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

The following management's discussion and analysis of financial condition and results of operations should be read in conjunction with the interim condensed 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, unless otherwise stated. The interim financial statements have been prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") and in accordance with the instructions to Form 10-Q related to smaller reporting companies as promulgated by the SEC. This Item 2 was prepared without regards to potential effects of the Transaction, except where stated otherwise.

OVERVIEW

Atlantic Power is an independent power producer that owns power generation assets in eleven states in the United States and two provinces in Canada. Our power generation projects, which are diversified by geography, fuel type, dispatch profile and offtaker, sell electricity to utilities and other large customers predominantly under long-term PPAs, which seek to minimize exposure to changes in commodity prices. As of March 31, 2021, our portfolio consisted of twenty-one operating projects with an aggregate electric generating capacity of approximately 1,723 megawatts ("MW") on a gross ownership basis and approximately 1,327 MW on a net ownership basis. Sixteen of the projects are majority-owned by the Company.

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 September 2021 (Kenilworth) to November 2043 (Allendale). 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.

We directly operate and maintain sixteen of our operating 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.

Available Information

Access to our Quarterly Reports on Form 10-Q, Annual Reports on Form 10-K, Current Reports on Form 8-K, and amendments to these reports filed with or furnished to the Securities and Exchange Commission ("SEC") pursuant to Section 13(a) or 15(d) of the Exchange Act may be obtained free of charge through the Investors section of our website at https://investors.atlanticpower.com/corporate-profile as soon as is reasonably practical after we electronically file or furnish these reports. In addition, our filings with the SEC may be accessed through the SEC's website at www.sec.gov and our filings with the Canadian Securities Administrators ("CSA") may be accessed through the CSA's System for Electronic Document Analysis and Retrieval ("SEDAR") at www.sedar.com. Except for the documents specifically incorporated by reference into this Form 10-Q, information contained on our website or the SEC or CSA websites is not incorporated by reference in the Form 10-Q and should not be considered to be a part of the Form 10-Q. We have included our website address and that of the SEC and CSA only as inactive textual references and do not intend them to be active links to such websites. All statements made in any of our securities filings, including all forward-looking statements or information, are made as of the date of the document in which the statement is included, and we do not assume or undertake any obligation to update any of those statements or documents unless we are required to do so by applicable law. We are not a foreign private issuer, as defined in Rule 3b-4 under the Exchange Act.

RECENT DEVELOPMENTS

Proposed Transaction with I Squared Capital

On January 14, 2021, Atlantic Power announced that it had entered into a definitive agreement (as amended on April 1, 2021 and April 29, 2021, and as may be further amended from time to time, the "Arrangement Agreement") with certain affiliates of infrastructure funds managed by I Squared Capital Advisors (US) LLC ("I Squared Capital"), a leading global infrastructure investor (the "Purchasers"), under which the Company's outstanding common shares and 6.00% Series E convertible unsecured subordinated debentures due January 31, 2025 ("Convertible Debentures"), and the outstanding preferred shares and medium term notes of certain of its subsidiaries, would be acquired (the "Transaction"). The total enterprise value of the deal is approximately $961 million and the Transaction was unanimously approved by Atlantic Power's board of directors. The parties are currently targeting May 14, 2021 as the closing date for the Transaction.

In connection with the Transaction, and subject to and conditional to the closing of the Transaction:

- Holders of common shares of Atlantic Power will receive $3.03 per common share in cash.
- Atlantic Power Preferred Equity Ltd.'s ("APPEL's") cumulative redeemable preferred shares, Series 1, cumulative rate reset preferred shares, Series 2, and cumulative floating rate preferred shares, Series 3, will be purchased by APPEL for Cdn$22.00 per preferred share in cash.
- Atlantic Power Limited Partnership's ("APLP's") 5.95% medium term notes due June 23, 2036 (the "MTNs") will be redeemed for consideration equal to 106.071% of the principal amount of MTNs held as of the closing of the Transaction, plus accrued and unpaid interest on the MTNs up to, but excluding, the closing date of the Transaction. Holders of MTNs that have delivered a valid consent to the proposed amendments to the trust indenture governing the MTNs (as described below) prior to 5:00 p.m. (Toronto time) on March 16, 2021 will also entitled to a consent fee equal to 0.25% of the principal amount of MTNs held by such holders in respect of which a consent was delivered, conditional on closing of the Transaction.
- Holders of Atlantic Power's Convertible Debentures who deliver a conversion notice prior to 4:00 p.m. (Toronto time) on May 11, 2021 (the "Conversion Deadline") will receive $3.03 per common share issuable on conversion of the Convertible Debentures in respect of which such conversion notice has been delivered (including common shares issuable on account of the Make Whole Premium (as defined in the Arrangement Agreement), plus accrued and unpaid interest up to, but excluding, the date of conversion, and all other Convertible Debentures will be defeased in accordance with the terms of the trust indenture governing the Convertible Debentures (the "Debenture Indenture") (as described below)

