ATLANTIC POWER CORP
Form 10-Q
November 10, 2010

Use these links to rapidly review the document
TABLE OF CONTENTS

Table of Contents

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, 2010

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 o 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

The number of shares outstanding of the registrant's Common Stock as of November 10, 2010 was 66,634,461.

Table of Contents

ATLANTIC POWER CORPORATION

FORM 10-Q

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2010

Index

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.

Table of Contents

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, 2010 (unaudited)	December 31, 2009
Assets		
Current assets:		
Cash and cash equivalents	$ 8,998	$ 49,850
Restricted cash	22,257	14,859
Accounts receivable	20,553	17,480
Note receivable related party (Note 14)	12,801	
Current portion of derivative instruments asset (Notes 8 and 9)	5,988	5,619
Prepayments, supplies, and other	5,717	3,019
Deferred income taxes	11,531	17,887
Refundable income taxes	7,463	10,552
Total current assets	95,308	119,266
Property, plant, and equipment, net (Note 6)	187,648	193,822
Transmission system rights (Note 6)	190,097	195,984
Equity investments in unconsolidated affiliates (Note 5)	301,388	259,230
Other intangible assets, net (Note 6)	60,395	71,770
Goodwill (Note 4)	12,453	8,918
Derivative instruments asset (Notes 8 and 9)	11,931	14,289
Other assets	5,273	6,297
Total assets	$ 864,493	$ 869,576
Liabilities and Shareholders' Equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 26,195	$ 21,661
Revolving credit facility (Note 17)	20,000	
Current portion of long-term debt (Note 7)	18,456	18,280
Current portion of derivative instruments liability (Notes 8 and 9)	4,916	6,512
Interest payable on convertible debentures	1,797	800
Dividends payable	5,363	5,242
Other current liabilities	8	752
Total current liabilities	76,735	53,247
Long-term debt (Note 7)	211,521	224,081
Convertible debentures	142,100	139,153
Derivative instruments liability (Notes 8 and 9)	26,459	5,513
Deferred income taxes	33,459	28,619
Other non-current liabilities	4,916	4,846

Commitments and contingencies (Note 16)				
Shareholders' equity				
Common shares		545,447		541,917
Accumulated other comprehensive income (loss) (Note 9)		98		(859)
Retained deficit		(179,623)		(126,941)
Noncontrolling interest (Note 4)		3,381		
Total shareholders' equity		369,303		414,117
Total liabilities and shareholders' equity	$	864,493	$	869,576

See accompanying notes to consolidated financial statements.

Table of Contents

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,	
	2010	**2009**	**2010**	**2009**
Project revenue:				
Energy sales	$ 22,713	$ 14,795	$ 55,285	$ 44,810
Energy capacity revenue	23,196	22,113	69,585	66,337
Transmission services	7,813	7,792	23,186	23,208
Other	317	157	1,108	806
	54,039	44,857	149,164	135,161
Project expenses:				
Fuel	19,678	15,667	51,606	43,255
Operations and maintenance	5,674	6,105	16,174	15,755
Project operator fees and expenses	1,172	768	3,074	2,799
Depreciation and amortization	10,082	10,053	30,224	31,307
	36,606	32,593	101,078	93,116
Project other income (expense):				
Change in fair value of derivative instruments (Notes 8 and 9)	(9,744)	351	(20,946)	711
Equity in earnings of unconsolidated affiliates	4,088	(3,646)	12,550	323
Interest expense, net	(4,165)	(4,525)	(12,884)	(13,845)
Other income, net	22		233	1,205
	(9,799)	(7,820)	(21,047)	(11,606)
Project income	7,634	4,444	27,039	30,439
Administrative and other expenses (income):				
Management fees and administration	4,103	2,907	12,046	8,391
Interest, net	2,707	11,285	8,019	31,455
Foreign exchange (gain) loss (Note 9)	(2,253)	12,528	179	22,034
Other income, net		(18)	(26)	(48)
	4,557	26,702	20,218	61,832
Income (loss) from operations before income taxes	3,077	(22,258)	6,821	(31,393)
Income tax expense (benefit) (Note 10)	3,614	(6,455)	12,105	(9,104)
Net loss	(537)	(15,803)	(5,284)	(22,289)
Net loss attributable to noncontrolling interest	(99)		(228)	
Net loss attributable to Atlantic Power Corporation	$ (438)	$ (15,803)	$ (5,056)	$ (22,289)
Net loss per share attributable to Atlantic Power Corporation shareholders: (Note 12)				
Basic	$ (0.01)	$ (0.26)	$ (0.08)	$ (0.37)
Diluted	$ (0.01)	$ (0.26)	$ (0.08)	$ (0.37)

See accompanying notes to consolidated financial statements.

4

Table of Contents

ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands of U.S. dollars)

(Unaudited)

	Nine months ended September 30, 2010	Nine months ended September 30, 2009
Cash flows from operating activities:		
Net loss	$ (5,284)	$ (22,289)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	30,224	31,307
Long-term incentive plan expense	3,287	1,392
Loss on sale of property, plant and equipment		933
Gain on step-up valuation of Rollcast acquisition	(211)	
Earnings from unconsolidated affiliates	(12,550)	(323)
Distributions from unconsolidated affiliates	9,897	19,023
Unrealized foreign exchange loss	4,369	23,866
Change in fair value of derivative instruments	20,946	(711)
Change in deferred income taxes	10,555	(5,833)
Change in other operating balances		
Accounts receivable	(3,072)	7,994
Prepayments, refundable income taxes and other assets	1,189	(6,633)
Accounts payable and accrued liabilities	3,747	(5,504)
Other liabilities	576	1,673
Net cash provided by operating activities	63,673	44,895
Cash flows used in investing activities:		
Acquisitions and investments, net of cash acquired	(41,182)	(3,000)
Loan to Idaho Wind	(12,801)	
Change in restricted cash (Note 1)	(7,398)	(7,816)
Biomass development costs	(1,827)	
Proceeds from sale of property, plant and equipment		167
Purchase of property, plant and equipment	(2,077)	(1,641)
Net cash used in investing activities	(65,285)	(12,290)
Cash flows used in financing activities:		
Shares acquired in normal course issuer bid (Note 15)		(3,369)
Proceeds from revolving credit facility borrowings	20,000	
Repayments of revolving credit facility borrowings		(20,000)
Repayment of project-level debt	(11,841)	(7,684)
Equity contribution from noncontrolling interest	200	
Dividends paid	(47,599)	(18,110)
Net cash used in financing activities	(39,240)	(49,163)
Net decrease in cash and cash equivalents	(40,852)	(16,558)
Cash and cash equivalents at beginning of period	49,850	37,327
Cash and cash equivalents at end of period	$ 8,998	$ 20,769

Supplemental cash flow information

Interest paid	$	16,587	$	40,098
Income taxes paid (refunded), net	$	(1,607)	$	651

See accompanying notes to consolidated financial statements.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of presentation

Overview

Atlantic Power Corporation ("Atlantic Power") is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia, Canada on July 8, 2005. We issued income participating securities ("IPSs") for cash pursuant to an initial public offering on the Toronto Stock Exchange, or the TSX, on November 18, 2004. Each IPS was comprised of one common share and Cdn$5.767 principal value of 11% subordinated notes due 2016. On November 27, 2009 our shareholders approved a conversion from the IPS structure to a traditional common share structure. Each IPS has been exchanged for one new common share and each old common share that did not form a part of an IPS was exchanged for approximately 0.44 of a new common share. Our shares trade on the TSX under the symbol "ATP" and began trading on the New York Stock Exchange, or the NYSE, under the symbol "AT" on July 23, 2010.

We are an independent power producer with interests in 11 operational power generation projects across eight states, one wind project under construction in Idaho, one biomass project under construction in Georgia, a 500 kilovolt 84-mile electric transmission line located in California and a number of development projects. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,738 megawatts (or "MW"), in which our ownership interest is approximately 788 MW. Four of our projects are wholly-owned subsidiaries: Lake Cogen, Ltd., Pasco Cogen, Ltd., Auburndale Power Partners, L.P. and Atlantic Path 15, LLC. The interim consolidated financial statements have been prepared in accordance with United States generally accepted accounting principles ("GAAP") with a reconciliation to Canadian GAAP in Note 18. The Canadian securities legislation allow issuers that are required to file reports with the Securities and Exchange Commission ("SEC") in the United States to file financial statements under United States GAAP to meet their continuous disclosure obligations in Canada. Prior to 2010, we prepared our consolidated financial statements in accordance with Canadian GAAP.

The interim consolidated financial statements have been prepared in accordance with the SEC's regulations for interim financial information and with the instructions to Form 10-Q. The accounting policies we follow are set forth below in Note 2, *Summary of significant accounting policies.* The interim consolidated financial statements follow the same accounting principles and methods of application as the most recent annual consolidated financial statements as there are no material differences in our accounting policies between United States and Canadian GAAP at September 30, 2010 other than as denoted in Note 18. Interim results are not necessarily indicative of results for a 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, 2010, the results of operations for the three and nine month periods ended September 30, 2010 and 2009, and our cash flows for the nine month periods ended September 30, 2010 and 2009.

Beginning in the first quarter of 2010, changes in restricted cash in the consolidated statement of cash flows have been reported as an investing activity. In previous periods, changes in restricted cash were reported as cash flows from operating activities. The prior period amounts have been reclassified to conform with the current year presentation. This reclassification does not impact the consolidated balance sheet or the consolidated statements of operations. We have changed the classification of restricted cash because the revised presentation is more widely used by companies in our industry.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies

(a) Basis of consolidation and accounting:

The accompanying interim consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America and include the consolidated accounts and operations of our subsidiaries in which we have a controlling financial interest. The usual condition for a controlling financial interest is ownership of the majority of the voting interest of an entity. However, a controlling financial interest may also exist in entities, such as a variable interest entity, through arrangements that do not involve controlling voting interests.

We apply the standard that requires consolidation of variable interest entities ("VIEs"), for which we are the primary beneficiary. The guidance requires a variable interest holder to consolidate a VIE if that party has both the power to direct the activities that most significantly impact the entities' economic performance, as well as either the obligation to absorb losses or the right to receive benefits that could potentially be significant to the VIE. We have determined that our investments are not VIEs by evaluating their design and capital structure. Accordingly, we use the equity method of accounting for all of our investments in which we do not have an economic controlling interest. We eliminate all intercompany accounts and transactions in consolidation.

(b) Use of estimates:

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and power purchase agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions 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. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(c) Revenue:

We recognize energy sales revenue on a gross basis when electricity and steam are delivered under the terms of the related contracts. Revenue associated with capacity payments under the power purchase agreements ("PPAs") are recognized as the lesser of (1) the amount billable under the PPA or (2) an amount determined by the kilowatt hours made available during the period multiplied by the estimated average revenue per kilowatt hour over the term of the PPA.

Transmission services revenue is recognized as transmission services are provided. The annual revenue requirement for transmission services is regulated by the Federal Energy Regulatory Commission ("FERC") and is established through a rate-making process that occurs every three years. When actual cash receipts from transmission services revenue are different than the regulated revenue requirement because of timing differences, the over or under collections are deferred until the timing differences reverse in future periods.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(d) Use of fair value:

We utilize a fair value hierarchy that gives the highest priority to quoted prices in active markets and is applicable to fair value measurements of derivative contracts and other instruments that are subject to mark-to-market accounting. Refer to Note 8 for more information.

(e) Derivative financial instruments:

We use derivative financial instruments in the form of interest rate swaps and foreign exchange forward contracts to manage our current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. We have also entered into natural gas supply contracts and natural gas forwards or swaps to minimize the effects of the price volatility of natural gas, which is a major production cost. We do not enter into derivative financial instruments for trading or speculative purposes; however, not all derivatives qualify for hedge accounting.

