ATLANTIC POWER CORP
Form 10-Q
August 10, 2015

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

ý **QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the quarterly period ended June 30, 2015

OR

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to
COMMISSION FILE NUMBER 001-34691

ATLANTIC POWER CORPORATION

(Exact name of registrant as specified in its charter)

British Columbia, Canada (State or other jurisdiction of incorporation or organization)	**55-0886410** (I.R.S. Employer Identification No.)
3 Allied Drive, Suite 220 **Dedham, MA** (Address of principal executive offices)	**02026** (Zip code)

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ý No o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ý No o

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer o	Accelerated filer ý	Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No ý

The number of shares outstanding of the registrant's Common Stock as of August 7, 2015 was 122,032,729.

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ATLANTIC POWER CORPORATION

FORM 10-Q

THREE AND SIX MONTHS ENDED JUNE 30, 2015

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GENERAL

In this Quarterly Report on Form 10-Q, references to "Cdn$" and "Canadian dollars" are to the lawful currency of Canada and references to "$" and "US$" and "U.S. dollars" are to the lawful currency of the United States. All dollar amounts herein are in U.S. dollars, unless otherwise indicated.

Unless otherwise stated, or the context otherwise requires, references in this Quarterly Report on Form 10-Q to "we," "us," "our," "Atlantic Power" and the "Company" refer to Atlantic Power Corporation, those entities owned or controlled by Atlantic Power Corporation and predecessors of Atlantic Power Corporation.

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ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in millions of U.S. dollars)

	June 30, 2015 (unaudited)	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$ 393.8	$ 106.0
Restricted cash	17.6	22.5
Accounts receivable	45.2	46.2
Inventory	16.5	19.3
Prepayments and other current assets	12.3	13.9
Assets held for sale (Note 3)		792.1
Refundable income taxes		0.2
Total current assets	485.4	1,000.2
Property, plant, and equipment, net of accumulated depreciation of $218.9 million and $195.9 million at June 30, 2015 and December 31, 2014, respectively	908.6	962.9
Equity investments in unconsolidated affiliates (Note 4)	300.6	305.2
Other intangible assets, net of accumulated amortization of $220.8 million and $200.3 million at June 30, 2015 and December 31, 2014, respectively	342.7	377.1
Goodwill	197.2	197.2
Derivative instruments asset (Notes 7 and 8)	0.4	1.1
Deferred financing costs	56.0	62.8
Other assets	9.0	10.1
Total assets	$ 2,299.9	$ 2,916.6
Liabilities		
Current liabilities:		
Accounts payable	$ 4.4	$ 9.4
Income taxes payable	3.8	
Accrued interest	5.2	5.3
Other accrued liabilities	36.7	30.7
Current portion of long-term debt (Note 5)	328.4	20.0
Current portion of derivative instruments liability (Notes 7 and 8)	36.0	36.1
Liabilities held for sale (Note 3)		271.8
Other current liabilities	7.6	6.8
Total current liabilities	422.1	380.1
Long-term debt (Note 5)	762.4	1,145.9
Convertible debentures (Note 6)	304.6	340.6
Derivative instruments liability (Notes 7 and 8)	37.1	47.5
Deferred income taxes (Note 9)	111.1	92.4
Power purchase and fuel supply agreement liabilities, net of accumulated amortization of $12.8 million and $11.4 million at June 30, 2015 and December 31, 2014, respectively	30.3	33.4
Other non-current liabilities	58.0	60.2
Commitments and contingencies (Note 15)		
Total liabilities	1,725.6	2,100.1
Equity		
Common shares, no par value, unlimited authorized shares; 122,007,113 and 121,323,614 issued and outstanding at June 30, 2015 and December 31, 2014, respectively (Note 12)	1,289.5	1,288.4
Accumulated other comprehensive loss	(98.9)	(68.3)

Retained deficit	(837.6)	(863.9)
Total Atlantic Power Corporation shareholders' equity	353.0	356.2
Preferred shares issued by a subsidiary company (Note 12)	221.3	221.3
Noncontrolling interests held for sale (Notes 3 and 12)		239.0
Total equity	574.3	816.5
Total liabilities and equity	$ 2,299.9	$ 2,916.6

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(in millions of U.S. dollars, except per share amounts)

(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Project revenue:				
Energy sales	$ 47.5	$ 62.4	$ 101.5	$ 124.7
Energy capacity revenue	38.0	41.3	71.5	74.8
Other	17.6	19.4	41.4	48.9
	103.1	123.1	214.4	248.4
Project expenses:				
Fuel	38.0	50.4	84.2	110.2
Operations and maintenance	35.3	29.1	56.8	56.7
Development		1.1	1.1	1.8
Depreciation and amortization	28.2	30.8	56.1	61.4
	101.5	111.4	198.2	230.1
Project other income (expense):				
Change in fair value of derivative instruments (Notes 7 and 8)	6.8	(0.4)	5.2	21.6
Equity in earnings of unconsolidated affiliates (Note 4)	8.6	3.7	19.3	12.1
Interest expense, net	(2.0)	(2.2)	(4.1)	(13.3)
Other income (expense), net	2.2	(14.8)	2.2	(14.8)
	15.6	(13.7)	22.6	5.6
Project (loss) income	17.2	(2.0)	38.8	23.9
Administrative and other expenses (income):				
Administration	6.6	10.2	16.0	17.5
Interest, net	24.6	27.7	50.3	94.1
Foreign exchange loss (gain) (Note 8)	4.8	15.3	(27.4)	(1.5)
Other income, net (Note 6)	(1.7)		(3.1)	
	34.3	53.2	35.8	110.1
(Loss) income from continuing operations before income taxes	(17.1)	(55.2)	3.0	(86.2)
Income tax expense (benefit) (Note 9)	2.9	(4.5)	(1.7)	(21.4)
(Loss) income from continuing operations	(20.0)	(50.7)	4.7	(64.8)
Net income (loss) from discontinued operations, net of tax (Note 3)	33.6	(5.7)	21.1	(14.0)
Net income (loss)	13.6	(56.4)	25.8	(78.8)
Net loss attributable to noncontrolling interests of discontinued operations	(3.4)	(0.3)	(11.0)	(6.7)
Net income attributable to preferred shares of a subsidiary company	2.3	3.1	4.6	5.9
Net income (loss) attributable to Atlantic Power Corporation	$ 14.7	$ (59.2)	$ 32.2	$ (78.0)

Basic and diluted earnings per share: (Note 11)								
Loss from continuing operations attributable to Atlantic Power Corporation	$	(0.18)	$	(0.45)	$	0.00	$	(0.59)
Income (loss) from discontinued operations, net of tax		0.30		(0.04)		0.26		(0.06)
Net income (loss) attributable to Atlantic Power Corporation	$	0.12	$	(0.49)	$	0.26	$	(0.65)
Weighted average number of common shares outstanding: (Note 11)								
Basic		121.9		120.6		121.7		120.5
Diluted		122.1		120.6		121.9		120.5
Dividends paid per common share:	$	0.02	$	0.09	$	0.05	$	0.17

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

(in millions of U.S. dollars)

(Unaudited)

	Three months ended June 30,		Six months ended June 30,	
	2015	**2014**	**2015**	**2014**
Net income (loss)	$ 13.6	$ (56.4)	$ 25.8	$ (78.8)
Other comprehensive income (loss), net of tax:				
Unrealized income (loss) on hedging activities	$ 0.2	$ (0.3)	$ (0.4)	$ (0.7)
Net amount reclassified to earnings	0.1	0.1	0.4	0.4
Net unrealized gain (loss) on derivatives	0.3	(0.2)		(0.3)
Foreign currency translation adjustments	4.5	17.3	(30.6)	(1.4)
Other comprehensive income (loss), net of tax	4.8	17.1	(30.6)	(1.7)
Comprehensive income (loss)	18.4	(39.3)	(4.8)	(80.5)
Less: Comprehensive (loss) income attributable to noncontrolling interests	(1.1)	2.8	(6.4)	(0.8)
Comprehensive income (loss) attributable to Atlantic Power Corporation	$ 19.5	$ (42.1)	$ 1.6	$ (79.7)

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in millions of U.S. dollars)

(Unaudited)

	Six months ended June 30, 2015	Six months ended June 30, 2014
Cash flows from operating activities:		
Net (loss) income	$ 25.8	$ (78.8)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	66.4	81.5
Gain on sale of discontinued operations	(47.3)	(2.1)
Gain on sale of development project and other assets	(2.3)	
Gain on purchase and cancellation of convertible debentures	(3.0)	
Stock-based compensation expense	1.0	0.9
Impairment charges		14.8
Equity in earnings from unconsolidated affiliates	(19.3)	(11.9)
Distributions from unconsolidated affiliates	27.0	37.8
Unrealized foreign exchange gain	(27.6)	(1.4)
Change in fair value of derivative instruments	(4.5)	(11.9)
Change in deferred income taxes	20.4	(15.5)
Change in other operating balances		
Accounts receivable	0.6	2.8
Inventory	2.8	(2.6)
Prepayments, refundable income taxes and other assets	9.3	14.7
Accounts payable	(3.4)	(4.6)
Accruals and other liabilities	7.5	(18.2)
Cash provided by operating activities	53.4	5.5
Cash flows provided by investing activities:		
Change in restricted cash	4.9	78.4
Proceeds from sale of discontinued operations and development project, net of cash sold	326.3	1.0
Contribution to unconsolidated affiliate	(0.6)	
Capitalized development costs	(0.8)	
Construction in progress		(1.5)
Purchase of property, plant and equipment	(5.0)	(2.5)
Cash provided by investing activities	324.8	75.4
Cash flows used in financing activities:		
Proceeds from senior secured term loan facility		600.0
Repayment of corporate and project-level debt	(62.2)	(608.0)
Repayment of convertible debentures	(18.0)	
Deferred financing costs		(38.8)
Dividends paid to common shareholders	(5.8)	(20.9)
Dividends paid to noncontrolling interests	(8.4)	(14.2)
Cash used in financing activities	(94.4)	(81.9)
Net increase (decrease) in cash and cash equivalents	283.8	(1.0)
Cash and cash equivalents at beginning of period at discontinued operations	3.9	

Cash and cash equivalents at beginning of period		106.1		158.6
Cash and cash equivalents at end of period	$	393.8	$	157.6
Supplemental cash flow information				
Interest paid	$	46.3	$	114.7
Income taxes paid, net	$	1.7	$	1.0
Accruals for construction in progress	$		$	8.2

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

1. Nature of business

General

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 power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. As of June 30, 2015, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,137 megawatts ("MW") in which our aggregate ownership interest is approximately 1,502 MW. Our current portfolio consists of interests in twenty-three operational power generation projects across nine states in the United States and two provinces in Canada. Eighteen of our projects are majority-owned subsidiaries. These totals exclude an aggregate of 521 MWs from our previous 100% ownership interest in Meadow Creek Project Company, LLC ("Meadow Creek"), 99% ownership in Canadian Hills Wind, LLC ("Canadian Hills"), 50% ownership interest in Rockland Wind Farm, LLC ("Rockland"), 27.6% ownership interest in Idaho Wind Partners 1, LLC ("Idaho Wind") and 12.5% ownership interest in Goshen Phase II, LLC ("Goshen") (collectively, the "Wind Projects"), which we sold on June 26, 2015, and which are designated as discontinued operations for the three and six months ended June 30, 2015 and 2014.

Atlantic Power is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange under the symbol "ATP" and on the New York Stock Exchange under the symbol "AT." Our registered office is located at 215-10451 Shellbridge Way, Richmond, British Columbia V6X 2W8 Canada and our headquarters is located at 3 Allied Drive, Suite 220, Dedham, Massachusetts 02026, USA. Our telephone number in Dedham is (617) 977-2400 and the address of our website is www.atlanticpower.com. Information contained on Atlantic Power's website or that can be accessed through its website is not incorporated into and does not constitute a part of this Quarterly Report on Form 10-Q. We have included our website address only as an inactive textual reference and do not intend it to be an active link to our website. We make available on our website, free of charge, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission ("SEC"). Additionally, we make available on our website our Canadian securities filings, which are not incorporated by reference into our Exchange Act filings.

Basis of presentation

The interim consolidated financial statements included in this Quarterly Report on Form 10-Q have been prepared in accordance with the SEC regulations for interim financial information and with the instructions to Form 10-Q. The following notes should be read in conjunction with the accounting policies and other disclosures as set forth in the notes to our financial statements in our Annual Report on Form 10-K for the year ended December 31, 2014. Interim results are not necessarily indicative of results for the full year.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

1. Nature of business (Continued)

In our opinion, the accompanying unaudited interim consolidated financial statements present fairly our consolidated financial position as of June 30, 2015, the results of operations and comprehensive income (loss) for the three and six months ended June 30, 2015 and 2014, and our cash flows for the six months ended June 30, 2015 and 2014 in accordance with U.S generally accepted accounting policies. In the opinion of management, all adjustments (consisting of normal recurring accruals and other adjustments) considered necessary for a fair presentation have been included.

Use of estimates

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment, valuation of goodwill, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the fair value of financial instruments and derivatives, pension obligations, asset retirement obligations, equity-based compensation and the allocation of taxable income and losses, tax credits and cash distributions using the hypothetical liquidation book value ("HLBV") method. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates" in our Annual Report on Form 10-K for the year ended December 31, 2014. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

Revision to the presentation of preferred shares issued by a subsidiary company

The classification of preferred shares issued by a subsidiary company has been revised from total Atlantic Power Corporation shareholder's equity on the Consolidated Balance Sheets at December 31, 2014 to a separate line item in the noncontrolling interests section of equity. The revision does not impact total equity in either period presented. The revision was appropriate in order to properly present the preferred shares issued by a subsidiary company in the consolidated balance sheet. The revision is not considered material to any previously issued financial statements.

Recently issued accounting standards

Adopted

In April 2014, the Financial Accounting Standards Board ("FASB") issued changes to reporting discontinued operations and disclosures of disposals of components of an entity. These changes require a disposal of a component to meet a higher threshold in order to be reported as a discontinued

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

1. Nature of business (Continued)

operation in an entity's financial statements. The threshold is defined as a strategic shift that has, or will have, a major effect on an entity's operations and financial results such as a disposal of a major geographical area or a major line of business. Additionally, the following two criteria have been removed from consideration of whether a component meets the requirements for discontinued operations presentation: (i) the operations and cash flows of a disposal component have been or will be eliminated from the ongoing operations of an entity as a result of the disposal transaction, and (ii) an entity will not have any significant continuing involvement in the operations of the disposal component after the disposal transaction. Furthermore, equity method investments now may qualify for discontinued operations presentation. These changes also require expanded disclosures for all disposals of components of an entity, whether or not the threshold for reporting as a discontinued operation is met, related to profit or loss information and/or asset and liability information of the component. These changes became effective on January 1, 2015 and were implemented when designating the Wind Projects as assets held for sale and discontinued operations on March 31, 2015. See Note 3, *Discontinued operations*.

Issued

In January 2015, the FASB issued changes to the presentation of extraordinary items. Such items are defined as transactions or events that are both unusual in nature and infrequent in occurrence, and, currently, are required to be presented separately in an entity's income statement, net of income tax, after income from continuing operations. The changes eliminate the concept of an extraordinary item and, therefore, the presentation of such items will no longer be required. Notwithstanding this change, an entity will still be required to present and disclose a transaction or event that is both unusual in nature and infrequent in occurrence in the notes to the financial statements. These changes become effective for us on January 1, 2016. We have determined that the adoption of these changes will not have an impact on the consolidated financial statements.

In February 2015, the FASB issued changes to the analysis that an entity must perform to determine whether it should consolidate certain types of legal entities. These changes (i) modify the evaluation of whether limited partnerships and similar legal entities are variable interest entities or voting interest entities, (ii) eliminate the presumption that a general partner should consolidate a limited partnership, (iii) affect the consolidation analysis of reporting entities that are involved with variable interest entities, particularly those that have fee arrangements and related party relationships, and (iv) provide a scope exception from consolidation guidance for reporting entities with interests in legal entities that are required to comply with or operate in accordance with requirements that are similar to those in Rule 2a-7 of the Investment Company Act of 1940 for registered money market funds. These changes become effective for us on January 1, 2016. We are currently evaluating the potential impact of these changes on the consolidated financial statements.

In April 2015, the FASB issued changes to the presentation of debt issuance costs. Currently, such costs are required to be presented as a noncurrent asset in an entity's balance sheet and amortized into interest expense over the term of the related debt instrument. The changes require that debt issuance costs be presented in an entity's balance sheet as a direct deduction from the carrying value of the related debt liability. The amortization of debt issuance costs remains unchanged. These changes

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

1. Nature of business (Continued)

become effective for us on January 1, 2016. Management has determined that the adoption of these changes will result in a decrease of approximately $56.0 million based on the outstanding amount at June 30, 2015 to both Deferred financing costs located in noncurrent assets and Long-term debt on the accompanying consolidated balance sheets.

