

this Quarterly Report on Form 10-Q and, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

## **ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS**

*The following discussion of the financial condition and results of operations of Atlantic Power should be read in conjunction with the interim consolidated financial statements and the related notes thereto included elsewhere in this Quarterly Report on Form 10-Q. All dollar amounts discussed below are in millions of U.S. dollars except per share amounts, or unless otherwise stated. The interim financial statements have been prepared in accordance with GAAP.*

### **OVERVIEW**

Atlantic Power owns and operates a diverse fleet of power generation assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term PPAs, which seek to minimize exposure to changes in commodity prices. As of September 30, 2017, our power generation projects had an aggregate gross electric generation capacity of approximately 2,138 MW in which our aggregate ownership interest is approximately 1,500 MW. Our current portfolio consists of interests in twenty-three power generation projects across nine states in the United States and two provinces in Canada. Nineteen of the projects are currently operational, totaling 1,975 MW on a gross capacity basis and 1,337 MW on a net ownership basis. The remaining four projects, all in Ontario, are not operational, three due to revised contractual arrangements with the offtaker and the other, Tunis, has a forward-starting 15-year contractual agreement that will commence before June 2019. Eighteen of our projects are majority-owned.

We sell the majority of the capacity and energy from our power generation projects under PPAs to a variety of utilities and other parties. Under the PPAs, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). Our PPAs have expiration dates ranging from December 31, 2017 to December 31, 2037. Nine of our projects, representing 25% of our net MW and 30% of our 2016 Project Adjusted EBITDA, have PPAs or other contractual arrangements that will expire within the next five years. These projects are Kapuskasing (2017), North Bay (2017), Williams Lake (2018), Kenilworth (2018), Naval Station (2019), NTC (2019), North Island (2019), Calstock (2020) and Oxnard (2020). There are no PPA expirations in 2021. See *Recent Developments – Impairments* below for further discussion of Naval Station, NTC and North Island. When a PPA expires, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. Our MW-weighted average remaining PPA life is approximately 7 years. We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. Sales of electricity are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

The majority of our natural gas, coal and biomass power generation projects have long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the term of the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is no pass-through of fuel costs, we often attempt to mitigate the market price risk of changing commodity costs through the use of hedging strategies.

We directly operate and maintain eighteen of our power generation projects. We also partner with recognized leaders in the independent power industry to operate and maintain our other projects. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

### **RECENT DEVELOPMENTS**

#### *Senior secured term loan facility repricing*

On October 18, 2017, the repricing of the \$563 million senior secured term loan and senior secured revolving credit facility became effective. On October 30, 2017, the extension of our \$200 million senior secured revolving credit facility also became effective. As a result of the repricing, the interest rate margin on the term loan and revolver was

reduced by an additional 0.75% to LIBOR plus 3.50%. The senior secured revolving credit facility was extended one year through April 13, 2022. The senior secured term loan and revolving credit facility were previously repriced in April 2017, reducing the interest rate from LIBOR plus 5.00% to LIBOR plus 4.25%. The LIBOR floor remains at 1.00% and the mandatory 1% annual amortization and cash sweep provisions of the term loan are unchanged.

#### *Piedmont term loan repayment*

On October 13, 2017, we repaid the \$54.6 million Piedmont term loan due August 2018, in full, with cash on hand. In addition to the principal repayment, we paid \$0.1 million of accrued interest, \$9.4 million to terminate interest rate swap agreements and wrote off \$0.9 million of deferred financing costs. The swap termination costs and deferred financing costs write down will be recorded as interest expense in the three months ended December 31, 2017.

#### *Credit upgrade*

In October 2017, Moody's Investors Service ("Moody's") upgraded our Corporate Family Rating to Ba3 from B1 and the senior secured term loan and revolving credit facilities at APLP Holdings to Ba2 from Ba3.

#### *San Diego impairments*

We test our long-lived assets and goodwill for impairment at least annually, or more often if deemed appropriate based on management's determination of the occurrence of certain trigger events under our impairment policy. When we have an expectation that we will be unable to renew or renegotiate a PPA, the value of the project may be impaired such that we would record an impairment loss.

The San Diego Projects sell power to SDG&E under PPAs that are scheduled to expire in December 2019. In addition, the three projects supply steam to the U.S. Navy under agreements that provide these projects with the right to use the property at the respective sites on which each project is located (the "Navy agreements"). The Navy agreements are scheduled to expire in February 2018. In August 2017, we were unsuccessful in obtaining contracts to provide the Navy energy security and resilience that would have provided us with the right to use the Naval Station and North Island sites beyond February 2018. Although we are pursuing alternative paths to maintaining rights to the sites, if not successful, the plants may cease to operate as early as February 2018.

Following notification of the outcome of the Navy solicitation, we determined that it was a triggering event to test the long-lived assets at the San Diego projects for impairment. We performed this test at each of these projects as of July 31, 2017. As a result, we recorded a total \$57.3 million impairment (\$22.5 million at Naval Station, \$13.5 million at NTC and \$21.2 million at North Island) in the three and nine months ended September 30, 2017. The San Diego projects have net removal obligations recorded of \$4.6 million at September 30, 2017. We are in the process of evaluating the estimated removal costs and may have further adjustments to this amount in the three months ended December 31, 2017 as the timing and final arrangements for decommissioning the sites have not been determined.

Subsequent to recording the impairment, we will also accelerate amortization through February 2018 of the remaining property, plant and equipment with the three projects, totaling approximately \$7.7 million. Both the accelerated amortization and the impairment are non-cash expenses that do not affect cash flow, nor are they included in Project Adjusted EBITDA.

Additionally, in connection with the potential early termination of the PPAs, we could be liable for liquidated damages under the PPAs. However, we believe that we will not be required to pay any liquidated damages associated with the early termination of the PPAs, because we believe that the circumstances of the termination and the agreements in place between us and the PPA counterparty relieve us of potential liabilities.

## OUR POWER PROJECTS

The table below outlines our portfolio of power generating assets in operation as of November 7, 2017, including our interest in each facility. Management believes the portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region. Our customers are generally large utilities and other parties with investment-grade credit ratings, as measured by Standard & Poor's ("S&P"). For customers rated by Moody's, we substitute the corresponding S&P rating in the table below. Customers that have assigned ratings at the top end of the range of investment-grade have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the lower end of the range of investment-grade have weaker capacity. Agency ratings are subject to change, and there can be no assurance that a ratings agency will continue to rate the customers, and/or maintain their current ratings. A security rating may be subject to revision or withdrawal at any time by the rating agency, and each rating should be evaluated independently of any other rating. We cannot predict the effect that a change in the ratings of the customers will have on their liquidity or their ability to pay their debts or other obligations.

Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)
<b>East U.S. Segment</b>								
Orlando <sup>(1)</sup>	Florida	Natural Gas	129	50.00 %	65	Progress Energy Florida	December 2023	A-
Piedmont	Georgia	Biomass	55	100.00 %	55	Georgia Power	September 2032	A-
Morris	Illinois	Natural Gas	177	100.00 %	120	Merchant	N/A	NR
					57	Equistar Chemicals, LP <sup>(2)</sup>	December 2034	BBB+
Cadillac	Michigan	Biomass	40	100.00 %	40	Consumers Energy	June 2028	BBB+
Chambers <sup>(1)</sup>	New Jersey	Coal	262	40.00 %	89	Atlantic City Electric <sup>(3)</sup>	March 2024	BBB+
					16	Chemours Co.	March 2024	BB-
Kenilworth	New Jersey	Natural Gas	29	100.00 %	29	Merck & Co., Inc.	September 2018	AA
Curtis Palmer	New York	Hydro	60	100.00 %	60	Niagara Mohawk Power Corporation	December 2027 <sup>(4)</sup>	A-
Selkirk <sup>(1)</sup>	New York	Natural Gas	345	17.70 %	61	Merchant	N/A	NR
<b>West U.S. Segment</b>								
Naval Station	California	Natural Gas	47	100.00 %	47	San Diego Gas & Electric	November 2019 <sup>(5)</sup>	A
Naval Training Center	California	Natural Gas	25	100.00 %	25	San Diego Gas & Electric	November 2019 <sup>(5)</sup>	A
North Island	California	Natural Gas	40	100.00 %	40	San Diego Gas & Electric	November 2019 <sup>(5)</sup>	A
Oxnard	California	Natural Gas	49	100.00 %	49	Southern California Edison	April 2020	BBB+
Manchief	Colorado	Natural Gas	300	100.00 %	300	Public Service Company of Colorado	April 2022 <sup>(6)</sup>	A-
Frederickson <sup>(1)</sup>	Washington	Natural Gas	250	50.15 %	50	Benton Co. PUD	August 2022	AA-
					45	Grays Harbor PUD	August 2022	A+
					30	Franklin, Co. PUD	August 2022	A+
Koma Kulshan <sup>(1)</sup>	Washington	Hydro	13	49.80 %	6	Puget Sound Energy	March 2037	BBB
<b>Canada Segment</b>								
Mamquam	British Columbia	Hydro	50	100.00 %	50	British Columbia Hydro and Power Authority	September 2027 <sup>(7)</sup>	AAA
Moresby Lake	British Columbia	Hydro	6	100.00 %	6	British Columbia Hydro and Power Authority	August 2022	AAA
Williams Lake	British Columbia	Biomass	66	100.00 %	66	British Columbia Hydro and Power Authority	March 2018	AAA
Calstock	Ontario	Biomass	35	100.00 %	35	Ontario Electricity Financial Corporation	June 2020	AA
Kapuskasing	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2017 <sup>(8)</sup>	AA
Nipigon	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2022 <sup>(9)</sup>	AA
North Bay	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2017 <sup>(8)</sup>	AA
Tunis	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	<sup>(10)</sup>	AA