Derivative financial instruments not designated as a hedge are measured at fair value with changes in fair value recorded in the consolidated statements of operations.

The following table summarizes derivative financial instruments that are not designated as hedges for accounting purposes and the accounting treatment in the consolidated statements of operations of the changes in fair value and cash settlements of such derivative financial instrument:

Derivative financial instrument	Classification of changes in fair value	Classification of cash settlements
Foreign currency forward contracts	Foreign exchange loss (gain)	Foreign exchange loss (gain)
Lake natural gas swaps	Change in fair value of derivative instruments	Fuel expense
Auburndale natural gas swaps	Change in fair value of derivative instruments	Fuel expense
Interest rate swap	Change in fair value of derivative instruments	Interest expense

Certain derivative instruments qualify for a scope exception to fair value accounting because they are considered normal purchases or normal sales. This exception applies when we have the ability to and it is probable that we will deliver or take delivery of the underlying physical commodity. Derivatives that are considered to be normal purchases and normal sales are exempt from derivative accounting treatment and are recorded as executory contracts.

We have designated one of our interest rate swaps as a hedge of cash flows for accounting purposes. Tests are performed to evaluate hedge effectiveness and ineffectiveness at inception and on an ongoing basis, both retroactively and prospectively. Unrealized gains or losses on the interest rate swap designated as a hedge are deferred and recorded as a component of accumulated other comprehensive income (loss) until the hedged transactions occur and are recognized in earnings. The ineffective portion of the cash flow hedge, if any, is immediately recognized in earnings.

(f) Property, plant and equipment:

Property, plant and equipment are stated at cost, net of accumulated depreciation. Depreciation is provided on a straight-line basis over the estimated useful life of the related asset. As major

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

maintenance occurs and parts are replaced on the plant's combustion and steam turbines, maintenance costs are either expensed or transferred to property, plant and equipment if the maintenance extends the useful lives of the major parts. These costs are depreciated over the parts' estimated useful lives, which is generally three to six years, depending on the nature of maintenance activity performed.

(g) Transmission system rights:

Transmission system rights are an intangible asset that represents the long-term right to approximately 72% of the capacity of the Path 15 transmission line in California. Transmission system rights are amortized on a straight-line basis over 30 years, the regulatory life of Path 15.

(h) Impairment of long-lived assets, non-amortizing intangible assets and equity method investments:

Long-lived assets, such as property, plant and equipment, transmission system rights and other intangible assets subject to depreciation and amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds its fair value.

Investments in and the operating results of 50%-or-less owned entities not required to be consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment, failure of cash flow coverage ratio tests included in project-level non-recourse debt or, where applicable, estimated sales proceeds which are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long-term investments. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

(i) Other intangible assets:

Other intangible assets include PPAs and fuel supply agreements at our projects.

Power purchase agreements are valued at the time of acquisition based on the contract prices under the PPAs compared to projected market prices. Fuel supply agreements are valued at the time of acquisition based on the contract prices under the fuel supply agreement compared to projected market prices. The balances are presented net of accumulated amortization in the consolidated balance sheets. Amortization is recorded on a straight-line basis over the remaining term of the agreement.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(j) Income taxes:

Income tax expense includes the current tax obligation or benefit and change in deferred income tax asset or liability for the period. We use the asset and liability method of accounting for deferred income taxes and record deferred income taxes for all significant temporary differences. Income tax benefits associated with uncertain tax positions are recognized when we determine that it is more-likely-than-not that the tax position will be ultimately sustained. Refer to Note 10 for more information.

(k) Foreign currency translation:

Our functional currency and reporting currency is the United States dollar. The functional currency of our subsidiaries and other investments is the United States dollar. Monetary assets and liabilities denominated in Canadian dollars are translated into United States dollars using the rate of exchange in effect at the end of the period. All transactions denominated in Canadian dollars are translated into United States dollars at average exchange rates.

(l) Long-term incentive plan:

The officers and other employees of Atlantic Power are eligible to participate in the Long-Term Incentive Plan ("LTIP") that was implemented in 2007. In the second quarter of 2010, the board of directors approved an amendment to the LTIP and the amended plan was approved by our shareholders on June 29, 2010. The amended LTIP will be effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units that vest will be based, in part, on the total shareholder return of Atlantic Power compared to a group of peer companies in Canada. In addition, vesting of the notional units for officers of Atlantic Power will occur on a three-year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendments.

Unvested notional units are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date or if we do not meet certain ongoing cash flow performance targets.

Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and the fair value of the award at each balance sheet date for notional units accounted for as liability awards. Fair value of the awards granted prior to the 2010 amendment is determined by projecting the total number of notional units that will vest in future periods, including dividends received on notional units during the vesting period, and applying the current market price per share to the projected number of notional units that will vest. The fair value of awards granted for the 2010 performance period with market vesting conditions is based upon a Monte Carlo simulation model on their grant date. The aggregate number of shares which may be issued from treasury under the amended LTIP is limited to one million. Unvested notional units are recorded as either a liability or equity award based on management's intended method of redeeming the notional units when they vest.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

(m) Concentration of credit risk:

The financial instruments that potentially expose us to credit risk consist primarily of cash and cash equivalents, restricted cash, derivative instruments and accounts receivable. Cash and restricted cash are held by major financial institutions that are also counterparties to our derivative instruments. We have long-term agreements to sell electricity, gas and steam to public utilities and corporations. We have exposure to trends within the energy industry, including declines in the creditworthiness of our customers. We do not normally require collateral or other security to support energy-related accounts receivable. We do not believe there is significant credit risk associated with accounts receivable due to payment history. See Note 13, *Segment and related information*, for a further discussion of customer concentrations.

(n) Segments:

We have six reportable segments: Path 15, Auburndale, Lake, Pasco, Chambers and Other Project Assets. Each of our projects is an operating segment. Based on similar economic and other characteristics, we aggregate several of the projects into the Other Project Assets reportable segment.

(o) Recently issued accounting standards:

Adopted

On January 1, 2010, we adopted changes issued by the Financial Accounting Standards Board (FASB) to accounting for variable interest entities. These changes require an enterprise to perform an analysis to determine whether the enterprise's variable interest or interests give it a controlling financial interest in a variable interest entity; to require ongoing reassessments of whether an enterprise is the primary beneficiary of a variable interest entity; to eliminate the solely quantitative approach previously required for determining the primary beneficiary of a variable interest entity; to add an additional reconsideration event for determining whether an entity is a variable interest entity when any changes in facts and circumstances occur such that holders of the equity investment at risk, as a group, lose the power from voting rights or similar rights of those investments to direct the activities of the entity that most significantly impact the entity's economic performance; and to require enhanced disclosures that will provide users of financial statements with more transparent information about an enterprise's involvement in a variable interest entity. The adoption of these changes had no impact on the consolidated financial statements.

On January 1, 2010, we adopted changes issued by the FASB to accounting for transfers of financial assets. These changes remove the concept of a qualifying special-purpose entity and remove the exception from the application of variable interest accounting to variable interest entities that are qualifying special-purpose entities; limit the circumstances in which a transferor derecognizes a portion or component of a financial asset; define a participating interest; require a transferor to recognize and initially measure at fair value all assets obtained and liabilities incurred as a result of a transfer accounted for as a sale; and require enhanced disclosure. The adoption of these changes had no impact on the consolidated financial statements.

Effective January 1, 2010, we adopted changes issued by the FASB on January 6, 2010 for a scope clarification to the FASB's previously-issued guidance on accounting for noncontrolling interests in consolidated financial statements. These changes clarify the accounting and reporting guidance for

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

noncontrolling interests and changes in ownership interests of a consolidated subsidiary. An entity is required to deconsolidate a subsidiary when the entity ceases to have a controlling financial interest in the subsidiary. Upon deconsolidation of a subsidiary, an entity recognizes a gain or loss on the transaction and measures any retained investment in the subsidiary at fair value. The gain or loss includes any gain or loss associated with the difference between the fair value of the retained investment in the subsidiary and its carrying amount at the date the subsidiary is deconsolidated. In contrast, an entity is required to account for a decrease in its ownership interest of a subsidiary that does not result in a change of control of the subsidiary as an equity transaction. The adoption of these changes had no impact on the consolidated financial statements.

Effective January 1, 2010, we adopted changes issued by the FASB on January 21, 2010 to disclosure requirements for fair value measurements. Specifically, the changes require a reporting entity to disclose separately the amounts of significant transfers in and out of Level 1 and Level 2 fair value measurements and describe the reasons for the transfers. The changes also clarify existing disclosure requirements related to how assets and liabilities should be grouped by class and valuation techniques used for recurring and nonrecurring fair value measurements. The adoption of these changes had no impact on the consolidated financial statements.

Effective January 1, 2010, we adopted changes issued by the FASB on February 24, 2010 to accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or available to be issued, otherwise known as "subsequent events." Specifically, these changes clarify that an entity that is required to file or furnish its financial statements with the Securities and Exchange Commission is not required to disclose the date through which subsequent events have been evaluated. The adoption of these changes had no impact on the consolidated financial statements.

On July 1, 2010, we adopted changes to existing accounting requirements for embedded credit derivatives. Specifically, the changes clarify the scope exception regarding when embedded credit derivative features are not considered embedded derivatives subject to potential bifurcation and separate accounting. The adoption of these changes had no impact on the consolidated financial statements.

Issued

In October 2009, the FASB issued changes to revenue recognition for multiple-deliverable arrangements. These changes require separation of consideration received in such arrangements by establishing a selling price hierarchy (not the same as fair value) for determining the selling price of a deliverable, which will be based on available information in the following order: vendor-specific objective evidence, third-party evidence, or estimated selling price; eliminate the residual method of allocation and require that the consideration be allocated at the inception of the arrangement to all deliverables using the relative selling price method, which allocates any discount in the arrangement to each deliverable on the basis of each deliverable's selling price; require that a vendor determine its best estimate of selling price in a manner that is consistent with that used to determine the price to sell the deliverable on a standalone basis; and expand the disclosures related to multiple-deliverable revenue arrangements. These changes become effective on January 1, 2011. We have determined that the adoption of these changes will not have an impact on the consolidated financial statements, as our projects do not currently have any such arrangements with its customers.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

2. Summary of significant accounting policies (Continued)

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. These changes become effective beginning January 1, 2011. Other than the additional disclosure requirements, we have determined these changes will 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 become effective on January 1, 2011. We have determined these changes will not have an impact on the consolidated financial statements.

3. Comprehensive income (loss)

The following table summarizes the components of comprehensive income (loss), net of tax of $(25) and $(1,365), respectively, for the three months ended September 30, 2010 and 2009, and net of tax of $(135) and $7, respectively, for the nine months ended September 30, 2010 and 2009:

	Three months ended September 30,		Nine months ended September 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss)	$ (537)	$ (15,803)	$ (5,284)	$ (22,289)
Unrealized gain (loss) on hedging activity	38	2,048	202	(10)
Comprehensive income (loss)	$ (499)	$ (13,755)	$ (5,082)	$ (22,299)

4. Acquisitions

Idaho Wind

On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind Partners 1, LLC ("Idaho Wind") for $38.9 million and approximately $3.0 million in transaction costs. Idaho Wind recently commenced construction of a 183 MW wind power project located near Twin Falls, Idaho, which is expected to be completed in phases in late 2010 and early 2011. Idaho Wind has 20-year PPAs with Idaho Power Company. Our investment in Idaho Wind was funded with cash on hand and a $20.0 million borrowing under our senior credit facility, which was repaid in October 2010 with a portion of the proceeds from our public offering (see Note 17). Idaho Wind is accounted for under the equity method of accounting.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Acquisitions (Continued)

Rollcast

On March 31, 2009, we acquired a 40% equity interest in Rollcast Energy, Inc., a North Carolina Corporation for $3.0 million in cash. On March 1, 2010, we paid $1.2 million in cash for an additional 15% of the shares of Rollcast, increasing our interest from 40% to 55% and providing us control of Rollcast. We consolidated Rollcast as of this date. We previously accounted for our 40% interest in Rollcast as an equity method investment. On April 28, 2010, we paid an additional $0.8 million to increase our ownership interest in Rollcast to 60%.

