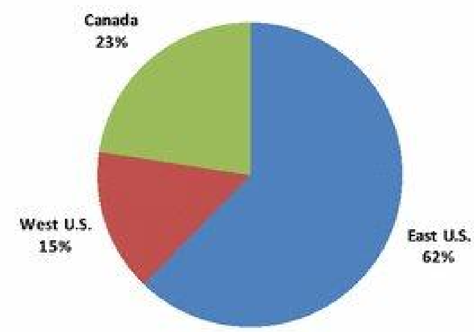
Project Adjusted EBITDA by Project



Project Adjusted EBITDA by Segment (1)



Cash Distributions from Projects by Segment (2)

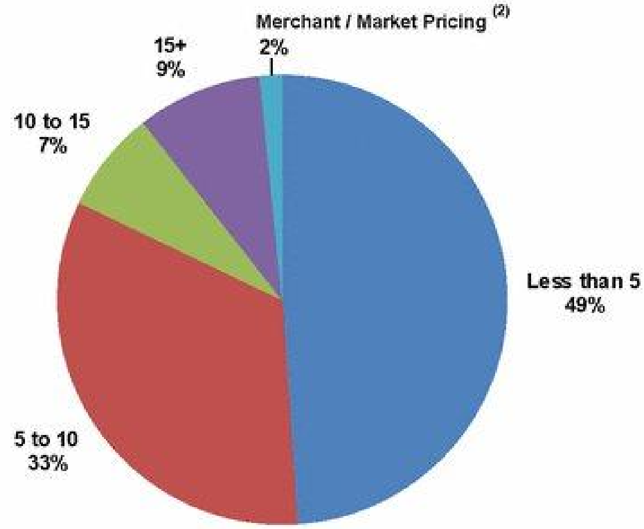


(1) Based on Project Adjusted EBITDA for the nine months ended September 30, 2019, excluding non-operational projects and one other project that has negative Project Adjusted EBITDA for the period. See Project Adjusted EBITDA by Project in this Appendix. (2) Based on $149.5 million in Cash Distributions from Projects for the nine months ended September 30, 2019.

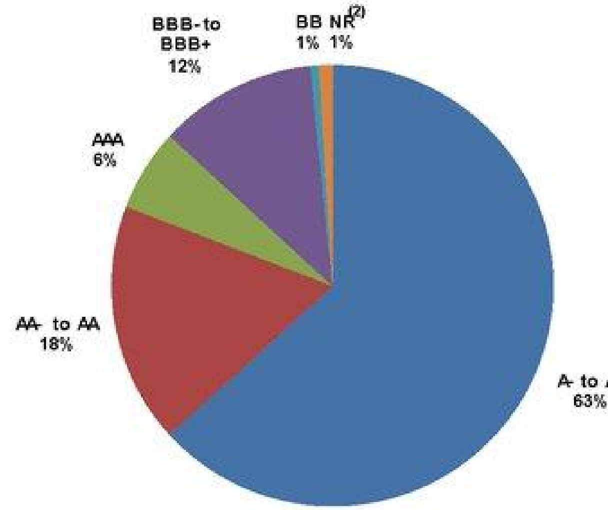
More Than Half of EBITDA Covered by Contracts with At Least 5 Years Remaining

Contracted projects have an average remaining PPA life of 6.2 years (1)

Remaining PPA Term (years) (1)



Pro Forma Offtaker Credit Rating (1)



(1) Weighted by FY 2019 Project Adjusted EBITDA. Includes newly acquired projects. (2) Primarily merchant energy revenue at Morris.

Summary of Financial and Operating Results

($ millions, unaudited)

Financial Results	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Project revenue	$71.1	$65.4	$215.4	$211.6
Project income	27.9	26.2	80.1	68.0
Net income (loss) attributable to Atlantic Power Corporation	12.6	(3.2)	22.7	12.1
Cash provided by operating activities	36.4	19.5	104.5	97.8
Cash used in investing activities	(29.1)	(14.5)	(28.0)	(16.9)
Cash used in financing activities	(20.3)	(29.7)	(87.1)	(107.9)
Project Adjusted EBITDA[1]	48.9	45.4	153.2	138.5
Operating Results				
Aggregate power generation (net GWh)	1,268.3	1,234.6	3,499.4	3,335.0
Weighted average availability	95.1%	94.3%	95.8%	95.4%

(1) See non-GAAP disclosures in this Appendix.

