ATLANTIC POWER CORP
Form 10-Q
November 14, 2011

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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 September 30, 2011

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	**55-0886410**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

200 Clarendon Street, Floor 25	
Boston, MA	**02116**
(Address of principal executive offices)	(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 o	Non-accelerated filer ý (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

As of November 9, 2011 there were 113,474,259 shares of common stock, no par value, of the registrant were outstanding.

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ATLANTIC POWER CORPORATION

FORM 10-Q

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2011

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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" and "Atlantic Power" refer to Atlantic Power Corporation, those entities owned or controlled by Atlantic Power Corporation and predecessors of Atlantic Power Corporation.

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PART I FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands of U.S. dollars)

	September 30, 2011 (unaudited)	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 38,254	$ 45,497
Restricted cash	28,123	15,744
Accounts receivable	19,104	19,362
Note receivable related party (Note 14)	7,326	22,781
Current portion of derivative instruments asset (Notes 8 and 9)	649	8,865
Prepayments, supplies, and other	10,967	8,480
Refundable income taxes	1,594	1,593
Total current assets	106,017	122,322
Property, plant, and equipment, net	360,594	271,830
Transmission system rights	182,245	188,134
Equity investments in unconsolidated affiliates (Note 4)	275,425	294,805
Other intangible assets, net	71,802	88,462
Goodwill	12,453	12,453
Derivative instruments asset (Notes 8 and 9)	4,593	17,884
Other assets	15,892	17,122
Total assets	$ 1,029,021	$ 1,013,012
Liabilities		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 42,373	$ 20,530
Current portion of long-term debt (Note 6)	22,562	21,587
Current portion of derivative instruments liability (Notes 8 and 9)	34,921	10,009
Interest payable on convertible debentures (Note 7)	2,442	3,078
Dividends payable	6,003	6,154
Other current liabilities	10	5
Total current liabilities	108,311	61,363
Long-term debt (Note 6)	294,989	244,299
Convertible debentures (Note 7)	188,620	220,616
Derivative instruments liability (Notes 8 and 9)	27,892	21,543
Deferred income taxes	18,142	29,439
Other non-current liabilities	2,193	2,376
Commitments and contingencies (Note 15)		

Total liabilities	640,147	579,636
Equity		
Common shares, no par value, unlimited authorized shares; 68,997,122 and 67,118,154 issued and outstanding at September 30, 2011 and December 31, 2010, respectively	649,070	626,108
Accumulated other comprehensive (loss) income (Note 9)	(1,218)	255
Retained deficit	(262,136)	(196,494)
Total Atlantic Power Corporation shareholders' equity	385,716	429,869
Noncontrolling interest	3,158	3,507
Total equity	388,874	433,376
Total liabilities and equity	$ 1,029,021	$ 1,013,012

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

(In thousands of U.S. dollars, except per share amounts)

(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2011	**2010**	**2011**	**2010**
Project revenue:				
Energy sales	$ 17,104	$ 22,713	$ 53,471	$ 55,285
Energy capacity revenue	27,070	23,196	81,859	69,585
Transmission services	7,638	7,813	22,773	23,186
Other	521	317	1,153	1,108
	52,333	54,039	159,256	149,164
Project expenses:				
Fuel	14,818	19,678	46,202	51,606
Operations and maintenance	8,645	6,846	27,518	19,248
Depreciation and amortization	10,908	10,082	32,711	30,224
	34,371	36,606	106,431	101,078
Project other income (expense):				
Change in fair value of derivative instruments (Notes 8 and 9)	(11,484)	(9,744)	(12,497)	(20,946)
Equity in earnings of unconsolidated affiliates, net	2,374	4,088	5,647	12,550
Interest expense, net	(4,494)	(4,165)	(13,684)	(12,884)
Other income (expense), net	(7)	22	(40)	233
	(13,611)	(9,799)	(20,574)	(21,047)
Project income	4,351	7,634	32,251	27,039
Administrative and other expenses (income):				
Administration	11,936	4,103	20,661	12,046
Interest	3,337	2,707	10,815	8,019
Foreign exchange loss (gain) (Note 9)	21,576	(2,253)	20,383	179
Other income, net				(26)
	36,849	4,557	51,859	20,218
(Loss) income from operations before income taxes	(32,498)	3,077	(19,608)	6,821
Income tax (benefit) expense (Note 10)	(4,520)	3,614	(10,681)	12,105
Net loss	(27,978)	(537)	(8,927)	(5,284)
Net loss attributable to noncontrolling interest	(78)	(99)	(349)	(228)
Net loss attributable to Atlantic Power Corporation	$ (27,900)	$ (438)	$ (8,578)	$ (5,056)
Net loss per share attributable to Atlantic Power Corporation shareholders: (Note 12)				
Basic	$ (0.40)	$ (0.01)	$ (0.13)	$ (0.08)
Diluted	$ (0.40)	$ (0.01)	$ (0.13)	$ (0.08)
Weighted average number of common shares outstanding: (Note 12)				
Basic	68,910	60,511	68,384	60,466

Diluted	68,910	60,511	68,384	60,466

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands of U.S. dollars)

(Unaudited)

	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Cash flows from operating activities:		
Net loss	$ (8,927)	$ (5,284)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	32,711	30,224
Long-term incentive plan expense	2,257	3,287
Gain on step-up valuation of Rollcast acquisition		(211)
Equity in earnings from unconsolidated affiliates	(5,647)	(12,550)
Distributions from unconsolidated affiliates	15,542	9,897
Unrealized foreign exchange loss	28,175	4,369
Change in fair value of derivative instruments	12,497	20,946
Change in deferred income taxes	(10,315)	10,555
Change in other operating balances		
Accounts receivable	258	(3,072)
Prepayments, refundable income taxes and other assets	(570)	1,189
Accounts payable and accrued liabilities	1,536	3,747
Other liabilities	(1,178)	576
Net cash provided by operating activities	66,339	63,673
Cash flows used in investing activities:		
Acquisitions and investments, net of cash acquired		(41,182)
Change in restricted cash	(12,379)	(7,398)
Proceeds from sale of equity investments	8,500	
Proceeds from Idaho Wind loan	15,455	
Short-term loan to Idaho Wind		(12,801)
Biomass development costs	(753)	(1,827)
Purchase of property, plant and equipment	(79,070)	(2,077)
Net cash used in investing activities	(68,247)	(65,285)
Cash flows used in financing activities:		
Proceeds from project-level debt	65,374	
Repayment of project-level debt	(13,166)	(11,841)
Equity investment from noncontrolling interest		200
Proceeds from revolving credit facility borrowings		20,000
Dividends paid	(57,543)	(47,599)
Net cash used in financing activities	(5,335)	(39,240)
Net decrease in cash and cash equivalents	(7,243)	(40,852)
Cash and cash equivalents at beginning of period	45,497	49,850
Cash and cash equivalents at end of period	$ 38,254	$ 8,998
Supplemental cash flow information		
Interest paid	$ 21,567	$ 16,587

Income taxes paid (refunded), net	$ (352)	$ (1,607)
Accruals for capital expenditures	$ 19,547	$

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of presentation and summary of significant accounting policies

Overview

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements, which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,948 megawatts (or "MW") in which our ownership interest is approximately 871 MW. Our current portfolio consists of interests in 12 operational power generation projects across nine states, one biomass project under construction in Georgia, and a 500 kilovolt 84-mile electric transmission line located in California. We also own a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development. Six of our projects are wholly-owned subsidiaries: Lake Cogen, Ltd., Pasco Cogen, Ltd., Auburndale Power Partners, L.P., Cadillac Renewable Energy, LLC, Piedmont Green Power, LLC and Atlantic Path 15, LLC.

The interim consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission ("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 consolidated financial statements in our Annual Report on Form 10-K for the year ended December 31, 2010. Interim results are not necessarily indicative of results for the full year.

In our opinion, the accompanying unaudited interim consolidated financial statements contain all material adjustments consisting of normal and recurring accruals necessary to present fairly our consolidated financial position as of September 30, 2011, the results of operations for the three and nine-month periods ended September 30, 2011 and 2010, and our cash flows for the nine-month periods ended September 30, 2011 and 2010.

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 period. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and power purchase agreements ("PPAs"), the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the valuation of shares associated with our long-term incentive plan and the fair value of financial instruments and derivatives. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets if indications of impairment exist during the period. These estimates and assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying assumptions and estimates change, the recorded amounts could change by a material amount.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

1. Basis of presentation and summary of significant accounting policies (Continued)

Reclassifications:

Certain prior year amounts have been reclassified to conform to the current year presentation.

Recently issued accounting standards:

Adopted

In December 2010, the FASB issued changes to the disclosure of pro forma information for business combinations. These changes clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Also, the existing supplemental pro forma disclosures were expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. We adopted these changes beginning January 1, 2011. These changes will be reflected upon the closing of significant acquisitions during 2011.

In December 2010, the FASB issued changes to the testing of goodwill for impairment. These changes require an entity to perform all steps in the test for a reporting unit whose carrying value is zero or negative if it is more likely than not (more than 50%) that a goodwill impairment exists based on qualitative factors, resulting in the elimination of an entity's ability to assert that such a reporting unit's goodwill is not impaired and additional testing is not necessary despite the existence of qualitative factors that indicate otherwise. We adopted these changes beginning January 1, 2011. Based on the most recent impairment review of our goodwill (2010 fourth quarter), we determined these changes did not impact the consolidated financial statements.

In January 2010, the FASB issued changes to disclosure requirements for fair value measurements. Specifically, the changes require a reporting entity to disclose, in the reconciliation of fair value measurements using significant unobservable inputs (Level 3), separate information about purchases, sales, issuances, and settlements (that is, on a gross basis rather than as one net number) of these Level 3 financial instruments. We adopted these changes beginning January 1, 2011. We determined that these changes did not have an impact on the consolidated financial statements.

In April 2010, the FASB issued changes to the classification of certain employee share-based payment awards. These changes clarify that there is not an indication of a condition that is other than market, performance, or service if an employee share-based payment award's exercise price is denominated in the currency of a market in which a substantial portion of the entity's equity securities trade and differs from the functional currency of the employer entity or payroll currency of the employee. An employee share-based payment award is required to be classified as a liability if the award does not contain a market, performance, or service condition. These changes were adopted beginning on January 1, 2011. We determined that these changes did not have an impact on the consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

1. Basis of presentation and summary of significant accounting policies (Continued)

Issued

In May 2011, the FASB issued changes to conform existing guidance regarding fair value measurement and disclosure between GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio; application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. These changes become effective on January 1, 2012. We are currently evaluating the potential impact of these changes on the consolidated financial statements.

In June 2011, the FASB issued changes to the presentation of comprehensive income. These changes give an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements; the option to present components of other comprehensive income as part of the statement of changes in stockholders' equity was eliminated. The items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income were not changed. Additionally, no changes were made to the calculation and presentation of earnings per share. These changes become effective on January 1, 2012. We are currently evaluating these changes to determine which option will be chosen for the presentation of comprehensive income. Other than the change in presentation, we have determined these changes will not have an impact on the consolidated financial statements.

In September 2011, the FASB issued changes to the testing of goodwill for impairment. These changes provide an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of a reporting unit is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions; industry and market considerations; cost factors; overall financial performance; and other relevant entity-specific events. If an entity elects to perform a qualitative assessment and determines that an impairment is more likely than not, the entity is then required to perform the existing two-step quantitative impairment test, otherwise no further analysis is required. An entity also may elect not to perform the qualitative assessment and, instead, go directly to the two-step quantitative impairment test. These changes become effective for any goodwill impairment test performed on January 1, 2012 or later, although early adoption is permitted. We perform a review of our goodwill in the fourth quarter of each calendar year and plan to early adopt these changes effective for our review of goodwill in the fourth quarter of 2011. As these changes should not affect

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

1. Basis of presentation and summary of significant accounting policies (Continued)

the outcome of the impairment analysis of a reporting unit, we have determined these changes will not have an impact on the consolidated financial statements.

2. Comprehensive income (loss)

The following table summarizes the components of comprehensive income (loss) for the three and nine-month periods ended September 30, 2011 and 2010:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Net loss	$ (27,978)	$ (537)	$ (8,927)	$ (5,284)
Unrealized loss on hedging activity	(2,492)	(118)	(3,762)	(275)
Less income tax benefit	(997)	(47)	(1,505)	(110)
Comprehensive loss	$ (29,473)	$ (608)	$ (11,184)	$ (5,449)

3. Acquisitions and divestitures

(a) Capital Power Income L.P.

On November 5, 2011, we completed the acquisition of all the outstanding limited partnership interests of Capital Power Income L.P. ("CPILP") pursuant to the terms and conditions of an Arrangement Agreement, dated June 20, 2011, as amended by Amendment No. 1, dated July 15, 2011 (the "Arrangement Agreement"), by and among us, CPILP, CPI Income Services Ltd., the general partner of CPILP, and CPI Investments Inc., a unitholder of CPILP that is owned by EPCOR Utilities Inc. and Capital Power Corporation. The transactions contemplated by the Arrangement Agreement were effected through a court-approved plan of arrangement under the *Canada Business Corporations Act* (the "Plan of Arrangement"). The Plan of Arrangement was approved by the unitholders of CPILP, and the issuance of shares of the Company's stock to CPILP unitholders pursuant to the Plan of Arrangement was approved by the shareholders, at respective special meetings held on November 1, 2011. A Final Order approving the Plan of Arrangement was entered by the Court of Queen's Bench of Alberta, Judicial District of Calgary, on November 1, 2011. Pursuant to the Plan of Arrangement, CPILP sold its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, for approximately Cdn$121.0 million which equates to approximately Cdn$2.15 per unit of CPILP. In addition, in connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power Corporation and CPILP and certain of its subsidiaries were terminated in consideration of a payment of Cdn$10.0 million. Atlantic Power and its subsidiaries assumed the management of CPILP upon closing and entered into a transitional services agreement with Capital Power Corporation for a term of six to up to twelve months to facilitate and support the integration of CPILP into Atlantic Power.

The acquisition expands and diversifies our asset portfolio to include projects in Canada and regions of the United States where we did not have a presence. The enhanced geographic diversification is anticipated to lead to additional growth opportunities in those regions where we did not previously operate. Our average PPA term increases from 8.8 to 9.1 years and enhances the credit

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

3. Acquisitions and divestitures (Continued)

quality of our off takers. Our market capitalization and enterprise value are expected to nearly double, which is expected to add liquidity and enhance access to capital to fuel the long term growth of our asset base throughout North America.