Rollcast is a developer of biomass power plants in the southeastern U.S. with several projects in various stages of development. The investment in Rollcast gives us the option but not the obligation to invest equity in Rollcast's biomass power plants. In October 2010, we completed the project-level non-recourse financing and began construction on Rollcast's Piedmont Green Power project near Barnesville, Georgia. See Note 17 for additional information.

The following table summarizes the consideration transferred to acquire Rollcast and the preliminary estimated amounts of identifiable assets acquired and liabilities assumed at the March 1, 2010 acquisition date, as well as the fair value of the noncontrolling interest in Rollcast at the acquisition date:

Fair value of consideration transferred:	
Cash	$ 1,200
Other items to be allocated to identifiable assets acquired and liabilities assumed:	
Fair value of our investment in Rollcast at the acquisition date	2,758
Fair value of noncontrolling interest in Rollcast	3,410
Gain recognized on the step acquisition	211
Total	$ 7,579
Recognized amounts of identifiable assets acquired and liabilities assumed:	
Cash	$ 1,524
Property, plant and equipment	130
Prepaid expenses and other assets	133
Capitalized development costs	2,705
Trade and other payables	(448)
Total identifiable net assets	4,044
Goodwill	3,535
	$ 7,579

As a result of obtaining control over Rollcast, our previously held 40% interest was remeasured to fair value, resulting in a gain of $0.2 million. This has been recognized in other income (expense) in the consolidated statements of operations.

The fair value of the noncontrolling interest of $3.4 million in Rollcast was estimated by applying an income approach using the discounted cash flow method. This fair value measurement is based on significant inputs not observable in the market and thus represents a Level 3 fair value measurement.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Acquisitions (Continued)

The fair value estimate utilized an assumed discount rate of 9.4% which is composed of a risk-free rate and an equity risk premium determined by the capital asset pricing of companies deemed to be similar to Rollcast. The estimate assumed that no fair value adjustments are required because of the lack of control or lack of marketability that market participants would consider when estimating the fair value of the noncontrolling interest in Rollcast.

The goodwill is attributable to the value of future biomass power plant development opportunities. It is not expected to be deductible for tax purposes. All of the $3.5 million of goodwill was assigned to the Other Project Assets segment.

5. Equity method investments

The following summarizes the operating results for the nine months ended September 30, 2010 and 2009, respectively, for the proportional ownership interest in our equity method investments:

	Nine-months ended September 30, 2010	2009
Revenue		
Chambers	43,146	38,303
Badger Creek	10,435	9,394
Gregory	24,461	20,529
Orlando	31,617	30,907
Selkirk	39,156	35,372
Other	4,728	23,062
	153,543	157,567
Project expenses		
Chambers	30,883	31,519
Badger Creek	9,188	7,891
Gregory	21,448	18,479
Orlando	30,039	29,047
Selkirk	36,802	32,461
Other	3,773	21,073
	132,133	140,470
Project other income (expense)		
Chambers	(2,706)	(3,052)
Badger Creek	200	(3)
Gregory	(1,346)	(828)
Orlando	(99)	(30)
Selkirk	(4,704)	(3,679)
Other	(205)	(9,182)
	(8,860)	(16,774)
Project income (loss)		
Chambers	9,557	3,732
Badger Creek	1,447	1,500
Gregory	1,667	1,222

Orlando	1,479	1,830
Selkirk	(2,350)	(768)
Other	750	(7,193)
	12,550	323

15

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

6. 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, 2010 and December 31, 2009:

	September 30, 2010	December 31, 2009
Property, plant and equipment	$ 82,948	$ 74,567
Transmission system rights	41,574	35,685
Other intangible assets	61,016	45,368

7. Long-term debt

Long-term debt represents project 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 debt is non-recourse to Atlantic Power and generally amortizes during the term of the respective revenue generating contracts of the projects.

	September 30, 2010	December 31, 2009
Project debt, interest rates ranging from 5.1% to 9.0% maturing through 2028	$ 218,490	$ 230,331
Purchase accounting fair value adjustments	11,487	12,030
Less: current portion of long-term debt	(18,456)	(18,280)
Long-term debt	$ 211,521	$ 224,081

Project-level debt is secured by the respective projects and their contracts with no other recourse to us. At September 30, 2010, all of our projects were in compliance with the covenants contained in project-level debt.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Fair value of financial instruments

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of September 30, 2010 and December 31, 2009. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	September 30, 2010			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 8,998	$	$	$ 8,998
Restricted cash	22,257			22,257
Derivative instruments asset		17,919		17,919
Total	$ 31,255	$ 17,919	$	$ 49,174
Liabilities:				
Derivative instruments liability	$	$ 31,375	$	$ 31,375
Total	$	$ 31,375	$	$ 31,375

	December 31, 2009			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 49,850	$	$	$ 49,850
Restricted cash	14,859			14,859
Derivative instruments asset		19,908		19,908
Total	$ 64,709	$ 19,908	$	$ 84,617
Liabilities:				
Derivative instruments liability	$	$ 12,025	$	$ 12,025
Total	$	$ 12,025	$	$ 12,025

We adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating or the credit rating of our counterparties. As of September 30, 2010, the credit reserve resulted in a $1.7 million net increase in fair value, which is comprised of a $0.4 million gain in other comprehensive income and a $1.4 million gain in change in fair value of derivative instruments offset by a $0.1 million loss in foreign exchange.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

9. Accounting for derivative instruments and hedging activities

Fair value of derivative instruments

We have elected to disclose derivative instruments 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, 2010	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swap current	$	$ 398
Interest rate swap long-term		159
Total derivative instruments designated as cash flow hedges		557
Derivative instruments not designated as cash flow hedges:		
Interest rate swap current		1,248
Interest rate swap long-term		3,132
Foreign currency forward contracts current	5,988	
Foreign currency forward contracts long-term	11,931	
Natural gas swap current		3,270
Natural gas swap long-term		23,168
Total derivative instruments not designated as cash flow hedges	17,919	30,818
Total derivative instruments	$ 17,919	$ 31,375

	December 31, 2009	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swap current	$	$ 726
Interest rate swap long-term		167
Total derivative instruments designated as cash flow hedges		893
Derivative instruments not designated as cash flow hedges:		
Interest rate swap current		1,705
Interest rate swap long-term		1,707
Foreign currency forward contracts current	5,619	
Foreign currency forward contracts long-term	14,289	
Natural gas swap current	95	4,174
Natural gas swap long-term	14	3,655

Total derivative instruments not designated as cash flow hedges	20,017	11,241
Total derivative instruments	$ 20,017	$ 12,134

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Natural gas swaps

The Lake project's operating margin is exposed to changes in natural gas spot market prices from the expiration of its natural gas supply contract on June 30, 2009 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 expiry of the fuel supply agreement in mid-2012 until the termination of its PPA at the end of 2013.

Our strategy to mitigate the future exposure to changes in natural gas prices at 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. Changes in the fair value of the natural gas swaps through June 30, 2009 were recorded in other comprehensive income (loss) as they were designated as a hedge of the risk associated with changes in market prices of natural gas. As of July 1, 2009, we de-designated these natural gas swap hedges and the changes in their fair value subsequent to July 1, 2009 are now recorded in change in fair value of derivative instruments in the consolidated statements of operations. Amounts in accumulated other comprehensive income (loss) remaining prior to de-designation are amortized into the consolidated statements of operations over the remaining term of the natural gas swaps.

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 its 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 agreement. The interest rate swap was executed in November 2009 and expires on November 30, 2013.

The interest rate swap is a derivative financial instrument designated as a cash flow hedge and is recorded in the balance sheet at fair value. Changes in the fair value of the interest rate swap are recorded in accumulated other comprehensive income (loss) and reclassified to interest expense when settled in cash.

Impact of derivative instruments on the consolidated income statements

Unrealized gains on interest rate swaps designated as cash flow hedges have been recorded in the consolidated statements of operations as a gain in other comprehensive income of $0.1 million and $0.4 million for the three and nine month periods ended September 30, 2010. Realized losses on these interest rate swaps of $0.2 million and $0.6 million were recorded in interest expense, net for the three and nine month periods ended September 30, 2010.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Unrealized gains and losses on natural gas swaps previously designated as cash flow hedges are recorded in other comprehensive income. In the period in which the unrealized gains and losses are settled, the cash settlement payments are recorded as fuel expense. Other comprehensive loss recorded for natural gas swap contracts accounted for as cash flow hedges totaled $5.1 million, net of tax, prior to July 1, 2009 when hedge accounting for these natural gas swaps was discontinued prospectively. Amortization of the loss of $0.4 million and $1.3 million was recorded in change in fair value of derivative instruments for the three and nine month periods ended September 30, 2010.

Unrealized gains and losses on derivative instruments not designated as cash flow hedges are recorded in change in fair value of derivative instruments in the consolidated statements of operations.

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, 2010	Nine months ended September 30, 2010
Natural gas swaps	Fuel	$ 2,076	$ 6,515
Foreign currency forwards	Foreign exchange gain	(1,423)	(4,190)
Interest rate swaps	Interest, net	365	1,314

Unrealized gains and losses associated with changes in the fair value of derivative instruments not designated as cash flow hedges and ineffectiveness of derivatives designated as cash flow hedges are reflected in current period earnings. The following table summarizes the pre-tax changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Change in fair value of derivative instruments:				
Interest rate swaps	$ (804)	$ 262	$ (970)	$ (98)
Natural gas swaps	(8,940)	(613)	(19,976)	(613)
	$ (9,744)	$ (351)	$ (20,946)	$ (711)

Notional volumes of derivative instruments transactions

The following table summarizes the net notional volume of our derivative instruments transactions by type, excluding those derivatives that qualified for the normal purchases and normal sales exception as of September 30, 2010:

	Units	Notional amount as of September 30, 2010
Interest rate swaps	US$	$ 9,679
Currency forwards	Cdn$	$ 239,700
Natural gas swaps	Mmbtu	15,150

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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 reinforcing 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 of Cdn$1.134 per U.S. dollar in amounts sufficient to make monthly dividend payments at the current annual dividend level of Cdn$1.094 per common share, as well as interest payments on our 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures"), through December 2013.

In addition, we have executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual payments on our 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"). The contracts provide for the purchase of Cdn$1.9 million in April and in October of each year through 2011 at a rate of Cdn$1.1075 per U.S. dollar.

It is our intention to periodically consider extending the length of these forward contracts. In addition, we will consider executing additional foreign currency forward contracts to hedge expected additional dividend and interest payments associated with the common shares and convertible debentures issued in our October 2010 public offering (see Note 17).

The foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and our estimation of the counterparty's credit risk. The fair value of our forward foreign currency contracts at September 30, 2010 is an asset of $17.9 million. 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, 2010 and 2009:

	Three months ended September 30,		Nine months ended September 30,	
	2010	**2009**	**2010**	**2009**
Unrealized foreign exchange (gain) loss:				
Subordinated notes and convertible debentures	$ 4,886	$ 33,625	$ 2,380	$ 51,282
Forward contracts and other	(5,716)	(19,389)	1,989	(27,416)
	(830)	14,236	4,369	23,866
Realized foreign exchange gains on forward contract settlements	(1,423)	(1,708)	(4,190)	(1,832)
	$ (2,253)	$ 12,528	$ 179	$ 22,034

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table illustrates the impact on 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, 2010:

Convertible debentures	$ 14,210
Foreign currency forward contracts	$ 25,245

The following table summarizes the changes in the accumulated other comprehensive income (loss) ("OCI") balance attributable to derivative financial instruments designated as a hedge, net of a 40% effective tax rate:

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, 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

10. Income taxes

The difference between the actual tax expense of $3.6 million and $12.1 million for the three and nine months ended September 30, 2010, respectively, and the expected income tax expense, based on the Canadian enacted statutory rate of 30%, of $0.9 million and $2.0 million, respectively, is primarily due to an increase in the valuation allowance and various other permanent differences. The difference between the actual tax expense and the expected income tax for the nine months ended September 30, 2010 primarily relates to a $7.5 million increase in the valuation allowance and a $3.3 permanent difference related to the estimated percentage ownership at Selkirk based on the priority distribution computation.

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Current income tax expense (benefit)	$ 474	$ (58)	$ 1,550	$ (3,271)
Deferred tax expense (benefit)	3,140	(6,397)	10,555	(5,833)
Total income tax expense (benefit)	$ 3,614	$ (6,455)	$ 12,105	$ (9,104)

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

10. Income taxes (Continued)

Valuation Allowance

As of September 30, 2010, we have recorded a valuation allowance of $74.6 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

The following table summarizes the changes in outstanding LTIP notional units during the nine months ended September 30, 2010:

	Units	Grant Date Weighted-Average Fair Value per Unit
Outstanding at December 31, 2009	471,281	$ 7.30
Granted	305,112	$ 13.29
Additional shares from dividends	35,390	$ 9.30
Vested	(222,265)	$ 7.94
Outstanding at September 30, 2010	589,518	$ 10.28

In the second quarter of 2010, the board of directors approved an amendment to the LTIP. The amended LTIP will be effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units that vest will be based, in part, on the total shareholder return of Atlantic Power compared to a group of peer companies in Canada. In addition, vesting of the notional units for officers of Atlantic Power will occur on a three year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendments.

Vested notional units are expected to be redeemed one-third in cash and two-thirds in shares of our common stock. Notional units granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional units granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Notional units granted prior to the 2010 performance period are subject to the vesting conditions of the LTIP before the amendments made in 2010. We reclassified the portion of outstanding awards expected to vest in common shares totaling $1.4 million from accounts payable and accrued liabilities and other non-current liabilities to common shares as of June 29, 2010, the date the amended LTIP was approved by our shareholders.

On March 29, 2010, our board of directors approved the grant of 138,892 notional LTIP units for the 2009 performance period under the terms of the LTIP before the 2010 amendments. In May 2010, our board of directors approved the initial grant of 83,110 notional LTIP units for executive officers under the amended LTIP for the 2010-2012 performance period, subject to final shareholder approval of the amended LTIP, which occurred on June 29, 2010. Also in May 2010 and subject to the final shareholder approval of the amended LTIP, our board of directors granted transition awards to our executive officers consisting of an additional 83,110 notional LTIP units. The transition awards are

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Long-Term Incentive Plan (Continued)

designed to mitigate the impact of the changes in vesting provisions of the LTIP from a ratable vesting over three years to cliff vesting at the end of three years. The transition awards are subject to the performance measurement and other provisions of the amended LTIP, except that $^{1}/_{3}$ of the transition awards vest in the first quarter of 2011 and the other $^{2}/_{3}$ vest in the first quarter of 2012.

The notional units, other than the transition awards, granted under the amended LTIP cliff-vest three years after the grant date. The final number of notional units, if any, that will vest at the end of the three year vesting period will be based on the Company's achievement of target levels of relative total shareholder return, which is the change in the value of an investment in the Company's common stock, including reinvestment of dividends, compared to that of a peer group of companies during the performance period. The total number of notional units vesting will range from zero up to a maximum 150% of the number of notional units in the executives' accounts on the vesting date for that award, depending on the level of achievement of relative total shareholder return during the measurement period.

Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and the fair value of the award at each balance sheet date for notional units accounted for as liability awards. Fair value of the awards granted prior to the 2010 LTIP amendment is determined by projecting the total number of notional units that will vest in future periods, including dividends received on notional units during the vesting period, and applying the current market price per share to the projected number of notional units that will vest. The fair value of awards granted in 2010 under the amended LTIP with market vesting conditions is based upon a Monte Carlo simulation model on their grant date. Compensation expense is recognized regardless of the relative total shareholder return performance, provided that the LTIP participant remains employed by the Company. The fair value of all outstanding notional units under the amended LTIP and the amended LTIP at September 30, 2010, is approximately $7.7 million. The aggregate number of shares which may be issued from treasury under the amended LTIP is limited to one million. Unvested notional units are recorded as either a liability or equity award based on management's intended method of redeeming the notional units when they vest.

Both the total shareholder return performance and the fair value of the notional units under the Monte Carlo simulation are determined for the Company by a third party.

In calculating the fair value of the awards granted in 2010 under the amended LTIP, the Monte Carlo simulation model utilizes multiple input variables over the performance period in order to determine the likely relative total shareholder return. The Monte Carlo simulation model computed simulated total shareholder return for the Company and for its peer companies during the remaining time in the performance period with the following inputs: (i) stock price on the measurement date (ii) expected volatility; (iii) risk-free interest rate; (iv) dividend yield and (v) correlations of historical common stock returns between the Company and the peer companies and among the peer companies. Expected volatilities utilized in the Monte Carlo model are based on historical volatility of the Company's and the peer companies' stock prices over a period equal in length to that of the remaining vesting period. The risk-free interest rate is derived from the U.S. Treasury yield curve in effect at the time of grant with a term equal to the performance period assumption at the time of grant.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Long-Term Incentive Plan (Continued)

The calculation of simulated total shareholder return under the Monte Carlo model for the remaining time in the performance period included the following assumptions:

	Nine months ended September 30, 2010
Weighted-average risk free rate of return	0.53%
Dividend yield	9.4%
Expected volatility Company	45%
Expected volatility peer companies	28 - 64%
Weighted-average remaining measurement period	1.6 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, 2010. Dilutive potential shares also include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss for the three and nine month period ended September 30, 2010 and the three and nine month periods ended September 30, 2009, diluted earnings per share is equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the three and nine month periods ended September 30, 2010 and 2009:

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Numerator:				
Net loss attributable to Atlantic Power Corporation	$ (438)	$ (15,803)	$ (5,056)	$ (22,289)
Add: interest expense for potentially dilutive convertible debentures, net(1)				
Diluted net loss attributable to Atlantic Power Corporation	$ (438)	$ (15,803)	$ (5,056)	$ (22,289)

(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 all periods presented.

	Three months ended September 30,		Nine months ended September 30,	
	2010	2009	2010	2009
Denominator:				
Basic shares outstanding	60,511	60,518	60,466	60,685
Dilutive potential shares:				
Convertible debentures	11,473	4,839	11,473	4,839
LTIP notional units	614	455	499	395
Potentially dilutive shares	72,598	65,812	72,438	65,919
Diluted EPS	$ (0.01)	$ (0.26)	$ (0.08)	$ (0.37)

Potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units have been excluded from fully diluted shares because their impact would be anti-dilutive.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Segment and related information

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

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

	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	$	$	$	$ 54,039
Segment assets	218,947	116,033	118,591	40,083		8,116	362,723	864,493
Goodwill	8,918					3,535		12,453
Project Adjusted EBITDA	$ 7,318	$ 10,018	$ 9,325	$ 1,335	$ 4,637	$ 8,910	$	$ 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 (income) 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)
Other income, net								
Loss from operations before income taxes	2,150	355	2,429	606	1,331	763	(4,557)	3,077
Income tax expense (benefit)							3,614	3,614
Net loss	$ 2,150	$ 355	$ 2,429	$ 606	$ 1,331	$ 763	$ (8,171)	$ (537)

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Segment and related information (Continued)

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Three month period ended September 30, 2009:								
Operating revenues	$ 7,792	$ 18,124	$ 15,957	$ 2,984	$	$	$	$ 44,857
Segment assets	229,983	140,340	122,258	42,877			320,861	856,319
Goodwill	8,918							8,918
Project Adjusted EBITDA	$ 7,061	$ 9,707	$ 5,128	$ 247	$ 4,301	$ 9,631	$	$ 36,075
Change in fair value of derivative instruments		175	(787)		161	(487)		(938)
Depreciation and amortization	2,095	4,949	2,263	746	855	5,853		16,761
Interest, net	3,220	655	(4)	1	1,876	2,016		7,764
Other project (income) expense			(1)		627	7,418		8,044
Project income	1,746	3,928	3,657	(500)	782	(5,169)		4,444
Interest, net							11,285	11,285
Administration							2,907	2,907
Foreign exchange gain							12,528	12,528
Other income, net							(18)	(18)
Loss from operations before income taxes	1,746	3,928	3,657	(500)	782	(5,169)	(26,702)	(22,258)
Income tax expense (benefit)							(6,455)	(6,455)
Net loss	$ 1,746	$ 3,928	$ 3,657	$ (500)	$ 782	$ (5,169)	$ (20,247)	$ (15,803)

	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	$	$	$	$ 149,164
Segment assets	218,947	116,033	118,591	40,083		8,116	362,723	864,493
Goodwill	8,918					3,535		12,453
Project Adjusted EBITDA	$ 21,348	$ 29,820	$ 23,937	$ 3,752	$ 14,780	$ 25,181	$	$ 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 gain							179	179
Other income, net							(26)	(26)
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 loss	$ 5,582	$ 4,564	$ 6,285	$ 1,531	$ 6,268	$ 2,647	$ (32,161)	$ (5,284)

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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, 2009:								
Operating revenues	$ 23,208	$ 56,113	$ 47,061	$ 8,779	$	$	$	$ 135,161
Segment assets	229,983	140,340	122,258	42,877			320,861	856,319
Goodwill	8,918							8,918
Project Adjusted EBITDA	$ 20,894	$ 28,254	$ 20,749	$ 3,116	$ 9,325	$ 28,788	$	$ 111,126
Change in fair value of derivative instruments		175	(787)		(1,722)	803		(1,531)
Depreciation and amortization	6,406	14,831	7,829	2,240	2,540	17,919		51,765
Interest, net	9,664	1,969	(10)	(42)	5,906	5,913		23,400
Other project (income) expense	(1,229)		61	(25)	1,037	7,209		7,053
Project income	6,053	11,279	13,656	943	1,564	(3,056)		30,439
Interest, net							31,455	31,455
Administration							8,391	8,391
Foreign exchange gain							22,034	22,034
Other income, net							(48)	(48)
Loss from operations before income taxes	6,053	11,279	13,656	943	1,564	(3,056)	(61,832)	(31,393)
Income tax expense (benefit)							(9,104)	(9,104)
Net loss	$ 6,053	$ 11,279	$ 13,656	$ 943	$ 1,564	$ (3,056)	$ (52,728)	$ (22,289)

Progress Energy Florida and the California Independent System Operator ("CAISO") provide for 74% and 15%, respectively, of total consolidated revenues for the three months ended September 30, 2010 and 75% and 17% for the three months ended September 30, 2009 and 76% and 16%, respectively, of total consolidated revenues for the nine months ended September 30, 2010 and 76% and 17% for the nine months ended September 30, 2009. Progress Energy Florida purchases electricity from Auburndale and Lake, and the CAISO makes payments to Path 15.