<sup>(1)</sup> Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

- (2) Represents the credit rating of LyondellBasell, the parent company of Equistar Chemicals, as Equistar is not rated.
- (3) The base PPA with Atlantic City Electric (“ACE”) makes up the majority of the revenue from the 89 Net MW. For sales of energy and capacity not purchased by ACE under the base PPA and sold to the spot market, profits are shared with ACE under a separate power sales agreement.
- (4) The Curtis Palmer PPA expires at the earlier of December 2027 or the provision of 10,000 GWh of generation. From January 6, 1995 through September 30, 2017, the facility has generated 7,246 GWh under its PPA. Based on cumulative generation to date, we expect the PPA to expire prior to December 2027.
- (5) Our land use license agreements with the U.S. Navy expire on February 8, 2018. Our PPAs with SDG&E expire on December 1, 2019. See *Recent Developments – Impairments* for additional information on these PPAs.
- (6) Public Service Company of Colorado has options to purchase Manchief in either May 2020 or May 2021.
- (7) BC Hydro has the option to purchase Mamquam in November 2021 and every five years thereafter.
- (8) In December 2016, we entered into agreements to terminate our PPAs originally scheduled to expire on December 31, 2017 one year ahead of their expiration dates. Additionally, we entered into enhanced dispatch contracts with the IESO, which provide a fixed monthly payment to the plants until December 31, 2017. The contracts have no delivery obligations and allow us to retain operating flexibility. Based on our assessment of the Ontario power market, including the estimated impact on plant economics, we do not expect to operate the plants during the term of the enhanced dispatch contracts or subsequent to their expiration.
- (9) In December 2016, we entered into an enhanced dispatch contract with IESO. The enhanced dispatch contract for Nipigon provides fixed monthly payments to that plant through October 31, 2018. During that period, the plant’s PPA with the OEFC will be suspended. At the conclusion of that period, the arrangement will revert to the existing terms of the PPA, which is scheduled to expire in December 2022. We do not expect Nipigon to be operational through October 31, 2018.
- (10) In December 2014, we entered into an agreement with the Ontario Power Authority and its successor, the IESO for the future operations of the Tunis facility. Subject to meeting certain technical requirements, Tunis will operate under a 15-year agreement with the IESO commencing before June 2019. The new agreement provides the Tunis project with a fixed monthly payment which escalates annually according to a pre-defined formula while allowing it to earn additional energy revenues for those periods during which it operates.

## Consolidated Overview and Results of Operations

### *Performance highlights*

The following table provides a summary of our consolidated results of operations for the three and nine months ended September 30, 2017 and 2016, which are analyzed in greater detail below:

	Three months ended		Nine months ended	
	September 30,		September 30,	
	2017	2016	2017	2016
Project revenue	\$ 108.6	\$ 101.2	\$ 331.0	\$ 305.8
Project loss	\$ (20.9)	\$ (57.1)	\$ (7.7)	\$ (3.3)
Net loss attributable to Atlantic Power Corporation	\$ (32.9)	\$ (82.4)	\$ (57.5)	\$ (116.2)
Loss per share attributable to Atlantic Power Corporation—basic and diluted	\$ (0.29)	\$ (0.69)	\$ (0.50)	\$ (0.96)
Project Adjusted EBITDA <sup>(1)</sup>	\$ 77.4	\$ 51.3	\$ 226.6	\$ 159.9

<sup>(1)</sup> See reconciliation and definition in Supplementary Non-GAAP Financial Information.

Revenue increased by \$7.4 million from \$101.2 million in the three months ended September 30, 2016 to \$108.6 million in the three months ended September 30, 2017. The primary drivers of the increase are as follows:

- *Hydrological conditions* – a \$4.7 million increase in revenue from higher water flows at our hydro projects; and
- *Morris* – a \$4.3 million increase in revenue at our Morris project, which underwent a turbine overhaul in the comparable 2016 period.

These increases in project revenue were partially offset by:

- *Enhanced dispatch contracts* – under the enhanced dispatch contracts with the IESO, we suspended operations at our Kapuskasing, North Bay and Nipigon projects, which resulted in approximately \$4.2 million of lower revenue than the comparable 2016 period.

Consolidated project loss decreased by \$36.2 million from \$57.1 million of project loss in the three months ended September 30, 2016 to \$20.9 million project loss in the three months ended September 30, 2017. The primary drivers of the decrease are as follows:

- *Revenue* – revenue increased by \$7.4 million as discussed above;
- *Fuel expense* – fuel expense decreased \$11.8 million from the comparable 2016 period primarily due to the expiration of fuel contracts at North Bay and Kapuskasing on December 31, 2016, a \$1.1 million decrease related to favorable fuel swap settlements at our Orlando project and a \$1.7 million decrease at Nipigon, which is currently not in operation under the terms of its enhanced dispatch contract. This was partially offset by \$3.3 million of higher fuel expense at Morris, which underwent a turbine overhaul in the comparable 2016 period;
- *Operations and maintenance* – operations and maintenance expense decreased \$8.4 million from the comparable 2016 period primarily due to a \$6.5 million decrease at our Morris project, which underwent a turbine overhaul in August 2016; and
- *Impairment* – we recorded \$57.3 million of long-lived asset impairments at Naval Station, NTC and North Island in August 2017. We recorded \$84.7 million of goodwill and long-lived asset impairments in the comparable period in 2016.

These decreases in project loss were partially offset by increases in project loss resulting from:

- *Depreciation and amortization* – depreciation expense increased \$6.1 million from the comparable 2016 period due to the acceleration of depreciation at North Bay and Kapuskasing through December 2017, the expiration date of the plants' enhanced dispatch contracts; and
- *Fuel swap and natural gas purchase agreements* – the change in fair value of our derivative instruments decreased \$10.9 million from the comparable 2016 period.

Revenue increased by \$25.2 million from \$305.8 million in the nine months ended September 30, 2016 to \$331.0 million in the nine months ended September 30, 2017. The primary drivers of the increase are as follows:

- *OEFC settlement* – we recorded approximately \$25.6 million of revenue at North Bay, Kapuskasing and Tunis related to our settlement agreement entered into with the OEFC in April 2017 arising out of our disagreement over the interpretation of the price escalator calculation in our PPAs at these projects;
- *Hydrological conditions* – an \$8.1 million increase in revenue from higher water flows at our hydro projects, primarily at Curtis Palmer;
- *San Diego projects* – a \$6.7 million increase in revenue at our San Diego projects, primarily due to higher steam revenue than the comparable 2016 period; and

- *Morris* – a \$1.6 million increase in revenue at our Morris project, which underwent a turbine overhaul in the comparable 2016 period.

These increases in project revenue were partially offset by:

- *Enhanced dispatch contracts* – under the enhanced dispatch contracts with the IESO, we suspended operations at our Kapuskasing, North Bay and Nipigon projects, which resulted in approximately \$16.6 million of lower revenue than the comparable 2016 period.

Consolidated project loss increased by \$4.4 million from \$3.3 million of project loss in the nine months ended September 30, 2016 to \$7.7 million of project loss in the nine months ended September 30, 2017. The primary drivers of the increase are as follows:

- *Impairment* – we recorded \$57.3 million of impairments at our wholly-owned Naval Station, Naval Training Center and North Island projects, and \$57.7 million of impairments at our Chambers and Selkirk projects, which are accounted under the equity method of accounting in the nine months ended September 30, 2017. This was partially offset by \$84.7 million of goodwill and long-lived asset impairments recorded in the comparable 2016 period at our Mamquam, Curtis Palmer, North Bay and Kapuskasing projects;
- *Fuel swap and natural gas purchase agreements* – the change in fair value of our derivative instruments decreased \$25.8 million from the comparable 2016 period; and
- *Depreciation and amortization* – depreciation expense increased \$14.9 million from the comparable 2016 period primarily due to the acceleration of depreciation at North Bay and Kapuskasing through December 2017, the expiration date of the plants' enhanced dispatch contracts.