Under the terms of the Plan of Arrangement, CPILP unitholders exchanged each of their limited partnership units for, at their election, Cdn$19.40 in cash or 1.3 Atlantic Power common shares. All cash elections were subject to proration if total cash elections exceeded approximately Cdn$506.5 million and all share elections were subject to proration if total share elections exceeded approximately 31.5 million Atlantic Power common shares. At closing, the consideration paid to acquire CPILP totaled $904.5 million, consisting of $497.6 million paid in cash and $406.9 million in shares of our common shares (31.5 million shares issued).

On October 19, 2011, we closed a public offering of 12,650,000 shares of our common stock, which included 1,650,000 common shares issued pursuant to the exercise in full of the underwriters' over-allotment option, at a purchase price of $13.00 per common share sold in US dollars and Cdn$13.26 per common share sold in Canadian dollars, for an aggregate gross proceeds of $164.5 million. We used the proceeds to fund a portion of the cash portion of our acquisition of CPILP and to pay the related fees and expenses incidental to the transaction.

On November 4, 2011, we completed a private placement of US$460.0 million aggregate principal amount of 9% Senior Notes due 2018 to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"), and to non-U.S. persons outside of the United States in compliance with Regulation S under the Securities Act. The Notes were issued at an issue price of 97.471% for aggregate gross proceeds to us of $448.0 million. The Notes are our senior unsecured obligations, guaranteed by certain of our subsidiaries. We used and intend to use the proceeds to fund a portion of the cash portion of our acquisition of CPILP, to pay the related fees and expenses incidental thereto, repay indebtedness outstanding under CPILP's revolving credit facilities and, to the extent of any remaining net proceeds, to fund additional growth opportunities and for general corporate purposes.

Our acquisition of CPILP will be accounted for under the acquisition method of accounting as of the transaction closing date. Final acquisition accounting is not complete as of the date of this Quarterly Report on Form 10-Q because we are in the process of assessing the fair value of the assets acquired and liabilities assumed in the transaction.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

3. Acquisitions and divestitures (Continued)

Our initial purchase price allocation for the business combination is estimated as follows (in thousands):

Fair value of consideration transferred:		
Cash	$	497,575
Equity		406,904
Total estimated purchase price	$	904,479
Preliminary purchase price allocation		
Working capital	$	19,499
Property, plant and equipment		985,265
Intangibles		600,197
Other long-term assets		76,952
Long-term debt		(712,440)
Other long-term liabilities		(95,829)
Deferred tax liability		(159,121)
Total identifiable net assets		714,523
Noncontrolling interest		(215,515)
Goodwill		405,471
Total estimated purchase price		904,479

The preliminary purchase price was computed using CPILP's outstanding units as of June 30, 2011, adjusted for the exchange ratio at November 4, 2011. The preliminary purchase price reflects the market value of Atlantic Power's common shares issued in connection with the transaction based on the closing price of CPILP's units on the Toronto Stock Exchange on November 4, 2011.

The allocation of the preliminary purchase price to the fair values of assets acquired and liabilities assumed includes pro forma adjustments to reflect the fair values of CPILP's assets and liabilities at the time of the completion of the transaction. The final allocation of the purchase price could differ materially from this preliminary allocation primarily because power market prices, interest rates and other valuation variables will fluctuate over time and be different at the time of completion of the transaction compared to the amounts assumed in the pro forma adjustments.

The following unaudited pro-forma consolidated results of operations for three and nine month periods ended September 30, 2011 and 2010, assume the CPILP acquisition occurred as of January 1 of each period. The pro forma results of operations are presented for informational purposes only and are not indicative of the results of operations that would have been achieved if the acquisition had taken

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

3. Acquisitions and divestitures (Continued)

place on January 1, 2011, January 1, 2010 or of results that may occur in the future (amounts in thousands):

	Unaudited			
	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Total project revenue	$ 172,853	$ 169,309	$ 518,868	$ 496,379
Net income (loss) attributable to Atlantic Power Corporation	(51,196)	2,017	(41,668)	(15,847)
Net income (loss) per share attributable to Atlantic Power Corporation shareholders:				
Basic	$ (0.45)	$ 0.02	$ (0.37)	$ (0.15)
Diluted	$ (0.45)	$ 0.02	$ (0.37)	$ (0.15)

(b) Onondaga Renewables

During the three month period ended September 30, 2011, we reviewed the recoverability of our 50% investment in the Onondaga Renewables project. The review was undertaken as a result of the project's partners initiating a plan to sell their interests in the project.

Based on this review, we determined that the carrying value of the Onondaga Renewables project was impaired and recorded a pre-tax long-lived asset impairment of $1.1 million as of September 30, 2011. Our estimate of the fair market value of our 50% investment in the Onondaga Renewables project was determined utilizing a probability weighted analysis of potential disposal scenarios based on market factors and industry experience. The Onondaga Renewables project is accounted for under the equity method of accounting and the impairment charge is included in equity earnings from unconsolidated affiliates in the consolidated statements of operations.

(c) Topsham

On February 28, 2011, we entered into a purchase and sale agreement with an affiliate of ArcLight Capital Partners, LLC ("ArcLight") for the purchase of our lessor interest in the project. The transaction closed on May 6, 2011 and we received proceeds of $8.5 million, resulting in no gain or loss on the sale.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Equity method investments

The following summarizes the operating results for the three and nine months ended September 30, 2011 and 2010, respectively, for our equity earnings interest in our equity method investments:

	Three-months ended September 30,		Nine-months ended September 30,	
	2011	**2010**	**2011**	**2010**
Revenue				
Chambers	$ 11,616	$ 14,401	$ 37,894	$ 43,146
Badger Creek	1,415	3,344	6,070	10,435
Gregory	7,810	7,909	22,624	24,461
Orlando	10,549	10,857	29,851	31,617
Selkirk	14,020	13,114	37,881	39,156
Other	3,093	1,487	8,045	4,728
	48,503	51,112	142,365	153,543
Project expenses				
Chambers	9,107	10,592	28,032	30,883
Badger Creek	1,509	2,964	5,907	9,188
Gregory	7,007	6,751	20,537	21,448
Orlando	10,156	10,124	29,224	30,039
Selkirk	12,572	12,053	37,861	36,802
Other	2,617	1,194	6,412	3,773
	42,968	43,678	127,973	132,133
Project other income (expense)				
Chambers	(730)	(954)	(1,820)	(2,706)
Badger Creek	(9)	(7)	(20)	200
Gregory	(218)	(661)	(449)	(1,346)
Orlando	(13)	(33)	(57)	(99)
Selkirk	(33)	(1,618)	(2,599)	(4,704)
Other	(2,158)	(73)	(3,800)	(205)
	(3,161)	(3,346)	(8,745)	(8,860)
Project income (loss)				
Chambers	1,779	2,855	8,042	9,557
Badger Creek	(103)	373	143	1,447
Gregory	585	497	1,638	1,667
Orlando	380	700	570	1,479
Selkirk	1,415	(557)	(2,579)	(2,350)
Other	(1,682)	220	(2,167)	750
	2,374	4,088	5,647	12,550

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

5. Accumulated depreciation and amortization

The following table presents accumulated depreciation of property, plant and equipment and the accumulated amortization of transmission system rights and other intangible assets as of September 30, 2011 and December 31, 2010:

	September 30, 2011	December 31, 2010
Property, plant and equipment	$ 101,421	$ 91,851
Transmission system rights	49,424	43,535
Other intangible assets	74,221	57,000

6. Long-term debt

Long-term debt represents project-level long-term debt of our consolidated subsidiaries and the unamortized balance of purchase accounting adjustments that were recorded in connection with the Path 15 acquisition in order to adjust the debt to its fair value on the acquisition date. Project-level debt is non-recourse to Atlantic Power and generally amortizes during the term of the respective revenue generating contracts of the projects.

	September 30, 2011	December 31, 2010
Project debt, interest rates ranging from 5.1% to 9.0% maturing through 2028	$ 306,790	$ 254,581
Purchase accounting fair value adjustments	10,761	11,305
Less: current portion of long-term debt	(22,562)	(21,587)
Long-term debt	$ 294,989	$ 244,299

Project-level debt is secured by the respective project and its contracts with no other recourse to us. The loans have certain financial covenants that must be met. At September 30, 2011, all of our projects were in compliance with the covenants contained in the project-level debt. However, the holding company for our investment in the Chambers project, Epsilon Power Partners, the Gregory, Selkirk and Delta-Person projects had not achieved the levels of debt service coverage ratios required by the project-level debt arrangements as a condition to make distributions and were therefore restricted from making distributions to us.

As of September 30, 2011 the inception to date balance of $65.4 million on the Piedmont construction debt is funded by the related bridge loan of $51.0 million and $14.4 million was funded by the construction loan that will convert to a term loan. The terms of the Piedmont project-level debt financing include a $51.0 million bridge loan for approximately 95.0% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations and an $82.0 million construction -term loan. The $51.0 million bridge loan will be repaid in early 2013 and repayment of the expected $82.0 million term loan will commence in 2013.

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(Unaudited)

7. Convertible debentures

The following table contains details related to outstanding convertible debentures:

(In thousands, except for share amounts)	due October 2014	due March 2017	due June 2017	Total
Balance at December 31, 2010 (Cdn$)	55,801	83,124	80,500	219,425
Principal amount converted to equity (Cdn$)	(10,948)	(10,766)		(21,714)
Balance at September 30, 2011 (Cdn$)	44,853	72,358	80,500	197,711
Balance at September 30, 2011 (US$)	42,790	69,031	76,799	188,620
Common shares issued on conversion during the nine-months ended September 30, 2011	882,893	828,147		1,711,040

Aggregate interest expense related to the convertible debentures was $2.8 million and $2.4 million for the three-month periods ended September 30, 2011 and 2010, respectively, and $9.3 million and $6.7 million for the nine-month periods ended September 30, 2011 and 2010, respectively.

8. Fair value of financial instruments

The following represents our financial assets and liabilities that were recognized at fair value as of September 30, 2011 and December 31, 2010. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	September 30, 2011			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 38,254	$	$	$ 38,254
Restricted cash	28,123			28,123
Derivative instruments asset		5,242		5,242
Total	$ 66,377	$ 5,242	$	$ 71,619
Liabilities:				
Derivative instruments liability	$	$ 62,813	$	$ 62,813
Total	$	$ 62,813	$	$ 62,813

	December 31, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 45,497	$	$	$ 45,497
Restricted cash	15,744			15,744
Derivative instruments asset		26,749		26,749
Total	$ 61,241	$ 26,749	$	$ 87,990
Liabilities:				
Derivative instruments liability	$	$ 31,552	$	$ 31,552

Total	$	$ 31,552	$	$ 31,552

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Fair value of financial instruments (Continued)

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 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 September 30, 2011, the credit valuation adjustments resulted in a $6.2 million net increase in fair value, which consists of a $1.2 million pre-tax gain in other comprehensive income and a $4.8 million gain in change in fair value of derivative instruments and a $0.2 million gain in foreign exchange. As of December 31, 2010, the credit reserve resulted in a $0.6 million net increase in fair value, which is attributable to a $0.2 million pre-tax gain in other comprehensive income and a $0.5 million gain in change in fair value of derivative instruments, partially offset by a $0.1 million loss in foreign exchange.

9. 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 each reporting period. For certain contracts designated as cash flow hedges, we defer the effective portion of the change in fair value of the derivatives to accumulated other comprehensive income (loss) ("OCI"), until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge is immediately recognized in earnings.

For derivatives that are not designated as cash flow hedges, the changes in the fair value are immediately recognized in earnings. The guidelines apply to our natural gas swaps, interest rate swaps, and foreign exchange contracts.

Natural gas swaps

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. In the third quarter of 2010 we entered into natural gas swaps in order to effectively fix the price of 1.2 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. In the third quarter of 2011, we entered into additional natural gas swaps for 2014 and 2015 increasing the total to 2.0 million Mmbtu or approximately 40% of our share of expected natural gas purchases for that period. We also entered into natural gas swaps to effectively fix the price of 1.3 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2016 and 2017.

The Lake project's operating margin is exposed to changes in natural gas spot market prices through the expiration of its PPA on July 31, 2013. The Auburndale project purchases natural gas under a fuel supply agreement which provides approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% is purchased at spot market prices and therefore the project is exposed to changes in natural gas prices for that portion of its gas requirements through the termination of the fuel supply agreement and 100% of its natural gas requirements from the expiration of the fuel supply agreement in mid-2012 until the termination of its PPA at the end of 2013.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Our strategy to mitigate the future exposure to changes in natural gas prices at Orlando, Lake and Auburndale 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 sheet at fair value and the changes in their fair market value are recorded in the consolidated statement of operations.

Interest Rate Swaps

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 6.02% from February 16, 2011 to February 15, 2015, 6.14% from February 16, 2015 to February 15, 2019, 6.26% from February 16, 2019 to February 15, 2023, and 6.38% 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 changes in the fair market value is recorded in accumulated other comprehensive income.

We executed two interest rate swaps at our consolidated Piedmont project to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.75% from March 31, 2011 to February 29, 2016. From February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.47%. The swap continues at the fixed rate of 4.47% from the maturity of the debt in November 2017 until November 2030. The notional amounts of the interest rate swap agreements match the estimated outstanding principal balance of Piedmont's cash grant bridge loan and the construction loan facility which will convert to a term loan. 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. 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.

In November 2009, we executed an interest rate swap at our consolidated Auburndale project to hedge a portion of its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 3.12%. The notional amount of the swap matches the outstanding principal balance over the remaining life of Auburndale's debt. This swap agreement is effective through November 30, 2012. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Auburndale debt agreement and changes in the fair market value is recorded in accumulated other comprehensive income.

In July 2007, we executed an interest rate swap to economically fix the exposure to changes in interest rates related to the variable-rate non-recourse debt at our wholly-owned subsidiary Epsilon Power Partners. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 5.29%. In June 2010, the swap agreement was amended to reduce the fixed interest rate 4.24% and extend the maturity date from July 2012 to July 2019. The notional amount of the swap matches the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. This interest rate swap agreement is not designated as a hedge and changes in its fair market value are recorded in the consolidated statements of operations.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Foreign currency forward contracts

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as we generate cash flow in U.S. dollars but pay dividends to shareholders and interest on convertible debentures predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge approximately 84% of our expected dividend and convertible debenture interest payments through 2013. Changes in the fair value of the forward contracts partially offset foreign exchange gain or losses on the U.S. dollar equivalent of our Canadian dollar obligations. The forward contracts consist of (1) monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) purchase in October 2011 of Cdn$1.9 million at an exchange rate of Cdn$1.1075 per U.S. dollar. It is our intention to periodically consider extending the length of these forward contracts.