14. Related party transactions

During the third quarter of 2010, we made a short-term $12.8 million loan to Idaho Wind to provide temporary funding for construction of the project until a portion of the project-level construction financing was completed in early October 2010, resulting in $4.1 million of the loan being repaid to us. The outstanding loans bear interest at a prime rate plus 10% (13.25% as September 30, 2010).

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 Capital Partners, LLC ("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 million, to be satisfied by a payment of $6 million that was made at the termination date, and additional payments of $5 million, $3 million and $1 million on the respective first, second and third anniversaries of the termination date. We recorded the remaining liability associated with the termination fee at its estimated fair value of $8.1 million at December 31, 2009. The contract termination liability is being accreted to the final amounts due over the term of these payments.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

15. Normal course issuer bid

In 2008, we initiated a normal course issuer bid to purchase up to four million IPSs, representing approximately 8% of Atlantic Power's public float at that time. For the nine months ended September 30, 2009, we acquired 481,600 IPSs at an average price of Cdn$8.42 under the terms of our existing normal course issuer bid. As of September 30, 2009, we had acquired a cumulative total of 1,040,220 IPSs at an average price of Cdn$8.61 since the inception of the issuer bid in July 2008. We paid the market price at the time of acquisition for any IPSs purchased through the facilities of the Toronto Stock Exchange, and all IPSs acquired under the bid have been cancelled. The issuer bid expired on July 24, 2009.

16. Commitments and contingencies

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, 2010 which are expected to have a material adverse impact on our financial position or results of operations.

17. Subsequent events

On October 8, 2010, Idaho Wind closed a $221.7 million project-level credit facility. The facility is composed of two tranches, which includes a $138.5 million construction loan that will convert to a 17-year term loan following commercial operation and a $83.2 million cash grant facility which will be repaid with federal stimulus grant proceeds after completion of construction. We own a 27.6% equity interest in Idaho Wind.

On October 18, 2010, we entered into natural gas swaps that are effective in 2014 and 2015. The natural gas swaps are related to expected fuel purchases attributable to our 50% share of the Orlando project as its operating margin is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. These financial swaps effectively fix the price of 1.2 million Mmbtu of natural gas at the Orlando Project at a weighted average price of $5.76/Mmbtu and represents approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. These natural gas swaps are derivative financial instruments and will be recorded in the consolidated balance sheets at fair value. Changes in the fair value of the natural gas swaps will be recorded in the statement of operations.

On October 20, 2010, we completed a public offering of 6,029,000 common shares, including 784,000 common shares issued pursuant to the exercise in full of the underwriters' over-allotment option, at a price of $13.35 per common share. We received net proceeds from the common share offering, after deducting the underwriting discounts and expenses, of approximately $75.6 million.

On October 20, 2010, we also completed the closing of a public offering of Cdn$80.5 million aggregate principal amount of convertible unsecured subordinated debentures at a price of Cdn$1,000 per debenture, including Cdn$10.5 million aggregate principal amount of debentures pursuant to the exercise in full of the underwriters' over-allotment option. The debentures bear interest at a rate of 5.60%, and will 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 (equivalent to US$18.03 per common share). We received net proceeds from the

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

17. Subsequent events (Continued)

debenture offering, after deducting the underwriting discounts and expenses, of approximately Cdn$76.4 million.

The net proceeds from the public offering of approximately $152.0 million are expected to be used as follows:

- $20.0 million to repay the outstanding borrowings on our revolving credit facility that was used to partially fund the acquisition of Idaho Wind;

- Up to $75 million to fund our equity contribution to the Piedmont Green Power biomass project described below;

- Approximately $35.0 million to fund our expected acquisition of the Cadillac biomass plant described below; and

- Remaining net proceeds of approximately $20.0 million for general corporate purposes and continued execution of our growth strategy.

On October 21, 2010, we closed a non-recourse, project-level bank financing for Piedmont, our first biomass power project. The terms of the financing include an $82 million construction and term loan and a $51 million bridge loan related to the stimulus grant to be received from the U.S. Treasury 60 days after the start of commercial operations. The project has executed a swap that results in an average fixed interest rate of approximately 5.2% during the construction period and the first three years of the term loan. In addition, we will make an equity contribution of approximately $75 million for substantially all of the equity interests in Piedmont.

On October 22, 2010, we entered into a purchase and sale agreement to acquire 100% of the membership interests of Cadillac Renewable Energy, LLC, a 39.6 MW wood fired facility located in Cadillac, Michigan from a joint venture which is jointly owned by ArcLight Energy Partners Fund II and Olympus Power, LLC. The purchase price will be approximately $77 million, subject to customary working capital adjustments, and will be funded by $35 million cash on hand and $42 million of assumed non-recourse, project-level debt. Operations and maintenance will be managed by our majority-owned subsidiary Rollcast Energy. The acquisition is anticipated to close by the end of 2010.

18. United States and Canadian accounting policy differences

In accordance with Canadian securities legislation, issuers that file reports with the Securities and Exchange Commission in the United States are allowed to file financial statements under United States GAAP to meet their continuous disclosure obligations in Canada. We have included a reconciliation highlighting the material differences between our consolidated financial statements prepared in accordance with United States GAAP compared to its consolidated financial statements prepared in accordance with Canadian GAAP below.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. United States and Canadian accounting policy differences (Continued)

Consolidated reconciliation of net income and shareholders' equity

Net income (loss) and shareholders' equity reconciled to Canadian GAAP are as follows:

	Three months ended September 30,		Nine months ended September 30,	
	2010	**2009**	**2010**	**2009**
Net income (loss), based on United States GAAP	$ (537)	$ (15,803)	$ (5,284)	$ (22,289)
Changes in fair value of power purchase agreement, net of tax[(1)]	4,026	39,319	(12,867)	29,193
Projects accounted for under the cost method of accounting, net of tax[(2)]	787	379	2,610	4,391
Net income (loss), based on Canadian GAAP	$ 4,276	$ 23,895	$ (15,541)	$ 11,295

	September 30,	
	2010	**2009**
Shareholders' equity, based on United States GAAP	$ 369,303	$ 110,307
Adjusted for cumulative effect of US/Canadian differences	70,848	67,649
	440,151	177,956
Net earnings for the period, Canadian GAAP	(15,541)	11,295
Shareholders' equity, based on Canadian GAAP	$ 424,610	$ 189,251

---

(1) The United States GAAP accounting standard for derivative instruments provides an exemption for PPAs that contain both a capacity payment and an energy component which, if certain criteria are met, qualifies the PPA for the normal purchases and normal sales treatment. A similar exemption does not exist under Canadian GAAP and accordingly, a PPA with a capacity payment, a minimum or specified quantity of energy and delivery into a liquid market is subject to fair value accounting. Our PPA at the Chambers project meets the normal purchases and normal sales exemption under United States GAAP and is not subject to fair value accounting.

(2) We follow a standard under United States GAAP that establishes a presumption of significant influence with a low threshold of ownership in investments in limited partnerships and requires accounting under the equity method. Our investments in the Selkirk and Gregory projects are accounted for under the cost method for Canadian GAAP because there is not a different threshold for ownership interest in limited partnerships and we do not exercise significant influence over the operating and financial policies of these investments.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. United States and Canadian accounting policy differences (Continued)

Earnings per share

	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010	Nine months ended September 30, 2009
Earnings per share under Canadian GAAP				
Income from continuing operation per share basic	$ 0.07	$ 0.42	$ (0.25)	$ 0.23
Income from discontinued operation per share basic		(0.03)		(0.04)
Net income from share basic	$ 0.07	$ 0.39	$ (0.25)	$ 0.19
Income from continuing operation per share diluted	$ 0.07	$ 0.39	$ (0.25)	$ 0.22
Income from discontinued operation per share diluted		(0.03)		(0.04)
Net income from share diluted	$ 0.07	$ 0.36	$ (0.25)	$ 0.18

Condensed consolidated balance sheet

	September 30, 2010 (Canadian GAAP)	December 31, 2009 (Canadian GAAP)
Assets		
Current assets	$ 114,036	$ 149,340
Equity investments in unconsolidated affiliates[(1)]	99,824	61,037
Other long-term assets	783,046	827,175
Total assets	$ 996,906	$ 1,037,552
Liabilities and Shareholders' Equity		
Current liabilities	$ 100,392	$ 77,471
Other non-current liabilities	471,904	480,398
Shareholders' equity:		
Common shares	544,834	541,304
Accumulated other comprehensive loss	98	(859)
Retained deficit	(123,703)	(60,762)
Noncontrolling interest	3,381	
Total shareholders' equity	424,610	479,683
Total liabilities and shareholders' equity	$ 996,906	$ 1,037,552

(1) We follow a standard under United States GAAP that requires the equity method of accounting for our investments with 50% or less ownership interest in which we do not have a controlling interest. Under Canadian GAAP, our share of each of the assets, liabilities, revenues and expenses of our investments that are subject to joint control is proportionately consolidated.

Table of Contents

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

18. United States and Canadian accounting policy differences (Continued)

Condensed consolidated statement of operations

	Three months ended September 30, 2010 (Canadian GAAP)	Three months ended September 30, 2009 (Canadian GAAP)	Nine months ended September 30, 2010 (Canadian GAAP)	Nine months ended September 30, 2009 (Canadian GAAP)
Project income (loss)				
Project revenue	$ 83,430	$ 70,518	$ 236,969	$ 216,170
Project expenses	61,721	54,343	175,198	165,649
Project other (expenses) income	(13,753)	48,064	(69,209)	29,035
	7,956	64,239	(7,438)	79,556
Administration and other expenses, net	4,549	21,755	20,211	56,426
Income (loss) from operations before income taxes	3,407	42,484	(27,649)	23,130
Income tax expense (benefit)	(868)	17,072	(12,107)	8,935
Income (loss) from continuing operations	4,275	25,412	(15,542)	14,195
Less: Net loss attributable to noncontrolling interest	(99)		(228)	
Loss from discontinued operations, net of tax		(1,517)		(2,900)
Net income (loss) attributable to Atlantic Power Corporation	$ 4,374	$ 23,895	$ (15,314)	$ 11,295

Condensed consolidated statement of cash flows

	Three months ended September 30, 2010 (Canadian GAAP)	Three months ended September 30, 2009 (Canadian GAAP)	Nine months ended September 30, 2010 (Canadian GAAP)	Nine months ended September 30, 2009 (Canadian GAAP)
Cash provided by operating activities of continuing operations	$ 34,078	$ 19,770	$ 75,054	$ 51,160
Cash provided by operating activities of discontinued operations		138		470
	34,078	19,908	75,054	51,630
Cash used in investing activities of continuing operations	(66,438)	(12,723)	(68,818)	(12,067)
Cash used in investing activities of discontinued operations				
	(66,438)	(12,723)	(68,818)	(12,067)
Cash used in financing activities of continuing operations	(21,639)	(29,910)	(48,013)	(55,851)
Cash used in financing activities of discontinued operations		(1,038)		(1,853)
	(21,639)	(30,948)	(48,013)	(57,704)
Decrease in cash and cash equivalents	(53,999)	(23,763)	(41,777)	(18,141)
Cash and cash equivalents, beginning of period	66,725	48,188	54,503	42,566

Cash and cash equivalents, end of period	$	12,726	$	24,425	$	12,726	$	24,425

Table of Contents

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.

