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 March 31, 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 between November 2017 and 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), Naval Training Center (2019), North Island (2019), Calstock (2020) and Oxnard (2020). There are no PPA expirations in 2021. 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

OEFC Settlement

On April 27, 2017, we entered into a settlement agreement with the OEFC relating to a standstill agreement we entered into with the OEFC in April 2015, with respect to our North Bay, Kapuskasing and Tunis projects, arising out of our disagreement with the OEFC over the interpretation of the price escalator calculation in our PPAs. As a result of the settlement, the OEFC has agreed to pay us approximately Cdn$36.1 million, representing the application of the price escalator calculation under their respective PPAs for power sold to the OEFC beginning in April 2013 and through December 31, 2017.

Of the Cdn$36.1 million amount agreed upon in settlement, the OEFC previously paid Cdn$8.4 million for our North Bay and Kapuskasing plants representing the application of the price escalator calculation under their respective PPAs for power sold to the OEFC in 2016, as well as Cdn$2.3 million representing the application of the price escalator to the enhanced dispatch contracts at North Bay and Kapuskasing for the three months ended March 31, 2017. The total Cdn$10.7 million received through March 31, 2017 is recorded as deferred revenue on the consolidated balance sheets at March 31, 2017. This amount, as well as Cdn$20.3 million that was received in May 2017 pursuant to the settlement agreement, will be recorded as revenue in the three and six months ended June 30, 2017, the period when all contingencies have been resolved. The remaining Cdn$5.1 of the settlement relates to the application of the price escalator to the enhanced dispatch contracts at North Bay and Kapuskasing and will be recognized as revenue, when earned, through the expiration date of December 31, 2017.

Senior secured term loan facility repricing

On April 17, 2017, the repricing of the $615 million senior secured term loan and $200 million senior secured revolving credit facility became effective. As a result of the repricing, the interest rate margin on the term loan and revolver was reduced by 0.75% 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.

OUR POWER PROJECTS

The table below outlines our portfolio of power generating assets in operation as of May 2, 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)
East U.S. Segment								
Orlando[1]	Florida	Natural Gas	129	50.00 %	65	Progress Energy Florida	December, 2023	A–
Piedmont	Georgia	Biomass	55	100.00 %	55	Georgia Power	December, 2032	A–
Morris	Illinois	Natural Gas	177	100.00 %	120	Merchant	N/A	NR
					57	Equistar Chemicals, LP[2]	December, 2034	BBB+
Cadillac	Michigan	Biomass	40	100.00 %	40	Consumers Energy	December, 2028	BBB+
Chambers[1]	New Jersey	Coal	262	40.00 %	89	Atlantic City Electric[3]	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[4]	New York	Hydro	60	100.00 %	60	Niagara Mohawk Power Corporation	December, 2027	A–
Selkirk[1]	New York	Natural Gas	345	17.70 %	61	Merchant	N/A	NR
West U.S. Segment								
Naval Station	California	Natural Gas	47	100.00 %	47	San Diego Gas & Electric[5]	December, 2019	A
Naval Training Center	California	Natural Gas	25	100.00 %	25	San Diego Gas & Electric[5]	December, 2019	A
North Island	California	Natural Gas	40	100.00 %	40	San Diego Gas & Electric[5]	December, 2019	A
Oxnard	California	Natural Gas	49	100.00 %	49	Southern California Edison	May, 2020	BBB+
Manchief	Colorado	Natural Gas	300	100.00 %	300	Public Service Company of Colorado	April, 2022	A–
Frederickson[1]	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[1]	Washington	Hydro	13	49.80 %	6	Puget Sound Energy	December, 2037	BBB
Canada Segment								
Mamquam	British Columbia	Hydro	50	100.00 %	50	British Columbia Hydro and Power Authority	September, 2027	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 [6]	AA
Nipigon	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2022 [7]	AA
North Bay	Ontario	Natural Gas	40	100.00 %	40	Ontario Electricity Financial Corporation	December 2017 [6]	AA
Tunis	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	[8]	AA

(1) 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 March 31, 2017, the facility has generated 7,055 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 San Diego Gas & Electric expire on December 31, 2019. If we are unable to extend our land use license agreements through the end of our PPAs, we will not be able to operate these plants beyond February 8, 2018 and could be subject to potential liabilities under our PPAs. For a description of the status of these agreements and related renegotiations, see Item 1A. Risk Factors - *The expiration or termination of our PPAs could have a material adverse impact on our business, results of operation and financial condition* in our Annual Report on Form 10-K.