In the third quarter of 2011 we executed a series of financial transactions with an exercise date of January 18, 2012, to hedge a portion of the foreign currency exchange risk associated with the closing of the CPILP transaction. These transactions are summarized as follows with strike prices per Cdn$1.00:

Transaction Date	Forward Purchases	Call Options	Put Options
July 27, 2011	$84.7 million at 0.9465	$32.0 million at 0.9460	$116.7 million at 0.90
August 3, 2011	$76.0 million at 0.9665	$14.5 million at 0.9665	$90.5 million at 0.90
August 5, 2011	$81.2 million at 0.9872	$9.3 million at 0.9872	$90.5 million at 0.90
August 18, 2011	$97.8 million at 0.9913		

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 normal purchases and normal sales exception as of September 30, 2011:

	Units	September 30, 2011
Natural gas swaps	Natural Gas (Mmbtu)	15,000
Interest rate swaps	Interest (US$)	$ 53,973
Currency forwards and options	Cdn$	$ 617,630

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

9. 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:

	September 30, 2011	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1,614
Interest rate swaps long-term		5,141
Total derivative instruments designated as cash flow hedges		6,755
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		2,427
Interest rate swaps long-term		8,686
Foreign currency forward contracts current	6,340	25,300
Foreign currency forward contracts long-term	4,593	
Natural gas swaps current		11,272
Natural gas swaps long-term		14,064
Total derivative instruments not designated as cash flow hedges	10,933	61,749
Total derivative instruments	$ 10,933	$ 68,504

	December 31, 2010	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 2,124
Interest rate swaps long-term		2,626
Total derivative instruments designated as cash flow hedges		4,750
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		1,286
Interest rate swaps long-term	3,299	2,000
Foreign currency forward contracts current	8,865	
Foreign currency forward contracts long-term	14,585	
Natural gas swaps current		6,599

Natural gas swaps long-term		16,917
Total derivative instruments not designated as cash flow hedges	26,749	26,802
Total derivative instruments	$ 26,749	$ 31,552

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

9. 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) balance attributable to derivative financial instruments designated for hedge accounting, net of tax:

For the three month period ended September 30, 2011	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at June 30, 2011	$ (479)	$ 503	$ 24
Change in fair value of cash flow hedges	(1,495)		(1,495)
Realized from OCI during the period	344	(91)	253
Accumulated OCI balance at September 30, 2011	$ (1,630)	$ 412	$ (1,218)

For the three month period ended September 30, 2010	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at June 30, 2010	$ (374)	$ 180	$ (194)
Change in fair value of cash flow hedges	(71)		(71)
Realized from OCI during the period	109	254	363
Accumulated OCI balance at September 30, 2010	$ (336)	$ 434	$ 98

For the nine month period ended September 30, 2011	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2010	$ (427)	$ 682	$ 255
Change in fair value of cash flow hedges	(2,257)		(2,257)
Realized from OCI during the period	1,054	(270)	784
Accumulated OCI balance at September 30, 2011	$ (1,630)	$ 412	$ (1,218)

For the nine month period ended September 30, 2010	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2009	$ (538)	$ (321)	$ (859)
Change in fair value of cash flow hedges	(165)		(165)
Realized from OCI during the period	367	755	1,122
Accumulated OCI balance at September 30, 2010	$ (336)	$ 434	$ 98

A $5.1 million loss was deferred in other comprehensive loss for natural gas swap contracts accounted for as cash flow hedges prior to July 1, 2009 when hedge accounting for these natural gas swaps was discontinued prospectively. Amortization of the remaining loss in other comprehensive income of $(0.2) million and $0.4 million was recorded in change in fair value of derivative instruments for the three-month periods ended September 30, 2011 and 2010, respectively, and $(0.4) million and $1.3 million for the nine-month periods ended September 30, 2011 and 2010, respectively.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Impact of derivative instruments on the consolidated income statements

The following table summarizes realized (gains) and losses for derivative instruments not designated as cash flow hedges:

	Classification of (gain) loss recognized in income	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Natural gas swaps	Fuel	$ 1,744	$ 2,076	$ 6,275	$ 6,515
Interest rate swaps	Interest, net	1,091	365	3,022	1,314
Foreign currency forwards	Foreign exchange (gain) loss	(2,100)	(1,423)	(7,792)	(4,190)

The following table summarizes the unrealized (gains) and losses 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 September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Natural gas swaps	Change in fair value of derivatives	$ (3,017)	$ (8,940)	$ (1,372)	$ (19,976)
Interest rate swaps	Change in fair value of derivatives	(8,467)	(804)	(11,125)	(970)
		$ (11,484)	$ (9,744)	$ (12,497)	$ (20,946)
Forward currency forwards	Foreign exchange (gain) loss	$ 39,950	$ (5,716)	$ 37,817	$ 1,989

10. Income taxes

The difference between the actual tax benefit of $4.5 million and the expected income tax benefit, based on the Canadian enacted statutory rate of 26.5%, of $8.6 million for the three months ended September 30, 2011 is primarily due to a $1.5 million increase in the valuation allowance and various other permanent differences. The difference between the actual tax benefit of $10.7 million and expected income tax benefit of $5.2 million for the nine months ended September 30, 2011 is primarily due to the change in basis of the Idaho Wind assets due to the receipt of the proceeds of the stimulus grant offset by an increase of $0.5 million in the valuation allowance and various other permanent differences.

	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Current income tax expense (benefit)	$ 104	$ 474	$ (366)	$ 1,550
Deferred tax expense (benefit)	(4,624)	3,140	(10,315)	10,555
Total income tax expense (benefit)	$ (4,520)	$ 3,614	$ (10,681)	$ 12,105

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

10. Income taxes (Continued)

Valuation Allowance

As of September 30, 2011, we have recorded a valuation allowance of $79.9 million. This amount is comprised primarily of provisions against available 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.

11. Long-Term Incentive Plan ("LTIP")

The following table summarizes the changes in outstanding notional units during the nine months ended September 30, 2011:

	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2010	600,981	$ 10.28
Granted	153,094	$ 14.18
Forfeited	(101,559)	$ 11.61
Additional shares from dividends	27,386	$ 10.95
Vested	(263,523)	$ 9.40
Outstanding at September 30, 2011	416,379	$ 11.00

Certain awards have a market condition based on our total shareholder return during the performance period compared to a group of peer companies. Compensation expense for notional units granted in 2011 is recorded net of estimated forfeitures. See further details as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010.

The calculation of simulated total shareholder return under the Monte Carlo model for the remaining time in the performance period for awards with market conditions included the following assumptions as of September 30, 2011:

Weighted average risk free rate of return	0.19%	0.34%
Dividend yield		7.4%
Expected volatility Company	21.1%	23.5%
Expected volatility peer companies	16.5%	94.1%
Weighted average remaining measurement period	1.06 years	

12. 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 shares that would be issued if all of the convertible debentures were converted into shares at January 1, 2011. Dilutive potential shares also include the weighted average number of

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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 nine months ended September 30, 2011 and 2010, diluted earnings per share are equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive. The following table sets forth the diluted net income (loss) and potentially dilutive shares utilized in the per share calculation for the three and nine month periods ended September 30, 2011 and 2010:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Numerator:				
Net loss attributable to Atlantic Power Corporation	$ (27,900)	$ (438)	$ (8,578)	$ (5,056)
Add: interest expense for potentially dilutive convertible debentures, net[(1)]				
Diluted net loss attributable to Atlantic Power Corporation	(27,900)	(438)	(8,578)	(5,056)

(1) The above adjustment for net interest on the potential common shares that would be issued on the conversion of the convertible debentures has been excluded as the impact would be anti-dilutive for the three and nine months ended September 30, 2011 and 2010.

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Denominator:				
Weighted average basic shares outstanding	68,910	60,511	68,384	60,466
Dilutive potential shares:				
Convertible debentures	13,718	11,473	14,190	11,473
LTIP notional units	415	614	363	499
Potentially dilutive shares	83,043	72,598	82,937	72,438
Diluted EPS	$ (0.40)	$ (0.01)	$ (0.13)	$ (0.08)

Potentially dilutive shares from convertible debentures for the three and nine-month periods ended September 30, 2011 and 2010 have been excluded from fully diluted earnings per share because their impact would be anti-dilutive.

13. Segment and related information

We have six reportable segments: Path 15, Auburndale, Lake, Pasco, Chambers and Other Project Assets.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and related information (Continued)

We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income 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 income to Project Adjusted EBITDA is included in the table below.

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Three month period ended September 30, 2011:								
Operating revenues	$ 7,638	$ 19,805	$ 16,950	$ 2,906	$ 0	$ 5,034	$ 0	$ 52,333
Segment assets	213,701	93,526	104,436	36,970	148,662	378,557	53,169	1,029,021
Project Adjusted EBITDA	$ 7,117	$ 10,158	$ 8,517	$ 1,149	$ 3,358	$ 10,681	$ 0	$ 40,980
Change in fair value of derivative instruments		1,613	842		449	7,967		10,871
Depreciation and amortization	2,027	4,959	2,241	758	850	6,989		17,824
Interest, net	2,918	243			1,571	1,892		6,624
Other project (income) expense			(3)		221	1,092		1,310
Project income	2,172	3,343	5,437	391	267	(7,259)		4,351
Interest, net							3,337	3,337
Administration							11,936	11,936
Foreign exchange loss							21,576	21,576
Income (loss) from operations before income taxes	2,172	3,343	5,437	391	267	(7,259)	(36,849)	(32,498)
Income tax expense (benefit)							(4,520)	(4,520)
Net income (loss)	2,172	3,343	5,437	391	267	(7,259)	(32,329)	(27,978)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Three month period ended September 30, 2010:								
Operating revenues	$ 7,813	$ 19,373	$ 23,721	$ 3,132	$ 0	$ 0	$ 0	$ 54,039
Segment assets	219,564	116,352	118,591	40,084	139,217	170,438	60,247	864,493
Project Adjusted EBITDA	$ 7,318	$ 10,018	$ 9,325	$ 1,335	$ 4,637	$ 8,910	$ 0	$ 41,543
Change in fair value of derivative instruments		4,319	4,623		621	1,143		10,706
Depreciation and amortization	2,096	4,949	2,275	751	848	5,430		16,349
Interest, net	3,071	395	(2)		1,638	804		5,906
Other project expense	1			(22)	199	770		948
Project income	2,150	355	2,429	606	1,331	763		7,634
Interest, net							2,707	2,707
Administration							4,103	4,103
Foreign exchange gain							(2,253)	(2,253)
	2,150	355	2,429	606	1,331	763	(4,557)	3,077

Income (loss) from operations before income taxes								
Income tax expense (benefit)							3,614	3,614
Net income (loss)	2,150	355	2,429	606	1,331	763	(8,171)	(537)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and related information (Continued)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Nine month period ended September 30, 2011:								
Operating revenues	$ 22,773	$ 62,021	$ 50,918	$ 8,808	$ 0	$ 14,736	$ 0	$ 159,256
Segment assets	213,701	93,526	104,436	36,970	148,662	378,557	53,169	1,029,021
Project Adjusted EBITDA	$ 20,873	$ 32,077	$ 25,431	$ 1,541	$ 12,389	$ 27,516	$ 0	$ 119,827
Change in fair value of derivative instruments		1,797	(1,020)		(103)	12,239		12,913
Depreciation and amortization	6,006	14,877	6,821	2,272	2,529	20,417		52,922
Interest, net	8,852	838	(5)		4,372	5,895		19,952
Other project (income) expense			(3)		621	1,171		1,789
Project income	6,015	14,565	19,638	(731)	4,970	(12,206)		32,251
Interest, net							10,815	10,815
Administration							20,661	20,661
Foreign exchange loss							20,383	20,383
Income (loss) from operations before income taxes	6,015	14,565	19,638	(731)	4,970	(12,206)	(51,859)	(19,608)
Income tax expense (benefit)							(10,681)	(10,681)
Net income (loss)	6,015	14,565	19,638	(731)	4,970	(12,206)	(41,178)	(8,927)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Nine month period ended September 30, 2010:								
Operating revenues	$ 23,186	$ 59,410	$ 57,804	$ 8,764	$ 0	$ 0	$ 0	$ 149,164
Segment assets	219,564	116,352	118,591	40,084	139,217	170,438	60,247	864,493
Project Adjusted EBITDA	$ 21,348	$ 29,820	$ 23,937	$ 3,752	$ 14,780	$ 25,181	$ 0	$ 118,818
Change in fair value of derivative instruments		9,128	10,849		408	3,050		23,435
Depreciation and amortization	6,290	14,847	6,811	2,243	2,536	16,604		49,331
Interest, net	9,313	1,281	(8)		4,965	2,233		17,784
Other project (income) expense	1			(22)	603	647		1,229
Project income	5,744	4,564	6,285	1,531	6,268	2,647		27,039
Interest, net							8,019	8,019
Administration							12,046	12,046
Foreign exchange loss							179	179
Other income, net							(26)	(26)
Income (loss) from operations before income taxes	5,744	4,564	6,285	1,531	6,268	2,647	(20,218)	6,821
Income tax expense (benefit)	162						11,943	12,105
Net income (loss)	5,582	4,564	6,285	1,531	6,268	2,647	(32,161)	(5,284)

Progress Energy Florida and the California Independent System Operator ("CAISO") provide for 70% and 15%, respectively, of total consolidated revenues for the three months ended September 30, 2011 and 74% and 15% for the three months ended September 30, 2010. Progress Energy Florida and CAISO provide for 70% and 14%, respectively, of total consolidated revenues for the nine-months ended September 30, 2011 and 76% and 16% for the nine-months ended September 30, 2010. Progress Energy Florida purchases electricity from Auburndale and Lake, and the CAISO makes payments to Path 15.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Related party transactions

During 2010, we made short-term loans totaling $22.8 million to Idaho Wind to provide temporary funding for construction of the project until a portion of the project-level construction financing is completed. A portion of the member loans have been paid down with a combination of excess proceeds from the federal stimulus grant after repaying the cash grant facility in June 2011. The remaining balance of the short-term loan will be paid down with funds from a third closing for additional debt and project cash flow expected by the end of the year. The outstanding loans bear interest at a prime rate plus 10% (13.25% as September 30, 2011). During the nine-months ended September 30, 2011, we received $1.2 million in interest payments related to the member loans. As of November 9, 2011, $15.5 million of the loans have been repaid.