2. Changes in accumulated other comprehensive loss by component

The changes in accumulated other comprehensive loss by component were as follows:

	Three months ended June 30,		Six months ended June 30,	
	2015	**2014**	**2015**	**2014**
Foreign currency translation				
Balance at beginning of period	$ (101.4)	$ (40.9)	$ (66.3)	$ (22.2)
Other comprehensive income (loss):				
Foreign currency translation adjustments[1]	4.5	17.3	(30.6)	(1.4)
Balance at end of period	$ (96.9)	$ (23.6)	$ (96.9)	$ (23.6)
Pension				
Balance at beginning of period	$ (2.1)	$ (0.4)	$ (2.1)	$ (0.4)
Other comprehensive loss:				
Amortization of net actuarial gain				
Balance at end of period	$ (2.1)	$ (0.4)	$ (2.1)	$ (0.4)
Cash flow hedges				
Balance at beginning of period	$ (0.2)	$ 0.1	$ 0.1	$ 0.2
Other comprehensive (loss) income:				
Net change from periodic revaluations	0.2	(0.5)	(0.3)	(1.1)
Tax benefit (expense)	(0.1)	0.2	0.1	0.4
Total Other comprehensive (loss) income before reclassifications, net of tax	0.1	(0.3)	(0.2)	(0.7)
Net amount reclassified to earnings (loss):				
Interest rate swaps[2]	0.3	0.2	0.6	0.7
Tax benefit (expense)	(0.1)	(0.1)	(0.4)	(0.3)
Total amount reclassified from Accumulated other comprehensive loss, net of tax	0.2	0.1	0.2	0.4
Total Other comprehensive (loss) income	0.3	(0.2)		(0.3)
Balance at end of period	$ 0.1	$ (0.1)	$ 0.1	$ (0.1)

(1)

In all periods presented, there were no tax impacts related to rate changes and no amounts were reclassified to earnings (loss).

(2) This amount was included in Interest expense, net on the accompanying consolidated statements of operations.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

3. Discontinued operations

Wind Projects

On March 31, 2015, Atlantic Power Transmission, Inc. ("APT"), our wholly-owned, direct subsidiary, entered into a definitive agreement (the "Purchase Agreement") with TerraForm AP Acquisition Holdings, LLC ("TerraForm"), an affiliate of SunEdison, Inc. (an affiliate of TerraForm Power, Inc.), to sell our Wind Projects. On June 26, 2015, the sale was completed for aggregate cash proceeds of approximately $335 million after transaction fees, exclusive of transaction-related taxes. We recorded a $47.3 million gain on sale, which is included as a component of income from discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2015.

Terraform acquired from APT, 100% of APT's direct membership interests in a holding company formed to facilitate the sale, thereby acquiring our indirect interests in our portfolio of Wind Projects consisting of five operating wind projects in Idaho and Oklahoma and representing 521 MW net ownership: Goshen (12.5% economic interest), Idaho Wind (27.6% economic interest), Meadow Creek (100% economic interest); Rockland Wind Farm (50% economic interest, but consolidated on a 100% basis); and Canadian Hills (99% economic interest). As a result of the sale, we deconsolidated approximately $249 million of project debt (or approximately $274 million as adjusted for our proportional ownership of Rockland, Goshen North and Idaho Wind) and approximately $224 million of non-controlling interest related to tax equity interests at Canadian Hills and the minority ownership interests at Rockland and Canadian Hills.

On January 1, 2015, we adopted the FASB's issued changes to reporting discontinued operations and determined that the sale of the Wind Projects meets the threshold to be reported as discontinued operations in our consolidated financial statements. Our determination was based on the impact the sale will have on our operations and financial results and because the Wind Projects made up the entirety of our Wind reportable Segment. The Wind Projects were designated as assets held for sale and discontinued operations on March 31, 2015, the date we established a firm commitment to a plan to sell the wind assets. We stopped depreciating the property, plant and equipment of the Wind Projects on the designation date.

Greeley

In March 2014, we closed a transaction with Initium Power Partners, LLC. ("Initium"), whereby Initium agreed to purchase all of the issued and outstanding membership interests in Greeley for approximately $1.0 million. We recorded a $2.1 million non-cash gain on the sale resulting from the write-off of asset retirement obligations in the consolidated statement of operations as of March 31, 2014. Greeley is accounted for as a component of discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2014.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

3. Discontinued operations (Continued)

The following table summarizes the revenue and income (loss) from operations of the Wind Projects and Greeley for the three and six months ended June 30, 2015 and 2014:

	Three months ended June 30,		Six months ended June 30,	
	2015	**2014**	**2015**	**2014**
Revenue	$ 18.1	$ 20.1	$ 34.8	$ 40.1
Project expenses:				
Operations and maintenance	5.2	5.4	10.8	10.6
Depreciation and amortization	0.1	10.1	10.3	20.1
	5.3	15.5	21.1	30.7
Project other income (expense):				
Change in fair value of derivatives	6.7	(2.4)	(0.7)	(9.7)
Equity in earnings of unconsolidated affiliates	0.7	(0.4)	(0.2)	(0.2)
Interest expense, net	(3.3)	(3.6)	(6.7)	(7.1)
Gain on sale of discontinued operations	47.3		47.3	2.1
	51.4	(6.4)	39.7	(14.9)
Income (loss) from operations of discontinued businesses	64.2	(1.8)	53.4	(5.5)
Income tax expense	30.6	3.9	32.3	8.5
Income (loss) from operations of discontinued businesses, net of tax	33.6	(5.7)	21.1	(14.0)
Net loss attributable to noncontrolling interests of discontinued businesses	(3.4)	(0.3)	(11.0)	(6.7)
Income (loss) from operations of discontinued businesses, net of noncontrolling interests	$ 37.0	$ (1.5)	$ 32.1	$ 1.2

Basic and diluted earnings (loss) per share related to income (loss) from discontinued operations for the Wind Projects and Greeley was $0.30 and $(0.04) for the three months ended June 30, 2015 and 2014, respectively and $0.26 and $(0.06) for the six months ended June 30, 2015 and 2014, respectively.

The following table summarizes the operating and investing cash flows of the Wind Projects for the six months ended June 30, 2015 and 2014:

	Six months ended June 30,	
	2015	**2014**
Cash provided by operating activities	$ 21.9	$ 26.2

Cash (used in) provided by investing activities	(12.8)	6.5

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

3. Discontinued operations (Continued)

The following table summarizes the December 31, 2014 financial position of the Wind Projects that were classified as assets held for sale:

	December 31, 2014
Current assets:	
Cash and cash equivalents	$ 3.9
Accounts receivable	11.2
Other current assets	2.4
	17.5
Non-current assets:	
Property, Plant & Equipment	710.5
Equity investments in unconsolidated affiliates	38.7
Other intangible assets, net	4.3
Restricted cash	19.1
Other assets	2.0
Assets held for sale	792.1
Current liabilities:	
Accounts payable and other accrued liabilities	$ 5.9
Current portion of long-term debt	6.4
Current portion of derivative instruments liability	3.1
	15.4
Long term liabilities	
Long-term debt	242.4
Derivative instruments liability	10.0
Other long-term liabilities	4.0
Liabilities held for sale	271.8
Noncontrolling interests held for sale	239.0

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4. Equity method investments in unconsolidated affiliates

The following summarizes the operating results for the three and six months ended June 30, 2015 and 2014, respectively, for earnings in our equity method investments:

Operating results	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Revenue				
Chambers	$ 10.9	$ 12.6	$ 26.3	$ 30.6
Orlando	14.1	10.8	26.9	$ 24.1
Other[1]	8.0	19.1	17.6	41.6
	33.0	42.5	70.8	96.3
Project expenses				
Chambers	9.6	10.8	20.9	25.1
Orlando	6.7	7.5	13.3	16.2
Other[1]	7.6	18.8	16.4	40.5
	23.9	37.1	50.6	81.8
Project other expense				
Chambers	(0.5)	(1.5)	(0.9)	(2.1)
Orlando				
Other[1]		(0.2)		(0.3)
	(0.5)	(1.7)	(0.9)	(2.4)
Project income				
Chambers	$ 0.8	$ 0.3	$ 4.5	$ 3.4
Orlando	7.4	3.3	13.6	7.9
Other[1]	0.4	0.1	1.2	0.8
	8.6	3.7	19.3	12.1

(1) Includes equity method investments that individually do not exceed 10% of consolidated total assets or income (loss) before income taxes.

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5. Long-term debt

Long-term debt consists of the following:

	June 30, 2015	December 31, 2014	Interest Rate
Recourse Debt:			
Senior secured term loan facility, due 2021	$ 494.6	$ 541.5	LIBOR(1) plus 3.8%
Senior unsecured notes, due 2018(2)	310.9	319.9	9.0%
Senior unsecured notes, due June 2036 (Cdn$210.0)	168.1	181.0	6.0%
Non-Recourse Debt:(3)			
Epsilon Power Partners term facility, due 2019	22.5	25.5	LIBOR plus 3.1%
Cadillac term loan, due 2025	30.8	33.4	6.2%
Piedmont term loan, due 2018	63.4	64.0	5.2%
Other long-term debt	0.5	0.6	5.5% 6.7%
Less: current maturities	(328.4)	(20.0)	
Total long-term debt	$ 762.4	$ 1,145.9	

Current maturities consist of the following:

	June 30, 2015	December 31, 2014	Interest Rate
Current Maturities:			
Senior unsecured notes, due 2018(2)	$ 310.9		9.0%
Senior secured term loan facility, due 2021	4.9	5.4	LIBOR(1) plus 3.8%
Epsilon Power Partners term facility, due 2019	6.0	6.1	LIBOR plus 3.1%
Cadillac term loan, due 2025	2.5	3.9	6.2%
Piedmont term loan, due 2018	3.9	4.5	5.2%
Other short-term debt	0.2	0.1	5.5 6.7%
Total current maturities	$ 328.4	$ 20.0	

(1) LIBOR cannot be less than 1.00%. On May 5, 2014, we entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $167.3 million amount of the $494.6 million outstanding aggregate borrowings under our senior secured term loan facility. See Note 8, *Accounting for derivative instruments and hedging activities* for further details.

(2) On July 26, 2015, we redeemed all of our outstanding $310.9 million aggregate principal amount of 9.0% Senior Unsecured Notes due November 2018 (the "Notes") with the cash proceeds received from the sale of the Wind Projects. The Notes were redeemed at a price equal to 104.50 percent of the principal amount of the 9.0% notes, plus accrued and unpaid interest to the redemption date. We paid $330.4 million in cash to fund the full redemption

of the Notes. We will record approximately $28.5 million of interest in the third quarter of 2015 related to the redemption premium, accrued interest and the write-off of deferred financing costs.

(3) The table does not include non-recourse debt at the Wind Projects which have been sold and are classified as discontinued operations at December 31, 2014.

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(in millions U.S. dollars, except per-share amounts)

(Unaudited)

5. Long-term debt (Continued)

Non-Recourse 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 loans have certain financial covenants that must be met in order to distribute available cash to Atlantic Power. At June 30, 2015, all of our projects with the exception of Piedmont were in compliance with the covenants contained in project-level debt. We do not expect our Piedmont project to meet its debt service coverage ratio covenants limiting the project's ability to make distributions to us before 2017 at the earliest, due to continued operational issues that have resulted in higher forecasted maintenance and fuel expenses than initially expected.

6. Convertible debentures

The following table provides details related to outstanding convertible debentures:

	6.25% Debentures due March 2017	5.6% Debentures due June 2017	5.75% Debentures due June 2019	6.00% Debentures due December 2019	Total
Balance at December 31, 2014	$ 58.0	$ 68.6	$ 128.4	$ 85.6	$ 340.6
Repayment of convertible debentures		(0.3)	(3.4)	(2.0)	(5.7)
Foreign exchange gain	(4.9)	(5.8)		(7.2)	(17.9)
Gain on repurchase of convertible debentures			(0.8)	(0.5)	(1.3)
Balance at March 31, 2015	$ 53.1	$ 62.5	$ 124.2	$ 75.9	$ 315.7
Repayment of convertible debentures		(1.8)	(6.0)	(4.5)	(12.3)
Foreign exchange gain	0.8	0.9		1.2	2.9
Gain on repurchase of convertible debentures		(0.1)	(1.0)	(0.6)	(1.7)
Balance at June 30, 2015	$ 53.9	$ 61.5	$ 117.2	$ 72.0	$ 304.6

During the fourth quarter of 2014, we announced a Normal Course Issuer Bid ("NCIB") for our convertible debentures. Under the NCIB, we entered into a pre-defined automatic securities purchase plan with our broker in order to facilitate purchases of our convertible debentures. The NCIB commenced on November 11, 2014 and will expire on November 10, 2015 or such earlier date as we complete our purchases pursuant to the NCIB. The actual amount of convertible debentures that may be purchased under the NCIB cannot exceed approximately $31.0 million and is further limited based on the outstanding principal of the individual outstanding tranches. As of December 31, 2014, we had repurchased and cancelled $3.1 million of convertible debentures and recorded a gain of $0.7 million in the consolidated statement of operations related to these transactions. Through June 30, 2015, we repurchased and cancelled $21.0 million aggregate principal amount of convertible debentures at a cost

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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(Unaudited)

6. Convertible debentures (Continued)

of $18.0 million and recorded a gain of $3.0 million in the consolidated statement of operations for the six months ended June 30, 2015.

7. Fair value of financial instruments

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of June 30, 2015 and December 31, 2014. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	June 30, 2015			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 393.8	$	$	$ 393.8
Restricted cash	17.6			17.6
Derivative instruments asset		0.4		0.4
Total	$ 411.4	$ 0.4	$	$ 411.8
Liabilities:				
Derivative instruments liability	$	$ 73.1	$	$ 73.1
Total	$	$ 73.1	$	$ 73.1

	December 31, 2014			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 106.0	$	$	$ 106.0
Restricted cash	22.5			22.5
Derivative instruments asset		1.1		1.1
Total	$ 128.5	$ 1.1	$	$ 129.6
Liabilities:				
Derivative instruments liability	$	$ 83.6	$	$ 83.6
Total	$	$ 83.6	$	$ 83.6

The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment. The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk free interest rate.

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7. Fair value of financial instruments (Continued)

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of June 30, 2015, the credit valuation adjustments resulted in a $3.4 million net increase in fair value, which consists of a $0.2 million pre-tax gain in other comprehensive income and a $3.2 million gain in change in fair value of derivative instruments. As of December 31, 2014, the credit valuation adjustments resulted in an $8.3 million net increase in fair value, which consists of a $0.7 million pre-tax gain in other comprehensive income and a $7.6 million gain in change in fair value of derivative instruments.

The carrying amounts for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature.

8. Accounting for derivative instruments and hedging activities

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value in each reporting period. We have one contract designated as a cash flow hedge, and we defer the effective portion of the change in fair value of the derivatives in accumulated other comprehensive income (loss), until the hedged transactions occur and are recognized in earnings (loss). The ineffective portion of a cash flow hedge is immediately recognized in earnings (loss). For our other derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in earnings (loss). These guidelines apply to our natural gas swaps, interest rate swaps, and foreign exchange contracts.

Gas purchase agreements

Gas purchase agreements to purchase gas forward at our North Bay, Kapuskasing and Nipigon projects do not qualify for the normal purchase normal sales ("NPNS") exemption and are accounted for as derivative financial instruments. The gas purchase agreements at North Bay and Kapuskasing satisfy all of the forecasted fuel requirements for these projects through their expiration on December 31, 2016. The gas purchase agreement for Nipigon satisfies the majority of forecasted fuel requirements through December 31, 2022. These derivative financial instruments are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

In June 2014, Atlantic Power Limited Partnership (the "Partnership") entered into contracts for the purchase of 2.9 million Gigajoules ("Gj") of future natural gas purchases beginning on November 1, 2014 and expiring on December 31, 2017 for our projects in Ontario. These contracts effectively fix the price of approximately 98% of our expected uncontracted gas requirements for 2015 and 32% and 30% of our expected uncontracted gas requirements for 2016 and 2017, respectively. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

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8. Accounting for derivative instruments and hedging activities (Continued)

Natural gas swaps

Our strategy to mitigate future exposure to changes in natural gas prices at our projects consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheets at fair value and the changes in their fair market value are recorded in the consolidated statements of operations.

We have entered into various natural gas swaps to effectively fix the price of 6.3 million MMbtu of future natural gas purchases at Orlando, which is approximately 100% of our share of the expected on-peak natural gas purchases at the project through 2016 or approximately 96% and 65% of our share of the expected base load natural gas purchases for 2015 and 2016, respectively. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value at June 30, 2015. Changes in the fair market value of these contracts are recorded in the consolidated statement of operations. On February 20, 2014, we paid $4.0 million to terminate certain of the natural gas contracts for our Orlando project in connection with the termination of our prior revolving credit facility. We recorded fuel expense related to the settlement of these contracts in the consolidated statement of operations for the six months ended June 30, 2014.

Interest rate swaps

On May 5, 2014, the Partnership entered into interest rate swap agreements to mitigate exposure to changes in the Adjusted Eurodollar Rate for $199.0 million notional amount ($167.3 million at June 30, 2015) of the $600 million aggregate principal amount of borrowings ($494.6 million of borrowings at June 30, 2015) under the Term Loan Facility. Borrowings under the $600 million Term Loan Facility bear interest at a rate equal to the Adjusted Eurodollar Rate plus an applicable margin of 3.75%. Based on the terms of the Credit Agreement, the Adjusted Eurodollar Rate cannot be less than 1.00% resulting in a minimum of a 4.75% all-in rate on the Term Loan Facility. As a result of entering into the swap agreements, the all-in rate for $199.0 million of the Term Loan Facility cannot be less than 4.91% if the Adjusted Eurodollar Rate is equal to or greater than 1.00%. If the Adjusted Eurodollar Rate is below 1.00%, we will pay interest at a rate equivalent to the minimum 4.75% all-in rate plus any difference between the actual Adjusted Eurodollar Rate and 1.16%. The interest rate swap agreements were effective June 30, 2014 and terminate on December 29, 2017. The interest rate swap agreements are not designated as hedges and changes in their fair market value will be recorded in the consolidated statements of operations.