(6) 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.

(7) 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.

(8) 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 between November 2017 and 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 months ended March 31, 2017 and 2016, which are analyzed in greater detail below:

	Three months ended March 31,	
	2017	**2016**
Project revenue	$ 98.4	$ 106.4
Project income	$ 25.3	$ 28.7
Net loss attributable to Atlantic Power Corporation	$ (2.7)	$ (14.9)
Loss per share attributable to Atlantic Power Corporation—basic and diluted	$ (0.04)	$ (0.12)
Project Adjusted EBITDA[1]	$ 63.8	$ 62.5

(1) See reconciliation and definition in Supplementary Non-GAAP Financial Information.

Revenue decreased by $8.0 million from $106.4 million in the three months ended March 31, 2016 to $98.4 million in the three months ended March 31, 2017. The primary driver of the decrease is as follows:

- *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 \$1.9 million, \$1.7 million and \$2.3 million decreases in project revenue, respectively. Revenue recorded from the enhanced dispatch contracts is classified as other revenue on the consolidated statements of operations. Under the prior PPAs, revenue from these projects was recorded as energy and capacity revenue.

Consolidated project income decreased by \$3.4 million from \$28.7 million of project income in the three months ended March 31, 2016 to \$25.3 million of project income in the three months ended March 31, 2017. The primary drivers of the decrease are as follows:

- *Revenue* – revenue decreased \$8.0 million as discussed above; and

- *Depreciation expense* – depreciation expense increased \$4.7 million from the comparable 2016 period primarily due to a \$2.3 million and a \$1.8 million increase at our Kapuskasing and North Bay projects, respectively, as a result of accelerating depreciation through the December 31, 2017 termination date of their enhanced dispatch contracts. Prior to entering into the enhanced dispatch contracts, these projects were being depreciated through 2027, the estimated remaining useful lives determined on their acquisition date.

These decreases in project income were partially offset by an increase in project income resulting from:

- *Fuel expense* – fuel expense decreased \$10.0 million from the comparable 2016 period primarily due to the expiration of fuel contracts at North Bay and Kapuskasing on December 31, 2016. Natural gas purchased under those expired contracts in the comparable 2016 period were at prices well above market prices. These projects are also not in operation under the terms on 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 38.

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 March 31, 2017 compared to the three months ended March 31, 2016

The following table provides our consolidated results of operations:

	Three months ended March 31,			
	2017	2016	$ change	% change
Project revenue:				
Energy sales	$ 37.1	$ 52.5	$ (15.4)	(29.3)%
Energy capacity revenue	19.5	31.9	(12.4)	(38.9)%
Other	41.8	22.0	19.8	90.0 %
	98.4	106.4	(8.0)	(7.5)%
Project expenses:				
Fuel	28.9	38.9	(10.0)	(25.7)%
Operations and maintenance	20.4	21.2	(0.8)	(3.8)%
Depreciation and amortization	29.5	24.8	4.7	19.0 %
	78.8	84.9	(6.1)	(7.2)%
Project other expense:				
Change in fair value of derivative instruments	(1.2)	(1.2)	—	NM
Equity in earnings of unconsolidated affiliates	9.0	10.7	(1.7)	(15.9)%
Interest expense, net	(2.2)	(2.1)	(0.1)	NM
Other income, net	0.1	(0.2)	0.3	NM
	5.7	7.2	(1.5)	(20.8)%
Project income	25.3	28.7	(3.4)	(11.8)%
Administrative and other expenses:				
Administration	6.4	6.1	0.3	NM
Interest expense, net	17.3	16.6	0.7	NM
Foreign exchange loss	2.5	19.8	(17.3)	(87.4)%
Other income, net	—	(2.5)	2.5	NM
	26.2	40.0	(13.8)	(34.5)%
Loss from operations before income taxes	(0.9)	(11.3)	10.4	(92.0)%
Income tax (benefit) expense	(0.3)	1.6	(1.9)	NM
Net loss	(0.6)	(12.9)	12.3	NM
Net income attributable to Preferred share dividends of a subsidiary company	2.1	2.0	0.1	5.0 %
Net loss attributable to Atlantic Power Corporation	$ (2.7)	$ (14.9)	$ 12.2	NM