The Arrangement Agreement was amended on April 1, 2021 to provide for certain administrative and housekeeping amendments to the Arrangement Agreement and to, among other things, clarify the mechanics surrounding the payment of consideration payable pursuant to the Transaction. The amendments also added a step to the Arrangement to, among other things, provide for the creation of a class of non-voting preferred shares in connection with the Pre-Acquisition Reorganization (as defined in the Arrangement Agreement). The creation and issuance of any such shares will not occur until immediately prior to the effective time of the Arrangement and will only occur if the Purchasers have irrevocably waived or confirmed in writing the satisfaction of all conditions to closing in their favor and shall have confirmed in writing that they are prepared, and able, to promptly and without condition proceed to effect the Arrangement (as defined in the Arrangement Agreement).

The Arrangement Agreement was further amended on April 29, 2021 to provide for mutual covenants in connection with the proposed defeasance of the Convertible Debentures (the "Defeasance"), clarify the mechanics surrounding the payment of the amounts required to effect the Defeasance, and effect a waiver of certain conditions precedent in the Arrangement Agreement relating to the approval of the Transaction by holders of the Convertible Debentures. Notwithstanding the Defeasance, any holder of Convertible Debentures who converts their Convertible Debentures during the period beginning 10 trading days (as defined in the Debenture Indenture) prior to the closing of the Transaction ("Closing") and ending 30 calendar days following the delivery of the change of control notice under the Indenture (the "Make Whole Conversion Period") will be entitled to receive the Make Whole Premium. Assuming that the Closing occurs on May 14, 2021 and the change of control notice is delivered on Closing as is currently anticipated, the Make Whole Conversion Period opened on April 30, 2021 and will close on June 14, 2021.

In connection with the Defeasance, and if Closing occurs (i) Atlantic Power expects to de-list its Convertible Debentures from the TSX and its common shares from the TSX and the NYSE; (ii) Atlantic Power intends to apply to Canadian securities regulators to cease being a reporting issuer, or to be exempt from its reporting obligations as a Canadian reporting issuer, and also intends to file to deregister under the U.S. Securities Exchange Act of 1934; (iii) the Convertible Debentures will no longer be convertible into common shares and, if converted after the Conversion Deadline, holders will be entitled to receive a cash amount equal to Cdn$3.72 in lieu of each Common Share previously issuable on a conversion (including any common shares otherwise issuable on account of the Make Whole Premium if converted within the Make Whole Conversion Period), plus accrued and unpaid interest paid in Canadian dollars up to, but excluding, the date of conversion; and (iv) except as otherwise provided in the Debenture Indenture, any Convertible Debentures which remain outstanding following the expiry of the Make Whole Conversion Period will continue to receive interest at a rate of 6.00% per annum, payable semi-annually in arrears until, and the repayment of principal upon, the redemption of the Convertible Debentures. Following the Defeasance, the Convertible Debentures will be redeemed at par on January 31, 2023.

The Transaction has received approval from the holders of common shares of the Company and the holders of preferred shares and medium term notes of certain of the Company's subsidiaries. The Transaction also has received certain required regulatory approvals, including an advance ruling certificate from the Canadian Commissioner of Competition under the Competition Act (Canada) on February 5, 2021, the expiration of the required waiting period under the Hart-Scott-Rodino Antitrust Improvements Act of 1976 on March 9, 2021, the approval of the Federal Energy Regulatory Commission on April 2, 2021 and the approval in April 2021 from the Federal Communications Commission ("FCC") for the transfer of control of certain FCC licenses held by the Company or its subsidiaries.

The Transaction remains subject to the satisfaction or waiver of certain third-party consents, and other customary closing conditions.

Oxnard PPA Agreement

On March 31, 2021, we executed an agreement to sell Resource Adequacy (RA) capacity from the Oxnard plant effective January 1, 2022 through December 31, 2023. Capacity provided under the agreement will be used to satisfy the load obligations of a community choice aggregator. Under the RA agreement, Oxnard will receive a fixed monthly capacity payment. The RA agreement also provides the opportunity for the plant to receive revenue from the potential sale of energy and ancillary services as well as other non-capacity revenues.