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converts the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.8% through February 29, 2016. From February 2016 until the maturity of the debt in August 2018, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.5%. The swap continues at the fixed rate of 4.47% until November 2030. Prior to conversion of the Piedmont construction loan facility to a term loan, the notional amounts of the interest rate swap agreements matched the estimated outstanding principal balance of Piedmont's construction loan

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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8. Accounting for derivative instruments and hedging activities (Continued)

facility. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively. As a result of the Piedmont term loan conversion on February 14, 2014, these swap agreements were amended to reduce the notional amounts to match the outstanding $68.5 million principal of the term loan. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.0% through February 15, 2015, 6.1% from February 16, 2015 to February 15, 2019, 6.3% from February 16, 2019 to February 15, 2023, and 6.4% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies for and is designated as a cash flow hedge, is effective through June 2025 and the effective portion of the changes in the fair market value is recorded in accumulated other comprehensive loss.

Epsilon Power Partners, our wholly owned subsidiary, previously had an interest rate swap to economically fix the exposure to changes in interest rates related to the variable-rate non-recourse debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 7.37% and had a maturity date of July 2019. The notional amount of the swap matched the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. On February 20, 2014, we paid $2.6 million to terminate this contract in connection with the termination of our prior revolving credit facility. We recorded interest expense related to its settlement in the consolidated statement of operations for the six months ended June 30, 2014.

Foreign currency forward contracts

From time to time, we use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as many of our projects generate cash flow in U.S. dollars and Canadian dollars. On February 20, 2014, we paid $0.4 million to terminate all of our remaining foreign currency forward contracts in connection with the termination of our prior revolving credit facility and recorded their settlement in foreign exchange gain in the consolidated statement of operations for the six months ended June 30, 2014.

Volume of forecasted transactions

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the NPNS exemption at June 30, 2015 and December 31, 2014:

	Units	June 30, 2015	December 31, 2014
Natural gas swaps	Natural Gas (MMbtu)	4.5	6.3
Gas purchase agreements	Natural Gas (Gj)	29.4	33.9
Interest rate swaps	Interest (US$)	38.1	40.6

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

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8. Accounting for derivative instruments and hedging activities (Continued)

Fair value of derivative instruments

We have elected to disclose derivative instrument assets and liabilities on a trade-by-trade basis and do not offset amounts at the counterparty master agreement level. The following table summarizes the fair value of our derivative assets and liabilities:

	June 30, 2015	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1.2
Interest rate swaps long-term		2.8
Total derivative instruments designated as cash flow hedges		4.0
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		2.1
Interest rate swaps long-term	0.4	7.2
Natural gas swaps current		4.1
Natural gas swaps long-term		1.5
Gas purchase agreements current		28.6
Gas purchase agreements long-term		25.6
Total derivative instruments not designated as cash flow hedges	0.4	69.1
Total derivative instruments	$ 0.4	$ 73.1

	December 31, 2014	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1.1
Interest rate swaps long-term		2.9
Total derivative instruments designated as cash flow hedges		4.0
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		2.0
Interest rate swaps long-term	1.1	6.9
Natural gas swaps current		4.4
Natural gas swaps long-term		2.2
Gas purchase agreements current		28.6

Gas purchase agreements long-term				35.5
Total derivative instruments not designated as cash flow hedges		1.1		79.6
Total derivative instruments	$	1.1	$	83.6

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

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8. Accounting for derivative instruments and hedging activities (Continued)

Accumulated other comprehensive income

The following table summarizes the changes in the accumulated other comprehensive income (loss) ("OCI") balance attributable to derivative financial instruments designated as a hedge, net of tax:

For the three months ended June 30, 2015	**Interest Rate Swaps**
Accumulated OCI balance at March 31, 2015	$ (0.2)
Change in fair value of cash flow hedges	0.2
Realized from OCI during the period	0.1
Accumulated OCI balance at June 30, 2015	$ 0.1

For the three months ended June 30, 2014	**Interest Rate Swaps**
Accumulated OCI balance at March 31, 2014	$ 0.1
Change in fair value of cash flow hedges	(0.3)
Realized from OCI during the period	0.1
Accumulated OCI balance at June 30, 2014	$ (0.1)

For the six months ended June 30, 2015	**Interest Rate Swaps**
Accumulated OCI balance at January 1, 2014	$ 0.1
Change in fair value of cash flow hedges	(0.4)
Realized from OCI during the period	0.4
Accumulated OCI balance at June 30, 2015	$ 0.1

For the six months ended June 30, 2014	**Interest Rate Swaps**
Accumulated OCI balance at January 1, 2014	$ 0.2
Change in fair value of cash flow hedges	(0.7)

Realized from OCI during the period		0.4
Accumulated OCI balance at June 30, 2014	$	(0.1)

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(in millions U.S. dollars, except per-share amounts)

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8. Accounting for derivative instruments and hedging activities (Continued)

Impact of derivative instruments on the consolidated statements of operations

The following table summarizes realized loss (gain) for derivative instruments not designated as cash flow hedges:

	Classification of (gain) loss recognized in income	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Natural gas swaps	Fuel	$ 1.6	$ (0.2)	$ 3.0	$ 3.7
Gas purchase agreements	Fuel	12.3	13.4	24.2	29.3
Interest rate swaps	Interest, net	1.0	0.6	1.9	4.9
Foreign currency forwards	Foreign exchange (gain) loss				(0.1)

The following table summarizes the unrealized loss (gain) resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

	Classification of (gain) loss recognized in income	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Natural gas swaps	Change in fair value of derivatives	$ 1.4	$ (1.0)	$ 0.8	$ 3.5
Gas purchase agreements	Change in fair value of derivatives	3.9	2.6	5.6	18.6
Interest rate swaps	Change in fair value of derivatives	1.5	(2.0)	(1.2)	(0.5)
Total change in fair value of derivative instruments		$ 6.8	$ (0.4)	$ 5.2	$ 21.6
Foreign currency forwards	Foreign exchange (gain) loss	$	$ (1.4)	$	$ (0.3)

9. Income taxes

	Three months ended June 30, 2015	Three months ended June 30, 2014	Six months ended June 30, 2015	Six months ended June 30, 2014
Current income tax expense	$ 6.2	$ 1.3	$ 7.3	$ 2.6
Deferred tax benefit	(3.3)	(5.8)	(9.0)	(24.0)
Total income tax (benefit), net	$ 2.9	$ (4.5)	$ (1.7)	$ (21.4)

Income tax expense for the three months ended June 30, 2015 was $2.9 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26% was $4.4 million. The primary items impacting the tax rate for the three months ended June 30, 2015 were $9.0 million relating to a change in the valuation allowance, $3.4 million of dividend withholding and other state taxes, and $2.5 million of other permanent differences. These items were partially offset by $3.6 million relating to tax credits, $2.4 million relating to foreign exchange and $1.6 million relating to operating in higher tax rate jurisdictions.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

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9. Income taxes (Continued)

Income tax benefit for the three months ended June 30, 2014 was $9.1 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $12.9 million. The primary items impacting the tax rate for the three months ended June 30, 2014 were $14.2 million relating to a change in the valuation allowance and $2.4 million relating to foreign exchange. These items were partially offset by $4.1 million relating to operating in higher tax rate jurisdictions, $2.4 million of minority interest adjustments, and $6.3 million relating to other permanent differences.

Income tax benefit for the six months ended June 30, 2015 was $1.7 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $0.8 million. The primary items impacting the tax rate for the six months ended June 30, 2015 were $4.1 million relating to foreign exchange, $4.0 million relating to operating in higher tax rate jurisdictions, $3.6 million related to tax credits, and $0.6 million of other permanent differences. These items were partially offset by $6.2 million relating to a change in the valuation allowance, and $3.6 million relating to dividend withholding and other taxes.

Income tax benefit for the six months ended June 30, 2014 was $21.4 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $21.9 million. The primary items impacting the tax rate for the six months ended June 30, 2014 were $29.3 million relating to a change in the valuation allowance. These items were partially offset by $11.1 million of capital losses recognized on tax restructuring, $9.7 million of operating in higher tax rate jurisdictions, $1.2 million relating to foreign exchange and $6.8 million of other permanent differences.

As of June 30, 2015, we have recorded a valuation allowance of $174.7 million. The amount is comprised primarily of provisions against Canadian and U.S. net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

10. Equity compensation plans

Long-term incentive plan ("LTIP")

The following table summarizes the changes in outstanding LTIP notional units during the six months ended June 30, 2015:

	Units	Weighted-Average Price per Unit
Outstanding at December 31, 2014	1,443,254	$ 3.28
Granted	1,007,726	2.75
Reinvested	28,658	2.85
Forfeited	(63,499)	4.19
Vested	(597,406)	3.61
Outstanding at June 30, 2015	1,818,733	$ 2.85

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

10. Equity compensation plans (Continued)

Certain awards have a market condition based on our total shareholder return during the performance period as compared to a group of peer companies and, in some cases, Project Adjusted EBITDA per common share compared to budget. Compensation expense for notional units granted is recorded net of estimated forfeitures. See Note 16 to the consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2014 for further details. Cash payments made for vested notional units for the six months ended June 30, 2015 and 2014 was \$0.6 million and \$0.2 million, respectively. Compensation expense for LTIP was \$0.5 million and \$1.0 million for the three and six months ended June 30, 2015, respectively, and \$1.0 million and \$0.9 million for the three and six months ended June 30, 2014, respectively.

Transition Equity Participation Agreement

We also have 523,256 transition notional shares outstanding at June 30, 2015 under the Transition Equity Participation Agreement. Fifty percent of the transition notional shares granted with respect to fiscal year 2015 will vest upon the four-year anniversary of the date of grant and the remaining portion will vest on or any time after the two-year anniversary of the grant if the weighted average Canadian dollar closing price of our common shares on the TSX for at least three consecutive calendar months has exceeded the market price per common share determined as of January 22, 2015 (\$2.58) by at least 50%.

11. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss for the three and six months ended June 30, 2014, diluted earnings per share are equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

11. Basic and diluted earnings (loss) per share (Continued)

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the three and six months ended June 30, 2015 and 2014:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Numerator:				
Loss from continuing operations attributable to Atlantic Power Corporation	$ (22.3)	$ (53.8)	$ (0.1)	$ (70.7)
Income (loss) from discontinued operations, net of tax	37.0	(5.4)	32.1	(7.3)
Net income (loss) attributable to Atlantic Power Corporation	$ 14.7	$ (59.2)	$ 32.2	$ (73.0)
Denominator:				
Weighted average basic shares outstanding	121.9	120.6	121.7	120.5
Dilutive potential shares:				
Convertible debentures	22.6	27.7	23.0	27.7
LTIP notional units	0.2	0.4	0.2	0.2
Potentially dilutive shares	144.7	148.7	144.9	148.4
Diluted loss per share from continuing operations attributable to Atlantic Power Corporation	$ (0.18)	$ (0.45)	$ (0.0)	$ (0.59)
Diluted income (loss) per share from discontinued operations	0.30	(0.04)	0.26	(0.06)
Diluted income (loss) per share attributable to Atlantic Power Corporation	$ 0.12	$ (0.49)	$ 0.26	$ (0.65)

Potentially dilutive shares from convertible debentures of 22.6 million and 23.0 million have been excluded from fully diluted shares in the three and six months ended June 30, 2015, respectively, because their impact would be anti-dilutive. Potentially dilutive shares from convertible debentures of 27.7 million and 27.7 million have been excluded from fully diluted shares in the three and six months ended June 30, 2014, respectively, because their impact would be anti-dilutive. Potentially dilutive shares from LTIP notional units have been excluded from fully diluted shares in the three and six months ended June 30, 2014 because their impact would be anti-dilutive.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

12. Equity

The following table provides a reconciliation of the beginning and ending equity attributable to shareholders of Atlantic Power Corporation, preferred shares issued by a subsidiary company, noncontrolling interests and total equity for the six months ended June 30, 2015 and 2014:

	Six months ended June 30, 2015			
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Noncontrolling Interests	Total Equity
Balance at January 1	$ 356.2	$ 221.3	$ 239.0	$ 816.5
Net income (loss)	32.2	4.6	(11.0)	25.8
Foreign currency translation adjustment, net of tax	(30.6)			(30.6)
Stock-based compensation	1.0			1.0
Dividends paid to noncontrolling interests			(3.7)	(3.7)
Dividends declared on common shares	(5.8)			(5.8)
Dividends declared on preferred shares of a subsidiary company		(4.6)		(4.6)
Derecognition of noncontrolling interests upon sale of subsidiaries			(224.3)	(224.3)
Balance at June 30	$ 353.0	$ 221.3	$	$ 574.3

	Six months ended June 30, 2014			
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Noncontrolling Interests	Total Equity
Balance at January 1	$ 608.3	$ 221.3	$ 266.4	$ 1,096.0
Net (loss) income	(78.0)	5.9	(6.7)	(78.8)
Realized and unrealized gain on hedging activities, net of tax	(0.2)			(0.2)
Foreign currency translation adjustment, net of tax	(1.5)			(1.5)
Stock-based compensation	0.6			0.6
Dividends paid to noncontrolling interest			(5.2)	(5.2)
Dividends declared on common shares	(21.1)			(21.1)
Dividends declared on preferred shares of a subsidiary company		(5.9)		(5.9)
Balance at June 30	$ 508.1	$ 221.3	$ 254.5	$ 983.9

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

13. Segment and geographic information

We have four reportable segments: East U.S., West U.S., Canada and Un-allocated Corporate. We revised our reportable business segments in the second quarter of 2015 as the result of recent significant asset sales and in order to align with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. The Wind Projects, which made up the entirety of the former Wind segment, were sold in June 2015 and are designated as discontinued operations for the three and six months ended June 30, 2014 and 2015. Our financial results for the three and six months ended June 30, 2014 have been revised to reflect these changes in operating segments. We analyze the performance of our operating segments based on Project Adjusted EBITDA which 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 use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. Our equity investments in unconsolidated affiliates are presented as proportionately consolidated based on our ownership percentage in the reconciliation of Project Adjusted EBITDA to project income (loss).

A reconciliation of Project Adjusted EBITDA to project income (loss) for the three and six months ended June 30, 2014 and 2015 reflecting our revised reportable business segments is included in the table below:

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Three months ended June 30, 2015					
Project revenues	$ 38.9	$ 26.3	$ 37.7	$ 0.2	$ 103.1
Segment assets	858.6	375.8	612.8	452.7	2,299.9
Project Adjusted EBITDA	$ 27.0	$ 5.7	$ 11.6	$ (0.4)	$ 43.9
Change in fair value of derivative instruments	(3.0)		(3.9)		(6.9)
Depreciation and amortization	10.8	10.0	12.7	(0.2)	33.3
Interest, net	2.5				2.5
Other project expense (income)				(2.2)	(2.2)
Project income (loss)	16.7	(4.3)	2.8	2.0	17.2
Administration				6.6	6.6
Interest, net				24.6	24.6
Foreign exchange loss				4.8	4.8
Other income, net				(1.7)	(1.7)
Income (loss) from continuing operations before income taxes	16.7	(4.3)	2.8	(32.3)	(17.1)
Income tax expense				2.9	2.9
Net income (loss) from continuing operations	16.7	(4.3)	2.8	(35.2)	(20.0)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

13. Segment and geographic information (Continued)

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Three months ended June 30, 2014					
Project revenues	$ 44.9	$ 33.1	$ 44.9	$ 0.2	$ 123.1
Segment assets	921.4	477.6	770.8	222.7	2,392.5
Project Adjusted EBITDA	$ 30.8	$ 15.9	$ 14.6	$ (3.6)	$ 57.7
Change in fair value of derivative instruments	1.8		(2.6)	1.1	0.3
Depreciation and amortization	15.2	10.1	15.3	0.2	40.8
Interest, net	3.7			0.1	3.8
Other project expense			14.8		14.8
Project income (loss)	10.1	5.8	(12.9)	(5.0)	(2.0)
Administration				10.2	10.2
Interest, net				27.7	27.7
Foreign exchange loss				15.3	15.3
Other income, net					
Income (loss) from continuing operations before income taxes	10.1	5.8	(12.9)	(58.2)	(55.2)
Income tax benefit				(4.5)	(4.5)
Net income (loss) from continuing operations	10.1	5.8	(12.9)	(53.7)	(50.7)

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Six months ended June 30, 2015					
Project revenues	$ 76.5	$ 49.3	$ 88.3	$ 0.3	$ 214.4
Segment assets	960.7	273.7	612.8	452.7	2,299.9
Project Adjusted EBITDA	$ 53.7	$ 15.6	$ 35.4	$ (2.2)	$ 102.5
Change in fair value of derivative instruments	(0.4)		(5.5)	0.8	(5.1)
Depreciation and amortization	21.2	19.6	24.9	0.4	66.1
Interest, net	4.9				4.9
Other income				(2.2)	(2.2)
Project income (loss)	28.0	(4.0)	16.0	(1.2)	38.8
Administration				16.0	16.0
Interest, net				50.3	50.3
Foreign exchange gain				(27.4)	(27.4)
Other income, net				(3.1)	(3.1)
Income (loss) from continuing operations before income taxes	28.0	(4.0)	16.0	(37.0)	3.0

Income tax benefit				(1.7)	(1.7)
Net income (loss) from continuing operations	28.0	(4.0)	16.0	(35.3)	4.7

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

13. Segment and geographic information (Continued)

	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated
Six months ended June 30, 2014					
Project revenues	$ 90.6	$ 60.3	$ 97.2	$ 0.3	$ 248.4
Segment assets	921.4	477.6	770.8	222.7	2,392.5
Project Adjusted EBITDA	$ 55.2	$ 23.7	$ 39.3	$ (3.6)	$ 114.6
Change in fair value of derivative instruments	(4.0)		(18.6)	1.2	(21.4)
Depreciation and amortization	30.6	20.4	30.4	0.5	81.9
Interest, net	15.3	0.1			15.4
Other project expense			14.8		14.8
Project income (loss)	13.3	3.2	12.7	(5.3)	23.9
Administration				17.5	17.5
Interest, net				94.1	94.1
Foreign exchange gain				(1.5)	(1.5)
Other income, net					
Income (loss) from continuing operations before income taxes	13.3	3.2	12.7	(115.4)	(86.2)
Income tax benefit				(21.4)	(21.4)
Net income (loss) from continuing operations	13.3	3.2	12.7	(94.0)	(64.8)

The table below provides information, by country, about our consolidated operations for each of the three and six months ended June 30, 2015 and 2014 and Property, Plant & Equipment as of June 30, 2015 and December 31, 2014, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Project Revenue Three months ended June 30,		Project Revenue Six months ended June 30,		Property, Plant and Equipment, net of accumulated depreciation	
	2015	2014	2015	2014	June 30, 2015	December 31, 2014
United States	$ 65.4	$ 78.2	$ 126.1	$ 151.2	$ 541.6	$ 553.5
Canada	37.7	44.9	88.3	97.2	367.0	409.4
Total	$ 103.1	$ 123.1	$ 214.4	$ 248.4	$ 908.6	$ 962.9

Independent Electricity System Operator ("IESO"), San Diego Gas & Electric, BC Hydro and Niagara Mohawk Power Corporation provided 26.4%, 12.5%, 10.3% and 10.9%, respectively, of total consolidated revenues for the three months ended June 30, 2015 and 30.2%, 10.6%, 11.0% and 8.6%, respectively, of total consolidated revenues for the six months ended June 30, 2015. IESO, San Diego Gas & Electric and BC Hydro provided 25.4%, 19.4% and 11.1%, respectively, of total consolidated revenues for the three months ended June 30, 2014 and 29.0%, 17.4% and 10.1%, respectively, of total consolidated revenues for the six months ended June 30, 2014. IESO purchases electricity from the Calstock, Kapuskasing, Nipigon and North Bay projects in the Canada segment, San Diego Gas &

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

13. Segment and geographic information (Continued)

Electric purchases electricity from the Naval Station, Naval Training Center, and North Island projects in the West U.S. segment, BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the Canada segment and Niagara Mohawk Power Corporation purchases electricity from the Curtis Palmer project in the East U.S. segment.