These increases in project loss were partially offset by decreases in project loss resulting from:

- *Revenue* – revenue increased by \$25.2 million as discussed above;
- *Fuel expense* – fuel expense decreased \$31.7 million from the comparable 2016 period primarily due to the \$34.4 million impact of the expiration of fuel contracts at North Bay and Kapuskasing on December 31, 2016, a \$5.6 million decrease related to favorable fuel swap settlements at our Orlando project and a \$4.8 million decrease at Nipigon, which is currently not in operation under the terms of its enhanced dispatch contract. This was partially offset by \$6.5 million of higher fuel expense at Morris, which underwent a turbine overhaul in the comparable 2016 period, and \$6.1 million of higher fuel expense at our San Diego projects due to higher fuel prices; and
- *Operations and maintenance* – operations and maintenance expense decreased \$16.0 million from the comparable 2016 period primarily due to a \$7.3 million decrease at our Morris project, which underwent a turbine overhaul in August 2016, and a \$4.7 million decrease at Kapuskasing and North Bay, which do not operate under the term of their enhanced dispatch contracts.

A detailed discussion of project income (loss) by segment is provided in Consolidated Overview and Results of Operations below. The discussion of Project Adjusted EBITDA by segment begins on page 51.

We have four reportable segments: East U.S., West U.S., Canada and Un-Allocated Corporate. The segment classified as Un-allocated Corporate includes activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects and intercompany eliminations. These costs are not allocated to the operating segments when determining segment profit or loss. Project income (loss) is the primary GAAP measure of our operating results and is discussed below by reportable segment.

**Three months ended September 30, 2017 compared to the three months ended September 30, 2016**

The following table provides our consolidated results of operations:

	<b>Three months ended September 30,</b>			
	<b>2017</b>	<b>2016</b>	<b>\$ change</b>	<b>% change</b>
<b>Project revenue:</b>				
Energy sales	\$ 36.5	\$ 40.7	\$ (4.2)	(10.3)%
Energy capacity revenue	37.9	44.0	(6.1)	(13.9)%
Other	34.2	16.5	17.7	107.3 %
	<u>108.6</u>	<u>101.2</u>	<u>7.4</u>	<u>7.3 %</u>
<b>Project expenses:</b>				
Fuel	26.2	36.8	(10.6)	(28.8)%
Operations and maintenance	19.8	28.2	(8.4)	(29.8)%
Depreciation and amortization	31.4	25.3	6.1	24.1 %
	<u>77.4</u>	<u>90.3</u>	<u>(12.9)</u>	<u>(14.3)%</u>
<b>Project other expense:</b>				
Change in fair value of derivative instruments	(1.9)	9.0	(10.9)	(121.1)%
Equity in earnings of unconsolidated affiliates	9.2	9.6	(0.4)	NM
Interest expense, net	(2.2)	(2.4)	0.2	NM
Impairment	(57.3)	(84.7)	27.4	(32.3)%
Other income, net	0.1	0.5	(0.4)	(80.0)%
	<u>(52.1)</u>	<u>(68.0)</u>	<u>15.9</u>	<u>NM</u>
<b>Project loss</b>	<u>(20.9)</u>	<u>(57.1)</u>	<u>36.2</u>	<u>(63.4)%</u>
<b>Administrative and other expenses:</b>				
Administration	5.5	5.7	(0.2)	NM
Interest expense, net	13.8	20.0	(6.2)	(31.0)%
Foreign exchange loss (gain)	9.4	(3.4)	12.8	(376.5)%
Other income, net	—	(1.7)	1.7	(100.0)%
	<u>28.7</u>	<u>20.6</u>	<u>8.1</u>	<u>39.3 %</u>
<b>Loss from operations before income taxes</b>	<u>(49.6)</u>	<u>(77.7)</u>	<u>28.1</u>	<u>(36.2)%</u>
<b>Income tax (benefit) expense</b>	<u>(15.9)</u>	<u>2.6</u>	<u>(18.5)</u>	<u>NM</u>
<b>Net loss</b>	<u>(33.7)</u>	<u>(80.3)</u>	<u>46.6</u>	<u>(58.0)%</u>
<b>Net (loss) income attributable to Preferred share dividends of a subsidiary company</b>	<u>(0.8)</u>	<u>2.1</u>	<u>(2.9)</u>	<u>(138.1)%</u>
<b>Net loss attributable to Atlantic Power Corporation</b>	<u>\$ (32.9)</u>	<u>\$ (82.4)</u>	<u>\$ 49.5</u>	<u>(60.1)%</u>

The following tables provide our project income by segment:

	Three months ended September 30, 2017				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
<b>Project revenue:</b>					
Energy sales	\$ 20.1	\$ 8.4	\$ 8.0	\$ —	\$ 36.5
Energy capacity revenue	16.3	19.0	2.6	—	37.9
Other	3.4	7.7	22.9	0.2	34.2
	<u>39.8</u>	<u>35.1</u>	<u>33.5</u>	<u>0.2</u>	<u>108.6</u>
<b>Project expenses:</b>					
Fuel	11.6	11.4	3.2	—	26.2
Operations and maintenance	8.7	5.6	5.7	(0.2)	19.8
Depreciation and amortization	9.1	8.1	14.1	0.1	31.4
	<u>29.4</u>	<u>25.1</u>	<u>23.0</u>	<u>(0.1)</u>	<u>77.4</u>
<b>Project other income (expense):</b>					
Change in fair value of derivative instruments	(1.3)	—	(1.2)	0.6	(1.9)
Equity in earnings of unconsolidated affiliates	8.1	1.1	—	—	9.2
Interest expense, net	(2.2)	—	—	—	(2.2)
Impairment	—	(57.3)	—	—	(57.3)
Other income, net	—	—	0.1	—	0.1
	<u>4.6</u>	<u>(56.2)</u>	<u>(1.1)</u>	<u>0.6</u>	<u>(52.1)</u>
<b>Project income (loss)</b>	<u>\$ 15.0</u>	<u>\$ (46.2)</u>	<u>\$ 9.4</u>	<u>\$ 0.9</u>	<u>\$ (20.9)</u>

	Three months ended September 30, 2016				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
<b>Project revenue:</b>					
Energy sales	\$ 13.9	\$ 9.5	\$ 17.3	\$ —	\$ 40.7
Energy capacity revenue	15.0	19.0	10.0	—	44.0
Other	2.4	5.6	8.3	0.2	16.5
	<u>31.3</u>	<u>34.1</u>	<u>35.6</u>	<u>0.2</u>	<u>101.2</u>
<b>Project expenses:</b>					
Fuel	9.6	10.5	16.7	—	36.8
Operations and maintenance	14.2	5.5	8.2	0.3	28.2
Depreciation and amortization	8.5	7.3	9.4	0.1	25.3
	<u>32.3</u>	<u>23.3</u>	<u>34.3</u>	<u>0.4</u>	<u>90.3</u>
<b>Project other income (expense):</b>					
Change in fair value of derivative instruments	1.2	—	5.6	2.2	9.0
Equity in earnings of unconsolidated affiliates	9.0	0.6	—	—	9.6
Interest expense, net	(2.4)	—	—	—	(2.4)
Impairment	(15.4)	—	(69.3)	—	(84.7)
Other income, net	—	—	—	0.5	0.5
	<u>(7.6)</u>	<u>0.6</u>	<u>(63.7)</u>	<u>2.7</u>	<u>(68.0)</u>
<b>Project (loss) income</b>	<u>\$ (8.6)</u>	<u>\$ 11.4</u>	<u>\$ (62.4)</u>	<u>\$ 2.5</u>	<u>\$ (57.1)</u>

*East U.S.*

Project income was \$15.0 million for the three months ended September 30, 2017, an increase of \$23.6 million from a project loss of \$8.6 million in the comparable 2016 period primarily due to:

- increased project income of \$18.9 million at Curtis Palmer primarily due to a \$15.4 million goodwill impairment charge recorded in the three months ended September 30, 2016 and \$3.7 million of increased revenues due to higher water flows than the comparable 2016 period; and
- increased project income of \$6.7 million at Morris primarily due to \$6.5 million of decreased maintenance expense resulting from the overhaul of two gas turbines and one steam turbine in August 2016, as well as replacement of a continuous emissions monitoring system.

These increases were partially offset by:

- decreased project income of \$1.5 million at Piedmont primarily due to a negative \$1.8 million change in fair value of interest rate swap agreements.