AtlanticPower Corporation

Segment Results

($ millions, unaudited)

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Project income (loss)				
East U.S.	$16.8	$12.7	$59.3	$51.5
West U.S.	5.9	12.6	6.3	4.4
Canada	7.1	1.2	22.9	9.8
Un-allocated Corporate	(1.9)	(0.3)	(8.4)	2.3
Total	**$27.9**	**$26.2**	**$80.1**	**$68.0**
Project Adjusted EBITDA				
East U.S.	$31.4	$25.5	$100.8	$89.8
West U.S.	11.6	11.5	24.5	16.9
Canada	6.1	8.3	28.0	31.5
Un-allocated Corporate	(0.2)	0.1	(0.1)	0.3
Total	**$48.9**	**$45.4**	**$153.2**	**$138.5**

Project Income (Loss) by Project

($ millions, unaudited)

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
East U.S.				
Allendale	$0.6	-	$0.6	-
Cadillac	(0.4)	($0.6)	0.5	$1.4
Curtis Palmer	1.2	(0.3)	22.9	12.7
Dorchester	0.5	-	0.5	-
Kenilworth	0.4	(0.5)	(0.2)	(0.6)
Morris	2.6	2.1	7.0	6.9
Piedmont	4.5	4.0	4.2	4.2
Chambers (1)	0.0	0.5	2.6	5.2
Craven (1)	0.2	-	0.2	-
Grayling (1)	0.3	-	0.3	-
Orlando (1)	7.0	7.5	20.8	21.7
Total	**16.8**	**12.7**	**59.3**	**51.5**
West U.S.				
Koma Kulshan (2)	(0.3)	6.7	(0.0)	7.1
Manchief	1.4	1.8	3.6	(3.9)
Naval Station	(0.1)	(0.5)	(0.7)	(1.8)
Naval Training Center	(0.1)	(0.4)	(0.8)	(1.6)
North Island	(0.1)	(0.5)	(0.6)	(1.5)
Oxnard	2.1	3.6	(1.8)	0.9
Frederickson (1)	2.9	1.9	6.5	5.2
Total	**5.9**	**12.6**	**6.3**	**4.4**
Canada				
Calstock	0.9	0.9	2.5	3.2
Kapuskasing	(0.1)	(0.1)	(0.2)	(0.4)
Mamquam	1.1	1.3	4.7	6.0
Nipigon	6.6	(0.5)	16.5	0.4
North Bay	(0.1)	(0.1)	(0.2)	(0.2)
Williams Lake	(1.3)	0.5	(0.9)	5.7
Moresby Lake	(0.6)	(0.6)	(1.0)	(0.6)
Tunis	0.5	(0.2)	1.6	(4.3)
Total	**7.1**	**1.2**	**22.9**	**9.8**
Totals				
Consolidated projects	19.4	16.6	58.2	33.6
Equity method projects	10.4	9.9	30.4	32.1
Un-allocated corporate	(1.9)	(0.3)	(8.4)	2.3
Total Project Income	**$27.9**	**$26.2**	**$80.1**	**$68.0**

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.
(2) Consolidated as of July 27, 2018; equity investment prior to that date.

Project Adjusted EBITDA by Project

($ millions, unaudited)

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
East U.S.				
Allendale	$0.6	-	$0.6	-
Cadillac	1.8	$0.7	5.2	$5.4
Curtis Palmer	5.0	3.5	34.5	24.3
Dorchester	0.5	-	0.5	-
Kenilworth	1.1	0.1	1.9	1.4
Morris	4.5	4.3	12.3	12.5
Piedmont	6.4	5.8	9.7	9.7
Chambers [1]	2.6	3.1	10.4	13.2
Craven [1]	0.3	-	0.3	-
Grayling [1]	0.3	-	0.3	-
Orlando [1]	8.4	7.9	25.0	23.2
Total	**31.4**	**25.5**	**100.8**	**89.8**
West U.S.				
Koma Kulshan [2]	0.1	0.2	1.1	0.9
Manchief	4.2	4.6	11.9	4.4
Naval Station	(0.1)	(0.5)	(0.3)	(0.7)
Naval Training Center	(0.1)	(0.4)	(0.2)	(0.9)
North Island	(0.1)	(0.5)	(0.3)	(0.6)
Oxnard	3.1	4.7	1.2	4.1
Frederickson [1]	4.4	3.4	11.1	9.7
Total	**11.6**	**11.5**	**24.5**	**16.9**
Canada				
Calstock	1.4	1.5	4.0	4.8
Kapuskasing	(0.1)	(0.1)	(0.2)	(0.4)
Mamquam	1.5	1.7	5.9	7.3
Moresby Lake	(0.4)	(0.3)	(0.3)	0.1
Nipigon	3.7	4.9	16.1	17.1
North Bay	(0.1)	(0.1)	(0.2)	(0.2)
Tunis	0.7	(0.2)	2.3	(4.3)
Williams Lake	(0.8)	0.9	0.4	7.0
Total	**6.1**	**8.3**	**28.0**	**31.5**
Totals				
Consolidated projects	33.0	30.9	106.2	92.1
Equity method projects	16.0	14.5	47.1	46.1
Un-allocated corporate	(0.2)	0.1	(0.1)	0.3
Total Project Adjusted EBITDA	**$48.9**	**$45.4**	**$153.2**	**$138.5**