	Three months ended March 31, 2017				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 21.8	$ 8.5	$ 6.8	$ —	$ 37.1
Energy capacity revenue	10.1	6.7	2.7	—	19.5
Other	4.2	8.2	29.2	0.2	41.8
	36.1	23.4	38.7	0.2	98.4
Project expenses:					
Fuel	12.6	11.6	4.7	—	28.9
Operations and maintenance	7.5	6.1	6.6	0.2	20.4
Depreciation and amortization	8.8	7.3	13.2	0.2	29.5
	28.9	25.0	24.5	0.4	78.8
Project other income (expense):					
Change in fair value of derivative instruments	(0.2)	—	(3.3)	2.3	(1.2)
Equity in earnings of unconsolidated affiliates	8.1	0.9	—	—	9.0
Interest expense, net	(2.2)	—	—	—	(2.2)
Other expense, net	—	—	—	0.1	0.1
	5.7	0.9	(3.3)	2.4	5.7
Project income (loss)	$ 12.9	$ (0.7)	$ 10.9	$ 2.2	$ 25.3

	Three months ended March 31, 2016				
	East U.S.	West U.S.	Canada	Un-Allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 22.4	$ 6.5	$ 23.6	$ —	$ 52.5
Energy capacity revenue	11.8	6.6	13.5	—	31.9
Other	5.2	6.0	10.6	0.2	22.0
	39.4	19.1	47.7	0.2	106.4
Project expenses:					
Fuel	13.8	8.1	17.0	—	38.9
Operations and maintenance	8.1	6.9	5.8	0.4	21.2
Depreciation and amortization	8.5	7.3	8.9	0.1	24.8
	30.4	22.3	31.7	0.5	84.9
Project other income (expense):					
Change in fair value of derivative instruments	(0.7)	—	0.4	(0.9)	(1.2)
Equity in earnings of unconsolidated affiliates	9.9	0.8	—	—	10.7
Interest expense, net	(2.1)	—	—	—	(2.1)
Other expense, net	—	—	—	(0.2)	(0.2)
	7.1	0.8	0.4	(1.1)	7.2
Project income (loss)	$ 16.1	$ (2.4)	$ 16.4	$ (1.4)	$ 28.7

East U.S.

Project income for the three months ended March 31, 2017 decreased $3.2 million from the comparable 2016 period primarily due to:

- decreased project income of $3.6 million at Morris primarily due to higher fuel prices and lower PJM capacity revenue. Morris also recorded $1.0 million of revenue in the comparative 2016 period related to our management of a construction project;

- decreased project income of $1.5 million at Orlando primarily due to a $3.7 million decrease in the change in fair value of derivatives, offset by lower fuel expense resulting from the settlement of favorable fuel swaps position; and

- decreased project income of $0.8 million at Chambers primarily due to lower energy and steam revenue from mild weather.

These decreases were partially offset by:

- increased project income of $3.1 million at Piedmont primarily due to a $2.7 million increase in the change in fair value of interest rate swap agreements.

West U.S.

Project loss for the three months ended March 31, 2017 decreased $1.7 million from the comparable 2016 period primarily due to:

- increased project income of $1.0 million at Naval Station primarily due to a maintenance outage in the comparable 2016 period.

Canada

Project income for the three months ended Mach 31, 2017 decreased $5.5 million from the comparable 2016 period primarily due to:

- decreased project income of $1.9 million at Mamquam primarily due to a maintenance outage in March

2017; and

- decreased project income of $1.4 million at Calstock primarily due to lower waste heat revenue and higher fuel prices.

Un-allocated Corporate

Total project income for the three months ended March 31, 2017 was $2.2 million compared to a total project loss of $1.4 million in the comparable 2016 period primarily due to a $3.2 million increase in the fair value of fuel swaps and gas purchase agreements 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 increased $0.7 million from the comparable 2016 period primarily due to higher interest rates under the senior secured term loans entered into in April 2016, offset by the repurchase and cancellation of 6.25% and 5.60% convertible debentures in May 2016.

Foreign exchange loss

Foreign exchange loss for the three months ended March 31, 2017 decreased $17.3 million, or 87.4%, from the comparable 2016 period primarily due to $17.8 million decrease in unrealized gain in the revaluation of instruments denominated in Canadian dollars. The repurchase and cancellation of Cdn$152.1 million Canadian dollar-denominated convertible debentures was the most significant factor in the decrease. The closing U.S. dollar to Canadian dollar exchange rates were 1.33 and 1.30 at March 31, 2017 and 2016, respectively, a decrease of 0.9% as compared to a decrease of 6.2% in 2016. The average U.S. dollar to Canadian dollar exchange rates were 1.34 and 1.35 for the three months ended March 31, 2017 and 2016, respectively.