Sale of North Bay and Kapuskasing

Our North Bay and Kapuskasing projects are each 40 MW natural gas plants located in the Province of Ontario. These plants are currently being maintained, but do not operate because they do not have PPAs or a merchant market where operations would be profitable. On February 23, 2021, we entered into an agreement with SNS Power Corp. to sell our properties in the City of North Bay, the District of Nipissing and in Kapuskasing, Ontario for Cdn$3.0 million in cash. We determined the North Bay and Kapuskasing asset groups met the criteria for held for sale accounting as of March 31, 2021. See Note 2 – *Assets and Liabilities Held for Sale*. We currently expect the sale of the plants to be completed in the second quarter of 2021 subject to customary due diligence procedures.

OUR POWER PROJECTS

The table below outlines our portfolio of power generating assets in operation as of May 6, 2021, 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 rating 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)
Solid Fuel Segment								
Allendale	South Carolina	Biomass	20	100.00 %	20	South Carolina Public Service Authority	November 2043	A [1]
Cadillac	Michigan	Biomass	40	100.00 %	40	Consumers Energy	June 2028	A-
Calstock	Ontario	Biomass	35	100.00 %	35	Ontario Electricity Financial Corporation	December 2021 [2]	AA- [1]
Chambers[3]	New Jersey	Coal	262	40.00 %	89	Atlantic City Electric [4]	March 2024	A-
					16	Chemours Co.	March 2024	B+
Craven[3]	North Carolina	Biomass	48	50.00 %	24	Duke Energy Carolinas, LLC	December 2027	BBB+
Dorchester	South Carolina	Biomass	20	100.00 %	20	South Carolina Public Service Authority	October 2043	A [1]
Grayling[3]	Michigan	Biomass	37	30.00 %	11	Consumers Energy	December 2027	A-
Piedmont	Georgia	Biomass	55	100.00 %	55	Georgia Power	September 2032	A-
Williams Lake	British Columbia	Biomass	66	100.00 %	66	BC Hydro	September 2029	AAA [1]
Natural Gas Segment								
Frederickson[3]	Washington	Natural Gas	250	50.15 %	50	Benton Co. PUD	August 2022	AA- [1]
					45	Grays Harbor PUD	August 2022	A+ [1]
					30	Franklin Co. PUD	August 2022	A+ [1]
Kenilworth	New Jersey	Natural Gas	29	100.00 %	29	Merck & Co., Inc.	September 2021	AA-
						Merchant	N/A	NR
Manchief [5]	Colorado	Natural Gas	300	100.00 %	300	Public Service Company of Colorado	April 2022	A-
Morris [6]	Illinois	Natural Gas	177	100.00 %	100	Merchant	N/A	NR
					77	Equistar Chemicals, LP [7]	December 2034	BBB- [8]
Nipigon	Ontario	Natural Gas	40	100.00 %	40	Independent Electricity System Operator	December 2022	AA- [1]
Orlando[3]	Florida	Natural Gas	129	50.00 %	65	Duke Energy Florida, LLC	December 2023	BBB+
Oxnard	California	Natural Gas	49	100.00 %	49	California Independent System Operator	December 2023 [9]	A+
Tunis	Ontario	Natural Gas	37	100.00 %	37	Independent Electricity System Operator	October 2033	AA- [1]
Hydroelectric Segment								
Curtis Palmer	New York	Hydro	60	100.00 %	60	Niagara Mohawk Power Corporation	December 2027 [10]	BBB+
Koma Kulshan	Washington	Hydro	13	100.00 %	13	Puget Sound Energy	March 2037	BBB
Mamquam[11]	British Columbia	Hydro	50	100.00 %	50	BC Hydro	September 2027	AAA [1]
Moresby Lake	British Columbia	Hydro	6	100.00 %	6	BC Hydro	August 2022	AAA [1]

(1) Customer is rated by Moody's but not S&P; therefore, the rating shown in the table is the S&P rating that corresponds to the actual Moody's rating.

(2) In May 2020, the PPA with the Ontario Electricity Financial Corporation for Calstock, which had been scheduled to expire in June 2020, was extended to December 16, 2020 under existing terms. In December 2020, the Calstock PPA was extended for one year, also under existing terms, and runs to December 16, 2021.

(3) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated

affiliates.

(4) 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.

(5) In May 2019, we entered into an agreement to sell Manchief to PSCo following the expiration of the PPA in April 2022 for $45.2 million subject to working capital and other customary adjustments.

(6) Equistar has an option to purchase Morris that is exercisable in December 2027.

(7) Equistar has the right under the PPA to take up to 77 MW, but on average has taken approximately 50 MW.

(8) Represents the credit rating of LyondellBasell, the parent company of Equistar, as Equistar is not rated.