Prior to December 31, 2009, Atlantic Power was managed by Atlantic Power Management, LLC (the "Manager"), which was owned by two private equity funds managed by ArcLight. On December 31, 2009, we terminated our management agreements with the Manager and have agreed to pay the ArcLight funds an aggregate of $15.0 million, to be satisfied by a payment of $6.0 million that was made at the termination date, and additional payments of $5.0 million, $3.0 million and $1.0 million on the respective first, second and third anniversaries of the termination date. The remaining liability associated with the termination fee is recorded at its estimated fair value of $3.9 million at September 30, 2011. The contract termination liability is being accreted to the final amounts due over the term of these payments.

15. Commitments and contingencies

Our Lake project is currently involved in a dispute with Progress Energy Florida over off-peak energy sales in 2010. All amounts billed for off-peak energy during 2010 by the Lake project have been paid in full by Progress. The Lake project has filed a claim against Progress in which we seek to confirm our contractual right to sell off-peak energy at the contractual price for such sales. Progress filed a counter-claim against the Lake project, seeking, among other things, the return of amounts paid for off-peak power sales during 2010 and a declaratory order clarifying Lake's rights and obligations under the PPA. The Lake project has stopped dispatching during off-peak periods pending the outcome of the dispute. However, we strongly believe that the court will confirm our contractual right to sell off-peak power using the contractual price that was used during 2010 and that we will be able to continue such off-peak power sales for the remainder of the term of the PPA. We have not recorded any reserves related to this dispute and expect that the outcome will not have a material adverse effect on our financial position or results of operations.

In February 2011, we filed a rate application with the FERC to establish Path 15's revenue requirement of $30.3 million for the 2011-2013 period. In September 2011, we formally terminated settlement negotiations and pursued FERC rate litigation to determine the outcome of our revenue requirement. Path 15 began recording revenue based on the $30.3 million annual revenue requirement in April 2011. The FERC established a refund order in October 2011 which is the date the final 2011-2013 revenue requirement will be effective. The case is currently in initial discovery.

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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Commitments and contingencies (Continued)

matters pending as of September 30, 2011 which are expected to have a material adverse impact on our financial position or results of operations.

16. Subsequent events

As discussed in Note 3, on November 1, 2011 we held our special shareholder meeting to approve the issuance of shares of the Company's stock to CPILP unitholders pursuant to the Plan of Arrangement and the shareholders approved the issuance. On November 5, 2011, we acquired all of the issued and outstanding units of CPILP.

On November 4, 2011 we entered into an Amended and Restated Credit Agreement, pursuant to which we increased the capacity under our existing credit facility from $100.0 million to $300.0 million on a senior secured basis, $200.0 million of which may be utilized for letters of credit. The amended credit facility matures in November 2015 and bears interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.75% and 3.00% that varies based on our corporate credit rating.

The amended credit facility contains representations, warranties, terms and conditions customary for facilities of this type. We must meet certain financial covenants under the terms of the credit facility, which are generally based on ratios of debt to EBITDA and EBITDA to interest. The facility is secured by pledges of assets and interests in certain subsidiaries. We expect to remain in compliance with the covenants of the credit facility for at least the next 12 months.

On November 4, 2011 we terminated the foreign exchange forwards that were entered into in order to hedge a portion of the foreign currency exchange risk associated with the closing of the CPILP transaction. We also exercised all the outstanding foreign exchange options prior to their exercise date of January 18, 2012. As a result, we hedged the cash portion for the CPILP transaction at Cdn$0.99.

CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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:

- the amount of distributions expected to be received from the projects for the full year 2011 and 2012;
- our expectation of higher operating cash flow in 2012, primarily attributable to increased distributions from Selkirk;
- our expectation of a significant increase in cash distributions from Orlando beginning in 2014;
- our forecast of expected annual cash distributions from the Lake and Auburndale projects through 2012;
- the expected resumption of distributions from the holding company on our Chambers project in 2012; and
- the expectation of the Piedmont Construction to be completed in late 2012.

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. 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. 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 discussed under "Risk Factors" included in the filings we make from time to time with the SEC. Our business is both competitive and subject to various risks.

These risks include, without limitation:

- a reduction in revenue upon expiration or termination of power purchase agreements;
- the dependence of our projects on their electricity, thermal energy and transmission services customers;
- exposure of certain of our projects to fluctuations in the price of electricity or natural gas;
- projects not operating according to plan;
- the impact of significant environmental and other regulations on our projects;
- increased competition, including for acquisitions;

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

- the failure to integrate successfully the business of Atlantic Power and CPILP in the expected timeframe.

Other factors, such as general economic conditions, including exchange rate fluctuations, also may have an effect on the results of our operations. 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.

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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 or cash flows 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 Form 10-Q, 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 Corporation 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.

OVERVIEW

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements, which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,948 MW in which our ownership interest is approximately 871 MW. Our current portfolio consists of interests in 12 operational power generation projects across nine states, one biomass project under construction in Georgia, and a 500 kilovolt 84-mile electric transmission line located in California. We also own a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development. We sell the capacity and energy from our power generation projects under power purchase agreements (or "PPAs") with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2012 to 2037, 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). We also sell steam from a number of our projects under steam sales agreements to industrial purchasers. The transmission system rights (or "TSRs") we own in our power transmission project entitle us to payments indirectly from the utilities that make use of the transmission line.

On November 5, 2011 we completed our previously announced acquisition of all the outstanding limited partnership interest of CPILP. CPILP's project portfolio includes 17 wholly-owned power generation assets located in Canada and the United States and a 50.15 per cent interest in a power generation asset in Washington state. CPILP's assets have a total net generation capacity of approximately 1,400 MW and more than four million pounds per hour of thermal energy.

Our power generation projects generally operate pursuant to long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, 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 not a pass-through of fuel costs, we use a financial hedging strategy designed to mitigate a portion of the market price risk of fuel purchases.

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We partner with recognized leaders in the independent power industry to operate and maintain our projects, including Caithness Energy, LLC, Power Plant Management Services, Delta Power Services and the Western Area Power Administration. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

We completed our initial public offering on the Toronto Stock Exchange (TSX: ATP) in November 2004. Our shares began trading on the NYSE under the symbol "AT" on July 23, 2010.

As of November 9, 2011, we had 113,474,259 common shares, Cdn$44.9 million ($43.9 million) principal amount of 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"), Cdn$68.1 million ($66.7 million) principal amount of 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures"), and Cdn$80.5 million ($78.8 million) principal amount of 5.60% convertible debentures due June 30, 2017 (the "2010 Debentures" and together with the 2006 and 2009 Debentures, the "Debentures") outstanding. The 2006 Debentures, 2009 Debentures and 2010 Debentures are convertible at any time, at the option of the holder, into 80.645, 76.923 and 55.249, respectively, common shares per Cdn$1,000 principal amount of Debentures, representing a conversion price of Cdn$12.40, Cdn$13.00 and Cdn$18.10, respectively, per common share. Holders of common shares currently receive a monthly dividend at a current annual rate of Cdn$1.094 per common share. In addition, in connection with our recent acquisition of Capital Power Income L.P., as described below, we guaranteed the payment obligation of one of its subsidiaries with respect to an aggregate Cdn$220.1 million ($215.4 million) of outstanding preferred securities.

RECENT DEVELOPMENTS

On November 5, 2011, we completed the acquisition of all the outstanding limited partnership interests of Capital Power Income L.P. ("CPILP") pursuant to the terms and conditions of an Arrangement Agreement, dated June 20, 2011, as amended by Amendment No. 1, dated July 15, 2011 (the "Arrangement Agreement"), by and among us, CPILP, CPI Income Services Ltd., the general partner of CPILP, and CPI Investments Inc., a unitholder of CPILP that is owned by EPCOR Utilities Inc. and Capital Power Corporation. The transactions contemplated by the Arrangement Agreement were effected through a court-approved plan of arrangement under the *Canada Business Corporations Act* (the "Plan of Arrangement"). The Plan of Arrangement was approved by the unitholders of CPILP, and the issuance of shares of the Company's stock to CPILP unitholders pursuant to the Plan of Arrangement was approved by Company's shareholders, at respective special meetings held on November 1, 2011. A Final Order approving the Plan of Arrangement was entered by the Court of Queen's Bench of Alberta, Judicial District of Calgary, on November 1, 2011.

Pursuant to the Plan of Arrangement, CPILP sold its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, for approximately Cdn$121.0 million which equates to approximately Cdn$2.15 per unit of CPILP. In addition, connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power Corporation and CPILP and certain of its subsidiaries were terminated in consideration of a payment of Cdn$10.0 million. Atlantic Power and its subsidiaries assumed the management of CPILP upon closing and entered into a transitional services agreement with Capital Power Corporation for a term of six to up to twelve months to facilitate and support the integration of CPILP into Atlantic Power.

Under the terms of the Plan of Arrangement, CPILP unitholders exchanged each of their limited partnership units for, at their election, CDN$19.40 in cash or 1.3 Atlantic Power common shares. All cash elections were subject to proration if total cash elections exceeded approximately CDN$506.5 million and all share elections were subject to proration if total share elections exceeded approximately 31.5 million Atlantic Power common shares. At closing, the consideration paid to acquire CPILP totaled $904.5 million, consisting of $497.6 million paid in cash and $406.9 million in shares of our common shares (31.5 million shares issued).

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On November 4, 2011 we entered into an Amended and Restated Credit Agreement, pursuant to which we increased the capacity under our existing credit facility from $100.0 million to $300.0 million on a senior secured basis, $200.0 million of which may be utilized for letters of credit. The amended credit facility matures in November 2015 and bears interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.75% and 3.00% that varies based on our corporate credit rating.

The amended credit facility contains representations, warranties, terms and conditions customary for facilities of this type. We must meet certain financial covenants under the terms of the credit facility, which are generally based on ratios of debt to EBITDA and EBITDA to interest. The facility is secured by pledges of assets and interests in certain subsidiaries. We expect to remain in compliance with the covenants of the credit facility for at least the next 12 months.

On November 4, 2011 we terminated the foreign exchange forwards that were entered into in order to hedge a portion of the foreign currency exchange risk associated with the closing of the CPILP transaction. We also exercised all the outstanding foreign exchange options prior to their exercise date of January 18, 2012. As a result, we hedged the cash portion for the CPILP transaction at Cdn$0.99.

On November 4, 2011, we completed a private placement of US$460.0 million aggregate principal amount of 9% Senior Notes due 2018 to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the "Securities Act"), and to non-U.S. persons outside of the United States in compliance with Regulation S under the Securities Act. The Notes were issued at an issue price of 97.471% for aggregate gross proceeds to us of $448.0 million. The Notes are our senior unsecured obligations, guaranteed by certain of our subsidiaries. We used and intend to use the proceeds to fund a portion of the cash portion of our acquisition of CPILP, to pay the related fees and expenses incidental thereto, repay indebtedness outstanding under CPILP's revolving credit facilities and, to the extent of any remaining net proceeds, to fund additional growth opportunities and for general corporate purposes.

On October 19, 2011, we closed a public offering of 12,650,000 shares of our common stock, which included 1,650,000 common shares issued pursuant to the exercise in full of the underwriters' over-allotment option, at a purchase price of $13.00 per common share sold in US dollars and Cdn$13.26 per common share sold in Canadian dollars, for an aggregate gross proceeds of $164.5 million. We used the proceeds to fund a portion of the cash portion of our acquisition of CPILP, to pay the related fees and expenses incidental to the transaction.

During the three month period ended September 30, 2011, we reviewed the recoverability of our 50% investment in the Onondaga Renewables project. The review was undertaken as a result of the project's partners initiating a plan to sell Onondaga Renewables. Based on this review, we determined that the carrying value of the Onondaga Renewables project was impaired and recorded a pre-tax long-lived asset impairment of $1.1 million as of September 30, 2011.

In February 2011, we filed a rate application with the FERC to establish Path 15's revenue requirement of $30.3 million for the 2011-2013 period. In September 2011, we formally terminated settlement negotiations and pursued FERC rate litigation to determine the outcome of our revenue requirement. Path 15 began recording revenue based on the $30.3 million annual revenue requirement in April 2011. The FERC established a refund order in October 2011which is the date the final 2011-2013 revenue requirement will be effective. The case is currently in initial discovery.

In December 2008, the Chambers project filed suit against DuPont for breach of the energy services agreement related to unpaid amounts associated with disputed price change calculations for electricity. DuPont subsequently filed a counterclaim for an unspecified level of damages. In February 2011, the Chambers project received a favorable ruling from the court on its summary judgment motion as to liability. The court's decision included a description of the pricing methodology that is consistent

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with the project's position. A trial to determine the level of damages is scheduled for the fourth quarter of 2011.

On May 6, 2011 we closed the sale of our 50.0% lessor interest in the Topsham project for $8.5 million, resulting in no gain or loss on the sale.

OUR POWER PROJECTS

The following table outlines our portfolio of power generating and transmission assets in operation and under construction as of November 9, 2011, 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. The table below does not include those projects just recently acquired in connection with the CPILP plan of arrangement.

Project Name	Location (State)	Type	Total MW	Economic Interest[(1)]	Net MW[(2)]	Electricity Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Auburndale	Florida	Natural Gas	155	100.00%	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	121	Progress Energy Florida	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00%	121	Tampa Electric Co.	2018	BBB+
Chambers	New Jersey	Coal	262	40.00%	89	ACE[(3)]	2024	BBB+
					16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	N/A	California Utilities via CAISO[(4)]	N/A[(5)]	BBB+ to A[(6)]
Orlando	Florida	Natural Gas	129	50.00%	46	Progress Energy Florida	2023	BBB+
					19	Reedy Creek Improvement District	2013[(7)]	A1[(8)]
Selkirk	New York	Natural Gas	345	17.70%[(9)]	15	Merchant	N/A	N/R
					49	Consolidated Edison	2014	A-
Gregory	Texas	Natural Gas	400	17.10%	59	Fortis Energy Marketing and Trading	2013	AA-

					9	Sherwin Alumina	2020	NR
Badger Creek	California	Natural Gas	46	50.00%	23	Pacific Gas & Electric	2012[10]	BBB+
Koma Kulshan	Washington	Hydro	13	49.80%	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	53	PNM	2020	BB
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	2028	BBB-
Idaho Wind	Idaho	Wind	183	27.56%	50	Idaho Power Co.	2030	BBB
Piedmont[11]	Georgia	Biomass	54	98.00%	53	Georgia Power	2032	A

(1) Except as otherwise noted, economic interest represents the percentage ownership interest in the project held indirectly by Atlantic Power.