	Three months ended September 30, 2019	Three months ended September 30, 2018	Nine months ended September 30, 2019	Nine months ended September 30, 2018
Total Project Adjusted EBITDA	**$48.9**	**$45.4**	**$153.2**	**$138.5**
Change in fair value of derivative instruments	(1.0)	-	8.3	(3.5)
Depreciation and amortization	20.2	25.0	60.6	78.0
Interest expense (income), net	0.8	(0.6)	2.0	2.7
Insurance loss	1.0	-	1.0	-
Other (income) expense, net	-	(5.2)	1.2	(6.7)
Project income	**$27.9**	**$26.2**	**$80.1**	**$68.0**
Administration	5.5	5.7	17.3	17.9
Interest expense, net	10.9	14.6	33.0	40.7
Foreign exchange (gain) loss	(2.8)	4.5	7.1	(9.1)
Other (income) expense, net	(0.2)	2.5	0.7	0.3
Income (loss) from operations before income tax	14.5	(1.1)	22.0	18.2
Income tax expense	0.2	3.6	2.4	7.7
Net income (loss)	**$14.3**	**($4.7)**	**$19.6**	**$10.5**
Net income (loss) attributable to preferred share dividends of a subsidiary company	1.7	(1.5)	(3.1)	(1.6)
Net income (loss) attributable to Atlantic Power Corporation	**$12.6**	**($3.2)**	**$22.7**	**$12.1**

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.
(2) Consolidated as of July 27, 2018; equity investment prior to that date.

Cash Distributions from Projects by Quarter, 2018 - 2019

($ millions, unaudited)