Other income, net

Other income, net increased $2.5 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 March 31, 2017 was $0.3 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $0.2 million. The primary item increasing the tax rate for the three months ended March 31, 2017 was $0.7 million related to net increase to the Company’s valuation allowances in Canada due to an increase in tax assets. This was offset by $0.4 million relating to foreign exchange, $0.3 million relating to operating in higher tax rate jurisdictions and $0.1 million of other permanent differences.

Income tax expense for the three months ended March 31, 2016 was $1.6 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $3.0 million. The primary items increasing the tax rate for the three months ended March 31, 2016 were $2.8 million relating to a change in valuation allowance, $2.5 million related to foreign exchange, $0.6 million relating to dividend withholding and other taxes and $0.2 million of other permanent differences. These items were partially offset by $1.1 million relating to operating in higher tax rate jurisdictions and $0.4 million related to capital loss on intercompany notes.

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 MW hours. 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 months ended March 31, 2017. The terms of our PPAs provide for certain levels of planned and unplanned outages. All references below are denominated in thousands of Net MWh.

	Generation		
	Three months ended March 31,		
(in thousands of Net MWh)	2017	2016	% change 2017 vs. 2016
Segment			
East U.S.	596.3	664.1	(10.2)%
West U.S.	350.6	342.6	2.3 %
Canada	211.7	543.8	(61.1)%
Total	1,158.6	1,550.5	(25.3)%

Three months ended March 31, 2017 compared with three months ended March 31, 2016

Aggregate power generation for the three months ended March 31, 2017 decreased 25.3% from the comparable 2016 period primarily due to:

- decreased generation in the Canada segment primarily due to a decrease of 268.2 net MWh on a combined basis at Kapuskasing, Nipigon and North Bay, primarily due to their suspended operation status under the enhanced dispatch contracts, and a 38.6 net MWh decrease in generation at Mamquam due to lower water flows in March 2017; and

- decreased generation in the East U.S. segment primarily due to a 33.2 net MWh decrease in generation at Morris due to lower merchant demand.

These decreases were partially offset by:

- increased generation in the West U.S. segment primarily due to a 10.3 net MWh increase in generation at Naval Station due to a maintenance outage in the comparable 2016 period.

	Availability		
	Three months ended March 31,		
	2017	2016	% change 2017 vs. 2016
Segment			
East U.S.	98.8 %	99.0 %	(0.2)%

West U.S.	94.7 %	89.6 %	5.7 %
Canada	91.4 %	99.5 %	(8.1)%
Weighted average	96.8 %	96.6 %	0.2 %

Three months ended March 31, 2017 compared with three months ended March 31, 2016

Aggregate power availability for the three months ended March 31, 2017 increased 0.2% from the comparable 2016 period primarily due to:

- increased availability in the West U.S. segment primarily due to a maintenance outage at Naval Station in the comparable 2016 period.

  This increase was partially offset by:

- decreased availability in the Canada segment primarily due to a maintenance outage at Mamquam.

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

	March 31,		$ change
	2017	2016	2017 vs 2016
Net loss	$ (0.6)	$ (12.9)	$ 12.3
Income tax (benefit) expense	(0.3)	1.6	(1.9)
Loss from operations before income taxes	(0.9)	(11.3)	10.4
Administration	6.4	6.1	0.3
Interest expense, net	17.3	16.6	0.7
Foreign exchange loss	2.5	19.8	(17.3)
Other income, net	—	(2.5)	2.5
Project income	$ 25.3	$ 28.7	$ (3.4)
Reconciliation to Project Adjusted EBITDA			
Depreciation and amortization	34.9	29.9	5.0
Interest expense, net	2.4	2.5	(0.1)
Change in the fair value of derivative instruments	1.2	1.2	—
Other expense	—	0.2	(0.2)
Project Adjusted EBITDA	$ 63.8	$ 62.5	$ 1.3
Project Adjusted EBITDA by segment			
East U.S.	27.2	30.3	(3.1)
West U.S.	9.1	7.5	1.6
Canada	27.5	24.8	2.7
Un-Allocated Corporate	0.0	(0.1)	0.1
Total	63.8	62.5	1.3

East U.S.