#### *West U.S.*

Project loss was \$46.2 million for the three months ended September 30, 2017, a decrease of \$57.6 million from project income of \$11.4 million in the comparable 2016 period primarily due to:

- decreased project income of \$20.2 million, \$19.1 million and \$12.4 million at Naval Station, North Island and NTC primarily due to \$22.5 million, \$21.2 million and \$13.5 million long-lived asset impairments recorded for the three months ended September 30, 2017, respectively.

#### *Canada*

Project income was \$9.4 million for the three months ended September 30, 2017, an increase of \$71.8 million from a project loss of \$62.4 million in the comparable 2016 period primarily due to:

- increased project income of \$51.3 million at Mamquam primarily due to a \$50.2 million goodwill impairment charge recorded in the comparable period in 2016 and \$0.8 million increased revenue from higher water flows than the comparable 2016 period;
- increased project income of \$10.1 million at North Bay primarily due to \$10.2 million of goodwill and long-lived asset impairments recorded in the comparable 2016 period; and
- increased project income of \$7.9 million at Kapuskasing primarily due to \$8.9 million of goodwill and long-lived asset impairments recorded in the comparable 2016 period, \$6.0 million of lower fuel expense due to the expiration of fuel purchase agreements in December 2016, as well as the plant not being operational due to the enhanced dispatch agreements. These increases were partially offset by a positive \$3.4 million change in the fair value of gas purchase agreements that expired in December 2016 and were accounted for as derivatives, \$2.6 million of accelerated depreciation in the three months ended September 20, 2017 and \$1.0 million decreased revenue due to the plant not being operational under the enhanced dispatch agreement.

#### *Un-allocated Corporate*

Project income for the three months ended September 30, 2017 of \$0.9 million decreased from a project income of \$2.5 million in the comparable 2016 period primarily due to a \$1.6 million decrease in the fair value of interest swaps accounted for as derivatives.

#### ***Administrative and other expenses (income)***

Administrative and other expenses (income) include the income and expenses not attributable to any specific project and is allocated to the Un-allocated Corporate segment. These costs include the activities that support the executive and administrative offices, treasury function, costs of being a public registrant, costs to develop or acquire future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate taxes. Significant non-cash items that impact Administrative and other expenses (income), and that are subject to potentially significant fluctuations include the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar-denominated obligations and the related deferred income tax expense (benefit) associated with these non-cash items.

#### *Administration*

Administration expense did not change materially from the 2016 comparable period.

#### *Interest expense, net*

Interest expense decreased \$6.2 million from the comparable 2016 period primarily due to lower outstanding debt balances at September 30, 2017 than the comparable 2016 period, as well as a lower interest rate on our senior secured credit facility.

#### *Foreign exchange loss*

Foreign exchange loss was \$9.4 million for the three months ended September 30, 2017, a decrease of \$12.8 million from a \$3.4 million foreign exchange gain in the comparable 2016 period, primarily due to an \$11.8 million increase in unrealized loss from the revaluation of instruments denominated in Canadian dollars. The closing U.S. dollar to Canadian dollar exchange rates were 1.25 and 1.31 at September 30, 2017 and 2016, respectively, a decrease of 3.8% during the three months ended September 30, 2017, as compared to a decrease of 1.5% in the comparable 2016 period. The average U.S. dollar to Canadian dollar exchange rates were 1.25 and 1.31 for the three months ended September 30, 2017 and 2016, respectively.

#### *Other income, net*

Other income, net decreased \$1.7 million primarily due to a gain recorded on the purchase and cancellation of convertible debentures in the comparable 2016 period.

#### *Income tax expense*

Income tax benefit for the three months ended September 30, 2017 was \$15.9 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was \$12.9 million. The primary items impacting the tax rate for the three months ended September 30, 2017 were \$3.5 million related to a net increase to the Company's valuation allowances in Canada and \$0.3 million of other permanent differences. These items were offset by \$5.5 million relating to operating in higher tax rate jurisdictions and \$1.3 relating to foreign exchange.

Income tax expense for the three months ended September 30, 2016 was \$2.6 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was \$20.2 million. The primary item impacting the tax rate for the three months ended September 30, 2016 was \$22.5 million related to goodwill impairment. In addition, the rate was further impacted by a net increase to our valuation allowances of \$8.6 million, consisting

primarily of increases of \$9.3 million in Canada related to capital loss on intercompany notes, \$1.9 million relating to operating in higher tax rate jurisdictions and \$0.8 million of other permanent differences.

***Nine months ended September 30, 2017 compared to the nine months ended September 30, 2016***

The following table provides our consolidated results of operations:

	<b>Nine months ended September 30,</b>			
	<b>2017</b>	<b>2016</b>	<b>\$ change</b>	<b>% change</b>
<b>Project revenue:</b>				
Energy sales	\$ 113.6	\$ 138.4	\$ (24.8)	(17.9)%
Energy capacity revenue	85.7	113.2	(27.5)	(24.3)%
Other	131.7	54.2	77.5	143.0 %
	<u>331.0</u>	<u>305.8</u>	<u>25.2</u>	<u>8.2 %</u>
<b>Project expenses:</b>				
Fuel	79.1	110.8	(31.7)	(28.6)%
Operations and maintenance	63.4	79.4	(16.0)	(20.2)%
Depreciation and amortization	90.5	75.6	14.9	19.7 %
	<u>233.0</u>	<u>265.8</u>	<u>(32.8)</u>	<u>(12.3)%</u>
<b>Project other expense:</b>				
Change in fair value of derivative instruments	(5.8)	20.0	(25.8)	(129.0)%
Equity in (loss) earnings of unconsolidated affiliates	(36.1)	27.9	(64.0)	(229.4)%
Interest expense, net	(6.6)	(6.9)	0.3	(4.3)%
Impairment	(57.3)	(84.7)	27.4	(32.3)%
Other income, net	0.1	0.4	(0.3)	(75.0)%
	<u>(105.7)</u>	<u>(43.3)</u>	<u>(62.4)</u>	<u>NM</u>
<b>Project loss</b>	<u>(7.7)</u>	<u>(3.3)</u>	<u>(4.4)</u>	<u>133.3 %</u>
<b>Administrative and other expenses (income):</b>				
Administration	17.6	17.6	—	NM
Interest expense, net	49.5	87.9	(38.4)	(43.7)%
Foreign exchange loss	17.7	19.1	(1.4)	(7.3)%
Other income, net	—	(3.9)	3.9	(100.0)%
	<u>84.8</u>	<u>120.7</u>	<u>(35.9)</u>	<u>(29.7)%</u>
<b>Loss from continuing operations before income taxes</b>	<u>(92.5)</u>	<u>(124.0)</u>	<u>31.5</u>	<u>(25.4)%</u>
<b>Income tax benefit</b>	<u>(38.5)</u>	<u>(14.2)</u>	<u>(24.3)</u>	<u>171.1 %</u>
<b>Net loss</b>	<u>(54.0)</u>	<u>(109.8)</u>	<u>55.8</u>	<u>NM</u>
<b>Net income attributable to Preferred share dividends of a subsidiary company</b>	<u>3.5</u>	<u>6.4</u>	<u>(2.9)</u>	<u>(45.3)%</u>
<b>Net loss attributable to Atlantic Power Corporation</b>	<u>\$ (57.5)</u>	<u>\$ (116.2)</u>	<u>\$ 58.7</u>	<u>NM</u>

The following tables provide our project income by segment:

	Nine months ended September 30, 2017				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
<b>Project revenue:</b>					
Energy sales	\$ 66.3	\$ 24.6	\$ 22.7	\$ —	\$ 113.6
Energy capacity revenue	38.8	38.9	8.0	—	85.7
Other	11.2	22.7	97.1	0.7	131.7
	<u>116.3</u>	<u>86.2</u>	<u>127.8</u>	<u>0.7</u>	<u>331.0</u>
<b>Project expenses:</b>					
Fuel	34.8	33.5	10.8	—	79.1
Operations and maintenance	25.2	18.9	19.5	(0.2)	63.4
Depreciation and amortization	26.9	22.7	40.6	0.3	90.5
	<u>86.9</u>	<u>75.1</u>	<u>70.9</u>	<u>0.1</u>	<u>233.0</u>
<b>Project other income (expense):</b>					
Change in fair value of derivative instruments	(3.3)	—	(5.4)	2.9	(5.8)
Equity in loss of unconsolidated affiliates	(35.9)	(0.2)	—	—	(36.1)
Interest expense, net	(6.6)	—	—	—	(6.6)
Impairment	—	(57.3)	—	—	(57.3)
Other income, net	—	—	0.1	—	0.1
	<u>(45.8)</u>	<u>(57.5)</u>	<u>(5.3)</u>	<u>2.9</u>	<u>(105.7)</u>
Project (loss) income	<u>\$ (16.4)</u>	<u>\$ (46.4)</u>	<u>\$ 51.6</u>	<u>\$ 3.5</u>	<u>\$ (7.7)</u>