	Q1 2018	Q2 2018	Q3 2018	Q4 2018	FY 2018	Q1 2019	Q2 2019	Q3 2019	YTD 2019
East U.S.									
Allendale	-	-	-	-	-	-	-	$1.2	$1.2
Cadillac	$0.3	$1.3	$1.0	$1.0	$3.5	-	$1.0	0.5	1.5
Curtis Palmer	9.5	13.0	2.7	9.0	34.1	$14.3	15.2	7.6	37.1
Dorchester	-	-	-	-	-	-	-	0.9	0.9
Kenilworth	1.4	0.5	(0.0)	0.5	2.3	0.9	0.9	1.3	3.1
Morris	6.9	3.4	1.5	5.0	16.9	5.7	4.0	3.4	13.1
Piedmont	1.3	1.3	6.0	1.5	10.0	1.3	0.5	5.5	7.3
Chambers (1)	0.0	5.9	-	8.0	13.9	-	6.0	-	6.0
Craven (1)	-	-	-	-	-	-	-	-	-
Grayling (1)	-	-	-	-	-	-	-	0.4	0.4
Orlando (1)	2.6	9.7	6.4	13.7	32.3	1.9	10.1	10.6	22.6
Total	**21.8**	**35.0**	**17.5**	**38.8**	**113.1**	**24.0**	**37.7**	**31.4**	**93.1**
West U.S.									
Koma Kulshan (2)	0.6	0.1	0.4	0.8	1.8	0.3	0.6	0.1	0.9
Manchief	3.2	0.6	4.2	4.2	12.2	3.4	3.6	2.6	9.6
Naval Station	1.2	(0.7)	(0.4)	(0.4)	(0.4)	1.2	(0.1)	(0.4)	0.6
Naval Training Center	0.8	(0.5)	(0.4)	(0.6)	(0.7)	(0.2)	(0.1)	(0.4)	(0.7)
North Island	1.4	(0.7)	(0.4)	(0.6)	(0.3)	(0.3)	(0.1)	(0.2)	(0.6)
Oxnard	(0.2)	(0.2)	5.3	1.3	6.2	(1.1)	(1.9)	4.7	1.7
Frederickson (1)	4.0	3.0	3.4	3.7	14.1	3.8	2.8	4.5	11.1
Total	**11.0**	**1.8**	**12.0**	**8.3**	**33.0**	**7.1**	**4.7**	**10.9**	**22.6**
Canada									
Calstock	2.9	1.8	(0.1)	0.7	5.4	1.1	1.1	1.8	4.0
Kapuskasing	6.3	(0.2)	(0.1)	0.0	6.0	(0.1)	(0.1)	0.0	(0.2)
Mamquam	1.9	2.7	2.6	1.8	9.0	1.7	2.4	2.1	6.2
Moresby Lake	0.6	(0.1)	(0.2)	0.1	0.4	0.5	(0.3)	(0.3)	(0.1)
Nipigon	10.0	5.7	2.4	5.2	23.3	9.8	5.4	4.7	19.9
North Bay	6.6	(0.1)	(0.1)	0.0	6.4	(0.1)	(0.1)	(0.0)	(0.2)
Tunis	(0.5)	(3.1)	(0.5)	(0.5)	(4.5)	1.4	0.8	0.8	3.0
Williams Lake	4.0	1.2	(0.9)	1.7	5.9	2.5	(0.2)	(1.0)	1.3
Total	**31.7**	**8.0**	**3.2**	**9.0**	**51.9**	**16.7**	**9.0**	**8.1**	**33.7**
Total Cash Distributions	**$64.5**	**$44.7**	**$32.8**	**$56.1**	**$198.0**	**$47.8**	**$51.3**	**$50.4**	**$149.5**
Consolidated	57.4	26.0	23.0	30.7	137.7	42.1	32.4	34.9	109.4
Equity Method	7.1	18.8	9.8	25.4	60.3	5.7	18.9	15.4	40.1

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.
(2) Consolidated as of July 27, 2018; equity investment prior to that date.

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 pages 39-40.

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

	Three months ended September 30,		Nine months ended September 30,	
	2019	2018	2019	2018
Net income (loss) attributable to Atlantic Power Corporation	**$12.6**	**($3.2)**	**$22.7**	**$12.1**
Net income (loss) attributable to preferred share dividends of a subsidiary company	1.7	(1.5)	(3.1)	(1.6)
Net income (loss)	**$14.3**	**($4.7)**	**$19.6**	**$10.5**
Income tax expense	0.2	3.6	2.4	7.7
Income (loss) from operations before income taxes	14.5	(1.1)	22.0	18.2
Administration	5.5	5.7	17.3	17.9
Interest expense, net	10.9	14.6	33.0	40.7
Foreign exchange (gain) loss	(2.8)	4.5	7.1	(9.1)
Other (income) expense, net	(0.2)	2.5	0.7	0.3
Project income	**$27.9**	**$26.2**	**$80.1**	**$68.0**
Reconciliation to Project Adjusted EBITDA				
Depreciation and amortization	$20.2	$25.0	$60.6	$78.0
Interest expense (income), net	0.8	(0.6)	2.0	2.7
Change in the fair value of derivative instruments	(1.0)	-	8.3	(3.5)
Insurance loss	1.0	-	1.0	-
Other (income) expense, net	-	(5.2)	1.2	(6.7)
Project Adjusted EBITDA	**$48.9**	**$45.4**	**$153.2**	**$138.5**

Reconciliation of Net Income (Loss) to Project Adjusted EBITDA by Segment

($ millions)

Three months ended September 30, 2019

	East U.S.	West U.S.	Canada	Un-alloc. Corp.	Consolidated
Net income (loss) attributable to Atlantic Power Corporation	$16.8	$5.9	$7.1	($17.2)	$12.6
Net income attributable to preferred share dividends of a subsidiary company	-	-	-	1.7	1.7
Net income (loss)	16.8	5.9	7.1	(15.5)	14.3
Income tax expense	-	-	-	0.2	0.2
Net income (loss) before income taxes	16.8	5.9	7.1	(15.3)	14.5
Administration	-	-	-	5.5	5.5
Interest expense, net	-	-	-	10.9	10.9
Foreign exchange gain	-	-	-	(2.8)	(2.8)
Other income, net	-	-	-	(0.2)	(0.2)
Project income (loss)	16.8	5.9	7.1	(1.9)	27.9
Change in fair value of derivative instruments	1.1	-	(3.7)	1.6	(1.0)
Depreciation and amortization	11.7	5.7	2.8	-	20.2
Interest, net	0.8	-	-	-	0.8
Insurance loss	1.0	-	-	-	1.0
Other project (income) expense	-	-	(0.1)	0.1	-
Project Adjusted EBITDA	$31.4	$11.6	$6.1	($0.2)	$48.9