(9) On August 28, 2020, we executed an agreement to sell RA capacity from the Oxnard plant effective January 1, 2021 through to December 31, 2021. On March 31, 2021, we executed a new agreement to sell capacity from the Oxnard plant for an additional two years, effective January 1, 2022 through December 31, 2023.

(10) 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, 2021, the facility has generated 8,420 GWh under its PPA. Based on cumulative generation to date and assuming average water conditions going forward, we expect the PPA to expire in the first quarter of 2026.

(11) BC Hydro has an option to purchase Mamquam that is exercisable in November 2021 and every five-year anniversary thereafter.

Non-operating Natural Gas Plants

In August 2018, we terminated discussions with the Navy regarding site control for our Naval Station, Naval Training Center (“NTC”) and North Island projects located in San Diego, California. We are in the process of decommissioning all three sites, which is a requirement of our land use agreements with the Navy. We anticipate decommissioning will be completed in the second quarter of 2021.

Our Kapuskasing and North Bay projects are both 40 MW natural gas plants located in the Province of Ontario. These plants are currently being maintained, but do not operate because they do not have PPAs or a merchant market where operations would be profitable. On February 23, 2021, we entered into an agreement with SNS Power Corp. to sell our properties in City of North Bay, District of Nipissing and in Kapuskasing, Ontario for Cdn$3.0 million in cash. We determined the North Bay and Kapuskasing asset groups met the criteria for held for sale accounting as of March 31, 2021. See Note 2 – *Assets and Liabilities Held for Sale*. We currently expect the sale of the plants to be completed in the second quarter of 2021 subject to customary due diligence procedures.

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, 2021 and 2020, which are analyzed in greater detail below:

(in millions of U.S. dollars, except as otherwise stated)	**Three months ended March 31, 2021**	**2020**
Project revenue	$ 72.0	$ 72.8
Project income	32.4	24.7
Net (loss) income attributable to Atlantic Power Corporation	(0.1)	29.5
Net cash provided by operating activities	8.4	8.4
Net cash provided by (used in) investing activities	0.2	(2.6)
Net cash used in financing activities	(26.0)	(40.1)
(Loss) earnings per share attributable to Atlantic Power Corporation—basic	(0.00)	0.28
(Loss) earnings per share attributable to Atlantic Power Corporation—diluted	(0.00)	0.23
Project Adjusted EBITDA[1]	48.2	50.8

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

Project revenue decreased by $0.8 million to $72.0 million in the three months ended March 31, 2021 from $72.8 million in the three months ended March 31, 2020. The primary drivers of the decrease are as follows:

- *Curtis Palmer* – lower water flows resulted in a $5.5 million decrease in revenue; and
- *Dorchester* –a maintenance outage in March 2021 resulted in a $0.7 million decrease in revenue.

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

- *Cadillac* – the project ceased operation after the fire at the project in September 2019. The project resumed operations on August 20, 2020 resulting in a $2.9 million increase in energy and capacity revenue in the current period;
- *Morris* – a $1.4 million increase in project revenue due to higher fuel prices than in 2020; and
- *Williams Lake* – a $0.9 million increase in revenue primarily due to increased generation and the impact of foreign currency translation adjustments.

Consolidated project income increased by $7.7 million to $32.4 million in the three months ended March 31, 2021 from $24.7 million in the three months ended March 31, 2020. The primary drivers of the increase are as follows:

- *Derivative instruments* – the change in the fair value of our derivative instruments increased $8.8 million from the comparable 2020 period.

The increase in project income was partially offset by a decrease in project income resulting from:

- *Project revenue* – project revenue decreased $0.8 million as discussed above.

A detailed discussion of project income by segment is provided in Consolidated Overview and Results of Operations below. The discussion of Project Adjusted EBITDA by segment begins on page 45.

We have four reportable segments: Solid Fuel, Natural Gas, Hydroelectric and Corporate. Project income is the primary GAAP measure of our operating results and is discussed below by reportable segment.

Three months ended March 31, 2021 compared to the three months ended March 31, 2020

The following table provides our consolidated results of operations:

	Three months ended March 31,			
	2021	2020	$ change	% change
Project revenue:				
Energy sales	$ 36.0	$ 40.7	$ (4.7)	(11.5)%
Energy capacity revenue	29.8	28.0	1.8	6.4 %
Other	6.2	4.1	2.1	51.2 %
	72.0	72.8	(0.8)	(1.1)%
Project expenses:				
Fuel	20.7	19.6	1.1	5.6 %
Operations and maintenance	21.1	20.7	0.4	1.9 %
Depreciation and amortization	14.3	15.6	(1.3)	(8.3)%
	56.1	55.9	0.2	0.4 %
Project other income (expense):				
Change in fair value of derivative instruments	3.2	(5.6)	8.8	NM
Equity in earnings of unconsolidated affiliates	13.4	13.7	(0.3)	(2.2)%
Interest expense, net	(0.3)	(0.3)	—	—
Other income, net	0.2	—	0.2	NM
	16.5	7.8	8.7	NM
Project income	32.4	24.7	7.7	31.2 %
Administrative and other expenses:				
Administration	14.1	6.7	7.4	NM
Interest expense, net	11.4	10.8	0.6	5.6 %
Foreign exchange loss (gain)	3.2	(20.6)	23.8	NM
Other (income) expense, net	(0.1)	2.6	(2.7)	NM
	28.6	(0.5)	29.1	NM
Income from operations before income taxes	3.8	25.2	(21.4)	(84.9)%
Income tax expense	2.2	1.5	0.7	46.7 %
Net income	1.6	23.7	(22.1)	(93.2)%
Net income (loss) attributable to preferred shares of a subsidiary company	1.7	(5.8)	7.5	NM
Net (loss) income attributable to Atlantic Power Corporation	$ (0.1)	$ 29.5	$ (29.6)	NM

(1) NM is defined as “not meaningful” and includes changes greater than 100%

	Three months ended March 31, 2021				
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 18.2	$ 5.6	$ 12.2	$ —	$ 36.0
Energy capacity revenue	8.1	21.7	—	—	29.8
Other	0.6	4.4	0.9	0.3	6.2
	26.9	31.7	13.1	0.3	72.0
Project expenses:					
Fuel	12.0	8.7	—	—	20.7
Operations and maintenance	10.9	6.6	2.8	0.8	21.1
Depreciation and amortization	3.6	5.8	4.9	—	14.3
	26.5	21.1	7.7	0.8	56.1
Project other income (loss):					
Change in fair value of derivative instruments	—	2.5	—	0.7	3.2
Equity in earnings of unconsolidated affiliates	2.9	10.5	—	—	13.4
Interest expense, net	(0.3)	—	—	—	(0.3)
Other income, net	—	—	—	0.2	0.2
	2.6	13.0	—	0.9	16.5
Project income	$ 3.0	$ 23.6	$ 5.4	$ 0.4	$ 32.4

	Three months ended March 31, 2020				
	Solid Fuel	Natural Gas	Hydroelectric	Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 16.8	$ 6.2	$ 17.7	$ —	$ 40.7
Energy capacity revenue	6.3	21.7	—	—	28.0
Other	0.3	2.9	0.7	0.2	4.1
	23.4	30.8	18.4	0.2	72.8
Project expenses:					
Fuel	10.1	9.5	—	—	19.6
Operations and maintenance	11.2	5.6	3.1	0.8	20.7
Depreciation and amortization	3.2	7.5	4.9	—	15.6
	24.5	22.6	8.0	0.8	55.9
Project other income (expense):					
Change in fair value of derivative instruments	—	0.5	—	(6.1)	(5.6)
Equity in earnings of unconsolidated affiliates	2.9	10.8	—	—	13.7
Interest expense, net	(0.3)	—	—	—	(0.3)
	2.6	11.3	—	(6.1)	7.8
Project income (loss)	$ 1.5	$ 19.5	$ 10.4	$ (6.7)	$ 24.7

Solid Fuel

Project income for the three months ended March 31, 2021 increased $1.5 million from the comparable 2020 period primarily due to:

- increased project income of $2.8 million at Cadillac primarily due to the extended outage following the fire at the plant in September 2019. The project was non-operational through August 20, 2020.

  This increase was partially offset by:

- decreased combined project income of $1.7 million at Allendale and Dorchester primarily due to maintenance outages in March 2021.

Natural Gas

Project income for the three months ended March 31, 2021 increased $4.1 million from the comparable 2020 period primarily due to:

- increased project income of $2.5 million at Oxnard primarily due to the project's new RA contract that became effective in January 2021 in which the project receives a fixed monthly capacity payment, and decreased depreciation and amortization expense of $1.1 million as the PPA intangibles were fully amortized in May 2020;

- increased project income of $2.4 million at Orlando primarily due to a $1.7 million increase in the fair value of natural gas swaps; and

- increased project income of $1.0 million at Kenilworth primarily due to decreased depreciation and amortization expense of $0.7 million as the project's property, plant and equipment was fully depreciated as of October 2020.

  These increases were partially offset by:

- decreased project income of $1.4 million at Manchief primarily due to a forced outage in February 2021.