	Nine months ended September 30, 2016				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
<b>Project revenue:</b>					
Energy sales	\$ 53.8	\$ 23.6	\$ 61.0	\$ —	\$ 138.4
Energy capacity revenue	39.8	38.9	34.5	—	113.2
Other	10.7	16.2	26.5	0.8	54.2
	<u>104.3</u>	<u>78.7</u>	<u>122.0</u>	<u>0.8</u>	<u>305.8</u>
<b>Project expenses:</b>					
Fuel	35.4	26.4	49.0	—	110.8
Operations and maintenance	33.2	18.5	26.6	1.1	79.4
Depreciation and amortization	25.5	21.9	27.8	0.4	75.6
	<u>94.1</u>	<u>66.8</u>	<u>103.4</u>	<u>1.5</u>	<u>265.8</u>
<b>Project other income (expense):</b>					
Change in fair value of derivative instruments	3.0	—	17.6	(0.6)	20.0
Equity in earnings of unconsolidated affiliates	26.0	1.9	—	—	27.9
Interest expense, net	(6.9)	—	—	—	(6.9)
Impairment	(15.4)	—	(69.3)	—	(84.7)
Other income, net	—	—	—	0.4	0.4
	<u>6.7</u>	<u>1.9</u>	<u>(51.7)</u>	<u>(0.2)</u>	<u>(43.3)</u>
Project income (loss)	<u>\$ 16.9</u>	<u>\$ 13.8</u>	<u>\$ (33.1)</u>	<u>\$ (0.9)</u>	<u>\$ (3.3)</u>

*East U.S.*

Project loss was \$16.4 million for the nine months ended September 30, 2017, a decrease of \$33.3 million from project income of \$16.9 million in the comparable 2016 period primarily due to:

- decreased project income of \$47.7 million and \$11.5 million at Chambers and Selkirk, respectively, primarily due to impairments of \$47.1 million and \$10.6 million recorded in the nine months ended September 30, 2017; and
- decreased project income of \$6.8 million at Orlando primarily due to a \$9.6 million decrease in the change in fair value of derivatives and a maintenance outage, partially offset by lower fuel expense resulting from

the settlement of favorable fuel swaps.

These decreases were partially offset by:

- increased project income of \$25.4 million at Curtis Palmer primarily due to a \$15.4 million goodwill impairment charge recorded in the nine months ended September 30, 2016 and \$10.0 million in increased revenues due to higher water flows than the comparable 2016 period.

#### *West U.S.*

Project loss was \$46.4 million for the nine months ended September 30, 2017, a decrease of \$60.2 million from project income of \$13.8 million in the comparable 2016 period primarily due to:

- decreased project income of \$19.3 million, \$17.8 million and \$11.9 million at Naval Station, North Island and NTC primarily due to \$22.5 million, \$21.2 million and \$13.5 million long-lived asset impairments recorded for the nine months ended September 30, 2017, respectively.

#### *Canada*

Project income of \$51.6 million for the nine months ended September 30, 2017, an increase of \$84.7 million from project loss of \$33.1 million in the comparable 2016 period primarily due to:

- increased project income of \$47.7 million at Mamquam primarily due to a \$50.2 million goodwill impairment charge recorded in the comparable period in 2016, offset by \$1.9 million decrease due to lower water flows and a forced maintenance outage that occurred in the second quarter of 2017;
- increased project income of \$16.7 million at North Bay due to \$9.0 million received from the OEFC settlement, \$17.2 million of lower fuel expense due to the expiration of a fuel purchase agreement in December 2016 and \$1.9 million of lower maintenance expense as a result of the plant not being operational due to its enhanced dispatch contract and \$10.3 million of long-lived asset and goodwill impairment recorded in the comparable 2016 period. This was partially offset by a negative \$10.3 million change in the fair value of a gas purchase agreement that expired in December 2016 and was accounted for as a derivative and \$5.3 million of accelerated depreciation in the nine months ended September 30, 2017;
- increased project income of \$14.9 million at Kapuskasing due to \$9.5 million received from the OEFC settlement, \$17.2 million of lower fuel expense due to the expiration of a fuel purchase agreement in December 2016, \$2.7 million of lower maintenance expense as a result of the plant not being operational due to its enhanced dispatch contract and \$8.9 million of long-lived asset and goodwill impairment recorded in the comparable 2016 period. This was partially offset by a negative \$10.3 million change in the fair value of gas purchase agreement that expired in December 2016 and was accounted for as a derivative and \$7.3 million of accelerated depreciation in the nine months ended September 30, 2017; and
- increased project income at Tunis due to \$6.7 million received from the OEFC settlement.

#### *Un-allocated Corporate*

Total project income for the nine months ended September 30, 2017 was \$3.5 million compared to a total project loss of \$0.9 million in the comparable 2016 period. The change was primarily due to a \$3.5 million increase in the fair value of interest swaps accounted for as derivatives.

#### ***Administrative and other expenses (income)***

Administrative and other expenses (income) include the income and expenses not attributable to any specific project and is allocated to the Un-allocated Corporate segment. These costs include the activities that support the executive and administrative offices, treasury function, costs of being a public registrant, costs to develop or acquire future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate taxes. Significant non-cash items that impact Administrative and other expenses (income), and that are subject to

potentially significant fluctuations include the non-cash impact of foreign exchange fluctuations from period to period on the U.S. dollar equivalent of our Canadian dollar-denominated obligations and the related deferred income tax expense (benefit) associated with these non-cash items.

#### *Administration*

Administration expense did not change materially from the 2016 comparable period.

#### *Interest expense, net*

Interest expense decreased \$38.4 million from the comparable 2016 period primarily due to the write-off of \$30.2 million of deferred financing costs related to the senior secured credit facilities and repurchase and cancellation of convertible debentures during the nine months ended September 30, 2016, as well as lower outstanding debt balances and a lower interest rate on the senior secured credit facilities at September 30, 2017.

#### *Foreign exchange loss*

Foreign exchange loss for the nine months ended September 30, 2017 decreased \$1.4 million from the comparable 2016 period primarily due to a \$2.8 million decrease in unrealized loss in the revaluation of instruments denominated in Canadian dollars. The repurchase and cancellation of Cdn\$152.1 million Canadian dollar-denominated convertible debentures during the nine months ended September 30, 2016 was the most significant factor in the decrease. The closing U.S. dollar to Canadian dollar exchange rates were 1.25 and 1.31 at September 30, 2017 and 2016, respectively, a decrease of 7.0% during the nine months ended September 30, 2017, as compared to a decrease of 5.2% in the comparable 2016 period. The average U.S. dollar to Canadian dollar exchange rates were 1.30 and 1.34 for the nine months ended September 30, 2017 and 2016, respectively.

#### *Other income, net*

Other income, net decreased \$3.9 million primarily due to a gain recorded on the purchase and cancellation of convertible debentures in the comparable 2016 period.

#### *Income tax expense*

Income tax benefit for the nine months ended September 30, 2017 was \$38.5 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was \$24.1 million. The primary items impacting the tax rate for the nine months ended September 30, 2017 were \$1.5 million related to a net increase to the Company's valuation allowances in Canada and \$0.6 million relating to income taxes. These items were offset by \$14.2 million relating to operating in higher tax rate jurisdictions and \$2.3 million relating to foreign exchange.

Income tax benefit for the nine months ended September 30, 2016 was \$14.2 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was \$32.2 million. The primary items impacting the tax rate for the nine months ended September 30, 2016 were \$22.5 million relating to goodwill impairment, \$5.5 million relating to foreign exchange and \$1.1 million of other permanent differences. In addition, the rate was further impacted by a net increase to the Company's valuation allowances of \$13.2 million, consisting primarily of increases of \$31.6 million in Canada related to losses and a decrease of \$18.4 million in the United States due to tax restructurings and additional earnings. These items were offset by \$18.5 million Canadian capital losses recognized on tax restructurings, \$3.0 million related to capital loss on intercompany notes and \$2.8 million relating to operating in higher tax rate jurisdictions.

## Project Operating Performance

Two of the primary metrics we utilize to measure the operating performance of our projects are generation and availability. Generation measures the net output of our proportionate project ownership percentage in megawatt hours (“MWh”). Availability is calculated by dividing the total scheduled hours of a project less forced outage hours by the total hours in the period measured. The terms of our PPAs require our projects to maintain certain levels of availability. The majority of our projects were able to achieve their respective capacity payments. For projects where reduced availability adversely impacted capacity payments, the impact was not material for the three and nine months ended September 30, 2017. The terms of our PPAs provide for certain levels of planned and unplanned outages. All references below are denominated in net Gigawatt-hours (“net GWh”).