(2) Represents our interest in each project's electric generation capacity based on our economic interest.

(3) Includes a separate power sales agreement in which the project and Atlantic City Electric ("ACE") share profits on spot sales of energy and capacity not purchased by ACE under the base PPA.

(4) California utilities pay transmission access charges to the California Independent System Operator, who then pays owners of Transmission system rights, such as Path 15, in accordance with its annual revenue requirement approved every three years by the Federal Energy Regulatory Commission ("FERC").

(5) Path 15 is a FERC regulated asset with a FERC-approved regulatory life of 30 years: through 2034.

(6) Largest payers of transmission access charges supporting Path 15's annual revenue requirement are Pacific Gas & Electric (BBB+), Southern California Edison (BBB+) and San Diego Gas & Electric (A). The California Independent System Operator imposes minimum credit quality requirements for any participants rated A or better unless collateral is posted per the California Independent System Operator imposed schedule.

(7) Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to PEF under the terms of the current agreement.

(8) Fitch rating on Reedy Creek Improvement District bonds.

(9) Represents our residual interest in the project after all priority distributions are paid to us and the other partners, which is estimated to occur in 2012.

(10) Entered into a one-year interim agreement in April 2011.

(11) Project currently under construction and is expected to be completed in late 2012.

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Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the three and nine month periods ended September 30, 2011 and 2010. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

(Unaudited) (in thousands of U.S. dollars, except as otherwise stated)	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Project revenue				
Auburndale	$ 19,805	$ 19,373	$ 62,021	$ 59,410
Lake	16,950	23,721	50,918	57,804
Pasco	2,906	3,132	8,808	8,764
Path 15	7,638	7,813	22,773	23,186
Other Project Assets	5,034		14,736	
	52,333	54,039	159,256	149,164
Project expenses				
Auburndale	14,606	14,304	44,821	44,437
Lake	10,673	16,671	32,307	40,678
Pasco	2,515	2,548	9,539	7,255
Path 15	2,549	2,901	7,906	8,438
Chambers			1	
Other Project Assets	4,028	182	11,857	270
	34,371	36,606	106,431	101,078
Project other income (expense)				
Auburndale	(1,856)	(4,714)	(2,635)	(10,409)
Lake	(840)	(4,621)	1,027	(10,841)
Pasco		22		22
Path 15	(2,917)	(2,762)	(8,852)	(9,004)
Chambers	267	1,331	4,971	6,268
Other Project Assets	(8,265)	945	(15,085)	2,917
	(13,611)	(9,799)	(20,574)	(21,047)
Total project income				
Auburndale	3,343	355	14,565	4,564
Lake	5,437	2,429	19,638	6,285
Pasco	391	606	(731)	1,531
Path 15	2,172	2,150	6,015	5,744
Chambers	267	1,331	4,970	6,268
Other Project Assets	(7,259)	763	(12,206)	2,647
	4,351	7,634	32,251	27,039
Administrative and other expenses				
Administration	11,936	4,103	20,661	12,046
Interest, net	3,337	2,707	10,815	8,019
Foreign exchange loss (gain)	21,576	(2,253)	20,383	179
Other income, net				(26)
Total administrative and other expenses	36,849	4,557	51,859	20,218
Income (loss) from operations before income taxes	(32,498)	3,077	(19,608)	6,821
Income tax expense (benefit)	(4,520)	3,614	(10,681)	12,105
Net loss	(27,978)	(537)	(8,927)	(5,284)
Net loss attributable to noncontrolling interest	(78)	(99)	(349)	(228)

Net loss attributable to Atlantic Power Corporation shareholders	$	(27,900)	$	(438)	$	(8,578)	$	(5,056)

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Consolidated Overview

We have six reportable segments: Auburndale, Chambers, Lake, Pasco, Path 15 and Other Project Assets. The results of operations are discussed below by reportable segment.

Project income is the primary GAAP measure of our operating results and is discussed in "Project Operations Performance" below. In addition, an analysis of non-project expenses impacting our results is set out in "Administrative and Other Expenses (Income)" below.

Significant non-cash items, which are subject to potentially significant fluctuations, include: (1) the change in fair value of certain derivative financial instruments that are required by GAAP to be revalued at each balance sheet date (see "Quantitative and Qualitative Disclosures About Market Risk" for additional information); (2) 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; (3) the related deferred income tax expense (benefit) associated with these non-cash items.

Cash available for distribution was $27.0 million and $24.4 million for the three months ended September 30, 2011 and 2010, respectively and $61.6 million and $49.8 million for the nine-months ended September 30, 2011 and 2010, respectively. See "Cash Available for Distribution" in this Form 10-Q for additional information.

Income (loss) from operations before income taxes for the three months ended September 30, 2011 and 2010 was $(32.5) million and $3.1 million, respectively and $(19.6) million and $6.8 million for the nine-months ended September 30, 2011 and 2010, respectively. See "Project Income" below for additional information.

Three months ended September 30, 2011 compared with three months ended September 30, 2010

Project Income

Auburndale Segment

The increase in project income for our Auburndale segment of $2.9 million to $3.3 million in the three-month period ended September 30, 2011 from income of $0.4 million in the comparable 2010 period is primarily attributable to the annual contractual escalation of capacity payments under the project's PPA and a decrease of $2.7 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps.

Lake Segment

Project income for our Lake segment increased $3.0 million to $5.4 million in the three-month period ended September 30, 2011, from income of $2.4 million in the comparable 2010 period. The increase is primarily attributable to a decrease of $3.8 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as lower fuel expenses attributable to lower prices on natural gas swaps. This was partially offset by a decrease in energy sales due to the cessation of off-peak dispatch which began during the third quarter of 2010.

Pasco Segment

Project income for our Pasco segment decreased $0.2 million to $0.4 million in the three-month period ended September 30, 2011, from project income of $0.6 million in the comparable 2010 period. The decrease is due to higher operations and maintenance costs incurred in the third quarter of 2011 related to unplanned repairs on the generator and boiler.

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Path 15 Segment

The change in project income for Path 15 was not significant in the three-month period ended September 30, 2011 compared to same period in 2010.

Chambers Segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, decreased $1.0 million to $0.3 million in the three-month period ended September 30, 2011, from project income of $1.3 million in the comparable 2010 period. The decrease is due primarily to $1.0 million increase in operations and maintenance costs incurred in connection with a forced outage during July 2011.

Other Project Assets Segment

Project income for our Other Project Assets segment decreased $8.1 million to a project loss of $7.3 million for the three-month period ended September 30, 2011 compared to project income of $0.8 million in 2010. The most significant components to the change are as follows:

- increased expense at Piedmont in 2011 associated with a $7.6 million charge related to the non-cash change in value of interest rate swaps recorded at fair value;

- a $1.1 million impairment charge recorded at Onondaga Renewables;

- a project loss at Idaho Wind of $0.8 million which became operational in the first quarter of 2011; offset by

- project income of $0.6 million at Cadillac, which was acquired in December 2010; and

- increased project income of $2.0 million at Selkirk primarily due to non-cash income related to the fair value of a project level derivative.

Administrative and Other Expenses (Income)

Administration includes the non-project related costs of operating the company. Administration increased $7.8 million to $11.9 million in the three-month period ended September 30, 2011 from $4.1 million in the comparable 2010 period primarily due to higher business development costs associated with the CPILP transaction.

Interest expense at the corporate level primarily relates to our convertible debentures. Interest expense, net increased $0.6 million to $3.3 million in the three-month period ended September 30, 2011 from $2.7 million in the comparable 2010 period. This increase is due to the issuance of Cdn$80.5 million of convertible debentures in October of 2010 offset by a reduction in convertible debentures that converted to common shares during 2011.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar denominated obligations to holders of the convertible debentures. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations and our dividends to shareholders are included in foreign exchange loss (gain). Unrealized gains and losses on our forward contracts are reclassified to realized gains and losses upon cash settlement of the contracts. Foreign exchange loss increased $23.9 million to a $21.6 million loss in the three-month period ended September 30, 2011 compared to a $2.3 million gain in the comparable 2010 period. The U.S. dollar to Canadian dollar exchange rate increased by 8.7% during the three-month period ended September 30, 2011, compared to a decrease of 3.5% in the comparable period in 2010. See Item 3 "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our management of foreign currency risk and the components of the foreign exchange loss recognized during the three-month period ended September 30, 2011 compared to the foreign exchange gain in the comparable 2010 period.

Nine months ended September 30, 2011 compared with nine months ended September 30, 2010

Project Income

Auburndale Segment

The increase in project income for our Auburndale segment of $10.0 million to $14.6 million in the nine-month period ended September 30, 2011 from income of $4.6 million in the comparable 2010 period is primarily attributable to the decrease of $7.3 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as $2.6 million in increased revenue from favorable energy pricing compared to 2010 and the annual contractual escalation of capacity payments.

Lake Segment

Project income for our Lake segment increased $13.3 million to $19.6 million in the nine-month period ended September 30, 2011, from income of $6.3 million in the comparable 2010 period. The increase is primarily attributable to a decrease of $11.9 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as lower fuel expenses attributable to lower prices on natural gas swaps. This was partially offset by a decrease in energy sales due to the cessation of off-peak dispatch which began during the third quarter of 2010.

Pasco Segment

Project income for our Pasco segment decreased $2.2 million to a project loss of $0.7 million in the nine-month period ended September 30, 2011, from project income of $1.5 million in the comparable 2010 period. The decrease is due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine components and unplanned repairs on the generator and boiler during 2011.

Path 15 Segment

Project income for Path 15 increased $0.3 million to a project income of $6.0 million in the nine-month period ended September 30, 2011, from project income of $5.7 million in the comparable 2010 period. The increase is due to lower interest expenses and property taxes partially offset by decreased revenue recognized under the new 2011 revenue requirement rate filing beginning in April 2011.

Chambers Segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, decreased $1.3 million to $5.0 million in the nine-month period ended September 30, 2011 from $6.3 million in the comparable 2010 period. The decrease in project income at Chambers is primarily attributable to $1.0 million increase in operations and maintenance costs incurred in connection with a forced outage during July 2011 and lower dispatch compared to 2010.

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Other Project Assets Segment

Project income for our Other Project Assets segment decreased $14.8 million to a project loss of $12.2 million for the nine-month period ended September 30, 2011 compared to project income of $2.6 million in 2010. The most significant components to the change are as follows:

- increased expense at Piedmont in 2011 associated with a $10.4 million charge related to the non-cash change in the fair value of an interest rate swap that is recorded at fair value;
- a $1.1 million impairment charge recorded at Onondaga Renewables in the third quarter of 2011;
- the absence of $1.1 million of income from Topsham. The project was sold in May 2011;
- a project loss at Idaho Wind of $1.4 million which became operational in the first quarter of 2011; offset by
- project income at Cadillac of $1.9 million, which was acquired in December 2010.

Administrative and Other Expenses (Income)

Administration includes the non-project related costs of operating the company. Administration increased $8.7 million to $20.7 million for the nine-month period ended September 30, 2011 from $12.0 million in the comparable 2010 period primarily due to higher business development costs associated with the CPILP transaction.

Interest expense at the corporate level primarily relates to our convertible debentures. Interest expense, net increased $2.8 million to $10.8 million in the nine-month period ended September 30, 2011 from $8.0 million in the comparable 2010 period. This increase is due to the issuance of Cdn$80.5 million of convertible debentures in October of 2010 offset by a reduction in convertible debentures that converted to common shares during 2011.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar denominated obligations to holders of the convertible debentures. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations and our dividends to shareholders are included in foreign exchange loss (gain). Unrealized gains and losses on our forward contracts are reclassified to realized gains and losses upon cash settlement of the contracts. Foreign exchange loss increased $20.2 million to an $20.4 million loss in the nine-month period ended 2011 compared to a $0.2 million loss in the comparable 2010 period. The U.S. dollar to Canadian dollar exchange rate increased by 5.4% during the nine-month period ended September 30, 2011, compared to a decrease of 2.1% in the comparable period in 2010. See Item 3 "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our management of foreign currency risk and the components of the foreign exchange loss recognized during the nine-month period ended September 30, 2011 and 2010 compared to the foreign exchange loss in the comparable 2010 period.

Supplementary Non-GAAP Financial Information

The key measure we use to evaluate the results of our projects is Cash Available for Distribution. Cash Available for Distribution 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 Cash Available for Distribution is a relevant supplemental measure of our ability to pay dividends to our shareholders. A reconciliation of net cash provided by operating activities to Cash Available for Distribution is set out below under "Cash Available for Distribution." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

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The primary factor influencing Cash Available for Distribution is cash distributions received from the projects. These distributions received are generally funded from Project Adjusted EBITDA generated by the projects, reduced by project-level debt service and capital expenditures, and adjusted for changes in project-level working capital and cash reserves. Project Adjusted EBITDA is defined as project income 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 unaudited 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 income to Project Adjusted EBITDA is set out below under "Project Adjusted EBITDA." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

Because Project Adjusted EBITDA and project distributions are key drivers of both the performance of our projects and Cash Available for Distribution, please see the following supplementary unaudited non-GAAP information that summarizes Project Adjusted EBITDA by project and a reconciliation of Project Adjusted EBITDA by project to project distributions actually received by us.