Hydroelectric

Project income for the three months ended March 31, 2021 decreased $5.0 million from the comparable 2020 period primarily due to:

- decreased project income of $5.4 million at Curtis Palmer primarily due to lower water flows than in 2020.

Corporate

Project income for the three months ended March 31, 2021 increased $7.1 million from the comparable 2020 period primarily due to a $6.8 million increase in the fair value of interest rate swap agreements related to the Term Loan.

Administrative and other expenses (income)

Administrative and other expenses (income) include the income and expenses not attributable to any specific project and are allocated to the 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 for the three months ended March 31, 2021 increased by $7.4 million to $14.1 million in the three months ended March 31, 2021 from $6.7 million in the comparable period in 2020, primarily due to the costs related to the Transaction including third-party costs and accelerated incentive compensation.

Interest expense, net

Interest expense for the three months ended March 31, 2021 did not change materially from the three months ended March 31, 2020.

Foreign exchange loss (gain)

Foreign exchange gain decreased by $23.8 million to a $3.2 million loss in the three months ended March 31, 2021 from a $20.6 million gain in the comparable 2020 period, due to the revaluation of instruments denominated in Canadian dollars (primarily our MTNs and Series E Debentures). The Canadian dollar appreciated 1.2% against the U.S. dollar from December 31, 2020 to March 31, 2021, as compared to a 9.2% depreciation in the comparable 2020 period.

Other (income) expense, net

Other (income) expense, net for the three months ended March 31, 2021 increased by $2.7 million from other expense, net of $2.6 million primarily due to a $2.8 million change in the fair value of the conversion option of the Series E Debentures.

Income tax expense

Income tax expense for the three months ended March 31, 2021 was $2.2 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 27%, was $1.0 million. The primary items impacting the tax rate for the three months ended March 31, 2021 were $0.5 million relating to withholding and state taxes and $0.7 million of other permanent differences.

Income tax expense for the three months ended March 31, 2020 was $1.5 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 27%, was $6.8 million. The primary item impacting the tax rate for the three months ended March 31, 2020 was a net decrease to our valuation allowances of $8.7 million, consisting of $5.9 million decreases in Canada and $2.8 million decreases in the United States due to the utilization of net operating losses. These items were partially offset by $2.0 million relating to foreign exchange and $1.4 million of other permanent differences.

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 months ended March 31, 2021, with the exception of the Cadillac project. While the reduction in availability at the Cadillac project impacted capacity payments for the period ended March 31, 2021, we recovered these capacity payments through the business interruption insurance recoveries recorded during the year ended December 31, 2020. 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").

Generation

	Generation		
	Three months ended March 31,		
(in Net GWh)	**2021**	**2020**	**% change 2021 vs. 2020**
Segment			
Solid Fuel	466.6	423.1	10.3 %
Natural Gas	439.9	581.7	(24.4)%
Hydroelectric	122.1	172.5	(29.2)%
Total	1,028.6	1,177.3	(12.6)%

Three months ended March 31, 2021 compared with three months ended March 31, 2020

Aggregate power generation for the three months ended March 31, 2021 decreased 12.6% from the comparable 2019 period primarily due to:

- decreased generation in the Hydroelectric segment, primarily due to a 46.1 net GWh decrease at Curtis Palmer as a result of lower water flows than in 2020; and

- decreased generation in the Natural Gas segment, primarily due to a 90.0 net GWh decrease in generation at Frederickson due to lower dispatch than the comparable 2020 period, a 35.3 net GWh decrease in generation at Oxnard under the new RA contract, effective from January 2021 through December 2021, as the project runs only when it is called upon to operate, and a 15.9 net GWh decrease in generation at Manchief primarily due to an outage in February 2021.

These decreases in generation were partially offset by:

- increased generation in the Solid Fuel segment, primarily due to a 34.1 net GWh increase in generation at Cadillac. The project was non-operational through August 20, 2020 due to the extended outage following the fire at the plant in September 2019.

Availability

	Availability		
	Three months ended March 31,		
	2021	2020	% change 2021 vs. 2020
Segment			
Solid Fuel	91.3 %	83.6 %	7.7 %
Natural Gas	94.3 %	96.0 %	(1.7)%
Hydroelectric	98.3 %	71.6 %	26.7 %
Weighted average	94.6 %	86.8 %	7.8 %

Three months ended March 31, 2021 compared with three months ended March 31, 2020

Aggregate power availability for the three months ended March 31, 2021 increased 7.8% from the comparable 2019 period primarily due to:

- increased availability in the Hydroelectric segment, primarily due to forced outages at Moresby Lake and Koma Kulshan in the comparable 2020 period; and

- increased availability in the Solid Fuel segment, primarily due to the fire at Cadillac in September 2019. The project was non-operational through August 20, 2020 due to the extended outage.