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:

- expected opportunities for accretive acquisitions;
- the amount of distributions expected to be received from the projects for the full year 2010 and 2011;
- estimated net cash tax refund in 2010;
- our forecast of expected cash distributions from Idaho Wind, Piedmont and Cadillac for each full year of operations;
- our forecast of expected annual cash distributions from the Lake and Auburndale projects through 2012; and
- the expected resumption of distributions from our Chambers and Delta-Person projects in 2011 and the Selkirk project in 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 Securities and Exchange Commission. 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; and

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

Table of Contents

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.

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.

OVERVIEW

Atlantic Power Corporation is an independent power producer, with power projects located in major markets in the United States. Our current portfolio consists of interests in 11 operational power generation projects across eight states, one wind project under construction in Idaho, one biomass project under construction in Georgia, a 500 kilovolt 84-mile electric transmission line located in California and a number of development projects. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,738 megawatts (or "MW"), in which our ownership interest is approximately 788 MW.

We sell the capacity and power 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 2010 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.

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 most of the PPAs and steam sales agreements provide for the pass-through or indexing of fuel costs to our customers.

We partner with recognized leaders in the independent power industry to operate and maintain our projects, including Caithness Energy, LLC, Power Plant Management 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.

Atlantic Power Corporation is organized under the laws of the Province of British Columbia, Canada. Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 and our headquarters are located at 200 Clarendon Street, Floor 25, Boston, Massachusetts, USA 02116. Our website is atlanticpower.com. Information contained on, or otherwise accessible through, our website is not incorporated into this Quarterly Report on Form 10-Q.

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.

Table of Contents

As of November 10, 2010, we had 66,634,461 common shares, Cdn$59 million principal amount of 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"), Cdn$86.2 million principal amount of 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures"), and Cdn$80.5 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 receive a monthly dividend at a current annual rate of Cdn$1.094 per common share.

On November 24, 2009, our shareholders approved our conversion from the previous Income Participating Security ("IPS") structure to a traditional common share structure. Each IPS was exchanged for one new common share and each old common share that did not form part of an IPS was exchanged for approximately 0.44 of a new common share. This transaction resulted in the extinguishment of Cdn$347,832 principal value of 11% Subordinated Notes due 2016 that previously formed a part of each IPS.

Table of Contents

OUR POWER PROJECTS

The following table outlines our portfolio of power generating and transmission assets in operation and under construction as of November 10, 2010, including our interest in each facility. Management believes the portfolio is well diversified based on 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.

Project Name	Location (State)	Type	Total MW	Economic Interest[1]	Accounting Treatment[2]	Net MW[3]	Electricity Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Auburndale	Florida	Natural Gas	155	100.00%	C	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	C	121	Progress Energy Florida	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00%	C	121	Tampa Electric Co.	2018	BBB
Chambers	New Jersey	Coal	262	40.00%	E	89	ACE[4]	2024	BBB+
						16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	C	N/A	California Utilities via CAISO[5]	N/A[6]	BBB+ to A[7]
Orlando	Florida	Natural Gas	129	50.00%	E	46	Progress Energy Florida	2023	BBB+
						19	Reedy Creek Improvement District	2013[8]	A[9]
Selkirk	New York	Natural Gas	345	17.70%[10]	E	15	Merchant	N/A	N/R
						49	Consolidated Edison	2014	A-
Gregory	Texas	Natural Gas	400	17.10%	E	59	Fortis Energy Marketing and Trading	2013	AA
						9	Sherwin Alumina	2020	NR
Topsham[11]	Maine	Hydro	14	50.00%	E	7	Central Maine Power	2011	BBB+

Badger Creek	California	Natural Gas	46	50.00%	E	23	Pacific Gas & Electric	2011	BBB+
Koma Kulshan	Washington	Hydro	13	49.80%	E	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	E	53	PNM	2020	BB-
Idaho Wind[12]	Idaho	Wind	183	27.56%	E	51	Idaho Power Co.	2030	BBB
Piedmont[13]	Georgia	Biomass	54	100.00%	C	51	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) Accounting Treatment: C Consolidated; and E Equity Method of Accounting

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

(4) Includes separate power sales agreement in which the project and ACE share profits on spot sales of energy and capacity not purchased by ACE under the base PPA.

(5) California utilities pay transmission access charges to CAISO, who then pays owners of TSRs, such as Path 15, in accordance with its FERC approved annual revenue requirement.

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

(7) Largest payers of TACs supporting Path 15's annual revenue requirement are PG&E (BBB+), SoCal Ed (BBB+) and SDG&E (A). CAISO imposes minimum credit quality requirements for any participants of A or better unless collateral is posted per CAISO imposed schedule.

(8) Upon the expiry of the Reedy Creek PPA, the associated capacity and energy will be sold to PEF.

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

(10) 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.

(11) We own our interest in this project as a lessor.

(12) Project currently under construction and is expected to be completed in phases in late 2010 and 2011.

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

Table of Contents

Recent Developments

On July 2, 2010, we acquired a 27.6% equity interest in Idaho Wind for approximately $38.9 million and approximately $3.0 million in transaction costs. Idaho Wind recently commenced construction of a 183 MW wind power project located near Twin Falls, Idaho, which is expected to be completed in phases in late 2010 and early 2011. Idaho Wind has 20-year PPAs with Idaho Power Company. Our investment in Idaho Wind was funded with cash on hand and a $20 million borrowing under our senior credit facility. Upon completion of construction, we expect Idaho Wind to provide after-tax cash flows to us of $4.5 million to $5.5 million for each full year of operations. During the third quarter of 2010, we made a short-term $12.8 million loan to Idaho Wind to provide temporary funding for construction of the project. A portion of the project-level construction financing was completed in early October 2010, resulting in $4.1 million of the loan repaid to us. The remaining $8.7 million is expected to be repaid in late 2010 and early 2011.

On October 8, 2010, Idaho Wind closed a $221.7 million project-level credit facility. The facility is composed of two tranches, which includes a $138.5 million construction loan that will convert to a 17-year term loan following commercial operation and a $83.2 million cash grant facility which will be repaid with federal stimulus grant proceeds after completion of construction. We own a 27.6% equity interest in Idaho Wind.

On October 18, 2010, we entered into natural gas swaps that are effective in 2014 and 2015. The natural gas swaps are related to expected fuel purchases attributable to our 50% share of the Orlando project as its operating margin is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. These financial swaps effectively fix the price of 1.2 million Mmbtu of natural gas at the Orlando Project at a weighted average price of $5.76/Mmbtu. These natural gas swaps are derivative financial instruments and will be recorded in the consolidated balance sheets at fair value. Changes in the fair value of the natural gas swaps will be recorded in the statement of operations.

We expect cash distributions from Orlando to increase significantly following the expiration of the project's gas contract at the end of 2013 because 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 current gas contract.

On October 20, 2010, we completed a public offering of 6,029,000 common shares, including 784,000 common shares issued pursuant to the exercise in full of the underwriters' over-allotment option, at a price of $13.35 per common share. We received net proceeds from the common share offering, after deducting the underwriting discounts and expenses, of approximately $75.6 million.

On October 20, 2010, we also completed the closing of a public offering of Cdn$80.5 million aggregate principal amount of convertible unsecured subordinated debentures at a price of Cdn$1,000 per debenture, including Cdn$10.5 million aggregate principal amount of debentures pursuant to the exercise in full of the underwriters' over-allotment option. The debentures bear interest at a rate of 5.60%, and will 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 (equivalent to US$18.03 per common share). We received net proceeds from the debenture offering, after deducting the underwriting discounts and expenses, of approximately Cdn$76.4 million.

Table of Contents

The net proceeds from the public offering of approximately $152 million are expected to be used as follows:

- $20 million to repay the outstanding borrowings on our revolving credit facility that was used to partially fund the acquisition of Idaho Wind;
- Up to $75 million to fund our equity contribution to the Piedmont Green Power biomass project described below;
- Approximately $35 million to fund our expected acquisition of the Cadillac biomass plant described below; and
- Remaining net proceeds of approximately $22 million for general corporate purposes and continued execution of our growth strategy

On October 21, 2010, we closed a non-recourse, project-level bank financing for Piedmont, our first biomass power project. The terms of the financing include an $82 million construction and term loan and a $51 million bridge loan related to the stimulus grant to be received from the U.S. Treasury 60 days after the start of commercial operations, which is expected in late 2012. In addition, we will make an equity contribution of approximately $75 million for substantially all of the equity interests in Piedmont. The project has executed a swap that results in an average fixed interest rate of approximately 5.2% during the construction period and the first three years of the term loan. Cash distributions to us from the project are expected to average $8 million to $10 million for each full year of project operation. The project has a 20-year power purchase agreement under which capacity payments represent the majority of the revenues. In addition, the revenue and fuel supply contracts contain adjustment mechanisms that will mitigate potential biomass fuel price volatility.

On October 22, 2010, we entered into a purchase and sale agreement to acquire 100% of the membership interests of Cadillac Renewable Energy, LLC, a 39.6 MW wood fired facility located in Cadillac, Michigan from a joint venture which is jointly owned by ArcLight Energy Partners Fund II and Olympus Power, LLC. The purchase price will be approximately $77 million, subject to customary working capital adjustments, and will be funded by $35 million cash on hand and $42 million of assumed non-recourse, project-level debt. Operations and maintenance will be managed by our majority-owned subsidiary Rollcast Energy. The acquisition is anticipated to close by the end of 2010. We expect to receive distributions from the project in the range of $3.5 million to $4.5 million per year beginning in 2011.

Critical Accounting Policies and Estimates

Accounting standards require information in financial statements about the risks and uncertainties inherent in significant estimates, and the application of generally accepted accounting principles involves the exercise of varying degrees of judgment. Certain amounts included in or affecting our consolidated financial statements and related disclosures must be estimated, requiring us to make certain assumptions with respect to values or conditions that cannot be known with certainty at the time our financial statements are prepared. These estimates and assumptions affect the amounts we report for our assets and liabilities, our revenues and expenses during the reporting period, and our disclosure of contingent assets and liabilities at the date of our financial statements. We routinely evaluate these estimates utilizing historical experience, consultation with experts and other methods we consider reasonable in the particular circumstances. Nevertheless, actual results may differ significantly from our estimates and any effects on our business, financial position or results of operations resulting from revisions to these estimates are recorded in the period in which the facts that give rise to the revision become known.

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining fair

Table of Contents

values of acquired assets, the useful lives and recoverability of property, plant and equipment and PPAs, the recoverability of equity investments, the recoverability of deferred tax assets, the fair value of notional units granted under the terms of the Long-Term incentive plan, and the fair value of derivatives.

For a summary of our significant accounting policies, see Note 2 to our interim consolidated financial statements included elsewhere in this Quarterly Report on Form 10-Q. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others, which policies are discussed as follows.

Impairment of long-lived assets and equity investments

Long-lived assets, which include property, plant and equipment, transmission system rights and other intangible assets subject to depreciation and amortization, are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets by factoring in the probability weighting of different courses of action available. Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. We discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment or employ an expected present value method that probability-weights a range of possible outcomes. We also consider quoted market prices in active markets to the extent they are available. In the absence of such information, we may consider prices of similar assets, consult with brokers or employ other valuation techniques. We use our best estimates in making these evaluations. However, actual results could vary from the assumptions used in our estimates and the impact of such variations could be material.

Investments in and the operating results of 50%-or-less owned entities not required to be consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment, failure of cash flow coverage ratio tests included in project-level, non-recourse debt or, where applicable, estimated sales proceeds which are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary.