(in Net GWh)	Generation		
	Three months ended September 30,		% change
Segment	2017	2016	2017 vs. 2016
East U.S.	662.7	557.0	19.0 %
West U.S.	534.6	522.9	2.2 %
Canada	239.7	443.7	(46.0)%
Total	1,437.0	1,523.6	(5.7)%

*Three months ended September 30, 2017 compared with three months ended September 30, 2016*

Aggregate power generation for the three months ended September 30, 2017 decreased 5.7% from the comparable 2016 period primarily due to:

- decreased generation in the Canada segment primarily due to a decrease of 217.8 net GWh on a combined basis at Kapuskasing, Nipigon and North Bay, due to their suspended operation status under the enhanced dispatch contracts.

These decreases were partially offset by:

- increased generation in the East U.S. segment primarily due to a 105.3 net GWh increase in generation at Morris due to a maintenance outage in the comparable period in 2016 and a 31.3 net GWh increase in generation at Curtis Palmer due to higher water flows than the comparable period in 2016.

(in Net GWh)	Generation		
	Nine months ended September 30,		% change
Segment	2017	2016	2017 vs. 2016
East U.S.	1,866.2	1,835.7	1.7 %
West U.S.	1,155.7	1,225.6	(5.7)%
Canada	698.2	1,488.5	(53.1)%
Total	3,720.1	4,549.8	(18.2)%

*Nine months ended September 30, 2017 compared with nine months ended September 30, 2016*

Aggregate power generation for the nine months ended September 30, 2017 decreased 18.2% from the comparable 2016 period primarily due to:

- decreased generation in the Canada segment primarily due to a decrease of 702.0 net GWh on a combined basis at Kapuskasing, Nipigon and North Bay, due to their suspended operation status under the enhanced dispatch contracts, and a 60.1 net GWh decrease in generation at Mamquam due to lower water flows and a maintenance outage in the three months ended September 30, 2017; and
- decreased generation in the West U.S. segment primarily due to a 101.5 net GWh decrease in generation at Frederickson due to lower merchant dispatch, offset by a 36.8 net GWh increase in generation at Manchief

due to higher dispatch than the comparable period in 2016.

These decreases were partially offset by:

- increased generation in the East U.S. segment primarily due to a 79.6 net GWh increase in generation at Curtis Palmer due to higher water flows than the comparable period in 2016 and a 51.7 net GWh increase in generation at Morris due to a maintenance outage in the comparable period in 2016.

Segment	Availability		
	Three months ended September 30,		
	2017	2016	% change 2017 vs. 2016
East U.S.	99.3 %	88.2 %	12.6 %
West U.S.	97.1 %	96.9 %	0.2 %
Canada	97.5 %	90.6 %	7.6 %
Weighted average	98.4 %	91.1 %	8.0 %

*Three months ended September 30, 2017 compared with three months ended September 30, 2016*

Aggregate power availability for the three months ended September 30, 2017 increased 8.0% from the comparable 2016 period primarily due to:

- increased availability in the East U.S. segment primarily due to a maintenance outage at Morris in the comparable period in 2016; and
- increased availability in the Canada segment primarily due to a maintenance outage at Mamquam in the comparable period in 2016.

Segment	Availability		
	Nine months ended September 30,		
	2017	2016	% change 2017 vs. 2016
East U.S.	94.3 %	93.3 %	1.1 %
West U.S.	90.5 %	92.4 %	(2.1)%
Canada	91.8 %	95.5 %	(3.9)%
Weighted average	92.9 %	93.5 %	(0.6)%

*Nine months ended September 30, 2017 compared with nine months ended September 30, 2016*

Aggregate power availability for the nine months ended September 30, 2017 decreased 0.6% from the comparable 2016 period primarily due to:

- decreased availability in the West U.S. segment primarily due to a maintenance outage at Frederickson; and
- decreased availability in the Canada segment primarily due to maintenance outages at Williams Lake and Mamquam.

These decreases were partially offset by:

- increased availability in the East U.S. segment primarily due to a longer planned maintenance outage in the comparable period in 2016 at Morris.

#### ***Supplementary Non-GAAP Financial Information***

The key measurement we use to evaluate the results of our business is Project Adjusted EBITDA. Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including

non-cash impairment charges) and changes in fair value of derivative instruments. 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. We believe that Project Adjusted EBITDA is a useful measure of financial results at our projects because it excludes non-cash impairment charges, gains or losses on the sale of assets and non-cash mark-to-market adjustments, all of which can affect year-to-year comparisons. Project Adjusted EBITDA is before corporate overhead expense. The most directly comparable GAAP measure to Project Adjusted EBITDA is Project income. A reconciliation of Net (loss) income to Project income and to Project Adjusted EBITDA is provided under “Project Adjusted EBITDA” below. Project Adjusted EBITDA for our equity investments in unconsolidated affiliates is presented on a proportionately consolidated basis in the table below.

## Project Adjusted EBITDA

	Three months ended			Nine months ended		
	September 30, 2017	September 30, 2016	\$ change 2017 vs 2016	September 30, 2017	September 30, 2016	\$ change 2017 vs 2016
<b>Net loss</b>	\$ (33.7)	\$ (80.3)	\$ 46.6	\$ (54.0)	\$ (109.8)	\$ 55.8
Income tax (benefit) expense	(15.9)	2.6	(18.5)	(38.5)	(14.2)	(24.3)
Loss from operations before income taxes	(49.6)	(77.7)	28.1	(92.5)	(124.0)	31.5
Administration	5.5	5.7	(0.2)	17.6	17.6	—
Interest expense, net	13.8	20.0	(6.2)	49.5	87.9	(38.4)
Foreign exchange loss (gain)	9.4	(3.4)	12.8	17.7	19.1	(1.4)
Other income, net	—	(1.7)	1.7	—	(3.9)	3.9
<b>Project loss</b>	\$ (20.9)	\$ (57.1)	\$ 36.2	\$ (7.7)	\$ (3.3)	\$ (4.4)
<b>Reconciliation to Project Adjusted EBITDA</b>						
Depreciation and amortization	36.6	30.4	6.2	105.6	90.8	14.8
Interest expense, net	2.5	2.8	(0.3)	8.0	8.2	(0.2)
Change in the fair value of derivative instruments	2.0	(9.0)	11.0	5.8	(20.1)	25.9
Other (income) expense	(0.1)	(0.5)	0.4	57.6	(0.4)	58.0
Impairment	57.3	84.7	(27.4)	57.3	84.7	(27.4)
<b>Project Adjusted EBITDA</b>	\$ 77.4	\$ 51.3	\$ 26.1	\$ 226.6	\$ 159.9	\$ 66.7
<b>Project Adjusted EBITDA by segment</b>						
East U.S.	30.6	19.4	11.2	86.8	70.5	16.3
West U.S.	21.7	21.3	0.4	41.5	43.4	(1.9)
Canada	24.6	10.7	13.9	97.3	46.2	51.1
Un-Allocated Corporate	0.5	(0.1)	0.6	1.0	(0.2)	1.2
<b>Total</b>	77.4	51.3	26.1	226.6	159.9	66.7

### East U.S.

The following table summarizes Project Adjusted EBITDA for our East U.S. segment for the periods indicated:

	Three months ended September 30,		
	2017	2016	% change 2017 vs. 2016
<b>East U.S.</b>			
Project Adjusted EBITDA	\$ 30.6	\$ 19.4	58 %

Three months ended September 30, 2017 compared with three months ended September 30, 2016

Project Adjusted EBITDA for the three months ended September 30, 2017 increased \$11.2 million from the comparable 2016 period primarily due to increased Project Adjusted EBITDA of:

- \$7.5 million at Morris due to decreased maintenance expense resulting from the overhaul of two gas turbines and one steam turbine in August 2016; and
- \$3.5 million at Curtis Palmer primarily due to higher water flows than the comparable 2016 period.

	<u>Nine months ended September 30,</u>		
	<u>2017</u>	<u>2016</u>	<u>% change 2017 vs. 2016</u>
<b>East U.S.</b>			
Project Adjusted EBITDA	\$ 86.8	\$ 70.5	23 %

*Nine months ended September 30, 2017 compared with nine months ended September 30, 2016*

Project Adjusted EBITDA for the nine months ended September 30, 2017 increased \$16.3 million from the comparable 2016 period primarily due to increased Project Adjusted EBITDA of:

- \$10.0 million at Curtis Palmer primarily due to higher water flows than the comparable 2016 period;
- \$2.8 million at Orlando primarily due to lower fuel expense resulting from the settlement of favorable fuel swaps;
- \$2.4 million at Morris primarily due to the overhaul of two gas turbines and one steam turbine in August 2016; and
- \$2.1 million at Piedmont primarily due to the replacement of a superheater that occurred in the comparable 2016 period.