14. Guarantees

We and our subsidiaries enter into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchases and sale agreements, including the Purchase Agreement to sell the Wind Projects, joint venture agreements, operation and maintenance agreements, and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

In connection with the Purchase Agreement for the sale of the Wind Projects, on March 31, 2015, we entered into a guaranty agreement (the "Guaranty Agreement"), under which we agreed to guarantee the full and prompt payment of all payment obligations of APT under the Purchase Agreement as and when they shall become due. APT and TerraForm have agreed to utilize the representation and warranty insurance for coverage of certain indemnification obligations, subject to a cap and certain exclusions.

15. Contingencies

Shareholder class action lawsuits

Massachusetts District Court Actions

On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints were filed by alleged investors in Atlantic Power common shares in the United States District Court for the District of Massachusetts (the "District Court") against Atlantic Power and Barry E. Welch, our former President and Chief Executive Officer and a former Director of Atlantic Power, in each of the actions, and, in addition to Mr. Welch, some or all of Patrick J. Welch, our former Chief Financial Officer, Lisa Donahue, our former interim Chief Financial Officer, and Terrence Ronan, our current Chief Financial Officer, in certain of the actions (the "Proposed Individual Defendants," and together with Atlantic Power, the "Proposed Defendants") (the "U.S. Actions").

The District Court complaints differed in terms of the identities of the Proposed Individual Defendants they named, as noted above, the named plaintiffs, and the purported class period they alleged (July 23, 2010 to March 4, 2013 in three of the District Court actions and August 8, 2012 to February 28, 2013 in the other two District Court actions), but in general each alleged, among other things, that in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, Atlantic Power and the Proposed Individual Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

15. Contingencies (Continued)

dividend that artificially inflated the price of Atlantic Power's common shares. The District Court complaints assert claims under Section 10(b) and, against the Proposed Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended.

The parties to each District Court action filed joint motions requesting that the District Court set a schedule in the District Court actions, including: (i) setting a deadline for the lead plaintiff to file a consolidated amended class action complaint (the "Amended Complaint"), after the appointment of lead plaintiff and counsel; (ii) setting a deadline for Proposed Defendants to answer, file a motion to dismiss or otherwise respond to the Amended Complaint (and for subsequent briefing regarding any such motion to dismiss); and (iii) confirming that the Proposed Defendants need not answer, move to dismiss or otherwise respond to any of the five District Court complaints prior to the filing of the Amended Complaint. On May 7, 2013, each of six groups of investors (the "U.S. Lead Plaintiff Applicants") filed a motion (collectively, the "U.S. Lead Plaintiff Motions") with the District Court seeking: (i) to consolidate the five U.S. Actions (the "Consolidated U.S. Action"); (ii) to be appointed lead plaintiff in the Consolidated U.S. Action; and (iii) to have its choice of lead counsel confirmed. On May 22, 2013, three of the U.S. Lead Plaintiff Applicants filed oppositions to the other U.S. Lead Plaintiff Motions, and on June 6, 2013, those three Lead Plaintiff Applicants filed replies in support of their respective motions. On August 19, 2013, the District Court held a status conference to address certain issues raised by the U.S. Lead Plaintiff Motions, entered an order consolidating the five U.S. Actions, and directed two of the six U.S. Lead Plaintiff Applicants to file supplemental submissions by September 9, 2013. Both of those U.S. Lead Plaintiff Applicants filed the requested supplemental submissions, and then sought leave to file additional briefing. The Court granted those requests for leave and additional submissions were filed on September 13 and September 18, 2013.

On March 31, 2014, the Court entered an order consolidating the five individual U.S. Actions, appointing the Feldman, Shapero, Carter and Smith investor group (one of the six U.S. Lead Plaintiffs Applicants) as Lead Plaintiff and approving Lead Plaintiff's selection of counsel. The Court also granted the parties' joint motion regarding initial case scheduling and directed the parties to resubmit a proposed schedule that contains specific dates. In response to that directive, on April 7, 2014, Lead Plaintiff filed an application and proposed order, which sought an extension of the schedule contained in the joint motion. The application and proposed order requested that: (i) Lead Plaintiff be permitted to file an amended complaint on or before May 30, 2014, (ii) the Proposed Defendants be permitted to move to dismiss or otherwise respond to the amended complaint on or before July 29, 2014, (iii) Lead Plaintiff be permitted to file an opposition, if any, on or before September 24, 2014, and (iv) the Proposed Defendants be permitted to file a reply to Lead Plaintiff's opposition on or before November 13, 2014. Proposed Defendants did not object to the schedule proposed by Lead Plaintiff. On May 29, 2014, Lead Plaintiff filed a renewed application and proposed order, which sought another extension of the schedule, and on June 3, 2014, Lead Plaintiff and the Proposed Defendants jointly filed a stipulation and proposed order requesting the following revised schedule: (i) Lead Plaintiff be permitted to file an amended complaint on or before June 6, 2014, (ii) the Proposed Defendants be permitted to move to dismiss or otherwise respond to the amended complaint on or before August 5, 2014, (iii) Lead Plaintiff be permitted to file an opposition, if any, on or before October 6, 2014, and

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

15. Contingencies (Continued)

(iv) the Proposed Defendants be permitted to file a reply to Lead Plaintiff's opposition on or before November 20, 2014. On June 3, 2014, the Court entered an order setting this requested schedule.

On June 6, 2014, Lead Plaintiff filed the amended complaint (the "Amended Complaint"). The Amended Complaint names as defendants Barry E. Welch and Terrence Ronan (the "Individual Defendants") and Atlantic Power (together with the Individual Defendants, the "Defendants") and alleges a class period of June 20, 2011 to March 4, 2013 (the "Class Period"). The Amended Complaint makes allegations that are substantially similar to those asserted in the five initial complaints. Specifically, the Amended Complaint alleges, among other things, that in Atlantic Power's press releases, quarterly and year- end filings and conference calls with analysts and investors, Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend, which artificially inflated the price of Atlantic Power's common shares during the class period. The Amended Complaint continues to assert claims under Section 10(b) and, against the Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended. It also asserts a claim for unjust enrichment against the Individual Defendants. In accordance with the schedule referenced above, Defendants filed their motion to dismiss the consolidated (the "Motion to Dismiss") U.S. Action on August 5, 2014.

On September 30, 2014, citing Atlantic Power's September 16, 2014 announcement of changes to its dividend and its President and CEO transition, Lead Plaintiff filed a motion (the "Extension Motion") requesting a thirty-day extension of its October 6, 2014 deadline for filing its brief in opposition to the Motion to Dismiss, in which to determine whether to file a second amended complaint. On October 2, 2014, the Court entered an order (i) extending Lead Plaintiff's deadline to file its opposition to the Motion to Dismiss to October 10, 2014 and (ii) requiring Defendants to file their opposition to the Extension Motion by October 2, 2014. In accordance with this order, on October 2, 2014, Defendants filed their opposition to the Extension Motion. On October 10, 2014, Lead Plaintiff filed its opposition to the Motion to Dismiss (the "Opposition") and also filed a motion for leave to amend the Amended Complaint, attaching a proposed second amended complaint. On October 21, 2014, Lead Plaintiff and Defendants filed a joint scheduling motion requesting (i) November 7, 2014 as the deadline for Defendants to file their opposition to Lead Plaintiff's motion for leave to amend the Amended Complaint; (ii) November 24, 2014 as the deadline for Defendants to file their reply in further support of the Motion to Dismiss; and (iii) November 24, 2014 as the deadline for Lead Plaintiff to file its reply in further support of its motion for leave to amend the Amended Complaint. On October 22, 2014, the Court entered an order setting this requested schedule. Pursuant to that order, the Motion to Dismiss and Extension Motion were fully briefed on November 24, 2014. On January 22, 2015, the Court held oral argument on the Motion to Dismiss and Extension Motion.

On January 30, 2015, Lead Plaintiff filed a motion for leave to file a supplemental submission in opposition to Defendants' motion to dismiss (the "Motion for Leave"). The Court denied the Motion for Leave in an order entered on February 5, 2015, but permitted Lead Plaintiff to submit a brief letter identifying supplemental authorities. Lead Plaintiff filed that letter on February 9, 2015, and Defendants filed a response on February 10, 2015.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

15. Contingencies (Continued)

On March 13, 2015, the District Court entered an order granting Defendants' motion to dismiss and denying Lead Plaintiff's motion to amend the Amended Complaint, and on March 18, 2015, the District Court entered an order dismissing the Amended Complaint with prejudice. On April 16, 2015, Lead Plaintiff filed a notice of appeal to the United States Court of Appeals for the First Circuit. The Company will oppose that appeal.

Canadian Actions

On March 19, 2013, April 2, 2013 and May 10, 2013, three notices of action relating to Canadian securities class action claims against the Proposed Defendants were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, with the Ontario Superior Court of Justice in the Province of Ontario. On April 8, 2013, a similar claim issued by alleged investors in Atlantic Power common shares seeking to initiate a class action against the Proposed Defendants was filed with the Superior Court of Quebec in the Province of Quebec (the "Canadian Actions").

On April 17, May 22, and June 7, 2013, statements of claim relating to the notices of action were filed with the Ontario Superior Court of Justice in the Province of Ontario.

On August 30, 2013, the three Ontario actions were succeeded by one action with an amended claim being issued on behalf of Jacqeline Coffin and Sandra Lowry. As in the U.S. Action, this claim names the Company, Barry E. Welch and Terrence Ronan as Defendants. The Plaintiffs seek leave to commence an action for statutory misrepresentation under the Ontario Securities Act and assert common law claims for misrepresentation. The Plaintiffs' allegations focus on among other things, claims the Defendants made materially false and misleading statements and omissions in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The Plaintiffs sought to certify the statutory and common law claims under the Class Proceedings Act for security holders who purchased and held securities through a proposed class period of November 5, 2012 to February 28, 2013.

On October 4, 2013, the Plaintiffs delivered materials supporting their request for leave to commence an action for statutory misrepresentations and for certification of the statutory and common claims as class proceedings. These materials estimate the damages claimed for statutory misrepresentation at $197.4 million.

On March 26, 2015, the Plaintiffs amended their claim to add Scott Fife as a proposed representative plaintiff. On April 24, 2015, the Plaintiffs amended their claim to remove Ms. Lowry, who claimed to hold Atlantic Power convertible debentures, as a proposed representative plaintiff.

The Plaintiffs' motions for leave and certification were heard on May 20-21, 2015.

On July 24, 2015, the Ontario Superiour Court of Justice issued a decision denying the Plaintiffs' motion for leave and certification. The Superior Court granted leave to reconstitute a claim for debenture holders but required that there be a debenture holder as plaintiff, that the claim be

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(in millions U.S. dollars, except per-share amounts)

(Unaudited)

15. Contingencies (Continued)

amended and that the Plaintiffs pay the Defendants partial indemnity costs of responding to the Plaintiffs' motion.

Plaintiffs have advised that they intend to proceed with an appeal of the July 24 decision on leave and certification. The Company will oppose that appeal.

The proposed class action in Quebec is stayed until August 28, 2015.

Pursuant to the Private Securities Litigation Reform Act of 1995, all discovery is stayed in the U.S. Actions. Plaintiffs have not yet specified an amount of alleged damages in the U.S. Actions. As noted above, the plaintiffs in the Canadian Action have estimated their alleged statutory damages at $197.4 million. Because both the U.S. and Canadian Actions are in their early stages, Atlantic Power is unable to reasonably estimate the possible loss or range of losses, if any, arising from this litigation. Atlantic Power intends to defend vigorously against each of the actions.

Other

In addition to the other matters listed, from time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of June 30, 2015.

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FORWARD-LOOKING INFORMATION

Certain statements in this Quarterly Report on Form 10-Q constitute "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995. Forward-looking statements generally can be identified by the use of forward-looking terminology such as "outlook," "objective," "may," "will," "expect," "intend," "estimate," "anticipate," "believe," "should," "plans," "continue," or similar expressions suggesting future outcomes or events. Examples of such statements in this Quarterly Report on Form 10-Q include, but are not limited to, statements with respect to the following:

- our ability to generate sufficient cash flow to pay dividends, service our debt obligations or finance internal or external growth opportunities;

- the impact of recent management changes on our ability to execute our business plan;

- the outcome or impact of our business plan, including the objective of enhancing the value of our existing assets through optimization investments and commercial activities, delevering our balance sheet to improve our cost of capital and ability to compete for new investments, and utilizing our core competencies to create proprietary investment opportunities;

- our ability to evaluate and/or implement potential options in order to raise additional capital for growth and/or debt reduction, and the outcome or impact on our business of any such potential options;

- our ability to access liquidity for the ongoing operation of our business and the execution of our business plan or any potential options, which may involve one or more of the use of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately-placed bank or institutional non-recourse operating level debt;

- our ability to meet the financial covenants under our indebtedness;

- expectations regarding maintenance and capital expenditures; and

- the impact of legislative, regulatory, competitive and technological changes.

Such forward-looking statements reflect our current expectations regarding future events and operating performance and speak only as of the date of this Quarterly Report on Form 10-Q. Such forward-looking statements are based on a number of assumptions which may prove to be incorrect, including, but not limited to the assumption that the projects will operate and perform in accordance with our expectations. Many of these risks and uncertainties can affect our actual results and could cause our actual results to differ materially from those expressed or implied in any forward-looking statement made by us or on our behalf.

Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. In addition, a number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors included in the filings Atlantic Power makes from time to time with the SEC and the risk factors described under "Item 1A. Risk Factors" in our Annual Report on Form 10-K for the year ended December 31, 2014 and in this Quarterly Report on Form 10-Q. To the extent any risk factors in our Annual Report on Form 10-K for the year ended December 31, 2014 relate to the factual information disclosed elsewhere in this Quarterly Report on Form 10-Q, including with respect to our business plan and any updates to our business strategy, such risk factors should be read in light of such information. Our business is both highly competitive and subject to various risks.

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These risks include, without limitation:

- the concentration of our business as a result of the sale of our Wind Projects;
- our ability to generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or implement our business plan, including financing internal or external growth opportunities;
- the impact of recent management changes on our ability to execute our business plan;
- the outcome or impact of our business plan, and our ability to evaluate and/or implement potential options in order to raise additional capital for growth or potential debt reduction, and the outcome or impact of any such potential options;
- our ability to access liquidity for the ongoing operation of our business and the execution of our business plan or any potential options, which may involve one or more of the use of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately-placed bank or institutional non-recourse operating level debt;
- our indebtedness and financing arrangements and the terms, covenants and restrictions included in our Senior Secured Credit Facilities;
- exchange rate fluctuations;
- the impact of downgrades in our credit rating or the credit rating of our outstanding debt securities, and changes in our creditworthiness;
- unstable capital and credit markets;
- the outcome of certain shareholder class action lawsuits;
- the expiration or termination of power purchase agreements and our ability to renew or enter into new power purchase agreements on favorable terms or at all;
- the dependence of our projects on their electricity and thermal energy customers;
- exposure of certain of our projects to fluctuations in the price of electricity or natural gas;
- the dependence of our projects on third-party suppliers;
- projects not operating according to plan;

the effects of weather, which affects demand for electricity and fuel as well as operating conditions;

the dependence of our hydropower projects on suitable precipitation and associated weather conditions;

U.S., Canadian and/or global economic conditions and uncertainty;

risks beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events;

the adequacy of our insurance coverage;

the impact of significant energy, environmental and other regulations on our projects;

the impact of impairment of goodwill or long-lived assets;

increased competition, including for acquisitions;

our limited control over the operation of certain minority-owned projects;

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- transfer restrictions on our equity interests in certain projects;
- risks inherent in the use of derivative instruments;
- labor disruptions;
- the impact of hostile cyber intrusions;
- the impact of our failure to comply with the U.S. Foreign Corrupt Practices Act and/or Canadian Corruption of Foreign Public Officials Act; and
- our ability to retain, motivate and recruit executives and other key employees.

Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include third-party projections of regional fuel and electric capacity and energy prices that are based on assumptions about future economic conditions and courses of action. Although the forward-looking statements contained in this Quarterly Report on Form 10-Q are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. Certain statements included in this Quarterly Report on Form 10-Q may be considered "financial outlook" for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this Quarterly Report on Form 10-Q. These forward-looking statements are made as of the date of 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 power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. As of June 30, 2015, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,137 megawatts ("MW") in which our aggregate ownership interest is approximately 1,502 MW. Our current portfolio consists of interests in twenty-three operational power generation projects across nine states in the United States and two provinces in Canada. Eighteen of our projects are majority-owned subsidiaries. These totals exclude an aggregate 521 MW from our previous 100% ownership interest in Meadow Creek Project Company, LLC ("Meadow Creek"), 99% ownership in Canadian Hills Wind, LLC ("Canadian Hills"), 50% ownership interest in Rockland Wind Farm, LLC ("Rockland"), 27.6% ownership interest in Idaho Wind Partners 1, LLC ("Idaho Wind") and 12.5% ownership interest in Goshen Phase II, LLC ("Goshen") (collectively, the "Wind Projects"), which we sold on June 26, 2015, and which are designated discontinued operations.

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 (at our North Bay and Kapuskasing projects, which collectively accounted for 9% of Project Adjusted EBITDA for the year ended December 31, 2014) to December 31, 2037, and approximately 25% of our PPAs on a MW-weighted basis are scheduled to expire over the next five years. Our weighted average remaining PPA life is approximately 8 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, including Colorado Energy Management and Power Plant Management Services. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

We announce material financial information to our investors using our website (www.atlanticpower.com), SEC filings, investor events, news and earnings releases, public conference calls and webcasts. We use these channels as well as social media to communication with our investors and the public about our company, our power projects, and other issues. It is possible that information we post on our website or on social medial may be deemed to be material information. Therefore, we encourage investors, the media and others interested in our company to review the information we post on our website and on the social media channels listed below. This list may be updated from time to time on our website.

The contents of these websites are not intended to be incorporated by reference into this Quarterly Report on Form 10-Q or in any other report or document we file, and any reference to these websites are intended to be inactive textual references only.

RECENT DEVELOPMENTS

Redemption of 9.0% Senior Unsecured Notes due November 2018

On June 26, 2015, we called for the redemption of all our outstanding $310.9 million aggregate principal amount of 9.0% Senior Unsecured Notes due November 2018 (the "Notes"). On July 26, 2015, we completed the redemption of the Notes with the cash proceeds received from the sale of the Wind Projects at a price equal to 104.5 percent of the principal amount of the Notes, plus accrued and unpaid interest to the redemption date. We paid $330.4 million in cash to fund the full redemption of the Notes. We will record approximately $28.5 million of interest expense related to the redemption premium, accrued interest and the write-off of deferred financing costs for the three and nine months ended September 30. 2015.

Wind Projects Sale

On March 31, 2015, Atlantic Power Transmission, Inc. ("APT"), our wholly-owned, direct subsidiary, entered into a definitive agreement (the "Purchase Agreement") with TerraForm AP Acquisition Holdings, LLC ("TerraForm"), an affiliate of SunEdison, Inc. (an affiliate of TerraForm Power, Inc.), to sell our Wind Projects. On June 26, 2015, the sale was completed for aggregate cash proceeds of approximately $335 million after transaction fees, exclusive of transaction-related taxes. We recorded a $47.3 million gain on sale which is included as a component of income from discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2015.

Terraform acquired from APT, 100% of its direct membership interests in a holding company formed to facilitate the sale, thereby acquiring our indirect interests in our portfolio of Wind Projects consisting of five operating wind projects in Idaho and Oklahoma and representing 521 MW net ownership: Goshen (12.5% economic interest), Idaho Wind (27.6% economic interest), Meadow Creek (100% economic interest); Rockland Wind Farm (50% economic interest, but consolidated on a 100% basis); and Canadian Hills (99% economic interest). As a result of the sale, we deconsolidated approximately $249 million of project debt (or approximately $274 million as adjusted for our proportional ownership of Rockland, Goshen North and Idaho Wind) and approximately $224 million of noncontrolling interest related to tax equity interests at Canadian Hills and the minority ownership interests at Rockland and Canadian Hills. The Wind Projects are accounted for as assets held for sale in the consolidated balance sheet at December 31, 2014 and are a component of discontinued operations in the consolidated statements of operations for the three and six months ended June 30, 2015 and 2014.

In connection with the Purchase Agreement, on March 31, 2015, we entered into a guaranty agreement (the "Guaranty Agreement"), under which we agreed to guarantee the full and prompt payment of all payment obligations of APT under the Purchase Agreement as and when they shall become due. APT and TerraForm have agreed to utilize the representation and warranty insurance for coverage of certain indemnification obligations, subject to a cap and certain exclusions. In addition, on June 3, 2015, we and Terraform entered into an amendment to the Purchase Agreement (the

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"Amendment") to make certain immaterial amendments to the Purchase Agreement, which is filed as Exhibit 10.1 to this Quarterly Report on Form 10-Q.

The foregoing description is qualified in its entirety by reference to the full text of the Purchase Agreement and the Guaranty Agreement, which are filed as Exhibit 10.1 and 10.2, respectively, to our Quarterly Report on Form 10-Q for the quarter ended March 31, 2015, and incorporated by reference herein, and the Amendment, which is filed as Exhibit 10.1 to this Quarterly Report on Form 10-Q, and incorporated by reference herein.

Frontier Sale

On April 22, 2015, our indirect wholly-owned subsidiary, Ridgeline Energy LLC ("Ridgeline'), closed a transaction with CRE-Frontier Solar California LLC ("CRE"), a subsidiary of Centaurus Renewable Energy LLC, whereby CRE agreed to purchase 100% of Ridgeline's equity interests in Frontier Solar, LLC ("Frontier"), which is developing an approximately 20 MW solar electric generating facility in California, for net cash proceeds of $4.3 million. If Frontier achieves commercial operations and meets certain operating performance metrics, we could receive additional cash proceeds. We recorded a $2.3 million gain on sale related to the transaction in the consolidated statements of operations for the three and six months ended June 30, 2015.

OUR POWER PROJECTS

The table on the following page outlines our portfolio of power generating assets in operation as of August 7, 2015, 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

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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	53	100.0%	53	Georgia Power	December 2032	A
Morris	Illinois	Natural Gas	177	100.00%	120	Merchant	N/A	N/R
					57	Equistar Chemicals, LP[2]	November 2023	BBB+
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	December 2028	BBB+
Chambers[1]	New Jersey	Coal	262	40.00%	89	Atlantic City Elec.[3]	March 2024	BBB+
					16	DuPont	March 2024	A
Kenilworth	New Jersey	Natural Gas	25	100.00%	25	Merck, & Co., Inc.	September 2018	AA
Curtis Palmer	New York	Hydro	60	100.00%	60	Niagara Mohawk Power Corperation	December 2027[4]	A
Selkirk[1]	New York	Natural Gas	345	18.50%	64	Merchant	N/A	N/R
West U.S. Segment								
Naval Station	California	Natural Gas	47	100.00%	47	San Diego Gas & Electric	December 2019[5]	A

Naval Training Center	California	Natural Gas	25	100.00%	25	San Diego Gas & Electric	December 2019[5]	A
North Island	California	Natural Gas	42	100.00%	42	San Diego Gas & Electric	December 2019[5]	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	A+
					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	Independent Electricity System Operator	June 2020	AA
Kapuskasing	Ontario	Natural Gas	40	100.00%	40	Independent Electricity System Operator	December 2017	AA
Nipigon	Ontario	Natural Gas	40	100.00%	40	Independent Electricity System Operator	December 2022	AA
North Bay	Ontario	Natural Gas	40	100.00%	40	Independent Electricity System Operator	December 2017	AA

Tunis[6]	Ontario	Natural Gas	43	100.00%	43	Independent Electricity System Operator	NA	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 June 30, 2015, the facility has generated 6,550 GWh under its PPA.

(5) Our land leases with the U.S. Navy expire in February 2018 along with the associated energy sales agreements. We have initiated communications with the U.S. Navy to extend the leases through at least the expiration date of the PPAs in December 2019.

(6) On January 20, 2015, we entered into an agreement with the Ontario Power Authority and its successor, the Independent Electricity System Operator ("IESO"), for the future operations of the Tunis facility. Subject to meeting certain technical modifications to the plant, gas delivery and other requirements, Tunis will operate under a 15-year agreement with the IESO commencing between November 2017 and June 2019. The new contract will require the plant to become fully dispatchable as opposed to its current baseload configuration. As such, Tunis will only provide electricity to the Ontario grid when required, thereby assisting to reduce the incidents of surplus baseload generation in the market. 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 is called upon to operate.

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Consolidated Overview and Results of Operations

Performance highlights

The following table provides a summary of our consolidated results of operations for the three and six months ended June 30, 2015 and 2014, which are analyzed in greater detail below:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Project income (loss)	$ 17.2	$ (2.0)	$ 38.8	$ 23.9
Loss (income) from continuing operations	$ (20.0)	$ (50.7)	$ 4.7	$ (64.8)
Income (loss) from discontinued operations	$ 33.6	$ (5.7)	$ 21.1	$ (14.0)
Net income (loss) attributable to Atlantic Power Corporation	$ 14.7	$ (59.2)	$ 32.2	$ (78.0)
Loss per share from continuing operations attributable to Atlantic Power Corporation basic and diluted	$ (0.18)	$ (0.45)	$ 0.00	$ (0.59)
Income (loss) per share from discontinued operations basic	0.30	(0.04)	0.26	(0.06)
Income (loss) per share attributable to Atlantic Power Corporation basic and diluted	$ 0.12	$ (0.49)	$ 0.26	$ (0.65)
Project Adjusted EBITDA[(1)]	$ 43.9	$ 57.7	$ 102.5	$ 114.6
Free Cash Flow[(1)]	$ (18.2)	$ (15.1)	$ (13.2)	$ (61.0)

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

Consolidated project income (loss) increased $19.2 million for the three months ended June 30, 2015, as compared to the three months ended June 30, 2014. The increase was due primarily to a $14.8 million long-lived asset and goodwill impairment recorded in the comparative 2014 period, a $7.2 million increase in the change in fair values of derivatives and $12.4 million in decreased fuel costs due to lower gas prices. This was partially offset by a $20.0 million decrease in revenue primarily resulting from the Tunis PPA expiring on December 31, 2014 and lower water flows at our hydro projects. Consolidated project income (loss) increased $14.9 million for the six months ended June 30, 2015, as compared to the six months ended June 30, 2014. The increase was due primarily to a $14.8 million long-lived asset and goodwill impairment recorded in the comparative 2014 period, $26.0 million in decreased fuel costs due to lower gas prices, $9.2 million in decreased interest expense primarily due to the redemption of Curtis Palmer's 5.9% Senior Notes, and a $7.2 million increase in equity in earnings of unconsolidated affiliates primarily due to higher revenues and lower fuel expense at Orlando. This was partially offset by a $34.0 million decrease in revenue primarily resulting from the Tunis PPA expiring on December 31, 2014 and lower water flows at our hydro projects, as well as a $16.4 million decrease in the change in fair values of derivatives.

A detailed discussion of project (loss) income by segment is provided below. The discussion of Project Adjusted EBITDA by segment begins on page 58.

We have four reportable segments: East U.S., West U.S., Canada and Un-allocated Corporate. We revised our reportable business segments in the second quarter of 2015 as the result of recent significant asset sales and in order to align with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. The Wind Projects, which made up the entirety of the former Wind segment, were sold in June 2015 and are designated as discontinued operations for the three and six months ended June 30, 2014 and 2015. Our financial results for the three and six months ended June 30, 2014 have been revised to reflect these changes in operating segments. 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

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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 June 30, 2015 compared to the three months ended June 30, 2014

The following table provides our consolidated results of operations:

	Three months ended June 30,			
	2015	2014	$ change	% change
Project revenue:				
Energy sales	$ 47.5	$ 62.4	$ (14.9)	24%
Energy capacity revenue	38.0	41.3	(3.3)	8%
Other	17.6	19.4	(1.8)	9%
	103.1	123.1	(20.0)	16%
Project expenses:				
Fuel	38.0	50.4	(12.4)	25%
Operations and maintenance	35.3	29.1	6.2	21%
Development		1.1	(1.1)	100%
Depreciation and amortization	28.2	30.8	(2.6)	8%
	101.5	111.4	(9.9)	9%
Project other income (expense):				
Change in fair value of derivative instruments	6.8	(0.4)	7.2	NM
Equity in earnings of unconsolidated affiliates	8.6	3.7	4.9	132%
Interest expense, net	(2.0)	(2.2)	0.2	9%
Other income (expense), net	2.2	(14.8)	17.0	115%
	15.6	(13.7)	29.3	214%
Project income (loss)	17.2	(2.0)	19.2	960%
Administrative and other expenses (income):				
Administration	6.6	10.2	(3.6)	35%
Interest, net	24.6	27.7	(3.1)	11%
Foreign exchange loss	4.8	15.3	(10.5)	69%
Other income, net	(1.7)		(1.7)	NM
	34.3	53.2	(18.9)	36%
Income (loss) from continuing operations before income taxes	(17.1)	(55.2)	38.1	69%
Income tax expense (benefit)	2.9	(4.5)	7.4	164%
(Loss) income from continuing operations	(20.0)	(50.7)	30.7	61%
Income (loss) from discontinued operations, net of tax	33.6	(5.7)	39.3	NM
Net income (loss)	13.6	(56.4)	70.0	124%
Net loss attributable to noncontrolling interests	(3.4)	(0.3)	(3.1)	NM
Net income attributable to Preferred share dividends of a subsidiary company	2.3	3.1	(0.8)	26%
Net income (loss) attributable to Atlantic Power Corporation	$ 14.7	(59.2)	73.9	125%

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	Three months ended June 30, 2015(1)				
	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 20.5	$ 8.4	$ 18.6	$	$ 47.5
Energy capacity revenue	14.3	13.1	10.6		38.0
Other	4.1	4.8	8.5	0.2	17.6
	38.9	26.3	37.7	0.2	103.1
Project expenses:					
Fuel	13.5	8.8	15.7		38.0
Operations and maintenance	9.4	14.9	10.4	0.6	35.3
Development					
Depreciation and amortization	8.4	7.3	12.7	(0.2)	28.2
	31.3	31.0	38.8	0.4	101.5
Project other income (expense):					
Change in fair value of derivative instruments	2.9		3.9		6.8
Equity in earnings of unconsolidated affiliates	8.2	0.4			8.6
Interest expense, net	(2.0)				(2.0)
Other income (expense), net				2.2	2.2
	9.1	0.4	3.9	2.2	15.6
Project income (loss)	$ 16.7	$ (4.3)	$ 2.8	$ 2.0	$ 17.2

	Three months ended June 30, 2014(1)				
	East U.S.	West U.S.(2)	Canada	Un-allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 25.3	$ 13.8	$ 23.3	$	$ 62.4
Energy capacity revenue	13.0	13.1	15.2		41.3
Other	6.7	6.2	6.3	0.2	19.4
	45.0	33.1	44.8	0.2	123.1
Project expenses:					
Fuel	17.3	14.4	18.7		50.4
Operations and maintenance	8.5	6.3	11.6	2.7	29.1
Development				1.1	1.1
Depreciation and amortization	8.1	7.4	15.2	0.1	30.8
	33.9	28.1	45.5	3.9	111.4
Project other income (expense):					
Change in fair value of derivative instruments	(1.7)		2.6	(1.3)	(0.4)
Equity in earnings of unconsolidated affiliates	2.9	0.8			3.7
Interest expense, net	(2.2)				(2.2)
Other income (expense), net			(14.8)		(14.8)
	(1.0)	0.8	(12.2)	(1.3)	(13.7)

Project income (loss)	$ 10.1	$ 5.8	$ (12.9)	$ (5.0)	$ (2.0)

(1) Excludes the Wind Projects, which made up the entirety of the former Wind segment, and were sold in June 2015. The Wind Projects are designated as discontinued operations for the three months ended June 30, 2015 and 2014.

(2) Excludes Greeley which is designated as discontinued operations.

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East U.S.

Project income for the three months ended June 30, 2015 increased $6.6 million from the comparable 2014 period primarily due to:

- increased project income of $5.0 million at Orlando due primarily to $3.3 million in increased revenues from higher generation, $1.0 million in decreased fuel expense from lower gas prices and a $1.0 million non-cash increase in the fair value of a fuel swap from the comparable 2014 period.

This increase was partially offset by:

- decreased project income of $2.4 million at Curtis Palmer due to $2.2 million in decreased revenue from lower water flows than the comparable 2014 period.

West U.S.