When we determine that an impairment test is required, the future projected cash flows from the equity investment are the most significant factor in determining whether impairment exists and, if so, the amount of the impairment charges. We use our best estimates of market prices of power and fuel and our knowledge of the operations of the project and our related contracts when developing these cash flow estimates. In addition, when determining fair value using discounted cash flows, the discount rate used can have a material impact on the fair value determination. Discount rates are based on our risk of the cash flows in the estimate, including when applicable, the credit risk of the counterparty that is contractually obligated to purchase electricity or steam from the project.

We generally consider our investments in our equity method investees to be strategic long-term investments that comprise a significant portion of our core operating business. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, an appropriate write-down is recorded based on the excess of the carrying value over the best estimate of fair value of the investment. The use of these methods involves the same inherent uncertainty of future cash flows as previously discussed with respect to undiscounted cash flows. Actual future market prices and project costs could vary from those used in our estimates and the impact of such variations could be material.

Fair Value of Derivatives

We utilize derivative contracts to mitigate our exposure to fluctuations in fuel commodity prices, foreign currency and to balance our exposure to variable interest rates. We believe that these derivatives are generally effective in realizing these objectives.

In determining fair value for our derivative assets and liabilities, we generally use the market approach and incorporate assumptions that market participants would use in pricing the asset or liability, including assumptions about market risk and/or the risks inherent in the inputs to the valuation techniques.

A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. Our derivative instruments are classified as Level 2. The fair value measurements of these derivative assets and liabilities are based largely on quoted prices from independent brokers in active markets who regularly facilitate our transactions. An active market is considered to have transactions with sufficient frequency and volume to provide pricing information on an ongoing basis.

Derivative assets are discounted for credit risk using credit spreads representative of the counterparty's probability of default. For derivative liabilities, fair value measurement reflects the nonperformance risk related to that liability, which is our own credit risk. We derive our nonperformance risk by applying credit spreads approximating our estimate of corporate credit rating against the respective derivative liability.

Certain derivative instruments qualify for a scope exception to fair value accounting, as they are considered normal purchases or normal sales. The availability of this exception is based upon the assumption that we have the ability and it is probable to deliver or take delivery of the underlying physical commodity. Derivatives that are considered to be normal purchases and normal sales are exempt from derivative accounting treatment and are recorded as executory contracts.

Income Taxes and Valuation Allowance for Deferred Tax Assets

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. The valuation allowance is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards.

Long-term incentive plan

The officers and other employees of Atlantic Power are eligible to participate in the LTIP that was implemented in 2007. In the second quarter of 2010, the board of directors approved an amendment to the LTIP and the amended plan was approved by our shareholders on June 29, 2010. The amended LTIP will be effective for grants beginning with the 2010 performance year. Under the amended LTIP, the notional units granted to plan participants will have the same characteristics as notional units under the old LTIP. However, the number of notional units that vest will be based, in part, on the total shareholder return of Atlantic Power compared to a group of peer companies in Canada. In addition,

Table of Contents

vesting of the notional units for officers of Atlantic Power will occur on a three-year cliff basis as opposed to ratable vesting over three years for grants made prior to the amendments.

Unvested notional units are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date or if we do not meet certain ongoing cash flow performance targets.

Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and the fair value of the award at each balance sheet date for notional units accounted for as liability awards. Fair value of the awards granted prior to the 2010 amendment is determined by projecting the total number of notional units that will vest in future periods, including dividends received on notional units during the vesting period, and applying the current market price per share to the projected number of notional units that will vest. The fair value of awards granted for the 2010 performance period with market vesting conditions is based upon a Monte Carlo simulation model on their grant date. The aggregate number of shares which may be issued from treasury under the amended LTIP is limited to one million. Unvested notional units are recorded as either a liability or equity award based on management's intended method of redeeming the notional units when they vest.

Table of Contents

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, 2010 and 2009. 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, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010	Nine months ended September 30, 2009
Project revenue				
Auburndale	$ 19,373	$ 18,124	$ 59,410	$ 56,113
Lake	23,721	15,957	57,804	47,061
Pasco	3,132	2,984	8,764	8,779
Path 15	7,813	7,792	23,186	23,208
	54,039	44,857	149,164	135,161
Project expenses				
Auburndale	14,304	13,366	44,437	42,690
Lake	16,671	13,093	40,678	34,142
Pasco	2,548	3,484	7,255	7,903
Path 15	2,901	2,826	8,438	8,720
Other Project Assets	182	(176)	270	(339)
	36,606	32,593	101,078	93,116
Project other income (expense)				
Auburndale	(4,714)	(830)	(10,409)	(2,144)
Lake	(4,621)	793	(10,841)	737
Pasco	22		22	67
Path 15	(2,762)	(3,220)	(9,004)	(8,435)
Chambers	1,331	782	6,268	1,564
Other Project Assets	945	(5,345)	2,917	(3,395)
	(9,799)	(7,820)	(21,047)	(11,606)
Total project income				
Auburndale	355	3,928	4,564	11,279
Lake	2,429	3,657	6,285	13,656
Pasco	606	(500)	1,531	943
Path 15	2,150	1,746	5,744	6,053
Chambers	1,331	782	6,268	1,564
Other Project Assets	763	(5,169)	2,647	(3,056)
	7,634	4,444	27,039	30,439
Administrative and other expenses				
Management fees and administration	4,103	2,907	12,046	8,391
Interest, net	2,707	11,285	8,019	31,455
Foreign exchange loss (gain)	(2,253)	12,528	179	22,034
Other income, net		(18)	(26)	(48)
Total administrative and other expenses	4,557	26,702	20,218	61,832
Income (loss) from operations before income taxes	3,077	(22,258)	6,821	(31,393)
Income tax expense (benefit)	3,614	(6,455)	12,105	(9,104)
Net (loss) income	(537)	(15,803)	(5,284)	(22,289)
Net loss attributable to noncontrolling interest	(99)		(228)	
	$ (438)	$ (15,803)	$ (5,056)	$ (22,289)

Net loss attributable to Atlantic Power Corporation shareholders

Table of Contents

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 $24.4 million and $21.3 million for the three months ended September 30, 2010 and 2009, respectively and $49.8 million and $60.5 million for the nine months ended September 30, 2010 and 2009, respectively. See "Cash Available for Distribution" on page 55 for additional information.

Income (loss) from operations before income taxes for the three months ended September 30, 2010 and 2009, was $3.1 million and $(22.3) million, respectively, and $6.8 million and $(31.4) million for the nine months ended September 30, 2010 and September 30, 2009, respectively. See "Project Income" below for additional information.

Three months ended September 30, 2010 compared with three months ended September 30, 2009

Project Income

Auburndale Segment

The decrease in project income for our Auburndale segment of $3.5 million to $0.4 million in the three month period ended September 30, 2010 from $3.9 million in the comparable 2009 period is primarily attributable to the $4.3 million non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to the changes in market prices of natural gas. See "Quantitative and Qualitative Disclosures About Market Risk" elsewhere in this MD&A for additional details about our derivative instruments and other financial instruments. The change in fair value of derivative instruments was offset by increased dispatch and favorable pricing during a warmer summer in 2010 as compared to the period in 2009 and the annual escalation of capacity payments.

Lake Segment

Project income for our Lake segment decreased $1.3 million to $2.4 million in the three month period ended September 30, 2010 from $3.7 million in the comparable 2009 period. The decrease is primarily attributable to the $4.6 million non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to the changes in market prices of natural gas. See "Quantitative and Qualitative Disclosures About Market Risk" elsewhere in this MD&A for additional details about our derivative instruments and other financial instruments. The change in fair value of derivative instruments was offset by earnings from favorable off-peak dispatch during the summer months as well as the annual escalation of capacity payments.

Table of Contents

Pasco Segment

The increase in project income for our Pasco segment of $1.1 million to $0.6 million in the three month period ended September 30, 2010 from $(0.5) million in the comparable 2009 period is due to lower operations and maintenance expenses attributable to an unplanned outage during the 2009 period.

Path 15 Segment

Project income for our Path 15 segment increased $0.5 million to $2.2 million in the three month period ended September 30, 2010 from $1.7 million in the comparable 2009 period due to lower operations and maintenance expenses in the 2010 period.

Chambers Segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, increased $0.5 million to $1.3 million in the three month period ended September 30, 2010 from $0.8 million in the comparable 2009 period. The increase in project income at Chambers is primarily attributable to higher dispatch during a warmer summer in 2010 compared to the prior period, partially offset by a non-cash change in fair value of derivative instruments associated with its interest rate swaps.

Other Project Assets Segment

Project income (loss) for our Other Project Assets segment increased $6.0 million, to $0.8 million for the three months ended September 30, 2010 compared to a $(5.2) million loss in the comparable 2009 period. The most significant components of the change are as follows:

- combined losses in the 2009 period of $2.5 million at the Mid-Georgia and Stockton projects, which were sold in fourth quarter of 2009;

- a pre-tax long-lived asset impairment charge at the Rumford project of $5.5 million during the third quarter 2009, partially offset by the absence of revenue at Rumford in 2010 as the contract that provided substantially all of the project's income expired in the fourth quarter 2009.

Administrative and Other Expenses (Income)

Management fees and administration increased $1.2 million to $4.1 million for the three months ended September 30, 2010 from $2.9 million in the comparable period in 2009. The increase is partially attributable to a $0.5 million increase in employee share-based compensation plan expense in 2010. The expense associated with the plan varies, in part, with the market price of our common shares, which increased significantly during the third quarter of 2010 compared to the third quarter of 2009, resulting in higher expense in the 2010 period. In addition, we incurred $0.4 million of expenses associated with our initial NYSE listing completed in July 2010 and business development costs associated with potential acquisitions.

Interest expense at the corporate level in 2010 primarily relates to our convertible debentures. Interest expense decreased $8.6 million to $2.7 million in 2010 from $11.3 million in 2009. This decrease is primarily due to the extinguishment of the subordinated notes that were outstanding during 2009. In November 2009 we completed our common share conversion, which resulted in the extinguishment of Cdn$348 million principal value of 11% subordinated notes due 2016 that previously formed a part of each IPS.

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

Table of Contents

of the convertible debentures and, through 2009, our subordinated notes. 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 (gain) loss increased $14.8 million to a $2.3 million gain in 2010 compared to a $12.5 million loss in 2009. The U.S. dollar to Canadian dollar exchange rate decreased by 3.5% during the three months ended September 30, 2010, compared to a decrease of 8.6% in the comparable period in 2009. In addition, the amount of Canadian dollar denominated debt outstanding during the three months ended September 30, 2010 was lower than the amount outstanding in the prior year as a result of the Cdn$347.8 million extinguishment of subordinated notes in our common share conversion, partially offset by the issuance of Cdn$86.5 million of convertible debentures in December 2009. See "Quantitative and Qualitative Disclosures About Market Risk" below for additional details about our management of foreign currency risk and the components of the foreign exchange loss (gain) recognized during the three months ended September 30, 2010 compared to the foreign exchange loss (gain) in the comparable quarter of 2009.

Nine months ended September 30, 2010 compared with nine months ended September 30, 2009

Project Income

Auburndale Segment

Project income for our Auburndale segment decreased $6.7 million to $4.6 million in the nine month period ended September 30, 2010 from $11.3 million in the comparable 2009 period. The decrease in project income for the nine months ended September 30, 2010 is primarily attributable to the $9.0 million non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to the changes in market prices of natural gas. See "Quantitative and Qualitative Disclosures About Market Risk" below for additional details about our derivative instruments and other financial instruments. The change in fair value of derivative instruments was offset by increased dispatch and favorable pricing during a warmer seasonal climate in 2010 as compared to the period in 2009 and the annual escalation of capacity payments.