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Project Adjusted EBITDA (in thousands of U.S. dollars):

(unaudited)	Three months ended September 30, 2011	Three months ended September 30, 2010	Nine months ended September 30, 2011	Nine months ended September 30, 2010
Project Adjusted EBITDA by individual segment				
Auburndale	$ 10,158	$ 10,018	$ 32,077	$ 29,820
Lake	8,517	9,325	25,431	23,937
Pasco	1,149	1,335	1,541	3,752
Path 15	7,117	7,318	20,873	21,348
Chambers	3,358	4,637	12,389	14,780
Total	30,299	32,633	92,311	93,637
Other Project Assets				
Selkirk	4,322	3,927	8,636	10,983
Orlando	1,824	2,185	4,917	5,856
Cadillac	2,178		6,569	
Gregory	1,027	1,373	2,755	3,656
Idaho Wind	747		2,798	
Badger Creek	(63)	699	738	2,209
Delta Person	561	461	1,403	1,365
Koma Kulshan	374	53	808	606
Rollcast	(348)	(249)	(1,121)	(628)
Piedmont	(14)		(75)	
Topsham		415		1,378
Other	73	46	88	(244)
Total adjusted EBITDA from Other Project Assets segment	10,681	8,910	27,516	25,181
Total adjusted EBITDA from all Projects	40,980	41,543	119,827	118,818
Depreciation and amortization	17,824	16,349	52,922	49,331
Interest expense, net	6,624	5,906	19,952	17,784
Change in the fair value of derivative instruments	10,871	10,706	12,913	23,435
Other expense	1,310	948	1,789	1,229
Project income as reported in the statement of operations	$ 4,351	$ 7,634	$ 32,251	$ 27,039

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Reconciliation of Project Distributions (in thousands of U.S. dollars)
For the nine months ended September 30, 2011

	Project Adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable Segments						
Auburndale	$ 32,077	$ (7,350)	$ (838)	$ (44)	$ (1,795)	$ 22,050
Lake	25,431		5	(622)	1,780	26,594
Pasco	1,541			(41)	405	1,905
Path 15	20,873	(3,541)	(8,852)		(6,218)	2,262
Chambers	12,389	(9,221)	(4,372)	(661)	1,865	
Total Reportable Segments	92,311	(20,112)	(14,057)	(1,368)	(3,963)	52,811
Other Project Assets						
Selkirk	8,636	(5,354)	(1,036)	(7)	3,573	5,812
Orlando	4,917		2	(143)	(451)	4,325
Cadillac	6,569	(1,150)	(1,978)	(88)	(853)	2,500
Gregory	2,755	(1,281)	(450)	(133)	(225)	666
Idaho Wind	2,798	(33,699)	(2,204)	(11)	34,325	1,209
Badger Creek	738		(9)		631	1,360
Delta Person	1,403	(842)	(179)		(382)	
Koma Kulshan	808				(429)	379
Rollcast	(1,121)		1	(13)	1,133	
Piedmont	(75)				75	
Other	88		(42)	73	81	200
Total Other Project Assets Segment	27,516	(42,326)	(5,895)	(322)	37,478	16,451
Total all Segments	$ 119,827	$ (62,438)	$ (19,952)	$ (1,690)	$ 33,515	$ 69,262

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Reconciliation of Project Distributions (in thousands of U.S. dollars)
For the nine months ended September 30, 2010

	Project Adjusted EBITDA	Repayment of Project-Level debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distribution received
Reportable Segments						
Auburndale	$ 29,820	$ (7,350)	$ (1,281)	$ (58)	$ (731)	$ 20,400
Lake	23,937		8	(1,465)	(1,724)	20,756
Pasco	3,752			(498)	301	3,555
Path 15	21,348	(3,740)	(9,313)		(3,981)	4,314
Chambers	14,780	(9,039)	(4,965)	(40)	(736)	
Total Reportable Segments	93,637	(20,129)	(15,551)	(2,061)	(6,871)	49,025
Other Project Assets						
Selkirk	10,983	(4,657)	(1,653)	(75)	(4,598)	
Orlando	5,856		2	(116)	(1,079)	4,663
Gregory	3,656	(1,216)	(379)	(46)	(593)	1,422
Badger Creek	2,209		(11)		193	2,391
Topsham	1,378				(415)	963
Delta Person	1,365	(1,291)	(210)		136	
Koma Kulshan	606		1		(151)	456
Rollcast	(628)				628	
Other	(244)		17	(54)	310	29
Total Other Project Assets Segment	25,181	(7,164)	(2,233)	(291)	(5,569)	9,924
Total all Segments	$ 118,818	$ (27,293)	$ (17,784)	$ (2,352)	$ (12,440)	$ 58,949

Project Operations Performance Three months ended September 30, 2011 compared with three months ended September 30, 2010

Aggregate Project Adjusted EBITDA decreased $0.5 million to $41.0 million in the three-month period ended September 30, 2011 from $41.5 million in the comparable 2010 period, attributable to the following factors:

decreased Project Adjusted EBITDA of $1.3 million at Chambers due to an increase of $1.0 million in operations and maintenance costs in connection with a forced outage during July 2011;

decreased Project Adjusted EBITDA of $0.8 million at Lake attributable to the plant running favorable off-peak dispatch during the third quarter of 2010;

decreased Project Adjusted EBITDA of $0.8 million at Badger Creek due to lower capacity payments under the new one year interim power purchase agreement begining in April 2011; partially offset by

project Adjusted EBITDA of $2.2 million at Cadillac, which was acquired in December 2010.

Aggregate power generation for projects in operation for the three months ended September 30, 2011 was 15.1% less than the three-month period ended September 30, 2010. Generation was unfavorably impacted primarily due to lower generation at Lake, which had no off-peak deliveries in 2011, lower dispatch and an unplanned outage at the Chambers project in July 2011 and reduced dispatch at Badger under its new interim PPA. The unfavorable variance was partially offset by

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additional generation associated with the acquisition of Cadillac in the fourth quarter of 2010 and with Idaho Wind achieving commercial operation in the first quarter of 2011

The project portfolio achieved a weighted average availability of 94.9% for the three-month period ended September 30, 2011 compared to 97.3% in the 2010 period. The decrease in portfolio availability for the three-month period ended September 30, 2011 versus the prior period was primarily due to the unplanned outage at Chambers in July 2011, partially offset by the planned outage in the third quarter of 2010 at Lake. All but one project with reduced availability during the three month period ended September 30, 2011 were able to achieve all of their respective capacity payments as a result of PPA terms that provide for certain levels of planned and unplanned outages.

Project Operations Performance Nine months ended September 30, 2011 compared with nine months ended September 30, 2010

Aggregate Project Adjusted EBITDA increased $1.0 million to $119.8 million in the nine-month period ended September 30, 2011 from $118.8 million in the comparable 2010 period and included the following factors:

- project Adjusted EBITDA of $6.6 million at Cadillac, which was acquired in December 2010;

- project Adjusted EBITDA of $2.8 million at Idaho Wind, which became operational in the first quarter of 2011; partially offset by

- decreased Project Adjusted EBITDA of $2.3 million at Selkirk due to lower capacity revenue. A planned outage was longer than expected and resulted in a delay in recognition of capacity payments until the fourth quarter of 2011;

- Project Adjusted EBITDA reduction of $2.2 million at Pasco primarily due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine blades during a maintenance outage and un-planned repairs associated with the generator and boiler;

- decreased Project Adjusted EBITDA of $2.4 million at Chambers attributable to lower dispatch and a forced outage in July 2011; and

- Project Adjusted EBITDA lower by $1.4 million at Topsham, which was sold in May 2011.

Aggregate power generation for projects in operation for the nine-months ended September 30, 2011 was 2.9% less than the nine-month period ended September 30, 2010. Generation during the nine-month period ended September 30, 2011 was unfavorably impacted primarily due to reduced generation at Lake which had no off-peak deliveries in 2011, the Chambers project which had lower dispatch and an unplanned outage in July 2011, lower dispatch at Badger Creek which operated under its new interim PPA and was not dispatched in May and June 2011, as well as a planned major maintenance outage at Orlando in 2011. The unfavorable variance was partially offset by additional generation associated with the acquisition of Cadillac in the fourth quarter of 2010 and with Idaho Wind achieving commercial operation in the first quarter of 2011, as well as increased dispatch at Selkirk during the period and a planned outage in 2010.

The project portfolio achieved a weighted average availability of 94.8% for the nine-month period ended September 30, 2011 compared to 97.0% in the 2010 period. The decrease in portfolio availability for the nine-month period ended September 30, 2011 versus the prior period was primarily due to planned outages at Badger Creek and Selkirk and unplanned outages at Delta-Person and Chambers. All but one of the projects with reduced availability was nevertheless able to achieve all of their respective capacity payments as a result of PPA terms that provide for certain levels of planned and unplanned outages.

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Cash Flow from Operating Activities

Our cash flow from the projects may vary from year to year based on, among other things, changes in prices under the PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, changes in regulated transmission rates, compliance with the terms of non-recourse project-level financing including debt repayment schedules, the transition to market or re-contracted pricing following the expiration of PPAs, fuel supply and transportation contracts, working capital requirements and the operating performance of the projects. 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 $2.7 million for the nine-month period ended September 30, 2011 over the comparable period in 2010. The changes from the prior period are partially attributable to the changes in Project Adjusted EBITDA described above and the release of $5.8 million of previously restricted cash at our equity accounted Selkirk project, partially offset by changes in working capital at both consolidated and unconsolidated affiliates.

Cash Flow from Investing Activities

Cash flow from investing activities includes 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 used in investing activities for the nine-month period ended September 30, 2011 were $68.2 million compared to cash flows used in investing activities of $65.3 million for the comparable 2010 period. The cash flows used in investing activities is due to a $78.2 million investment for the construction-in-progress for our Piedmont biomass project and an increase in restricted cash of $12.3 million offset by the repayment of $15.5 million from our related party loan to Idaho Wind and the proceeds from the sale of our 50% investment in the Topsham project.

Cash Flow from Financing Activities

Cash used in financing activities for the nine-month period ended September 30, 2011 resulted in a net outflow of $5.3 million compared to a net outflow of $39.2 million for the same period in 2010. The change from the comparable period is primarily attributable to a $9.9 million increase in dividends paid due to a higher number of common shares outstanding to the comparable period in 2010. Since the year ended December 31, 2010, Cdn$21.7 million of convertible debentures have converted to 1.7 million common shares. In addition, we issued 6.8 million common shares in a public offering in October 2010. The increase in dividends is offset by proceeds of $65.4 million of project-level debt related to our Piedmont biomass project.

Cash Available for Distribution

Holders of our common shares receive monthly cash dividends at an annual rate of Cdn$1.094 per share. Total dividends paid to shareholders for the three and nine-month periods ended September 30, 2011 increased over the respective prior year amounts as a result of (i) changes in the value of the Canadian dollar, which is the currency in which the dividends are paid; (ii) a higher number of common shares outstanding in the 2011 periods as a result of the conversion of convertible debentures into common shares; (iii) the issuance of shares in our October 2010 public offering; and (iv) the issuance of vested shares from our long-term incentive plan. This increase in dividends paid is generally offset by realized gains on our foreign currency forward contracts, which are included in cash flows from operating activities. See "Foreign Currency Exchange Rate Risk" in Item 3 of this Form 10-Q for additional information about our foreign currency forward contracts. The payout ratio for the three-month periods ended September 30, 2011 and 2010 was 70% and 65%, respectively and 93% and 96% for the nine-month periods ended September 30, 2011 and 2010, respectively.

The table below presents our calculation of cash available for distribution for the three and nine-month periods ended September 30, 2011 and 2010:

(unaudited)	**Three months ended September 30,**		**Nine months ended September 30,**	
(in thousands of U.S. dollars, except as otherwise stated)	**2011**	**2010**	**2011**	**2010**
Cash flows from operating activities	$ 21,624	$ 27,695	$ 66,339	$ 63,673
Project-level debt repayments	(2,825)	(2,700)	(13,166)	(11,841)
Purchases of property, plant and equipment[(1)]	(268)	(557)	(814)	(2,077)
Transaction costs[(2)]	8,470		9,238	
Cash Available for Distribution[(3)]	27,001	24,438	61,597	49,755
Total dividends declared to shareholders	19,010	15,904	57,552	47,618
Payout ratio	70%	65%	93%	96%
Expressed in Cdn$				
Cash Available for Distribution	26,833	25,404	60,520	51,552
Total dividends declared to shareholders	18,874	16,556	56,259	49,639

(1) Excludes construction-in-progress related to our Piedmont biomass project.

(2) Represents costs associated with the CPILP acquisition.

(3) Cash Available for Distribution 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".

Outlook

Based on our actual performance to date and projections for the remainder of the year, we continue to expect to receive distributions from our projects in the range of $80 million to $90 million for the full year 2011. We expect overall levels of operating cash flows in 2011 to be improved over actual 2010 levels. Higher distributions from existing projects, initial distributions from our recent investment in Idaho Wind and Cadillac, and a slightly lower payment under the management termination agreement are expected to be partially offset by the one-time cash tax refund of $8.0 million received in 2010. In 2012, additional increases in distributions from projects are expected to further increase operating cash flow compared to 2011. The most significant factor in the expected higher operating cash flow in 2012 is accretion from the acquisition of CPILP and increased distributions from Selkirk following the final payment of its non-recourse project-level debt in 2012.

The following items comprise the most significant increases in projected 2011 project distributions compared to 2010:

- lower fuel costs at the Lake project;

resumption of distributions from the Selkirk project;

annual increase in contractual capacity payments from the Auburndale and Lake projects; and

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distributions from the recently acquired Cadillac and Idaho Wind projects.

In 2010, the following five projects comprised approximately 90% of project distributions received: Auburndale, Lake, Orlando, Path 15 and Pasco. For 2011, we expect these same five projects to contribute approximately 85% of total project distributions.

In addition to the items above, the following is a summary of other projections for project distributions in 2011 and beyond:

Lake

The Lake project is exposed to changes in natural gas spot market prices through the expiration of its PPA in July 2013 that are not passed through its PPA. We have executed a hedging strategy to mitigate this exposure by entering into financial swaps that effectively fixed the forward price of most of the natural gas expected to be purchased at the project. These hedges are summarized in Item 3, "Quantitative and Qualitative Disclosures About Market Risk", in this Form 10-Q. While we may continue to evaluate opportunities to further mitigate natural gas price exposure at Lake in 2013, we do not intend to execute additional hedges at Lake for 2011 and 2012 because our natural gas exposure for those years is already substantially hedged.

The variable energy revenues in the Lake project's PPA are indexed, in part, to the price of coal consumed by two specific utility plants in Florida, at Crystal River. The components of this coal price are proprietary to the utility, but we believe that the utility purchases coal for that plant under a combination of short to medium term contracts and spot market transactions.

Coal prices used in the energy revenue component of the projected distributions from the Lake project incorporate a forecast of the applicable Crystal River facility coal cost provided by the utility based on their internal projections. The projected annual cash distributions change by approximately $1.0 million for every $0.25/Mmbtu change in the projected price of coal.