*West U.S.*

The following table summarizes Project Adjusted EBITDA for our West U.S. segment for the periods indicated:

	<u>Three months ended September 30,</u>		
	<u>2017</u>	<u>2016</u>	<u>% change 2017 vs 2016</u>
<b>West U.S.</b>			
Project Adjusted EBITDA	\$ 21.7	\$ 21.3	2 %

*Three months ended September 30, 2017 compared with three months ended September 30, 2016*

Project Adjusted EBITDA for the three months ended September 30, 2017 increased \$0.4 million and did not change materially from the comparable 2016 period.

	<u>Nine months ended September 30,</u>		
	<u>2017</u>	<u>2016</u>	<u>% change 2017 vs 2016</u>
<b>West U.S.</b>			
Project Adjusted EBITDA	\$ 41.5	\$ 43.4	(4)%

*Nine months ended September 30, 2017 compared with nine months ended September 30, 2016*

Project Adjusted EBITDA for the nine months ended September 30, 2017 decreased \$1.9 million from the comparable 2016 period primarily due to decreased Project Adjusted EBITDA of:

- \$2.2 million at Frederickson primarily due to higher maintenance expense than the comparable 2016 period.

## Canada

The following table summarizes Project Adjusted EBITDA for our Canada segment for the periods indicated:

	<u>Three months ended September 30,</u>		
	<u>2017</u>	<u>2016</u>	<u>% change 2017 vs. 2016</u>
<b>Canada</b>			
Project Adjusted EBITDA	\$ 24.6	\$ 10.7	130 %

*Three months ended September 30, 2017 compared with three months ended September 30, 2016*

Project Adjusted EBITDA for the three months ended September 30, 2017 increased \$13.9 million from the comparable 2016 period primarily due to increased Project Adjusted EBITDA of:

- \$10.3 million at Kapuskasing and North Bay, primarily due to an \$11.8 million decrease in fuel expense, as a result of the expiration of fuel purchase agreements in December 2016 and their non-operational status under the terms of their enhanced dispatch contracts, partially offset by a \$2.1 million decrease in revenue;
- \$1.1 million at Mamquam primarily due to higher water flows than the comparable 2016 period; and
- \$1.0 million at Williams Lake primarily due to fewer maintenance projects and higher availability than the comparable 2016 period.

	<u>Nine months ended September 30,</u>		
	<u>2017</u>	<u>2016</u>	<u>% change 2017 vs. 2016</u>
<b>Canada</b>			
Project Adjusted EBITDA	\$ 97.3	\$ 46.2	111 %

*Nine months ended September 30, 2017 compared with nine months ended September 30, 2016*

Project Adjusted EBITDA for the nine months ended September 30, 2017 increased \$51.1 million from the comparable 2016 period primarily due to increased Project Adjusted EBITDA of:

- \$45.8 million at Kapuskasing and North Bay, primarily due to \$18.5 million received from the OEFC settlement, a \$22.9 million increase in gross margin and \$4.7 million decrease in maintenance expense resulting from the expiration of fuel purchase agreements in December 2016 and their non-operational status under the terms of their enhanced dispatch contracts; and
- \$6.6 million at Tunis primarily due to the collection of the OEFC settlement.

These increases were partially offset by a decrease in Project Adjusted EBITDA of:

- \$2.5 million at Mamquam primarily due to a maintenance outage that occurred during the nine months ended September 30, 2017, as well as to lower water flows than the comparable 2016 period; and
- \$2.1 million at Calstock primarily due to lower waste heat revenue and higher fuel prices than the comparable 2016 period.

### Un-allocated Corporate

The following table summarizes Project Adjusted EBITDA for our Un-allocated Corporate segment for the periods indicated:

	Three months ended September 30,		
	2017	2016	% change 2017 vs. 2016
<b>Un-allocated Corporate</b>			
Project Adjusted EBITDA	\$ 0.5	\$ (0.1)	NM

Three months ended September 30, 2017 compared with three months ended September 30, 2016

Project Adjusted EBITDA for the three months ended September 30, 2017 did not change materially from the comparable 2016 period.

	Nine months ended September 30,		
	2017	2016	% change 2017 vs. 2016
<b>Un-allocated Corporate</b>			
Project Adjusted EBITDA	\$ 1.0	\$ (0.2)	NM

Nine months ended September 30, 2017 compared with nine months ended September 30, 2016

Project Adjusted EBITDA for the nine months ended September 30, 2017 did not change materially from the comparable 2016 period.

### Liquidity and Capital Resources

	September 30, 2017	December 31, 2016
Cash and cash equivalents	\$ 122.4 <sup>(1)</sup>	\$ 85.6
Restricted cash	12.5 <sup>(1)</sup>	13.3
Total	134.9	98.9
Revolving credit facility availability	127.4 <sup>(1)</sup>	118.5
Total liquidity	\$ 262.3	\$ 217.4

<sup>(1)</sup> In October 2017, we utilized \$59.6 million of cash and \$4.5 million of restricted cash in order to pay off, in full, \$54.6 million of non-recourse debt, \$0.1 million of accrued interest and \$9.4 million of interest rate swap termination costs at our Piedmont project. Additionally, we reduced our outstanding letters of credit by \$11.7 million resulting in revolving credit facility availability of \$115.7 million.

### Overview

Our primary sources of liquidity are distributions from our projects and availability under our revolving credit facility. Our future liquidity depends in part on our ability to successfully enter into new PPAs at projects when PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from December 31, 2017 (at our North Bay and Kapuskasing projects) to December 2037. We are currently in negotiations with counterparties regarding the renewal or entry into new PPAs or we may elect to operate certain facilities in the merchant market upon expiration of their PPAs. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. As a result, this may reduce the cash received from project distributions and the cash available for further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, repurchase of common shares and other allocation of available cash. See “Risk Factors—Risks Related to Our Structure—We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing external growth opportunities or fund our operations” in our Annual Report on Form 10-K for the year ended December 31, 2016.

We expect to reinvest approximately \$39.7 million in our portfolio, including equity method investments, in the form of project capital expenditures and maintenance expenses in 2017, of which \$28.5 million has been incurred through September 30, 2017. Such investments are generally paid at the project level. See “—Capital and Major Maintenance Expenditures” in our Annual Report on Form 10-K for the year ended December 31, 2016. We do not expect any other material or unusual requirements for cash outflows for 2017 for capital expenditures or other required investments. We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due for at least the next 12 months.

### Consolidated Cash Flow Discussion

The following table reflects the changes in cash flows for the periods indicated:

	Nine months ended		
	September 30,		Change
	2017	2016	
Net cash provided by operating activities	\$ 137.9	\$ 91.9	\$ 46.0
Net cash (used in) provided by investing activities	(4.9)	0.8	(5.7)
Net cash used in financing activities	(96.2)	(71.3)	(24.9)

### Operating Activities

Cash flow from our projects may vary from period to period based on working capital requirements and the operating performance of the projects, as well as changes in prices under the PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, and the transition to merchant or re-contracted pricing following the expiration of PPAs. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

For the nine months ended September 30, 2017, the net increase in cash flows from operating activities of \$46.0 million was primarily the result of the following:

- *OEFC Settlement* – we received approximately \$25.6 million related to our settlement with the OEFC in the nine months ended September 30, 2017;
- *Impact of enhanced dispatch contracts and lower fuel costs in Ontario* – we recorded \$22.9 million of higher gross margin at North Bay, Kapuskasing and Nipigon as a result of the enhanced dispatch contracts in 2017, as well as the expiration of unfavorable gas purchase agreements in December 2016;
- *Operations and maintenance* – we incurred \$16.0 million of lower operations and maintenance costs, as a result of decreased maintenance expense at Morris and Williams Lake, which underwent outages in the comparable 2016 period, and at North Bay and Kapuskasing which did not operate during 2017 due to the terms of their enhanced dispatch contracts; and
- *Hydrological conditions at Curtis Palmer* – higher water flows at our Curtis Palmer project had a \$10.0 million impact on cash flows from operations.

These increases were partially offset by the following decreases to cash flows from operations:

- *Working capital* – changes in working capital resulted in a \$25.0 million decrease in cash flows from operating activities primarily due to \$11.7 million of timing in revenue receipts at our Oxnard and Morris projects, \$3.3 million of inventory buildup at our Manchief and Williams Lake projects in preparation for outages in 2018 and 2019, respectively, as well as other changes in timing of project and corporate receipts and payments;
- *Demand and fuel prices* – higher maintenance expense at Frederickson as well as higher fuel prices resulted in a \$2.2 million decrease in cash flows from operating activities from the comparable 2016 period;

- *Hydrological conditions and maintenance outage at Mamquam* – lower water flows and a forced outage at our Mamquam project had a \$2.5 million impact on cash flows from operations; and
- *Waste heat* – lower waste heat at our Calstock project had a \$2.2 million impact on cash flows from operations.