Project income for the three months ended June 30, 2015 decreased $10.1 million from the comparable 2014 period primarily due to:

- decreased project income of $8.6 million at Manchief due primarily to higher maintenance costs from a scheduled maintenance overhaul in the second quarter of 2015.

Canada

Project income for the three months ended June 30, 2015 increased $15.7 million from the comparable 2014 period primarily due to:

- increased project income of $15.0 million at Tunis which recorded a $14.8 million long-lived asset and goodwill impairment in the three months ended June 30, 2014.

Un-allocated Corporate

Total project income increased $7.0 million primarily due to a $2.2 million gain on sale of the Frontier solar development project and $1.1 million in decreased development and administrative costs at Ridgeline as well as a $1.3 million non-cash change in the fair value of interest rate swap agreements.

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 decreased $3.6 million or 35% from the comparable 2014 period primarily due to a $1.4 million decrease in business strategy costs, a $1.5 million decrease in legal expenses related to the U.S. Actions and Canadian Actions and a $1.0 million decrease in employee compensation expense.

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Interest, net

Interest expense decreased $3.1 million or 11% from the comparable 2014 period primarily due to the repurchase of $9 million of our 9.0% Senior unsecured notes in January 2015 as well as the purchase and cancellation of $24 million aggregate principal of convertible debentures beginning in the fourth quarter of 2015 and continuing through June 2015 under the Normal Course Issuer Bid ("NCIB").

Foreign exchange loss

Foreign exchange loss decreased $10.5 million or 69% from the comparable 2014 period primarily due to an $11.5 million increase in unrealized loss in the revaluation of instruments denominated in Canadian dollars and a $0.4 million decrease in realized gains related to foreign currency transactions, partially offset by a $1.4 million increase in unrealized gain on foreign exchange forward contracts. The closing U.S. dollar to Canadian dollar exchange rate was 1.25 and 1.07 at June 30, 2015 and 2014, respectively, a decrease of 1.4% in the three months ended June 30, 2015 compared to a decrease of 3.5% in the three months ended June 30, 2014. The average U.S. dollar to Canadian dollar exchange rate was 1.25 and 1.08 for the three months ended June 30, 2015 and 2014, respectively, a decrease of 1.0% in the three months ended June 30, 2015 compared to a decrease of 2.4% in the three months ended June 30, 2014.

Other income, net

Other income (expense), net increased $1.7 million from the 2014 comparable period due to a $1.7 million gain recorded on the purchase and cancellation of convertible debentures under the NCIB in the first quarter of 2015.

Income tax expense

Income tax expense for the three months ended June 30, 2015 was $2.9 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $4.4 million. The primary items impacting the tax rate for the three months ended June 30, 2015 were $9.0 million relating to a change in the valuation allowance, $3.4 million of dividend withholding and other state taxes, and $2.5 million of other permanent differences. These items were partially offset by $3.6 million relating to tax credits, $2.4 million relating to foreign exchange and $1.6 million relating to operating in higher tax rate jurisdictions.

Income tax benefit for the three months ended June 30, 2014 was $9.1 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $12.9 million. The primary items impacting the tax rate for the three months ended June 30, 2014 were $14.2 million relating to a change in the valuation allowance and $2.4 million relating to foreign exchange. These items were partially offset by $4.1 million relating to operating in higher tax rate jurisdictions, $2.4 million of minority interest adjustments, and $6.3 million relating to other permanent differences.

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Six months ended June 30, 2015 compared to the six months ended June 30, 2014

The following table provides our consolidated results of operations:

	Six months ended June 30,			
	2015	2014	$ change	% change
Project revenue:				
Energy sales	$ 101.5	$ 124.7	$ (23.2)	19%
Energy capacity revenue	71.5	74.8	(3.3)	4%
Other	41.4	48.9	(7.5)	15%
	214.4	248.4	(34.0)	14%
Project expenses:				
Fuel	84.2	110.2	(26.0)	24%
Operations and maintenance	56.8	56.7	0.1	0%
Development	1.1	1.8	(0.7)	39%
Depreciation and amortization	56.1	61.4	(5.3)	9%
	198.2	230.1	(31.9)	14%
Project other income (expense):				
Change in fair value of derivative instruments	5.2	21.6	(16.4)	76%
Equity in earnings of unconsolidated affiliates	19.3	12.1	7.2	60%
Interest expense, net	(4.1)	(13.3)	9.2	69%
Other income (expense), net	2.2	(14.8)	17.0	115%
	22.6	5.6	17.0	NM
Project income	38.8	23.9	14.9	62%
Administrative and other expenses (income):				
Administration	16.0	17.5	(1.5)	9%
Interest, net	50.3	94.1	(43.8)	47%
Foreign exchange gain	(27.4)	(1.5)	(25.9)	NM
Other income, net	(3.1)		(3.1)	NM
	35.8	110.1	(74.3)	67%
Income (loss) from continuing operations before income taxes	3.0	(86.2)	89.2	103%
Income tax benefit	(1.7)	(21.4)	19.7	NM
Income (loss) from continuing operations	(4.7)	(64.8)	(69.5)	107%
Income (loss) from discontinued operations, net of tax	21.1	(14.0)	35.1	NM
Net income (loss)	25.8	(78.8)	104.6	133%
Net loss attributable to noncontrolling interests	(11.0)	(6.7)	(4.3)	64%
Net income attributable to Preferred share dividends of a subsidiary company	4.6	5.9	(1.3)	22%
Net income (loss) attributable to Atlantic Power Corporation	$ 32.2	(78.0)	110.2	NM

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	Six months ended June 30, 2015[1]				
	East U.S.	West U.S.	Canada	Un-allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 40.0	$ 18.8	$ 42.7	$	$ 101.5
Energy capacity revenue	26.3	19.8	25.4		71.5
Other	10.2	10.7	20.1	0.4	41.4
	76.5	49.3	88.2	0.4	214.4
Project expenses:					
Fuel	29.9	19.5	34.8		84.2
Operations and maintenance	16.6	20.5	18.2	1.5	56.8
Development				1.1	1.1
Depreciation and amortization	16.4	14.5	24.8	0.4	56.1
	62.9	54.5	77.8	3.0	198.2
Project other income (expense):					
Change in fair value of derivative instruments	0.4		5.6	(0.8)	5.2
Equity in earnings of unconsolidated affiliates	18.1	1.2			19.3
Interest expense, net	(4.1)				(4.1)
Other income (expense), net				2.2	2.2
	14.4	1.2	5.6	1.4	22.6
Project income (loss)	$ 28.0	$ (4.0)	$ 16.0	$ (1.2)	$ 38.8

(1) Excludes the Wind Projects which are designated as discontinued operations.

	Six months ended June 30, 2014[1]				
	East U.S.	West U.S.[2]	Canada	Un-allocated Corporate	Consolidated Total
Project revenue:					
Energy sales	$ 49.2	$ 27.1	$ 48.4	$	$ 124.7
Energy capacity revenue	23.8	19.7	31.3		74.8
Other	17.7	13.4	17.5	0.3	48.9
	90.7	60.2	97.2	0.3	248.4
Project expenses:					
Fuel	45.1	29.5	35.6		110.2
Operations and maintenance	17.6	14.8	22.2	2.1	56.7
Development				1.8	1.8
Depreciation and amortization	16.2	14.3	30.6	0.3	61.4
	78.9	58.6	88.4	4.2	230.1
Project other income (expense):					
Change in fair value of derivative instruments	4.1		18.7	(1.2)	21.6
Equity in earnings of unconsolidated affiliates	10.7	1.6		(0.2)	12.1
Interest expense, net	(13.3)				(13.3)

Other income (expense), net			(14.8)		(14.8)
	1.5	1.6	3.9	(1.4)	5.6
Project income (loss)	$ 13.3	$ 3.2	$ 12.7	$ (5.3)	$ 23.9

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(1) Excludes the Wind Projects, which made up the entirety of the former Wind segment, and were sold in June 2015. The Wind Projects are designated as discontinued operations for the six months ended June 30, 2015 and 2014.

(2) Excludes Greeley which is designated as discontinued operations.

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East U.S.

Project income for the six months ended June 30, 2015 increased $14.7 million from the comparable 2014 period primarily due to:

- increased project income of $3.7 million at Orlando due primarily to $2.9 million in increased revenues from higher generation and $3.3 million in decreased fuel expense from lower gas prices, partially offset by a $2.9 million non-cash decrease in the fair value of a fuel swap from the comparable 2014 period;

- increased project income of $3.0 million at Piedmont due primarily to a $1.6 million non-cash change in the fair value of interest rate swap agreements, a $0.5 million increase in revenue from higher capacity payments and a $0.6 million decrease in fuel expense;

- increased project income of $2.8 million at Curtis Palmer due to $6.0 million lower interest expense resulting from the redemption of the project's 5.9% Senior Notes in the first quarter of 2014, partially offset by $2.9 million of decreased revenue from lower water flows during 2015; and

- increased project income of $2.1 million at Morris due primarily to lower fuel expenses from lower gas prices as compared to the comparable 2014 period.

West U.S.

Project income for the six months ended June 30, 2015 decreased $7.2 million from the comparable 2014 period primarily due to:

- decreased project income of $8.6 million at Manchief due primarily to higher maintenance costs from a scheduled maintenance overhaul in the second quarter of 2015.

This decrease was partially offset by:

- increased project income of $2.4 million at North Island due to lower maintenance expenses. North Island underwent a maintenance outage in the comparable 2014 period.

Canada

Project income for the six months ended June 30, 2015 increased $3.3 million from the comparable 2014 period primarily due to:

- increased project income of $11.7 million at Tunis, which recorded a $14.8 million long-lived asset and goodwill impairment in the comparable 2014 period; and

- increased project income of $2.0 million at Williams Lake due to higher revenues and lower maintenance expenses, partially offset by the impact of foreign exchange translation.

These increases were partially offset by:

- decreased project income of $9.3 million at Nipigon due primarily to a negative $10.7 million change in the fair value of fuel contracts that were accounted for as derivatives and the impact of foreign exchange translation, partially offset by higher revenue from waste heat; and decreased project income of $2.0 million at North Bay due to the impact of foreign exchange translation, a negative $1.3 million change in the fair value of fuel contracts that were accounted for as derivatives and higher fuel expense, partially offset by higher revenue from waste heat.

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Un-allocated Corporate

Total project loss decreased $4.1 million for the six months ended June 30, 2015 from the comparable 2014 period primarily due to a $2.2 million gain on sale of the Frontier solar development project and $1.8 million in decreased development and administrative costs at Ridgeline.

Administrative and other expenses (income)

Administration

Administration expense decreased $1.5 million or 9% from the comparable 2014 period primarily due to $3.2 million lower legal costs associated with the U.S. Actions and Canadian Actions than the prior year, partially offset by $2.0 million of increased compensation costs from $3.4 million of employee severance partially offset by lower incentive compensation expense and headcount reductions in the six months ended June 30, 2015.

Interest, net

Interest expense decreased $43.8 million or 47% from the comparable 2014 period primarily due to $23.3 million of make-whole premiums paid to redeem the Series A Notes and Series B Notes, as well as $16.4 million of premiums paid and non-cash deferred financing costs written off for the repurchase of $140.1 million aggregate principal amount of the 9.0% Notes in the first quarter of 2014. Interest expense also decreased due to the repurchase of $9 million of our 9.0% Senior unsecured notes in January 2015 as well as the purchase and cancellation of $24 million aggregate principal of convertible debentures under the NCIB beginning in the fourth quarter of 2015 and continuing through June 2015.

Foreign exchange gain

Foreign exchange gain increased $25.9 million from the comparable 2014 period primarily due to a $26.6 million increase in unrealized gain in the revaluation of instruments denominated in Canadian dollars offset by a $0.3 million increase in unrealized loss on foreign exchange forward contracts and $0.4 million in other realized losses. The closing U.S. dollar to Canadian dollar exchange rate was 1.25 and 1.07 at June 30, 2015 and 2014, respectively, an increase of 7.7% in the six months ended June 30, 2015 compared to an increase of 0.3% in the six months ended June 30, 2014. The average U.S. dollar to Canadian dollar exchange rate was 1.26 and 1.10 for the six months ended June 30, 2015 and 2014, respectively, an increase of 14.5% in the three months ended June 30, 2015 compared to a decrease of 2.4% in the three months ended June 30, 2014.

Other income, net

Other income, net increased $3.1 million from the 2014 comparable period due primarily to a $3.0 million gain recorded on the purchase and cancellation of convertible debentures under the NCIB during 2015.

Income tax benefit

Income tax benefit for the six months ended June 30, 2015 was $1.7 million. Expected income tax expense for the same period, based on the Canadian enacted statutory rate of 26%, was $0.8 million. The primary items impacting the tax rate for the six months ended June 30, 2015 were $4.1 million relating to foreign exchange, $4.0 million relating to operating in higher tax rate jurisdictions, $3.6 million related to tax credits, and $0.6 million of other permanent differences. These items were partially offset by $6.2 million relating to a change in the valuation allowance, and $3.6 million relating to dividend withholding and other taxes.

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Income tax benefit for the six months ended June, 2014 was $21.4 million. Expected income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $21.9 million. The primary items impacting the tax rate for the six months ended June 30, 2014 were $29.3 million relating to a change in the valuation allowance. These items were partially offset by $11.1 million of capital losses recognized on tax restructuring, $9.7 million of operating in higher tax rate jurisdictions, $1.2 million relating to foreign exchange and $6.8 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. Availability is calculated by dividing the total scheduled hours of a project less forced outage hours by the total hours in the period measured. The terms of our PPAs require our projects to maintain certain levels of availability. The majority of our projects were able to achieve their respective capacity payments. For projects where reduced availability adversely impacted capacity payments, the impact was not material for the three and six months ended June 30, 2015. 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[1]		
	Three months ended June 30,		
(in thousands of Net MWh)	**2015**	**2014**	**% change 2015 vs. 2014**
Segment			
East U.S.	633.5	672.3	5.8%
West U.S.[2]	417.7	320.2	30.4%
Canada	456.7	509.5	10.4%
Total	1,507.9	1,502.0	0.4%

(1) Excludes the Wind Projects, which comprised the entirety of the Wind segment. The Wind Projects were sold in June 2015 and are designated as discontinued operations for the three and six months ended June 30, 2015.

(2) Excludes (i) Delta-Person, which was sold in July 2014; and (ii) Greeley, which was sold in March 2014 and is designated as discontinued operations.

Three months ended June 30, 2015 compared with three months ended June 30, 2014

Aggregate power generation for the three months ended June 30, 2015 increased 0.4% from the comparable 2014 period primarily due to:

- increased generation in the West U.S. segment primarily due to a 143.1 net MWh increase in generation at Frederickson due to higher dispatch resulting from warmer weather than the comparable 2014 period, partially offset by a 32.4 net MWh decrease in generation at Manchief which underwent a maintenance overhaul in the second quarter of 2015.

These increases were partially offset by:

- decreased generation in the East U.S. segment primarily due to a 34.3 net MWh decrease in generation at Selkirk for which the PPA expired in August 2014 and which now operates as a merchant facility, a 28.2 net MWh decrease in generation at Curtis Palmer due to lower water flows and a 28.5 net MWh decrease in generation at Chambers which had lower dispatch due to unfavorable pricing, partially offset by a 34.3 net MWh increase in generation at Orlando which had a scheduled maintenance outage in the second quarter of 2014; and

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decreased generation in the Canada segment primarily due to a 57.8 net MWh decrease in generation at Tunis for which the PPA expired in December 2014 and a 31.0 net MWh decrease in generation at Mamquam due to lower water flows than the comparable 2014 period.

	Generation[(1)]		
	Six months ended June 30,		
(in thousands of Net MWh)	**2015**	**2014**	**% change 2015 vs. 2014**
Segment			
East U.S.	1,251.8	1,418.7	11.8%
West U.S.[(2)]	767.3	728.3	5.4%
Canada	973.7	1,005.1	3.1%
Total	2,992.8	3,152.1	5.1%

(1) Excludes the Wind Projects, which comprised the entirety of the Wind segment. The Wind Projects were sold in June 2015 and are designated as discontinued operations for the three and six months ended June 30, 2015.

(2) Excludes (i) Delta-Person, which was sold in July 2014; and (ii) Greeley, which was sold in March 2014 and is designated as discontinued operations.

Six months ended June 30, 2015 compared with six months ended June 30, 2014

Aggregate power generation for the six months ended June 30, 2015 decreased 5.1% from the comparable 2014 period primarily due to:

decreased generation in the East U.S. segment primarily due to a 102.8 net MWh decrease in generation at Selkirk for which the PPA expired in August 2014 and which operates as a merchant facility, a 40.9 net MWh decrease in generation at Curtis Palmer due to lower water flows and a 93.4 net MWh decrease in generation at Chambers which had lower dispatch due to unfavorable pricing, partially offset by increased generation of 49.1 net MWh at Morris which underwent maintenance in the comparable 2014 period and increased generation of 38.5 net MWh at Orlando which underwent maintenance in the comparable 2014 period; and

decreased generation in the Canada segment primarily due to a 131.0 net MWh decrease in generation at Tunis for which the PPA expired in December 2014, partially offset by increases in generation of 35.3 and 29.4 net MWh at Kapuskasing and Nipigon, respectively, due to favorable waste heat generation.

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These decreases were partially offset by:

increased generation in the West U.S. segment primarily due to a 43.8 net MWh increase in generation at Frederickson due to higher dispatch resulting from warmer weather than the comparable 2014 period.