Three months ended September 30, 2018

	East U.S.	West U.S.	Canada	Un-alloc. Corp.	Consolidated
Net income (loss) attributable to Atlantic Power Corporation	$12.7	$12.6	$1.2	($29.7)	($3.2)
Net loss attributable to preferred share dividends of a subsidiary company	-	-	-	(1.5)	(1.5)
Net income (loss)	12.7	12.6	1.2	(31.2)	(4.7)
Income tax expense	-	-	-	3.6	3.6
Income (loss) before income taxes	12.7	12.6	1.2	(27.6)	(1.1)
Administration	-	-	-	5.7	5.7
Interest expense, net	-	-	-	14.6	14.6
Foreign exchange loss	-	-	-	4.5	4.5
Other expense, net	-	-	-	2.5	2.5
Project income (loss)	12.7	12.6	1.2	(0.3)	26.2
Change in fair value of derivative instruments	0.5	-	(0.8)	0.3	-
Depreciation and amortization	11.6	5.5	7.9	-	25.0
Interest, net	0.7	(1.3)	-	-	(0.6)
Other project (income) expense	-	(5.3)	-	0.1	(5.2)
Project Adjusted EBITDA	$25.5	$11.5	$8.3	$0.1	$45.4

Reconciliation of Net Income (Loss) to Project Adjusted EBITDA by Segment

($ millions)

Nine months ended September 30, 2019

	East U.S.	West U.S.	Canada	Un-alloc. Corp.	Consolidated
Net income (loss) attributable to Atlantic Power Corporation	$59.3	$6.3	$22.9	($65.8)	$22.7
Net loss attributable to preferred share dividends of a subsidiary company	-	-	-	(3.1)	(3.1)
Net income (loss)	59.3	6.3	22.9	(68.9)	19.6
Income tax expense	-	-	-	2.4	2.4
Net income (loss) before income taxes	59.3	6.3	22.9	(66.5)	22.0
Administration	-	-	-	17.3	17.3
Interest expense, net	-	-	-	33.0	33.0
Foreign exchange loss	-	-	-	7.1	7.1
Other expense, net	-	-	-	0.7	0.7
Project income (loss)	59.3	6.3	22.9	(8.4)	80.1
Change in fair value of derivative instruments	3.4	-	(3.3)	8.2	8.3
Depreciation and amortization	34.8	17.3	8.4	0.1	60.6
Interest, net	2.3	(0.3)	-	-	2.0
Insurance loss	1.0	-	-	-	1.0
Other project expense	-	1.2	-	-	1.2
Project Adjusted EBITDA	$100.8	$24.5	$28.0	($0.1)	$153.2

Nine months ended September 30, 2018

	East U.S.	West U.S.	Canada	Un-alloc. Corp.	Consolidated
Net income (loss) attributable to Atlantic Power Corporation	$51.5	$4.4	$9.8	($53.6)	$12.1
Net loss attributable to preferred share dividends of a subsidiary company	-	-	-	(1.6)	(1.6)
Net income (loss)	51.5	4.4	9.8	(55.2)	10.5
Income tax expense	-	-	-	7.7	7.7
Net income (loss) before income taxes	51.5	4.4	9.8	(47.5)	18.2
Administration	-	-	-	17.9	17.9
Interest expense, net	-	-	-	40.7	40.7
Foreign exchange gain	-	-	-	(9.1)	(9.1)
Other expense, net	-	-	-	0.3	0.3
Project income	51.5	4.4	9.8	2.3	68.0
Change in fair value of derivative instruments	0.8	-	(2.2)	(2.1)	(3.5)
Depreciation and amortization	34.8	19.2	23.9	0.1	78.0
Interest, net	2.7	-	-	-	2.7
Other project income	-	(6.7)	-	-	(6.7)
Project Adjusted EBITDA	$89.8	$16.9	$31.5	$0.3	$138.5