These increases in availability were partially offset by:

- decreased availability in the Natural Gas segment, primarily due to an outage at Manchief in the current quarterly period.

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, impairment charges, insurance loss (gain), other (income) expenses 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 income (loss) to Project income and to Project Adjusted EBITDA is provided under "Project Adjusted EBITDA" below. Project Adjusted EBITDA for our equity method investments in unconsolidated affiliates is presented on a proportionately consolidated basis in the table below.

Project Adjusted EBITDA

	March 31,		$ change
	2021	2020	2021 vs 2020
Net income	$ 1.6	$ 23.7	$ (22.1)
Income tax expense	2.2	1.5	0.7
Income from operations before income taxes	3.8	25.2	(21.4)
Administration	14.1	6.7	7.4
Interest expense, net	11.4	10.8	0.6
Foreign exchange loss (gain)	3.2	(20.6)	23.8
Other (income) expense, net	(0.1)	2.6	(2.7)
Project income	$ 32.4	$ 24.7	$ 7.7
Reconciliation to Project Adjusted EBITDA			
Depreciation and amortization	18.6	19.8	(1.2)
Interest expense, net	0.6	0.7	(0.1)
Change in the fair value of derivative instruments	(3.2)	5.6	(8.8)
Other (income) expense, net	(0.2)	—	(0.2)
Project Adjusted EBITDA	$ 48.2	$ 50.8	$ (2.6)
Project Adjusted EBITDA by segment			
Solid Fuel	9.7	7.8	1.9
Natural Gas	28.7	28.2	0.5
Hydroelectric	10.3	15.3	(5.0)
Corporate	(0.5)	(0.5)	—
Total	$ 48.2	$ 50.8	$ (2.6)

Solid Fuel

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

	Three months ended March 31,		
			% change
	2021	2020	2021 vs. 2020
Solid Fuel			
Project Adjusted EBITDA	$ 9.7	$ 7.8	24 %

Three months ended March 31, 2021 compared with three months ended March 31, 2020

Project Adjusted EBITDA for the three months ended March 31, 2021 increased $1.9 million from the comparable 2020 period primarily due to increased Project Adjusted EBITDA of:

- $3.1 million at Cadillac, which was non-operational from September 2019 to August 20, 2020 due to a fire at the project.

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

- $1.6 million at Allendale and Dorchester primarily due to maintenance outages in March 2021.

Natural Gas

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

	Three months ended March 31,		
	2021	2020	% change 2021 vs 2020
Natural Gas			
Project Adjusted EBITDA	$ 28.7	$ 28.2	2 %

Three months ended March 31, 2021 compared with three months ended March 31, 2020

Project Adjusted EBITDA for the three months ended March 31, 2021 increased $0.5 million from the comparable 2020 period primarily due to increased Project Adjusted EBITDA of:

- $1.5 million at Oxnard primarily due to the project's new RA contract that became effective in January 2021 under which the project receives a fixed monthly capacity payment and lower maintenance expense than in the comparable 2020 period.

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

- $1.4 million at Manchief primarily due to a forced outage in February 2021.

Hydroelectric

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

	Three months ended March 31,		
	2021	2020	% change 2021 vs. 2020
Hydroelectric			
Project Adjusted EBITDA	$ 10.3	$ 15.3	(33)%

Three months ended March 31, 2021 compared with three months ended March 31, 2020

Project Adjusted EBITDA for the three months ended March 31, 2021 decreased $5.0 million from the comparable 2020 period primarily due to decreased Project Adjusted EBITDA of:

- $5.4 million at Curtis Palmer primarily due to lower water flows than in 2020.

Corporate

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

	Three months ended March 31,		
	2021	2020	% change 2021 vs. 2020
Corporate			
Project Adjusted EBITDA	$ (0.5)	$ (0.5)	NM

Three months ended March 31, 2021 compared with three months ended March 31, 2020

Project Adjusted EBITDA for the three months ended March 31, 2021 did not change materially from the comparable 2020 period.

Liquidity and Capital Resources

	March 31, 2021	December 31, 2020
Cash and cash equivalents	$ 21.6	$ 38.8
Restricted cash	6.9	7.1
Total	28.5	45.9
Revolving credit facility availability	98.8	102.9
Total liquidity	$ 127.3	$ 148.8

Overview

Our primary sources of liquidity are distributions from our projects and availability under our Revolver. Our 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 September 2021 (Kenilworth) to November 2043 (Allendale). Kenilworth is currently the only project operating under a PPA with an expiration date in 2021. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, 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, and other allocation of available cash. See "Risk Factors—Risks Related to Our Financial Position and Economic and Financial Market Conditions —We may not generate sufficient cash flow to service our debt obligations or implement our business plan, including financing internal or external growth opportunities" in our Annual Report on Form 10-K for the year ended December 31, 2020.