We expect to receive distributions from the Lake project of approximately $30 million to $34 million in both 2011 and 2012. The increases in 2011 and 2012 over the $28.8 million of distributions in 2010 are primarily due to higher contractual capacity payments and lower hedged and unhedged natural gas prices than in 2010.

Auburndale

Based on the current forecast, we expect distributions from Auburndale of $25 million to $27 million per year from 2011 through 2013, when the project's current PPA expires. Distributions received from Auburndale in the 2011 through 2013 period will be impacted by projected coal and gas prices in the forecast period.

The projected revenue from the Auburndale PPA contains a component related to the costs of coal consumed at the utility off-taker's Crystal River facility as described above for the Lake project. Because that mechanism does not pass through changes in the project's fuel costs, Auburndale's operating margin is exposed to changes in natural gas prices for approximately 20% of its natural gas requirements through the expiration of the project's gas supply contract. The remaining 80% of the project's fuel requirements are supplied under an agreement with fixed prices through its expiration in mid-2012. We have been executing a strategy to mitigate the future exposure to changes in natural gas prices at Auburndale by periodically entering into financial swaps that effectively fix the forward price of natural gas required at the project. These hedges are summarized in Item 3, "Quantitative and Qualitative Disclosures About Market Risk", in this Form 10-Q. The 2011 natural gas price exposure at Auburndale has been substantially hedged. We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Auburndale in 2012 and 2013.

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Orlando

The PPA at the Orlando project extends through 2023. However, the project's natural gas supply agreement expires in 2013. Currently projected market prices for natural gas following the expiration of the current supply agreement are lower than the price of natural gas currently being purchased under the project's gas contract. As a result, we expect a significant increase in cash distributions from the Orlando project beginning in 2014. We have begun to execute a hedging strategy to reduce the market price risk associated with expected natural gas requirements at Orlando in 2014 and beyond. See "Item 3. Quantitative and Qualitative Disclosures About Market Risks" in this Form 10-Q for further details.

Liquidity and Capital Resources

Overview

Our primary source of liquidity is distributions from our projects and availability under our revolving credit facility. A significant portion of the cash received from project distributions is used to pay dividends to our shareholders and interest on our outstanding convertible debentures. 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.

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.

Other than the capital requirements stated below for the CPILP acquisition, we do not expect any additional material or unusual requirements for cash outflows for the remainder of 2011 for capital expenditures or other required investments. We have contributed approximately $75.0 million to fund the equity portion of the construction costs for Piedmont. Approximately $59.0 million of this amount was contributed in the fourth quarter of 2010 and the remaining balance was paid in the first quarter of 2011. In addition, there are no debt instruments with significant maturities or refinancing requirements in 2011. See "Outlook" above for information about changes in expected distributions from our projects in 2011 and beyond.

We financed the cash portion of the purchase price for the transaction with CPILP by issuing 12.7 million common shares for gross proceeds of $164.5 million through a public offering in October 2011 and $448.4 million of 9% Senior Notes due 2018 through a private placement in November 2011.

Credit facility

On November 4, 2011 we entered into an Amended and Restated Credit Agreement, pursuant to which we increased the capacity under our existing credit facility from $100.0 million to $300.0 million on a senior secured basis, $200.0 million of which may be utilized for letters of credit. The amended credit facility matures in November 2015 and bears interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.75% and 3.00% that varies based on our corporate credit rating.

The amended credit facility contains representations, warranties, terms and conditions customary for facilities of this type. We must meet certain financial covenants under the terms of the credit facility, which are generally based on ratios of debt to EBITDA and EBITDA to interest. The facility is secured by pledges of assets and interests in certain subsidiaries. We expect to remain in compliance with the covenants of the credit facility for at least the next 12 months.

As of November 9, 2011, the applicable margin was 2.75%. As of November 9, 2011, $99.7 million were issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects, which includes the newly acquired projects from the CPILP acquisition.

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Convertible Debentures

In October 2006, we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.25% convertible secured debentures, which we refer to as the 2006 Debentures. In 2009 the holders agreed to change the rate to 6.50% and extend the maturity date to 2014. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The Debentures have a maturity date of October 31, 2014 and are convertible into approximately 80.6452 common shares per Cdn$1,000 principal amount of 2006 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per common share. The 2006 Debentures are secured by a subordinated pledge of our interest in certain subsidiaries and contain certain restrictive covenants. Through November 9, 2011, a cumulative Cdn$15.1 million of the 2006 Debentures have been converted to 1.2 million common shares. As of November 9, 2011 the 2006 Debentures balance is Cdn$44.9 million ($43.9 million).

In December 2009, we issued, in a public offering, Cdn$86.25 million aggregate principal amount of 6.25% convertible unsecured subordinated debentures, which we refer to as the 2009 Debentures. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year beginning September 15, 2010. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share. Through November 9, 2011, a cumulative Cdn$18.1 million of the 2009 Debentures have been converted to 1.4 million common shares. As of November 9, 2011 the 2009 Debentures balance is Cdn$68.1 million ($66.7 million).

In October 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of 5.60% convertible unsecured subordinated debentures, which we refer to as the 2010 Debentures. The 2010 Debentures pay interest semi-annually on June 30 and December 30 of each year beginning June 30, 2011. The 2010 Debentures mature on June 30, 2017, unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of debentures, representing an initial conversion price of approximately Cdn$18.10 per common share. As of November 9, 2011 the 2010 debentures balance is Cdn$80.5 million ($78.8 million).

Project-level debt

The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at September 30, 2011 and exclude any purchase accounting adjustments recorded to adjust the debt to its fair value at the time the project was acquired. 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. As of September 30, 2011, the covenants at the Gregory, Selkirk and Delta-Person projects and at Epsilon Power Partners are temporarily preventing those subsidiaries from making cash distributions to us. We expect to resume receiving distributions from Gregory, Selkirk, Delta-Person and Epsilon Power Partners in 2012. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. The non-recourse holding company debt relating to our investment in Chambers is held at Epsilon Power Partners, our wholly-owned subsidiary. For the nine-month period ended September 30, 2011, we have contributed approximately $0.5 million to Epsilon Power Partners for debt service payments on the holding company debt, but do not anticipate any additional required contributions to Epsilon.

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The range of interest rates presented represents the rates in effect at September 30, 2011.

	Range of Interest Rates	Total Remaining Principal Repayments	2011	2012	2013	2014	2015	Thereafter
Consolidated Projects:								
Epsilon Power Partners	7.40%	$ 35,357	$ 375	$ 1,500	$ 3,000	$ 5,000	$ 5,750	$ 19,732
Piedmont[1]	5.20%	65,375			55,357	4,789	4,772	457
Path 15	7.90% - 9.00%	150,327	4,446	8,667	9,402	8,065	8,749	110,998
Auburndale	5.10%	14,350	2,450	7,000	4,900			
Cadillac	6.02% - 8.00%	41,381	1,150	3,791	2,400	2,000	2,500	29,540
Total Consolidated Projects		306,790	8,421	20,958	75,059	19,854	21,771	160,727
Equity Method Projects:								
Chambers	1.70% - 5.50%	66,950	3,199	12,176	10,783	5,780	5,213	29,799
Delta-Person	1.80%	9,678	287	1,212	1,300	1,394	1,495	3,990
Selkirk	9.00%	11,439	5,594	5,845				
Gregory	1.80% - 7.50%	13,067	899	1,399	2,007	2,170	2,268	4,324
Idaho Wind[2]	2.80% - 13.30%	50,241	7,967	1,848	1,892	2,049	2,136	34,349
Total Equity Method Projects		151,375	17,946	22,480	15,982	11,393	11,112	72,462
Total Project-Level Debt		$ 458,165	$ 26,367	$ 43,438	$ 91,041	$ 31,247	$ 32,883	$ 233,189

(1) As of September 30, 2011 the inception to date balance of $65.4 million on the Piedmont construction debt is funded by the related bridge loan of $51.0 million and $14.4 million was funded by the construction loan that will convert to a term loan. The terms of the Piedmont project-level debt financing include a $51.0 million bridge loan for approximately 95.0% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations and an $82.0 million construction -term loan. The $51.0 million bridge loan will be repaid in early 2013 and repayment of the expected $82.0 million term loan will commence in 2013.

(2) The Idaho Wind project-level credit facility is composed of two tranches, which include a $157.5 million construction loan that was converted to a 17-year term loan upon commercial operations in Q1 2011, and a $83.2 million cash grant facility which was repaid in June 2011 with federal stimulus grant proceeds after completion of construction. The remaining costs of the project were funded with a combination of equity from the owners and member loans from affiliates of Atlantic Power and GE Energy Financial Services. As of September 30, 2011, our share of total debt outstanding for Idaho Wind was $50.2 million, and our share of the member loans was $7.3 million. Member loans will be paid down with a combination of funds from a third closing for additional debt expected by the end of the year and project cash flow.

Restricted cash

The projects generally have reserve requirements to support payments for major maintenance costs and project-level debt service. For projects that are consolidated, our share of these amounts is reflected as restricted cash on the consolidated balance sheet. At September 30, 2011, restricted cash at the consolidated projects totaled $28.1 million.

Capital Expenditures

Capital expenditures for the projects are generally made 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 projects in which we have investments generally consist of large capital assets that have established commercial operations. Ongoing capital expenditures for assets of this nature are generally not significant because most major expenditures relate to planned repairs and maintenance and are expensed when incurred.

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In 2011, several of the projects have planned outages to complete maintenance work. The level of maintenance and capital expenditures is slightly higher than in 2010. During the third quarter of 2011 the level of maintenance and capital expenditures was minimal which is customary in the third quarter. Outages occurred at Chambers and Cadillac. In July, Chambers was offline due to a forced outage associated with a leak in its steam turbines. The project completed repairs in July and despite the outage, by maintaining a high availability factor is expected to earn its full capacity payments. Cadillac conducted its scheduled fall outage in September that consisted of equipment inspections and minor boiler repairs. The maintenance outage was completed on time and slightly under budget. Cadillac's outage of six days will not impact its availability requirement under the project's PPA.

In the nine-month period ended September 30, 2011, we incurred approximately $97.8 million in capital expenditures for the construction of our Piedmont biomass project. For the remainder of 2011, we expect to incur approximately $26.5 million in capital expenditures related to the Piedmont project, with total project costs through expected completion in late 2012 of approximately $207.0 million.

Off-Balance Sheet Arrangements

As of September 30, 2011, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Market risk is the risk that changes in market prices, such as foreign exchange rates, interest rates and commodity prices, will affect our cash flows or the value of our holdings of financial instruments. The objective of market risk management is to minimize the impact that market risks have on our cash flows as described in the following paragraphs.

Our market risk-sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in fuel commodity prices, currency exchange rates or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in fuel commodity prices, currency exchange rates or interest rates and the timing of transactions.

Fuel Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity, natural gas and coal prices. The combination of long-term energy sales and fuel purchase agreements is generally designed to mitigate the impacts to cash flows of changes in commodity prices by generally passing through changes in fuel prices to the buyer of the energy.

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. In the third quarter of 2010 we entered into natural gas swaps in order to effectively fix the price of 1.2 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. In the third quarter of 2011, we entered into additional natural gas swaps for 2014 and 2015 increasing the total to 2.0 million Mmbtu or approximately 40% of our share of expected natural gas purchases for that period. We also entered into natural gas swaps to effectively fix the price of 1.3 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2016 and 2017.

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We expect cash distributions from Orlando to increase significantly following the expiration of the project's gas contract at the end of 2013 because both projected natural gas prices at that time and the prices in the natural gas swaps we have executed are lower than the price of natural gas being purchased under the project's gas contract.

The Lake project's operating margin is exposed to changes in the market price of natural gas until the expiration of its PPA on July 31, 2013. The Auburndale project purchases natural gas under a fuel supply agreement which provides approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% is purchased at market prices and therefore the project is exposed to changes in natural gas prices for that portion of its gas requirements through the termination of the fuel supply agreement and 100% of its natural gas requirements from the expiration of the fuel contract in mid-2012 until the termination of its PPA at the end of 2013.

In 2012, projected cash distributions at Auburndale would change by approximately $0.4 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project. In 2012, projected cash distributions at Lake would change by approximately $0.8 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project.

Coal prices used in the revenue component of the projected distributions from the Lake and Auburndale projects incorporate a forecast of the applicable Crystal River facility coal cost provided by the utility based on their internal projections. The projected annual cash distributions from Lake and Auburndale combined would change by approximately $2.4 million for every $0.25/Mmbtu change in the projected price of coal.

The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of September 30, 2011 and November 9, 2011:

	2011	2012	2013
Portion of gas volumes currently hedged:			
Lake:			
Contracted			
Financially hedged	78%	90%	83%
Total	78%	90%	83%
Auburndale:			
Contracted	80%	0%	0%
Financially hedged	13%	32%	79%
Total	93%	32%	79%
Average price of financially hedged volumes (per Mmbtu)			
Lake	$ 6.52	$ 6.90	$ 6.63
Auburndale	$ 6.68	$ 6.51	$ 6.92

Foreign Currency Exchange Rate Risk

We use forward foreign currency contracts to manage our exposure to changes in foreign exchange rates, as we generate cash flow in U.S. dollars but pay dividends to shareholders and interest on convertible debentures predominately in Canadian dollars. Since our inception, we have had an established hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of our dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at fixed rates of exchange to hedge approximately 84% of our expected dividend and convertible debenture interest payments through 2013. Changes in the fair value of the forward contracts partially offset foreign exchange gains or losses on the U.S. dollar equivalent

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of our Canadian dollar obligations. The forward contracts consist of monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar.

It is our intention to periodically consider extending the length of these forward contracts.

In the third quarter of 2011 we executed a series of financial transactions with an exercise date of January 18, 2012, to hedge a portion of the foreign currency exchange risk associated with the closing of the CPILP transaction. These transactions are summarized as follows with strike prices per Cdn$1.00:

Transaction Date		Forward Purchases		Call Options		Put Options
July 27, 2011	$	84.7 million at 0.9465	$	32.0 million at 0.9460	$	116.7 million at 0.90
August 3, 2011	$	76.0 million at 0.9665	$	14.5 million at 0.9665	$	90.5 million at 0.90
August 5, 2011	$	81.2 million at 0.9872		$9.3 million at 0.9872	$	90.5 million at 0.90
August 18, 2011		$97.8 million at 0.9913				

On November 4, 2011 we terminated the foreign exchange forwards that were entered into in order to hedge a portion of the foreign currency exchange risk associated with the closing of the CPILP transaction. We also exercised all the outstanding foreign exchange options prior to their exercise date of January 18, 2012. As a result, we hedged the cash portion for the CPILP transaction at Cdn$0.99.