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

	Three months ended March 31,		
	2017	2016	% change 2017 vs. 2016
East U.S.			
Project Adjusted EBITDA	$ 27.2	$ 30.3	(10)%

Three months ended March 31, 2017 compared with three months ended March 31, 2016

Project Adjusted EBITDA for the three months ended March 31, 2017 decreased $3.1 million from the comparable 2016 period primarily due to decreased Project Adjusted EBITDA of:

- $4.6 million at Morris primarily due to higher fuel prices and lower PJM capacity revenue. Morris also recorded $1.0 million of revenue in the comparative 2016 period related to our management of a construction project.

This decrease was partially offset by an increase in Project Adjusted EBITDA of:

- $2.1 million at Orlando due to lower fuel expenses resulting from the settlement of favorable fuel swaps.

West U.S.

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

	Three months ended March 31,		
	2017	2016	% change 2017 vs 2016
West U.S.			
Project Adjusted EBITDA	$ 9.1	$ 7.5	21 %

Three months ended March 31, 2017 compared with three months ended March 31, 2016

Project Adjusted EBITDA for the three months ended March 31, 2017 increased $1.6 million from the comparable 2016 period primarily due to increased Project Adjusted EBITDA of:

- $1.0 million at Naval Station primarily due to a maintenance outage in the comparable 2016 period.

Canada

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

	Three months ended March 31,		
	2017	2016	% change 2017 vs. 2016
Canada			
Project Adjusted EBITDA	$ 27.5	$ 24.8	11 %

Three months ended March 31, 2017 compared with three months ended March 31, 2016

Project Adjusted EBITDA for the three months ended March 31, 2017 increased $2.7 million from the comparable 2016 period primarily due to increases in Project Adjusted EBITDA of:

- $3.7 million and $3.1 million at Kapuskasing and North Bay, respectively, primarily due to the terms of the enhanced dispatch contracts and the expiration of unfavorable fuel purchase agreements on December 31, 2016.

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

- $1.8 million at Mamquam primarily due to lower water flows; and
- $1.4 million at Calstock primarily due to lower waste heat revenue and expiration of a rate adder in April 2016.

Un-allocated Corporate

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

	Three months ended March 31,		
	2017	**2016**	**% change 2017 vs. 2016**
Un-allocated Corporate			
Project Adjusted EBITDA	$ 0.0	$ (0.1)	(100)%

Three months ended March 31, 2017 compared with three months ended March 31, 2016

Project Adjusted EBITDA for the three months ended March 31, 2017 did not change materially from the comparable 2016 period.

Liquidity and Capital Resources

	March 31, 2017	**December 31, 2016**
Cash and cash equivalents	$ 91.5	$ 85.6
Restricted cash	10.0	13.3
Total	101.5	98.9
Revolving credit facility availability	122.5	118.5
Total liquidity	$ 224.0	$ 217.4

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 power purchase agreements 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 $50.6 million in our portfolio, including equity method investments, in the form of project capital expenditures and maintenance expenses in 2017, of which $6.7 million has been incurred through March 31, 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:

	Three months ended March 31, 2017	Three months ended March 31, 2016	Change
Net cash provided by operating activities	$ 34.1	$ 29.4	$ 4.7
Net cash provided by investing activities	1.3	9.2	(7.9)
Net cash used in financing activities	(29.5)	(46.7)	17.2

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 three months ended March 31, 2017, the net increase in cash flows from operating activities of $4.7 million was primarily the result of the following:

- *Increase in deferred revenue* – deferred revenue increased $7.9 million primarily due to cash payments received from the OEFC relating to the price escalator calculation under the respective PPAs for power sold to the OEFC in 2016, as well as the application of the price escalator to the enhanced dispatch contracts at North Bay and Kapuskasing for the three months ended March 31, 2017; and

- *Impact of enhanced dispatch contracts and lower fuel costs in Ontario* – we recorded $6.6 million of higher gross margin at North Bay, Kapuskasing and Nipigon as a result of the enhanced dispatch contracts and the expiration of unfavorable gas purchase agreements at North Bay and Kapuskasing.

These increases were partially offset by a decrease in net cash provided by operating activities primarily resulting from the following:

- *Morris* – a $4.6 million impact resulting from higher fuel prices, lower capacity prices in PJM and $1.0 million of revenue recorded in the comparative 2016 period related to our management of a construction project;

- *Interest payments* – we made $2.9 million of higher interest payments in the three months ended March 31, 2017 than the comparable 2016 period due to higher outstanding balances under the senior secured term loan facility and higher interest rates; and

- *Hydrological conditions* – lower water flows at our Mamquam project had a $1.8 million impact on cash flows from operations.