### ***Investing Activities***

For the nine months ended September 30, 2017, the net decrease in cash flows used in investing activities of \$5.7 million was primarily the result of the following:

- *Reimbursement of construction cost* – we received a reimbursement of \$4.7 million for the construction project at Morris in the comparable 2016 period; and
- *Restricted cash* – the change in restricted cash decreased \$1.8 million from the comparable 2016 period, primarily due to lower restricted cash requirements from decreased outstanding debt balances.

These decreases were partially offset by investments in capitalized plant additions that were \$0.8 million lower in the nine months ended September 30, 2017 as compared to the comparable 2016 period.

### ***Financing Activities***

For the nine months ended September 30, 2017, the net decrease in cash flows from financing activities of \$24.9 million was primarily the result of the following:

- *The Credit Facilities* – we received \$231.1 million of net proceeds from issuance of the senior secured term loan in the comparable 2016 period after repayment of the previous term loan;
- *Corporate and project-level debt repayments* – we made \$7.8 million of higher principal payments than the comparable 2016 period due to higher outstanding debt balances; and
- *Preferred share repurchases* – we paid \$3.1 million in the nine months ended September 30, 2017 to repurchase and cancel preferred shares.

These decreases were partially offset by the following increases to cash flows from financing activities:

- *Convertible debenture repayments* – we paid \$187.4 million to redeem and cancel convertible debentures in the comparable 2016 period;
- *Deferred financing costs* – we incurred \$16.2 million of deferred financing costs related to the refinancing of the senior secured credit facilities in the comparable 2016 period; and
- *Common share repurchases* – we paid \$0.2 million in the nine months ended September 30, 2017 to repurchase and cancel common shares as compared to \$13.9 million in the comparable 2016 period.

## Corporate Debt

The following table summarizes the maturities of our corporate debt at September 30, 2017:

	<b>Maturity Date</b>	<b>Interest Rates</b>	<b>Remaining Principal Repayments</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Thereafter</b>
Senior secured term loan facility <sup>(1)(2)</sup>	April 2023	5.40% - 5.70%	\$ 562.7	\$ 25.0	\$ 90.0	\$ 65.0	\$ 105.0	\$ 80.0	\$ 199.9
Atlantic Power Income LP Note	June 2036	5.95%	168.3	—	—	—	—	—	168.3
Convertible Debenture	June 2019	5.75%	42.5	—	—	42.5	—	—	—
Convertible Debenture	December 2019	6.00%	64.9	—	—	64.9	—	—	—
<b>Total Corporate Debt</b>			<b>\$ 838.4</b>	<b>\$ 25.0</b>	<b>\$ 90.0</b>	<b>\$ 172.4</b>	<b>\$ 105.0</b>	<b>\$ 80.0</b>	<b>\$ 368.2</b>

- (1) The senior secured term loans contain a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of Atlantic Power Limited Partnership Holdings (“APLP Holdings”) and its subsidiaries that remains after the application of funds, in accordance with a customary priority, to operations and maintenance expenses of APLP Holdings and its subsidiaries, debt service on the senior secured credit facilities and the Medium Term Notes, letters of credit costs to meet the requirements of the debt service reserve account, debt service on other permitted debt of APLP Holdings and its subsidiaries, capital expenditures permitted under the Credit Agreement, and payment on the preferred equity issued by APPEL, a subsidiary of APLP Holdings or (ii) such other amount up to 100% of the cash flow described in clause (i) above that is required to reduce the aggregate principal amount of senior secured term loans outstanding to achieve a target principal amount that declines quarterly based on a pre-determined specified schedule. Note that failing to meet the mandatory amortization requirements is not an event of default, but could result in APLP Holdings being unable to make distributions to Atlantic Power Corporation and APPEL being unable to pay dividends to its shareholders. The amortization profile in the table above is based on principal payments according to the targeted principal amount described in (ii) above.
- (2) In October 2017, the interest rate of the senior secured term loans was amended to LIBOR plus an applicable margin of 3.50%.

## Project-Level Debt

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue-generating contracts of the projects. The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at September 30, 2017. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project-level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. At November 7, 2017, all of our projects were in compliance with the covenants contained in project-level debt. Projects that do not meet their debt service coverage ratios are limited from making distributions, but are not callable or subject to acceleration under the terms of their debt agreements.

The range of interest rates presented represents the rates in effect at September 30, 2017. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

	<b>Maturity Date</b>	<b>Range of Interest Rates</b>	<b>Total Remaining Principal Repayments</b>	<b>2017</b>	<b>2018</b>	<b>2019</b>	<b>2020</b>	<b>2021</b>	<b>Thereafter</b>
<b>Consolidated Projects:</b>									
Epsilon Power Partners	January 2019	4.45 %	\$ 8.8	\$ 1.5	\$ 6.5	\$ 0.8	\$ —	\$ —	\$ —
Piedmont <sup>(1)</sup>	August 2018	8.20 %	54.6	1.2	53.4	—	—	—	—
Cadillac	August 2025	6.09 %	24.8	0.8	3.0	3.1	3.1	2.7	12.1
<b>Total Consolidated Projects</b>			<b>88.2</b>	<b>3.5</b>	<b>62.9</b>	<b>3.9</b>	<b>3.1</b>	<b>2.7</b>	<b>12.1</b>
<b>Equity Method Projects:</b>									
Chambers <sup>(2)</sup>	December 2019 and 2023	4.50 % - 5.00 %	42.9	—	—	5.2	7.8	8.8	21.1
<b>Total Equity Method Projects</b>			<b>42.9</b>	<b>—</b>	<b>—</b>	<b>5.2</b>	<b>7.8</b>	<b>8.8</b>	<b>21.1</b>
<b>Total Project-Level Debt</b>			<b>\$ 131.1</b>	<b>\$ 3.5</b>	<b>\$ 62.9</b>	<b>\$ 9.1</b>	<b>\$ 10.9</b>	<b>\$ 11.5</b>	<b>\$ 33.2</b>

- (1) In October 2017, Piedmont’s debt was repaid in full.

- (2) In June 2014, Chambers refinanced its project debt and issued (i) Series A (tax-exempt) Bonds due December 2023, of which our proportionate share is \$41.3 million and (ii) Series B (taxable) Bonds due December 2019, of which our proportionate share is \$1.6 million. The above table does not include our \$4.2 million proportionate share of issuance premiums.

### **Uses of Liquidity**

Our requirements for liquidity and capital resources, other than operating our projects, consist primarily of principal and interest on our outstanding convertible debentures, senior secured term loans, Medium Term Notes and other corporate and project-level debt, funding the repurchase of shares of our common stock, our convertible debentures, our preferred shares (to the extent we choose to pursue any such repurchases), collateral and investment in our projects through capital expenditures, including major maintenance and business development costs and dividend payments to preferred shareholders of a subsidiary company.

### ***Capital and Maintenance Expenditures***

Capital expenditures and maintenance expenses for the projects are generally paid at the project level using project cash flows and project reserves. Therefore, the distributions that we receive from the projects are made net of capital expenditures needed at the projects. The operating projects which we own consist of large capital assets that have established commercial operations. On-going capital expenditures for assets of this nature are generally not significant because most expenditures relate to planned repairs and maintenance and are expensed when incurred.

We expect to reinvest approximately \$5.4 million in 2017 (of which \$4.9 million was reinvested in the nine months ended September 30, 2017) in our portfolio, including equity method investments, in the form of project capital expenditures and incur \$34.3 million of maintenance expenses (of which \$23.6 million was incurred in the nine months ended September 30, 2017). Such investments are generally paid at the project level. See “—Capital and Major Maintenance Expenditures” in our Annual Report on Form 10-K for the year ended December 31, 2016. We do not expect any other material or unusual requirements for cash outflows for 2017 for capital expenditures or other required investments. We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due for at least the next 12 months.

We believe one of the benefits of our diverse fleet is that plant overhauls and other expenditures do not occur in the same year for each facility. Recognized industry guidelines and original equipment manufacturer recommendations provide a source of data to assess maintenance needs. In addition, we utilize predictive and risk-based analysis to refine our expectations, prioritize our spending and balance the funding requirements necessary for these expenditures over time. Future capital expenditures and maintenance expenses may exceed the projected level in 2017 as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

### **Recently Adopted and Recently Issued Accounting Guidance**

See Note 1 to the consolidated financial statements in this Quarterly Report on Form 10-Q.

### **Off-Balance Sheet Arrangements**

As of September 30, 2017, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

## **ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK**

Our exposure to financial market risk results primarily from fluctuations in interest and currency rates and fuel and electricity prices. There have been no material changes to our market risks as disclosed in our Annual Report on Form 10-K for the fiscal year ended December 31, 2016.

## **ITEM 4. CONTROLS AND PROCEDURES**

### *Evaluation of Disclosure Controls and Procedures*