	Availability(1) Three months ended June 30,		
	2015	2014	% change 2015 vs. 2014
Segment			
East U.S.	93.9%	88.8%	5.7%
West U.S.(2)	81.8%	90.4%	9.5%
Canada	94.1%	93.7%	0.4%
Total	89.7%	90.4%	0.8%

(1) Excludes the Wind Projects, which comprised the entirety of the former Wind segment. The Wind Projects were sold in June 2015 and are designated as discontinued operations for the three months ended June 30, 2015 and 2014.

(2) Excludes (i) Delta-Person, which was sold in July 2014; and (ii) Greeley, which was sold in March 2014 and is designated as discontinued operations.

Three months ended June 30, 2015 compared with three months ended June 30, 2014

Weighted average availability for the three months ended June 30, 2015 decreased 0.8% to 89.7% from the comparable 2014 period primarily due to:

decreased availability in the West U.S. segment resulting from decreased availability at Manchief, which underwent a scheduled maintenance overhaul outage during the second quarter of 2015.

These decreases were partially offset by:

increased availability in the East U.S. segment resulting from increased availability at Cadillac and Orlando, which underwent scheduled maintenance during the comparable 2014 period, partially offset by decreased availability at Kenilworth which had a planned maintenance outage during the second quarter of 2015; and

increased availability in the Canada segment resulting from increased availability at Moresby Lake and Williams Lake, which underwent forced maintenance outages during the comparable 2014 period.

	Availability(1) Six months ended June 30,		
	2015	2014	% change 2015 vs. 2014
Segment			
East U.S.	95.9%	91.6%	4.7%
West U.S.(2)	89.5%	91.6%	2.3%
Canada	95.5%	91.4%	4.5%
Total	93.7%	91.5%	2.4%

(1) Excludes the Wind Projects, which comprised the entirety of the former Wind segment. The Wind Projects were sold in June 2015 and are designated as discontinued operations for the six months ended June 30, 2015 and 2014.

(2) Excludes (i) Delta-Person, which was sold in July 2014; and (ii) Greeley, which was sold in March 2014 and is designated as discontinued operations.

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Six months ended June 30, 2015 compared with six months ended June 30, 2014

Weighted average availability for the six months ended June 30, 2015 increased 2.4% to 93.7% from the comparable 2014 period primarily due to:

- increased availability in the East U.S. segment resulting from increased availability at Chambers, Orlando and Cadillac, which underwent scheduled maintenance during the comparable 2014 period; and

- increased availability in the Canada segment resulting from increased availability at Moresby Lake and Williams Lake, which underwent forced maintenance outages during the comparable 2014 period.

These increases were partially offset by:

- decreased availability in the West U.S. segment resulting from decreased availability at Manchief, which underwent a scheduled maintenance overhaul outage during the second quarter of 2015.

Supplementary Non-GAAP Financial Information

A key measure we use to evaluate the results of our business is Free Cash Flow. Free Cash Flow is not a measure recognized under GAAP, does not have a standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by other issuers. We believe Free Cash Flow is a relevant supplemental measure of our ability to fund additional debt reduction, fund internal or external growth, pay any dividends to our shareholders, or many other allocations of any available cash. A reconciliation of Free Cash Flow to cash flows from operating activities, the most directly comparable GAAP measure, is set out below under "Free Cash Flow." Free Cash Flow is comparable to Cash Available for Distribution, the non-GAAP measure we previously used to evaluate the results of our business. Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

The primary factor influencing Free Cash Flow is cash distributions received from projects. These distributions are generally funded from Project Adjusted EBITDA generated by the projects, reduced by project-level debt service, capital expenditures, dividends paid on preferred shares of a subsidiary company, distributions to noncontrolling interests and adjusted for changes in project-level working capital and cash reserves. 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 use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of Project Adjusted EBITDA to project income (loss) is provided under "Project Adjusted EBITDA" below and a reconciliation of Project Adjusted EBITDA by segment to project income (loss) by segment is provided in Note 13 to the consolidated financial statements of this Quarterly Report on Form 10-Q. Project Adjusted EBITDA for our equity investments in unconsolidated affiliates is presented on a proportionately consolidated basis in the table below. Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

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Project Adjusted EBITDA

	Three months ended June 30,[1]			Six months ended June 30,[1]		$ change
	2015	2014	2015 vs 2014	2015	2014	2015 vs 2014
Project Adjusted EBITDA by segment						
East U.S.	$ 27.0	$ 30.8	$ (3.8)	$ 53.7	$ 55.2	$ (1.5)
West U.S.[2]	5.7	15.9	(10.2)	15.6	23.7	(8.1)
Canada	11.6	14.6	(3.0)	35.4	39.3	(3.9)
Un-allocated Corporate	(0.4)	(3.6)	3.2	(2.2)	(3.6)	1.4
Total	43.9	57.7	(13.8)	102.5	114.6	(12.1)
Reconciliation to project income						
Depreciation and amortization	33.3	40.8	(7.5)	66.1	81.9	(15.8)
Interest expense, net	2.5	3.8	(1.3)	4.9	15.4	(10.5)
Change in the fair value of derivative instruments	(6.9)	0.3	(7.2)	(5.1)	(21.4)	16.3
Other expense	(2.2)	14.8	(17.0)	(2.2)	14.8	(17.0)
Project income	$ 17.2	$ (2.0)	$ 19.2	$ 38.8	$ 23.9	$ 14.9

(1) Excludes the Wind Projects, which comprised the entirety of the former Wind segment. The Wind Projects were sold in June 2015 and are designated as discontinued operations for the three and six months ended June 30, 2015 and 2014.

(2) Excludes Greeley which is designated as discontinued operations.

East U.S.

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

	Three months ended June 30,		
	2015	2014	% change 2015 vs. 2014
East U.S.			
Project Adjusted EBITDA	$ 27.0	$ 30.8	12%

Three months ended June 30, 2015 compared with three months ended June 30, 2014

Project Adjusted EBITDA for the three months ended June 30, 2015 decreased $3.8 million or 12% from the comparable 2014 period primarily due to decreases in Project Adjusted EBITDA of:

- $4.2 million at Selkirk due to lower revenue from decreased generation from operating as a merchant facility since the expiration of its PPA in August 2014; and

- $2.4 million at Curtis Palmer due to decreased revenue resulting from lower water flows than the comparable 2014 period.

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

$2.7 million at Orlando primarily attributable to $3.3 million in increased revenues from higher generation and $1.0 million in decreased fuel expense from lower gas prices.

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

	Six months ended June 30,		
	2015	2014	% change 2015 vs. 2014
East U.S.			
Project Adjusted EBITDA	$ 53.7	$ 55.2	3%

Six months ended June 30, 2015 compared with six months ended June 30, 2014

Project Adjusted EBITDA for the six months ended June 30, 2015 decreased $1.5 million or 3% from the comparable 2014 period primarily due to decreases in Project Adjusted EBITDA of:

$9.0 million at Selkirk due to lower revenue from decreased generation from operating as a merchant facility since the expiration of its PPA in August 2014; and

$3.2 million at Curtis Palmer due to decreased revenue resulting from lower water flows than the comparable 2014 period.

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

$6.6 million at Orlando primarily attributable to $2.9 million in increased revenues from higher generation and $3.3 million in decreased fuel expense from lower gas prices.

West U.S.

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

	Three months ended June 30,		
	2015	2014	% change 2015 vs. 2014
West U.S.			
Project Adjusted EBITDA	$ 5.7	$ 15.9	64%

Three months ended June 30, 2015 compared with three months ended June 30, 2014

Project Adjusted EBITDA for the three months ended June 30, 2015 decreased $10.2 million or 64% from the comparable 2014 period primarily due to a decrease in Project Adjusted EBITDA of:

$8.6 million at Manchief which underwent a scheduled maintenance overhaul outage in the second quarter of 2015.

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

	Six months ended June 30,		
	2015	2014	% change 2015 vs. 2014
West U.S.			
Project Adjusted EBITDA	$ 15.6	$ 23.7	34%

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Six months ended June 30, 2015 compared with six months ended June 30, 2014

Project Adjusted EBITDA for the six months ended June 30, 2015 decreased $8.1 million or 34% from the comparable 2014 period primarily due to a decrease in Project Adjusted EBITDA of:

$8.6 million at Manchief which underwent a scheduled maintenance overhaul outage in the second quarter of 2015.

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

$2.4 million at North Island which underwent a scheduled maintenance outage in the comparable 2014 period.

Canada

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

	Three months ended June 30,		
	2015	2014	% change 2015 vs. 2014
Canada			
Project Adjusted EBITDA	$ 11.6	$ 14.6	21%

Three months ended June 30, 2015 compared with three months ended June 30, 2014

Project Adjusted EBITDA for the three months ended June 30, 2015 decreased $3.0 million or 21% from the comparable 2014 period primarily due to a decrease in Project Adjusted EBITDA of:

$1.6 million at Mamquam due to decreased revenues from lower water flows in the second quarter of 2015.

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

	Six months ended June 30,		
	2015	2014	% change 2015 vs. 2014
Canada			
Project Adjusted EBITDA	$ 35.4	$ 39.3	10%

Six months ended June 30, 2015 compared with six months ended June 30, 2014

Project Adjusted EBITDA for the six months ended June 30, 2015 decreased $3.9 million or 10% from the comparable 2014 period primarily due to a decrease in Project Adjusted EBITDA of:

$6.0 million at Tunis for which the PPA expired in December 2014.

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

$1.4 million at Calstock due to increased revenue from waste heat generation, partially offset by the impact of foreign currency translation.

Un-Allocated Corporate

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

	Three months ended June 30,		
	2015	2014	% change 2015 vs. 2014
Un-Allocated Corporate			
Project Adjusted EBITDA	$ (0.4)	$ (3.6)	89%

Three months ended June 30, 2015 compared with three months ended June 30, 2014

Project Adjusted EBITDA for the three months ended June 30, 2015 increased $3.2 million or 89% from the comparable 2014 period primarily due to a $1.1 million decrease in development expense at Ridgeline and $1.0 million decrease in employee compensation expenses.

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

	Six months ended June 30,		
	2015	2014	% change 2015 vs. 2014
Un-Allocated Corporate			
Project Adjusted EBITDA	$ (2.2)	$ (3.6)	39%

Six months ended June 30, 2015 compared with six months ended June 30, 2014

Project Adjusted EBITDA for the six months ended June 30, 2015 increased $1.4 million or 39% from the comparable 2014 period primarily due to a $0.7 million decrease in development expense at Ridgeline and a $2.0 million decrease in employee compensation expenses.

Discontinued operations

Project Adjusted EBITDA excludes the Wind Projects which are designated as discontinued operations for the three and six months ended June 30, 2015 and 2014. Project Adjusted EBITDA for the Wind Projects was $14.8 million and $17.2 million for the three months ended June 30, 2015 and 2014, respectively. Project Adjusted EBITDA for the Wind Projects was $28.1 million and $35.1 million for the six months ended June 30, 2015 and 2014, respectively.

Free Cash Flow

Free Cash Flow was $(18.2) million and ($15.1) million for the three months ended June 30, 2015 and 2014, respectively, a decrease of $3.1 million. The decrease was due primarily to a $15.7 million decrease in cash flows from operations and a $3.8 million increase in the purchase of property, plant and equipment. The total decrease was partially offset by an $11.9 million decrease of payments on the Atlantic Power Limited Partnership's (the "Partnership") term loan facility, a $1.7 million decrease in project-level debt repayments and a $2.0 million decrease in distributions to noncontrolling interest. Free Cash Flow was $(13.2) and ($61.0) million for the six months ended June 30, 2015 and 2014, respectively, an increase of $47.8 million. The increase was due primarily to a $47.9 million increase in cash flows from operations. The decrease of $16.1 million and increase of $47.9 million of cash flows from operations for the three and six months ended June 30, 2015 is discussed in "Consolidated Cash Flows" below. The table below presents our calculation of Free Cash Flow for the three and six months

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ended June 30, 2015 and 2014, and the reconciliation to cash flows from operating activities, the most directly comparable GAAP measure:

	Three months ended June 30,		Six months ended June 30,	
	2015	2014	2015	2014
Cash flows from operating activities	$ 18.3	$ 34.0	$ 53.4	$ 5.5
Term loan facility repayments(1)	(25.6)	(37.5)	(46.9)	(37.5)
Project-level debt repayments	(3.8)	(5.5)	(6.3)	(15.4)
Purchases of property, plant and equipment	(3.7)	0.1	(5.0)	(2.5)
Distributions to noncontrolling interests(2)	(1.1)	(3.1)	(3.8)	(5.2)
Dividends on preferred shares of a subsidiary company	(2.3)	(3.1)	(4.6)	(5.9)
Free Cash Flow(3)	$ (18.2)	$ (15.1)	$ (13.2)	$ (61.0)

(1) Includes mandatory 1% annual amortization and 50% excess cash flow repayments by the Partnership.

(2) Distributions to noncontrolling interests include distributions to the tax equity investors at Canadian Hills and to the other 50% owner of Rockland.

(3) Free Cash Flow is not a recognized measure under GAAP and does not have any standardized meaning prescribed by GAAP. Therefore, this measure may not be comparable to similar measures presented by other companies. See "Supplementary Non-GAAP Financial Information" above. This table should be read together with the below table under "Consolidated Cash Flows" that sets forth Net cash provided by investing activities and Net cash used in financing activities for the six months ended June 30, 2015 and 2014.

Consolidated Cash Flows

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

	Six months ended June 30,		
	2015	2014	Change
Net cash provided by operating activities	$ 53.4	$ 5.5	$ 47.9
Net cash provided by investing activities	324.8	75.4	249.4
Net cash used in financing activities	(94.4)	(81.9)	(12.5)

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.

Cash flow from operating activities increased by $47.9 million for the six months ended June 30, 2015 from the comparable period in 2014. The increase in cash flows from operating activities is primarily due to $46.8 million of interest expense related to make-whole, accrued interest and premium payments made in connection with the redemption of the Series A and Series B Notes and the Curtis Palmer Notes in the comparable 2014 period and the repurchase of $140.1 million aggregate principal amount of the 9.0% Notes, also in the comparable 2014 period.

Investing Activities

Cash flow from investing activities includes changes in restricted cash. Restricted cash fluctuates from period to period in part because non-recourse project-level financing arrangements typically require all operating cash flow from the project to be deposited in restricted accounts and then released at the time that principal payments are made and project-level debt service coverage ratios are met. As a result, the timing of principal payments on project-level debt causes significant fluctuations in restricted cash balances, which typically benefits investing cash flow in the second and fourth quarters of the year and decreases investing cash flow in the first and third quarters of the year.

Cash flows provided by investing activities for the six months ended June 30, 2015 were $324.8 million compared to cash flows provided by investing activities of $75.4 million for the six months ended June 30, 2014. The change is due primarily to $326.3 million of net proceeds received from the sale of the Wind Projects and the Frontier solar development project, partially offset by a $73.5 million decrease in the change in restricted cash primarily due to the release of the $75.0 million restricted cash requirement under the prior credit facility in the first quarter of 2014.

Financing Activities

Cash used in financing activities for the six months ended June 30, 2015 resulted in a net outflow of $94.4 million compared to a net outflow of $81.9 million for the comparable 2014 period. The increase in cash used in financing activities is due to $18.0 million in payments made to purchase and cancel convertible debentures during 2015.

Liquidity and Capital Resources

	June 30, 2015	December 31, 2014
Cash and cash equivalents[1]	$ 393.8	$ 106.0
Restricted cash	17.6	22.5
Total	411.4	128.5
Revolving credit facility availability	98.4	104.3
Total liquidity	$ 509.8	$ 232.8

(1) $330.4 million of cash was utilized to fund the redemption of the Notes on July 26, 2015. The Notes were redeemed at a price equal to 104.50 percent of the principal amount plus accrued and unpaid interest to the redemption date.

Overview

Our primary source of liquidity is distributions from our projects and availability under our revolving credit facility. 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 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 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, and other allocation of available cash. See "Risk Factors Risks Related to Our Structure We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth

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opportunities or fund our operations" in our Annual Report on Form 10-K for the year ended December 31, 2014.

We expect to reinvest approximately $11.0 million in 2015 (of which $5.0 million was reinvested in the six months ended June 30, 2015) in our portfolio in the form of project capital expenditures and incur $46.0 million of maintenance expenses (of which $25.7 million was incurred in the six months ended June 30, 2015). 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, 2014. We do not expect any other material or unusual requirements for cash outflows for 2015 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.

Corporate Debt

The following table summarizes the maturities of our corporate debt at June 30, 2015:

	Maturity Date	Interest Rates	Total Remaining Principal Repayments	2015	2016	2017	2018	2019	Thereafter
Senior Secured Term Loan Facility[1]	February 2021	4.75% - 5.90%	$ 494.6	$ 2.6	$ 5.2	$ 5.2	$ 5.2	$ 5.2	$ 471.2
Atlantic Power Corporation Notes[2]	November 2018	9.0%	310.9	310.9					
Atlantic Power Income LP Note	June 2036	6.0%	168.1						168.1
Convertible Debenture	March 2017	6.3%	53.9			53.9			
Convertible Debenture	June 2017	5.6%	61.6			61.6			
Convertible Debenture	June 2019	5.8%	117.0					117.0	
Convertible Debenture	December 2019	6.0%	72.1					72.1	
Total Corporate Debt			$ 1,278.2	$ 313.5	$ 5.2	$ 120.7	$ 5.2	$ 194.3	$ 639.3

(1) In addition to the annual principal payments described herein, the Credit Agreement requires payment of 50% of the excess cash flow of the Partnership and its subsidiaries. On May 5, 2014, we entered into interest rate swap agreements to mitigate the exposure to changes in LIBOR for $199.0 million notional amount ($167.3 million at June 30, 2015) of the $600.0 million ($494.6 million at June 30, 2015) outstanding aggregate borrowings. See Note 8, *Accounting for derivative instruments and hedging activities* for further details.