Investing Activities

For the three months ended March 31, 2017, the net decrease in cash flows provided by investing activities of $7.9 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;

- *Restricted cash* – the change in restricted cash decreased $1.9 million from the comparable 2016 period, primarily due to lower restricted cash requirements from decreased outstanding debt balances;

- *Purchase of property, plant and equipment* – we made investments of $1.4 million of capitalized plant additions, primarily at Morris, in the three months ended March 31, 2017 as compared to $0.7 million in the comparable 2016 period.

Financing Activities

For the three months ended March 31, 2017, the net decrease in cash flows used in financing activities of $17.2 million was primarily the result of the following:

- *Convertible debenture repayments* – we redeemed and cancelled $16.3 million of our convertible debentures in the comparable 2016 period; and

- *Common share repurchases* – we purchased and cancelled 0.6 million common shares at a cost of $0.9 million in the comparable 2016 period.

Corporate Debt

The following table summarizes the maturities of our corporate debt at March 31, 2017:

	Maturity Date	Interest Rates	Remaining Principal Repayments	2017	2018	2019	2020	2021	Thereafter
Senior secured term loan facility[1]	April 2023	6.00% - 6.12% [2]	$ 614.9	$ 75.0	$ 90.0	$ 65.0	$ 105.0	$ 80.0	$ 199.9
Atlantic Power Income LP Note	June 2036	5.95%	157.9	—	—	—	—	—	157.9
Convertible Debenture	June 2019	5.75%	42.5	—	—	42.5	—	—	—
Convertible Debenture	December 2019	6.00%	60.9	—	—	60.9	—	—	—
Total Corporate Debt			$ 876.2	$ 75.0	$ 90.0	$ 168.4	$ 105.0	$ 80.0	$ 357.8

(1) The senior secured term loans contain a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of APLP Holdings Limited Partnership ("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 Atlantic Power Preferred Equity Ltd., 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 Atlantic Power Preferred Equity Limited 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 April 2017, the interest rate of the senior secured term loans was amended to LIBOR plus an applicable margin of 4.25%.

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 March 31, 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 May 2, 2017, all of our projects with the exception of Piedmont 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. We do not expect our Piedmont project to meet its debt service coverage ratio covenants or to make distributions before the project's debt maturity in 2018 at the earliest. See Note 6 to the consolidated financial statements of this Quarterly Report on Form 10-Q, *Long-term debt—Non-Recourse Debt*.

The range of interest rates presented represents the rates in effect at March 31, 2017. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

	Maturity Date	**Range of Interest Rates**	**Total Remaining Principal Repayments**	**2017**	**2018**	**2019**	**2020**	**2021**	**Thereafter**
Consolidated Projects:									
Epsilon Power Partners	January 2019	4.20 %	$ 11.9	$ 4.7	$ 6.5	$ 0.7	$ —	$ —	$ —
Piedmont	August 2018	8.22 %	56.6	2.5	54.1	—	—	—	—
Cadillac	August 2025	6.10 %	26.3	2.3	3.0	3.1	3.1	2.7	12.1
Total Consolidated Projects			94.8	9.5	63.6	3.8	3.1	2.7	12.1
Equity Method Projects:									
Chambers[(1)]	December 2019 and 2023	4.50 % - 5.00 %	42.9	—	—	5.2	7.8	8.8	21.1
Total Equity Method Projects			42.9	—	—	5.2	7.8	8.8	21.1
Total Project-Level Debt			$ 137.7	$ 9.5	$ 63.6	$ 9.0	$ 10.9	$ 11.5	$ 33.2

(1) 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 $5.6 million in 2017 (of which $1.4 million was reinvested in the three months ended March 31, 2017) in our portfolio in the form of project capital expenditures and incur $45.0 million of maintenance expenses (of which $5.3 million was incurred in the three months ended March 31, 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 March 31, 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

Our Chief Executive Officer and Chief Financial Officer have evaluated our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d- 15(e) of the Securities Exchange Act of 1934, as amended, as of the end of the period covered by this report, and they have concluded that these controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have been no changes in internal control over financial reporting during the three months ended March 31, 2017, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations of Disclosure Controls and Internal Control over Financial Reporting

Because of their inherent limitations, our disclosure controls and procedures and our internal control over financial reporting may not prevent material errors or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to risks, including that the control may become inadequate because of changes in conditions or that the degree of compliance with our policies or procedures may deteriorate.