Consolidated Cash Flow Discussion

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

	Three months ended March 31,		
	2021	2020	Change
Net cash provided by operating activities	$ 8.4	$ 8.4	$ —
Net cash provided by (used in) investing activities	0.2	(2.6)	2.8
Net cash used in financing activities	(26.0)	(40.1)	14.1

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, 2021, cash provided by operating activities did not change materially from the comparable 2020 period.

Investing Activities

For the three months ended March 31, 2021, the net decrease in cash used in investing activities of $2.8 million was primarily the result of the following:

- *Capitalized plant additions* – capitalized plant additions were $9.7 million lower in the three months ended March 31, 2021 than the comparable 2020 period, primarily due to repairs at Cadillac performed during 2020; and

- *Insurance proceeds* – insurance recoveries related to the Cadillac fire were $7.4 million lower than the comparable 2020 period.

Financing Activities

For the three months ended March 31, 2021, the net decrease in cash used in financing activities of $14.1 million was primarily the result of the following:

- *Common share repurchases* – we paid $8.2 million to repurchase and cancel common shares in the comparable 2020 period;

- *Preferred share repurchases* – we paid $6.4 million to repurchase and cancel preferred shares in the comparable 2020 period; and

- *Deferred financing costs* – we incurred $1.6 million of deferred financing costs related to amending the Term Loan and the Revolver in the in the comparable 2020 period.

These decreases were partially offset by the following increase in cash flows used in financing activities:

- *Corporate and project-level debt repayments* – we made $2.1 million greater principal payments than in the comparable 2020 period.

Corporate Debt

The following table summarizes the maturities of our corporate debt at March 31, 2021:

	Maturity Date	Interest Rates	Remaining Principal Repayments	2021	2022	2023	2024	2025	Thereafter
Senior secured term loan facility[1]	April 2025	4.42%	$ 284.5	$ 70.0	$ 106.0	$ 60.0	$ 36.0	$ 12.5	$ —
MTNs	June 2036	5.95%	167.0	—	—	—	—	—	167.0
Convertible Debenture	January 2025	6.00%	91.4	—	—	—	—	91.4	—
Total Corporate Debt			$ 542.9	$ 70.0	$ 106.0	$ 60.0	$ 36.0	$ 103.9	$ 167.0

(1) The Term Loan Facility contains a mandatory amortization feature determined by using the greater of (i) 50% of the cash flow of 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 Term Loan Facility and the 5.95% MTNs, 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 Term Loan Facility, 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 the Term Loan Facility 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 through 2022 based on the schedule as amended in January 2020. After 2022, the amortization profile is based on (i) above and is an estimate, subject to change. See Note 6, *Long-term debt* for more information on our credit facilities.

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, 2021. 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 March 31, 2021, 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 March 31, 2021. 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	2021	2022	2023	2024	2025	Thereafter
Consolidated Projects:									
Cadillac	August 2025	6.26 % - 6.38 %	$ 14.1	$ 2.0	$ 3.3	$ 3.3	$ 3.7	$ 1.8	$ —
Total Consolidated Projects			14.1	2.0	3.3	3.3	3.7	1.8	—
Equity Method Projects:									
Chambers[(1)]	December 2023	5.00 %	30.5	8.8	10.1	11.6	—	—	—
Total Equity Method Projects			30.5	8.8	10.1	11.6	—	—	—
Total Project-Level Debt			$ 44.6	$ 10.8	$ 13.4	$ 14.9	$ 3.7	$ 1.8	$ —

(1) The above table does not include our $0.6 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 Series E Debentures, Term Loan Facility, MTNs and other corporate and project-level debt; funding the repurchase of shares of our common stock, our Series E Debentures, and 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

Our commercial operations require a significant amount of 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 major expenditures relate to planned repairs and maintenance and are expensed when incurred.

We expect to reinvest approximately $40.0 million in 2021 (of which $6.4 million was reinvested in the three months ended March 31, 2021) in our portfolio in the form of maintenance expenses and project capital expenditures. As explained above, these investments are generally paid at the project level. See “Liquidity and Capital Resources—Capital and Maintenance Expenditures” in our Annual Report on Form 10-K for the year ended December 31, 2020. We believe one of the benefits of our diverse fleet is that plant overhauls and other major 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 2021 level as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades. 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.

Recently Adopted and Recently Issued Accounting Guidance

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