(2) On July 26, 2015, we redeemed our entire outstanding $310.9 million aggregate principal amount of the Notes with the cash proceeds received from the sale of the Wind Projects. The Notes were redeemed at a price equal to 104.50 percent of the principal amount, plus accrued and unpaid interest to the redemption date. We paid $330.4 million in cash to fund the full redemption of the Notes.

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. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at June 30, 2015. 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 August 7, 2015, all of our projects, except for Piedmont, were in compliance with the covenants contained in project-level debt. We do not expect Piedmont to meet its debt service coverage ratio covenant or make distributions before 2017 at the earliest, due to continued operational issues that have resulted in higher forecasted maintenance and fuel expenses than initially expected. See Note 5, *Long-term debt Non-Recourse Debt*.

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The range of interest rates presented represents the rates in effect at June 30, 2015. 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	2015	2016	2017	2018	2019	Thereafter
Consolidated Projects:									
Epsilon Power Partners	January 2019	3.4%	$ 22.5	$ 3.0	$ 6.0	$ 6.2	$ 6.5	$ 0.8	$
Piedmont	August 2018	5.2%	63.4	3.9	3.3	4.7	51.5		
Cadillac	August 2025	6.2%	30.8	1.3	2.5	3.0	3.0	3.1	17.9
Total Consolidated Projects			116.7	8.2	11.8	13.9	61.0	3.9	17.9
Equity Method Projects:									
Chambers[(1)]	December 2019 and 2023	4.5% - 5.0%	43.0	0.1	0.1			5.2	37.6
Total Project-Level Debt			$ 159.7	$ 8.3	$ 11.9	$ 13.9	$ 61.0	$ 9.1	$ 55.5

(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 notes and other corporate and project level debt, funding the repurchase of shares of our common stock (to the extent we choose to pursue any such repurchase), collateral and capital expenditures, including major maintenance and business development costs and dividend payments, if and when declared by our board of directors, to our common shareholders and preferred shareholders of a subsidiary company. We may fund future acquisitions with a combination of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately placed bank or institutional non-recourse operating level debt, although we can provide no assurances regarding the availability of public or private financing on acceptable terms or at all.

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 $11.0 million in 2015 (of which $5.0 million was reinvested in the six months ended June 30, 2015) in our portfolio in the form of project capital expenditures and incur $46.0 million of maintenance expenses (of which $25.7 million was incurred in the six months ended June 30, 2015). As explained above, these investments are generally paid at the project level. 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 2015 as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

Scheduled maintenance outages during the three and six months ended June 30, 2015 occurred at such times that did not materially impact the facilities' availability requirements under their respective PPAs.

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 June 30, 2015, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

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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, 2014.

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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 June 30, 2015, 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.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

We are party to legal proceedings, including securities class actions, from time to time. In particular, we and/or certain of our current and former officers have been named as defendants in various class action lawsuits. Due to the nature of these proceedings, the lack of precise damage claims and the type of claims we are subject to, we are unable to determine the ultimate or maximum amount of monetary liability or financial impact, if any, to us in these legal matters, which unless otherwise specified, seek damages from the defendants of material or indeterminate amounts.

Shareholder class action lawsuits

Massachusetts District Court Actions

On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints were filed by alleged investors in Atlantic Power common shares in the United States District Court for the District of Massachusetts (the "District Court") against Atlantic Power and Barry E. Welch, our former President and Chief Executive Officer and a former Director of Atlantic Power, in each of the actions, and, in addition to Mr. Welch, some or all of Patrick J. Welch, our former Chief Financial Officer, Lisa Donahue, our former interim Chief Financial Officer, and Terrence Ronan, our current Chief Financial Officer, in certain of the actions (the "Proposed Individual Defendants," and together with Atlantic Power, the "Proposed Defendants") (the "U.S. Actions").

The District Court complaints differed in terms of the identities of the Proposed Individual Defendants they named, as noted above, the named plaintiffs, and the purported class period they alleged (July 23, 2010 to March 4, 2013 in three of the District Court actions and August 8, 2012 to February 28, 2013 in the other two District Court actions), but in general each alleged, among other things, that in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, Atlantic Power and the Proposed Individual Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The District Court complaints assert claims under Section 10(b) and, against the Proposed Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended.

The parties to each District Court action filed joint motions requesting that the District Court set a schedule in the District Court actions, including: (i) setting a deadline for the lead plaintiff to file a consolidated amended class action complaint (the "Amended Complaint"), after the appointment of lead plaintiff and counsel; (ii) setting a deadline for Proposed Defendants to answer, file a motion to dismiss or otherwise respond to the Amended Complaint (and for subsequent briefing regarding any such motion to dismiss); and (iii) confirming that the Proposed Defendants need not answer, move to dismiss or otherwise respond to any of the five District Court complaints prior to the filing of the Amended Complaint. On May 7, 2013, each of six groups of investors (the "U.S. Lead Plaintiff Applicants") filed a motion (collectively, the "U.S. Lead Plaintiff Motions") with the District Court seeking: (i) to consolidate the five U.S. Actions (the "Consolidated U.S. Action"); (ii) to be appointed lead plaintiff in the Consolidated U.S. Action; and (iii) to have its choice of lead counsel confirmed. On May 22, 2013, three of the U.S. Lead Plaintiff Applicants filed oppositions to the other U.S. Lead Plaintiff Motions, and on June 6, 2013, those three Lead Plaintiff Applicants filed replies in support of their respective motions. On August 19, 2013, the District Court held a status conference to address certain issues raised by the U.S. Lead Plaintiff Motions, entered an order consolidating the five U.S. Actions, and directed two of the six U.S. Lead Plaintiff Applicants to file supplemental submissions by September 9, 2013. Both of those U.S. Lead Plaintiff Applicants filed the requested supplemental submissions, and then sought leave to file additional briefing. The Court granted those requests for leave and additional submissions were filed on September 13 and September 18, 2013.

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On March 31, 2014, the Court entered an order consolidating the five individual U.S. Actions, appointing the Feldman, Shapero, Carter and Smith investor group (one of the six U.S. Lead Plaintiffs Applicants) as Lead Plaintiff and approving Lead Plaintiff's selection of counsel. The Court also granted the parties' joint motion regarding initial case scheduling and directed the parties to resubmit a proposed schedule that contains specific dates. In response to that directive, on April 7, 2014, Lead Plaintiff filed an application and proposed order, which sought an extension of the schedule contained in the joint motion. The application and proposed order requested that: (i) Lead Plaintiff be permitted to file an amended complaint on or before May 30, 2014, (ii) the Proposed Defendants be permitted to move to dismiss or otherwise respond to the amended complaint on or before July 29, 2014, (iii) Lead Plaintiff be permitted to file an opposition, if any, on or before September 24, 2014, and (iv) the Proposed Defendants be permitted to file a reply to Lead Plaintiff's opposition on or before November 13, 2014. Proposed Defendants did not object to the schedule proposed by Lead Plaintiff. On May 29, 2014, Lead Plaintiff filed a renewed application and proposed order, which sought another extension of the schedule, and on June 3, 2014, Lead Plaintiff and the Proposed Defendants jointly filed a stipulation and proposed order requesting the following revised schedule: (i) Lead Plaintiff be permitted to file an amended complaint on or before June 6, 2014, (ii) the Proposed Defendants be permitted to move to dismiss or otherwise respond to the amended complaint on or before August 5, 2014, (iii) Lead Plaintiff be permitted to file an opposition, if any, on or before October 6, 2014, and (iv) the Proposed Defendants be permitted to file a reply to Lead Plaintiff's opposition on or before November 20, 2014. On June 3, 2014, the Court entered an order setting this requested schedule.

On June 6, 2014, Lead Plaintiff filed the amended complaint (the "Amended Complaint"). The Amended Complaint names as defendants Barry E. Welch and Terrence Ronan (the "Individual Defendants") and Atlantic Power (together with the Individual Defendants, the "Defendants") and alleges a class period of June 20, 2011 to March 4, 2013 (the "Class Period"). The Amended Complaint makes allegations that are substantially similar to those asserted in the five initial complaints. Specifically, the Amended Complaint alleges, among other things, that in Atlantic Power's press releases, quarterly and year- end filings and conference calls with analysts and investors, Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend, which artificially inflated the price of Atlantic Power's common shares during the class period. The Amended Complaint continues to assert claims under Section 10(b) and, against the Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended. It also asserts a claim for unjust enrichment against the Individual Defendants. In accordance with the schedule referenced above, Defendants filed their motion to dismiss the consolidated (the "Motion to Dismiss") U.S. Action on August 5, 2014.

On September 30, 2014, citing Atlantic Power's September 16, 2014 announcement of changes to its dividend and its President and CEO transition, Lead Plaintiff filed a motion (the "Extension Motion") requesting a thirty-day extension of its October 6, 2014 deadline for filing its brief in opposition to the Motion to Dismiss, in which to determine whether to file a second amended complaint. On October 2, 2014, the Court entered an order (i) extending Lead Plaintiff's deadline to file its opposition to the Motion to Dismiss to October 10, 2014 and (ii) requiring Defendants to file their opposition to the Extension Motion by October 2, 2014. In accordance with this order, on October 2, 2014, Defendants filed their opposition to the Extension Motion. On October 10, 2014, Lead Plaintiff filed its opposition to the Motion to Dismiss (the "Opposition") and also filed a motion for leave to amend the Amended Complaint, attaching a proposed second amended complaint. On October 21, 2014, Lead Plaintiff and Defendants filed a joint scheduling motion requesting (i) November 7, 2014 as the deadline for Defendants to file their opposition to Lead Plaintiff's motion for leave to amend the Amended Complaint; (ii) November 24, 2014 as the deadline for Defendants to file their reply in further support of the Motion to Dismiss; and (iii) November 24, 2014 as the deadline for Lead Plaintiff to file its reply in further support of its motion for leave to amend the Amended Complaint. On October 22, 2014, the Court entered an order setting this requested schedule.

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Pursuant to that order, the Motion to Dismiss and Extension Motion were fully briefed on November 24, 2014. On January 22, 2015, the Court held oral argument on the Motion to Dismiss and Extension Motion.

On January 30, 2015, Lead Plaintiff filed a motion for leave to file a supplemental submission in opposition to Defendants' motion to dismiss (the "Motion for Leave"). The Court denied the Motion for Leave in an order entered on February 5, 2015, but permitted Lead Plaintiff to submit a brief letter identifying supplemental authorities. Lead Plaintiff filed that letter on February 9, 2015, and Defendants filed a response on February 10, 2015.

On March 13, 2015, the District Court entered an order granting Defendants' motion to dismiss and denying Lead Plaintiff's motion to amend the Amended Complaint, and on March 18, 2015, the District Court entered an order dismissing the Amended Complaint with prejudice. On April 16, 2015, Lead Plaintiff filed a notice of appeal to the United States Court of Appeals for the First Circuit. The Company will oppose that appeal.

Canadian Actions

On March 19, 2013, April 2, 2013 and May 10, 2013, three notices of action relating to Canadian securities class action claims against the Proposed Defendants were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, with the Ontario Superior Court of Justice in the Province of Ontario. On April 8, 2013, a similar claim issued by alleged investors in Atlantic Power common shares seeking to initiate a class action against the Proposed Defendants was filed with the Superior Court of Quebec in the Province of Quebec (the "Canadian Actions").

On April 17, May 22, and June 7, 2013, statements of claim relating to the notices of action were filed with the Ontario Superior Court of Justice in the Province of Ontario.

On August 30, 2013, the three Ontario actions were succeeded by one action with an amended claim being issued on behalf of Jacqeline Coffin and Sandra Lowry. As in the U.S. Action, this claim names the Company, Barry E. Welch and Terrence Ronan as Defendants. The Plaintiffs seek leave to commence an action for statutory misrepresentation under the Ontario Securities Act and assert common law claims for misrepresentation. The Plaintiffs' allegations focus on among other things, claims the Defendants made materially false and misleading statements and omissions in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The Plaintiffs sought to certify the statutory and common law claims under the Class Proceedings Act for security holders who purchased and held securities through a proposed class period of November 5, 2012 to February 28, 2013.

On October 4, 2013, the Plaintiffs delivered materials supporting their request for leave to commence an action for statutory misrepresentations and for certification of the statutory and common claims as class proceedings. These materials estimate the damages claimed for statutory misrepresentation at $197.4 million.

On March 26, 2015, the Plaintiffs amended their claim to add Scott Fife as a proposed representative plaintiff. On April 24, 2015, the Plaintiffs amended their claim to remove Ms. Lowry, who claimed to hold Atlantic Power convertible debentures, as a proposed representative plaintiff.

The Plaintiffs' motions for leave and certification were heard on May 20-21, 2015.

On July 24, 2015, the Ontario Superiour Court of Justice issued a decision denying the Plaintiffs' motion for leave and certification. The Superior Court granted leave to reconstitute a claim for debenture holders but required that there be a debenture holder as plaintiff, that the claim be amended and that the Plaintiffs pay the Defendants partial indemnity costs of responding to the Plaintiffs' motion.

Plaintiffs have advised that they intend to proceed with an appeal of the July 24 decision on leave and certification. The Company will oppose that appeal.

The proposed class action in Quebec is stayed until August 28, 2015.

Pursuant to the Private Securities Litigation Reform Act of 1995, all discovery is stayed in the U.S. Actions. Plaintiffs have not yet specified an amount of alleged damages in the U.S. Actions. As noted above, the plaintiffs in the Canadian Action have estimated their alleged statutory damages at $197.4 million. Because both the U.S. and Canadian Actions are in their early stages, Atlantic Power is unable to reasonably estimate the possible loss or range of losses, if any, arising from this litigation. Atlantic Power intends to defend vigorously against each of the actions.

Other than as described above, there were no material changes to legal proceedings disclosed in "Item 3. Legal Proceedings" of our Annual Report on Form 10-K for the year ended December 31, 2014 and "Item 1. Legal Proceedings" of our Quarterly Report on Form 10-Q for the quarter ended March 31, 2015.

ITEM 1A. RISK FACTORS

Other than as described below, there were no material changes to the risk factors disclosed in "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2014 and our Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 (except to the extent additional factual information disclosed elsewhere in this Quarterly Report on Form 10-Q relates to such risk factors (including, without limitation, the matters discussed in "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations"). To the extent any risk factors in our Annual Report on Form 10-K for the year ended December 31, 2014 and in our Quarterly Report on Form 10-Q for the quarter ended March 31, 2015 relate to the factual information disclosed elsewhere in this Quarterly Report on Form 10-Q, including with respect to our business plan and any updated to our business strategy, such risk factors should be read in light of such information.

As a result of the sale of our Wind Projects, our business has become more concentrated, subjecting it to increased risk from each individual portion of the business.

As a result of the sale of the Wind Projects on June 26, 2015, our operations have become more concentrated in our remaining East U.S., West U.S. and Canada segments, our portfolio of projects has become less diversified geographically and by fuel type, we have fewer renewable energy projects in our portfolio and our customer base is more concentrated. As a result, each of the risks that affected our projects described in our Annual Report on Form 10-K for the year ended December 31, 2014 prior to the sale of the Wind Projects, including, without limitation, our exposure to market prices of electricity and risks associated with equipment failure or frequent and/or larger than forecasted downtimes for equipment maintenance and repair, will now pose a greater risk to our overall business, financial condition and results of operations. Further, new laws or other regulatory developments that favor renewable energy and in particular, wind energy, may have a more significant adverse impact on our business than in the past. In addition, approximately 25% of our PPAs on a MW-weighted basis are scheduled to expire over the next five years, beginning in December 2017, and our weighted average remaining PPA life after the close of the sale of our Wind Project is approximately 8 years, down from 10 years previously. This increases our reliance on each of our existing PPAs and the potential adverse effect that could result from the expiration or termination of any single PPA. In addition, the increased concentration of our business in our remaining East U.S, West U.S. and Canada segments also increases our dependence on our remaining customers. For example, for the three and six months ended June 30, 2015, IESO, San Diego Gas & Electric, BC Hydro and Niagara Mohawk Power

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Corporation collectively accounted for nearly 60% of our total consolidated revenues. IESO, San Diego Gas & Electric, BC Hydro and Niagara Mohawk Power Corporation accounted for 26.4%, 12.5%, 10.3% and 10.9%, respectively, of total consolidated revenues for the three months ended June 30, 2015 and 30.2%, 10.6%, 11.0% and 8.6%, respectively, of total consolidated revenues for the six months ended June 30, 2015. If any such customer stops purchasing output from our power generation projects or purchases less power than anticipated, such customer may be difficult to replace, if at all, which may adversely impact our business.

ITEM 6. EXHIBITS

EXHIBIT INDEX

Exhibit No.	Description
10.1*	Amendment to Purchase Agreement, dated 3, 2015
10.2	Agreement dated May 21, 2015, by and among Mangrove Partners and the Company (incorporated by reference to Exhibit 10.1 to our Current Report on Form 8-K filed on May 21, 2015).
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS*	XBRL Instance Document
101.SCH*	XBRL Taxonomy Extension Schema
101.CAL*	XBRL Taxonomy Extension Calculation Linkbase
101.DEF*	XBRL Taxonomy Extension Definition Linkbase
101.LAB*	XBRL Taxonomy Extension Label Linkbase
101.PRE*	XBRL Taxonomy Extension Presentation Linkbase

* Filed herewith.

** Furnished herewith.

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SIGNATURES

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

Date: August 10, 2015	Atlantic Power Corporation
	By: /s/ TERRENCE RONAN
	Name: Terrence Ronan
	Title: *Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*