The foreign exchange forward and option contracts are recorded at fair value based on quoted market prices and the estimation of our credit rating or the credit rating of our counterparties. Changes in the fair value of the foreign currency forward contracts are recorded in foreign exchange (gain) loss in the consolidated statements of operations.

The following table contains the components of recorded foreign exchange (gain) loss for the three and nine-month periods ended September 30, 2011 and 2010:

	Three months ended September 30,		Nine months ended September 30,	
	2011	2010	2011	2010
Unrealized foreign exchange (gain) loss:				
Convertible debentures	$ (16,274)	$ 4,886	$ (9,642)	$ 2,380
Forward contracts and other	39,950	(5,716)	37,817	1,989
	23,676	(830)	28,175	4,369
Realized foreign exchange gains on forward contract settlements	(2,100)	(1,423)	(7,792)	(4,190)
	$ 21,576	$ (2,253)	$ 20,383	$ 179

The following table illustrates the impact on the fair value of our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of September 30, 2011:

Convertible debentures, at carrying value	$ (18,862)
Foreign currency forward contracts[(1)]	$ 17,051

(1) Includes only forward contracts for the monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar.

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Interest Rate Risk

Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 89% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

We have executed an interest rate swap at our consolidated Auburndale project to economically fix a portion of its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Auburndale debt. The interest rate swap was executed in November 2009 and expires on November 30, 2013.

We have an interest rate swap at our consolidated Cadillac project to economically fix a portion of its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Cadillac debt. The interest rate swap expires on June 30, 2025.

We executed two interest rate swaps at our consolidated Piedmont project to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreements are not designated as hedges and changes in their fair market value are recorded in the statements of operations. 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.

In July 2007, we executed an interest rate swap to economically fix the exposure to changes in interest rates related to the variable-rate non-recourse debt at our wholly-owned subsidiary Epsilon Power Partners. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 5.29%. In June 2010, the swap agreement was amended to reduce the fixed interest rate 4.24% and extend the maturity date from July 2012 to July 2019. The notional amount of the swap matches the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. This interest rate swap agreement is not designated as a hedge and changes in its fair market value is recorded in the consolidated statements of operations.

In accounting for cash flow hedges, gains and losses on the derivative contracts are reported in other comprehensive income, but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net income. That is, for cash flow hedges, all effective components of the derivative contracts' gains and losses are recorded in other comprehensive income (loss), pending occurrence of the expected transaction. Other comprehensive income (loss) consists of those financial items that are included in "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets but not included in our net income. Thus, in highly effective cash flow hedges, where there is no ineffectiveness, other comprehensive income changes by exactly as much as the derivative contracts and there is no impact on earnings until the expected transaction occurs.

After considering the impact of interest rate swaps, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at equity investments, by approximately $0.7 million.

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ITEM 4. CONTROLS AND PROCEDURES

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we evaluated the effectiveness of the design and operation of our disclosure controls and procedures, as such term is defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as amended, or the Exchange Act. Based on this evaluation, our principal executive officer and principal financial officer concluded that the disclosure controls and procedures were effective as of the end of the period covered by this report on Form 10-Q.

Changes in Internal Controls over Financial Reporting

There were no changes in our internal controls over financial reporting (as such term is defined in Rules 13a-15(f) under the Exchange Act) that occurred during the period covered by this report that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations over Internal Controls

Our internal controls over financial reporting are designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external purposes in accordance with generally accepted accounting principles. However, internal controls over financial reporting cannot provide absolute assurance of achieving financial reporting objectives because of its inherent limitations, including the possibility of human error and circumvention by collusion or overriding of controls. Accordingly, even an effective internal control system may not prevent or detect material misstatements on a timely basis. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions or that the degree of compliance with the policies or procedures may deteriorate.

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Our Lake project is currently involved in a dispute with Progress Energy Florida over off-peak energy sales in 2010. All amounts billed for off-peak energy during 2010 by the Lake project have been paid in full by Progress. The Lake project has filed a claim against Progress in which we seek to confirm our contractual right to sell off-peak energy at the contractual price for such sales. Progress filed a counter-claim against the Lake project, seeking, among other things, the return of amounts paid for off-peak power sales during 2010 and a declaratory order clarifying Lake's rights and obligations under the PPA. The Lake project has stopped dispatching during off-peak periods pending the outcome of the dispute. However, we strongly believe that the court will confirm our contractual right to sell off-peak power using the contractual price that was used during 2010 and that we will be able to continue such off-peak power sales for the remainder of the term of the PPA. We have not recorded any reserves related to this dispute and expect that the outcome will not have a material adverse effect on our financial position or results of operations.

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 as of September 30, 2011 which are expected to have a material adverse impact on our financial position or results of operations.

ITEM 1A. RISK FACTORS

Except as disclosed below and 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 Part I, "Item 2-Management's Discussion and Analysis of Financial Condition and Results of Operations"), there were no material changes to the risk factors disclosed in Part I, "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2010.

Risk Related to Our Acquisition of CPILP

The failure to integrate successfully the businesses of Atlantic Power and CPILP in the expected timeframe would adversely affect the combined company's future results.

The success of the Plan of Arrangement relating to our acquisition of CPILP will depend, in large part, on our ability to realize the anticipated benefits, including cost savings, from combining the businesses of Atlantic Power and CPILP. To realize these anticipated benefits, the businesses of Atlantic Power and CPILP must be successfully integrated. This integration will be complex and time-consuming. The failure to integrate successfully and to manage successfully the challenges presented by the integration process may result in the combined company not fully achieving the anticipated benefits of the Plan of Arrangement.

Potential difficulties that may be encountered in the integration process include the following:

- challenges and difficulties associated with managing the larger, more complex, combined business;
- conforming standards, controls, procedures and policies, business cultures and compensation structures between the entities;
- integrating personnel from the two entities while maintaining focus on developing, producing and delivering consistent, high quality services;
- consolidating corporate and administrative infrastructures;

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- coordinating geographically dispersed organizations;
- potential unknown liabilities and unforeseen expenses, delays or regulatory conditions associated with the Plan of Arrangement;
- performance shortfalls at one or both of the entities as a result of the diversion of management's attention caused by completing the Plan of Arrangement and integrating the entities' operations; and
- the ability of the combined company to deliver on its strategy going forward.

Our growth plans are dependent on future acquisitions and growth opportunities that may not be realized.

The ability to expand through acquisitions and growth opportunities is integral to our business strategy following completion of the Plan of Arrangement and requires that we identify and consummate suitable acquisition or investment opportunities that meet our investment criteria and are compatible with our growth strategy. We may not be successful in identifying and consummating acquisitions or investments that meet our investment criteria on satisfactory terms or at all. The failure to identify and consummate suitable acquisitions, to take advantage of other investment opportunities, or to integrate successfully any acquisitions without substantial expense, delay or other operational or financial problems, would impede our growth and negatively affect our results of operations and cash available for distribution to our shareholders.

We may be adversely affected by increased debt and debt service obligations.

We funded a significant portion of the cash consideration payable by us under the Plan of Arrangement, including related fees and expenses, with the net proceeds from a $460 million senior unsecured notes offering. The notes are guaranteed on a senior unsecured basis by our U.S. and Canadian subsidiaries that guarantee our amended senior secured revolving credit facility. The indenture governing the notes contains restrictive covenants that, among other things, will restrict our ability to: (i) incur or guarantee debt or issue disqualified stock; (ii) incur or guarantee additional secured indebtedness; (iii) enter into sale and leaseback transactions; (iv) pay dividends or distributions on capital stock; and (iv) merge or consolidate or sell all or substantially all of its assets. All of these covenants are subject to a number of important limitations and exceptions under the indenture.

On a pro forma basis assuming the completion of the Plan of Arrangement was consummated on September 30, 2011, we would have had approximately $1.6 billion of indebtedness. We may also obtain additional long-term debt and working capital lines of credit to meet future financing needs, subject to certain restrictions under our existing indebtedness, which would further increase our total debt.

The potential significant negative consequences on our financial condition and results of operations that could result from our increased amount of debt include:

- limitations on our ability to obtain additional debt or equity financing;
- instances in which we are unable to meet the financial covenants contained in our debt agreements or to generate cash sufficient to make required debt payments, which circumstances would have the potential of accelerating the maturity of some or all of our outstanding indebtedness;
- the allocation of a material portion of our cash flow from operations to service our debt, thus reducing the amount of our cash flow available for other purposes, including funding operating costs and capital expenditures that could improve our competitive position, results of operations or share price;

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- requiring us to sell debt or equity securities or to sell some of our core assets, possibly on unfavorable terms, to meet payment obligations;
- compromising our flexibility to plan for, or react to, competitive challenges in our business and the power industry;
- the possibility of us being put at a competitive disadvantage with our competitors that do not have as much debt as we have, and competitors that may be in a more favorable position to access additional capital resources in a timely manner; and
- limitations on our ability to execute business development activities to support our strategies.

A downgrade in Atlantic Power's or CPILP's credit ratings or any deterioration in their credit quality could negatively affect our ability to access capital and our ability to hedge and could trigger termination rights under certain contracts.

A downgrade in Atlantic Power's or CPILP's credit ratings or deterioration in their credit quality could adversely affect our ability to renew existing, or obtain access to new, credit facilities and could increase the cost of such facilities and trigger termination rights or enhanced disclosure requirements under certain contracts to which CPILP is a party. Any downgrade of CPILP's corporate credit rating could cause counterparties and financial derivative markets to require CPILP to post letters of credit or other collateral, make cash prepayments, obtain a guarantee agreement or provide other security, all of which would expose CPILP to additional costs. As anticipated during the structuring of the CPILP transaction, Standard & Poor's is expected to downgrade CPILP corporate credit rating to BB-. Similarly, we expect Dominion Bond Rating Services to downgrade CPILP to below investment grade after the closing.

We expect to incur significant expenses related to the integration of Atlantic Power and CPILP.

We have incurred significant expenses in connection with the Plan of Arrangement and may incur additional significant expenses in connection with the integration of Atlantic Power and CPILP.

There are a large number of processes, policies, procedures, operations, technologies and systems that must be integrated. While we have assumed that a certain level of expenses will be incurred, there are many factors beyond our control that could affect the total amount or the timing of the integration expenses. Moreover, many of the expenses that will be incurred are, by their nature, difficult to estimate accurately. These integration expenses likely will result in our taking significant charges against earnings following the completion of the Plan of Arrangement, and the amount and timing of such charges are uncertain at present.

If goodwill or other intangible assets that we record in connection with the Plan of Arrangement become impaired, we could have to take significant charges against earnings.

In connection with the accounting for the Plan of Arrangement, we expect to record a significant amount of goodwill and other intangible assets. Under U.S. GAAP, we must assess, at least annually and potentially more frequently, whether the value of goodwill and other indefinite-lived intangible assets has been impaired. Amortizing intangible assets will be assessed for impairment in the event of an impairment indicator. Any reduction or impairment of the value of goodwill or other intangible assets will result in a charge against earnings, which could materially adversely affect our results of operations and shareholders' equity in future periods.

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We must continue to retain, motivate and recruit executives and other key employees, which may be difficult in light of the uncertainty regarding the Plan of Arrangement, and failure to do so could negatively affect us.

We must be successful at retaining, recruiting and motivating key employees following the completion of the Plan of Arrangement. Experienced employees in the power industry are in high demand and competition for their talents can be intense. Employees of both Atlantic Power and CPILP may experience uncertainty about their future role with the combined company until, or even after, strategies with regard to the combined company are announced or executed. These potential distractions of the Plan of Arrangement may adversely affect our ability to attract, motivate and retain executives and other key employees and keep them focused on applicable strategies and goals. A failure to retain and motivate executives and other key employees could have an adverse impact on our business.

There are factors that could cause the Plan of Arrangement not to be accretive and could cause dilution to our distributable cash flow per share, which may negatively affect the market price of our common shares.

We could encounter transaction and integration-related costs or other factors such as the failure to realize benefits anticipated in the Plan of Arrangement. All of these factors could cause dilution to our distributable cash flow per share or decrease or delay the expected accretive effect of the Plan of Arrangement and cause a decrease in the market price of our common shares. Accordingly, we may not be able to increase our dividends following completion of the Plan of Arrangement to the extent anticipated or at all.

CPI Preferred Equity Ltd. is subject to Canadian tax, as is Atlantic Power's income from CPILP.

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes. See "Risk factors Risks related to our structure We are subject to Canadian tax". Following completion of the Plan of Arrangement, we will be required to include in computing our taxable income any income earned by CPILP. In addition, CPI Preferred Equity Ltd., a subsidiary of CPILP, is also a Canadian corporation and is generally subject to Canadian federal, provincial and other taxes. CPI Preferred Equity Ltd. is, and following the completion of the Plan of Arrangement will continue to be, liable to pay material Canadian cash taxes.

Our incorporation of the CPILP structure following the Plan of Arrangement may be subject to additional U.S. federal income tax liability.

CPILP's U.S. structure has in place certain intercompany financing arrangements (the "CPILP Financing Arrangements"). While CPILP has received advice from its U.S. accountants, based on certain representations by its holding companies, that the payments on the CPILP Financing Arrangements should be deductible for U.S. federal income tax purposes, it is possible that the IRS could successfully challenge the deductibility of these payments. If the IRS were to succeed in characterizing these payments as non-deductible, the adverse consequences discussed above with respect to the Intercompany Loan could apply in connection with the CPILP Financing Arrangements. In addition, even if the payments are respected as interest, the deduction thereof could nevertheless be limited by the earnings stripping limitations, as discussed above with respect to our current structure. The earnings stripping limitations will also apply to other indebtedness of CPILP's U.S. group that is guaranteed by CPILP or Atlantic Power. Finally, the applicability of recent changes to the U.S.-Canada Income Tax Treaty to the structure associated with certain of the CPILP Financing Arrangements may result in distributions from CPILP's U.S. group to its Canadian parent being subject to a 30% rate of withholding tax instead of the 5% rate that would otherwise have applied.

ITEM 6. EXHIBITS

Exhibit Number	Description
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.

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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: November 11, 2011	Atlantic Power Corporation		
	By:	/s/ LISA J. DONAHUE	
		Name:	Lisa J. Donahue
		Title:	*Interim Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*