Lake Segment

Project income for our Lake segment decreased $7.4 million to $6.3 million in the nine month period ended September 30, 2010 from $13.7 million in the comparable 2009 period. The decrease is primarily attributable to the $10.8 million non-cash change in fair value of derivative instruments associated with its natural gas swaps. These swaps were executed to financially hedge the project's exposure to the changes in market prices of natural gas. See "Quantitative and Qualitative Disclosures About Market Risk" below for additional details about our derivative instruments and other financial instruments. The change in fair value of derivative instruments was offset by earnings from favorable off-peak dispatch during the summer months as well as the annual escalation of capacity payments.

Pasco Segment

Project income for our Pasco segment increased $0.6 million to $1.5 million in the nine month period ended September 30, 2010 from $0.9 million in the comparable 2009 period. The increase in project income at Pasco is attributable to lower operations and maintenance expenses in the 2010 period is attributable to an unplanned outage during the 2009 period.

Table of Contents

Path 15 Segment

Project income for our Path 15 segment decreased $0.4 million to $5.7 million in the nine month period ended September 30, 2010 from $6.1 million in the comparable 2009 period. The decrease in project income at Path 15 is attributable to a non-recurring gain in prior year related to the settlement of disputes with landowners over right-of-way issues, partially offset by lower operations and maintenance expenses in 2010.

Chambers Segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, increased $4.7 million to $6.3 million in the nine month period ended September 30, 2010 from $1.6 million in the comparable 2009 period. The increase in project income at Chambers is primarily attributable to the non-recurrence of the planned major maintenance outage during the second quarter of 2009.

Other Project Assets Segment

Project income for our Other Project Assets segment increased $5.8 million, to $2.7 million for the nine months ended September 30, 2010 compared to a $3.1 million loss in the comparable 2009 period. The most significant components of the change are as follows:

- combined losses in the 2009 period of $4.8 million at the Mid-Georgia and Stockton projects, which were sold in the fourth quarter of 2009; and

- a pre-tax long-lived asset impairment charge at the Rumford project of $5.5 million during the third quarter 2009, partially offset by the absence of revenue at Rumford in 2010 as the contract that provided substantially all of the project's income expired in the fourth quarter 2009.

Administrative and Other Expenses (Income)

Management fees and administration increased $3.6 million to $12.0 million for the nine months ended September 30, 2010 from $8.4 million in the comparable period in 2009. The increase is partially attributable to a $1.9 million increase in employee share-based compensation plan expense in 2010. The expense associated with the plan varies, in part, with the market price of our common shares, which increased significantly during the period of 2010 compared to the comparable period of 2009, resulting in higher expense in the 2010 period. In addition, we incurred $1.0 million expenses associated with our initial NYSE listing completed in July 2010 and business development costs associated with potential acquisitions.

Interest expense at the corporate level in 2010 primarily relates to our convertible debentures. Interest expense decreased $23.5 million to $8.0 million in 2010 from $31.5 million in 2009. This decrease is primarily due to the extinguishment of the subordinated notes that were outstanding during 2009. In November 2009 we completed our common share conversion, which resulted in the extinguishment of Cdn$348 million principal value of 11% subordinated notes due 2016 that previously formed a part of each IPS.

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 and, through 2009, our subordinated notes. 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 decreased by $21.8 million to a $0.2 million loss in 2010 compared to a $22.0 million loss in 2009. The U.S. dollar to Canadian dollar exchange rate decreased by 2.1% during the nine months ended September 30, 2010, compared to a decrease of 13.8% in the comparable period in 2009. In addition, the amount of Canadian dollar denominated debt outstanding during the nine months ended September 30, 2010 was lower than the amount outstanding in the prior year as a result of the Cdn$347.8 million extinguishment of subordinated notes in our common share conversion, partially offset by the issuance of Cdn$86.5 million of convertible debentures in December 2009. See "Quantitative and Qualitative Disclosures About Market Risk" below for additional details about our management of foreign currency risk and the components of the foreign exchange loss (gain) recognized during the nine months ended September 30, 2010 compared to the foreign exchange loss (gain) in the comparable period of 2009.

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.

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 less 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.

Table of Contents

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

(unaudited)	Three months ended September 30, 2010	Three months ended September 30, 2009	Nine months ended September 30, 2010	Nine months ended September 30, 2009
Project Adjusted EBITDA by individual segment				
Auburndale	$ 10,018	$ 9,707	$ 29,820	$ 28,254
Lake	9,325	5,128	23,937	20,749
Pasco	1,335	247	3,752	3,116
Path 15	7,318	7,061	21,348	20,894
Chambers	4,637	4,301	14,780	9,325
Total	32,633	26,444	93,637	82,338
Other Project Assets				
Mid-Georgia		657		2,043
Stockton		55		(1,059)
Badger Creek	699	733	2,209	2,465
Koma Kulshan	53	64	606	476
Orlando	2,185	2,110	5,856	6,085
Topsham	415	415	1,378	1,533
Delta Person	461	70	1,365	894
Gregory	1,373	954	3,656	3,225
Rumford		655	(7)	1,963
Selkirk	3,927	3,860	10,983	11,507
Rollcast	(249)	(27)	(628)	(122)
Other	46	85	(237)	(222)
Total adjusted EBITDA from Other Project Assets segment	8,910	9,631	25,181	28,788
Project income				
Total adjusted EBITDA from all Projects	41,543	36,075	118,818	111,126
Depreciation and amortization	16,349	16,761	49,331	51,765
Interest expense, net	5,906	7,764	17,784	23,400
Change in the fair value of derivative instruments	10,706	(938)	23,435	(1,531)
Other (income) expense	948	8,044	1,229	7,053
Project income as reported in the statement of operations	$ 7,634	$ 4,444	$ 27,039	$ 30,439

Table of Contents

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

	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	$ 29,820	$ (7,350)	$ (1,281)	$ (58)	$ (731)	$ 20,400
Chambers	14,780	(9,039)	(4,965)	(40)	(736)	
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
Total Reportable Segments	93,637	(20,129)	(15,551)	(2,061)	(6,871)	49,025
Other Project Assets						
Badger Creek	2,209		(11)		193	2,391
Delta Person	1,365	(1,291)	(210)		136	
Gregory	3,656	(1,216)	(379)	(46)	(593)	1,422
Koma Kulshan	606		1		(151)	456
Orlando	5,856		2	(116)	(1,079)	4,663
Rumford	(7)				7	
Selkirk	10,983	(4,657)	(1,653)	(75)	(4,598)	
Topsham	1,378				(415)	963
Rollcast	(628)				628	
Other	(237)		17	(54)	303	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

Table of Contents

Reconciliation of Project Distributions (in thousands of U.S. dollars)
For the nine months ended September 30, 2009

	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	$ 28,254	$ (2,625)	$ (1,969)	$ (322)	$ (3,451)	$ 19,887
Chambers	9,325	(7,937)	(5,906)	(578)	5,096	
Lake	20,749		10	(1,000)	66	19,825
Pasco	3,116		42		5,192	8,350
Path 15	20,894	(3,765)	(9,664)		1,317	8,782
Total Reportable Segments	82,338	(14,327)	(17,487)	(1,900)	8,220	56,844
Other Project Assets						
Mid-Georgia	2,043		(2,625)		582	
Stockton	(1,059)		(57)		1,116	
Badger Creek	2,465		(3)		438	2,900
Delta Person	894	(820)	(226)		1,564	1,412
Gregory	3,225	(2,509)	(712)	(77)	73	
Koma Kulshan	476			(29)	(330)	117
Orlando	6,085		13	(499)	3,551	9,150
Rumford	1,963				(1,963)	
Selkirk	11,507	(4,247)	(2,303)	(53)	(1,908)	2,996
Topsham	1,533	(45)	(1)		(416)	1,071
Rollcast	(122)		1		121	
Other	(222)			(62)	827	543
Total Other Project Assets Segment	28,788	(7,621)	(5,913)	(720)	3,655	18,189
Total all Segments	$ 111,126	$ (21,948)	$ (23,400)	$ (2,620)	$ 11,875	$ 75,033

Project Operations Performance Three months ended September 30, 2010 compared with three months ended September 30, 2009

Aggregate Project Adjusted EBITDA increased $5.4 million to $41.5 million in the three months ended September 30, 2010 from $36.1 million in 2009 and included the following factors:

increased EBITDA of $4.2 million at Lake due to earnings from favorable off-peak dispatch during the summer months and annually increased contractual capacity payments under the project's PPA;

increased EBITDA of $1.1 million at Pasco primarily attributable to a maintenance outage during the three months ended September 30, 2009; partially offset by

the absence of Stockton and Mid-Georgia's EBITDA as both projects were sold in the fourth quarter of 2009.

Aggregate power generation for projects in operation at September 30, 2010 was 12.9% greater during the three month period ended September 30, 2010 compared to the third quarter of 2009. Generation during the three months ended September 30, 2010 compared to the prior year period was favorably impacted primarily by increased generation at Lake associated with dispatch during off-peak hours due to favorable market conditions, Chambers due to higher dispatch also as a result of

52

favorable market conditions and Selkirk due to increased dispatch by ConEd. The favorable variance was slightly offset by the absence of Stockton and Mid-Georgia generation as the projects were sold in the fourth quarter of 2009.

The project portfolio achieved a weighted average availability of 97.7% for the three months ended September 30, 2010 compared to 99.0% in the 2009 period. The slight decrease in portfolio availability in the third quarter of 2010 was primarily due to a planned outage at Lake and a minor unplanned outage at Auburndale in the third quarter of 2010. Each of the projects with reduced availability was nevertheless able to achieve substantially all of their respective capacity payments as a result of contract terms that provide for certain levels of planned and unplanned outages.

Project Operations Performance Nine months ended September 30, 2010 compared with nine months ended September 30, 2009

Aggregate Project Adjusted EBITDA increased $7.7 million to $118.8 million in the nine months ended September 30, 2010 from $111.1 million in the comparable 2009 period and included the following factors:

- increased EBITDA of $5.5 million at Chambers due primarily to a planned major maintenance outage during the nine months ended September 30, 2009;
- increased EBITDA of $3.2 million at Lake due to favorable off-peak dispatch and annually increased contractual capacity payments under the projects PPA;
- increased EBITDA of $1.6 million at Auburndale due to increased contractual capacity payments under the project's PPA;
- the absence of Stockton's $1.1 million EBITDA loss during the period in 2009 resulting from higher maintenance costs from a forced outage during 2009. The Stockton project was sold in the fourth quarter of 2009.

The increases in aggregate Project Adjusted EBITDA were partially offset by:

- the absence of EBITDA at Mid-Georgia as the project was sold in the fourth quarter of 2009; and
- the absence of EBITDA at Rumford in 2010 as the contract that provided substantially all of the project's cash flow expired in the fourth quarter 2009.

Aggregate power generation for projects in operation at September 30, 2010 was 0.1% lower during the nine month period ended September 30, 2010 compared to the nine month period in 2009. Generation during the first nine months of 2010 versus the comparable period in 2009 was unfavorably impacted primarily by the absence of Stockton and Mid-Georgia generation as the projects were sold in the fourth quarter of 2009 and to a lesser extent by reduced dispatch of the Selkirk project by its PPA counterparty. The reduced level of generation in the period was largely offset by increased generation at Lake due to favorable market conditions, and to a lesser extent by increased generation at Chambers, Badger Creek and Gregory due to planned and un-planned outages in the 2009 period.

The project portfolio achieved a weighted average availability of 97.2% for the nine months ended September 30, 2010 compared to 95.0% in the 2009 period. The increase in portfolio availability in 2010 was primarily due to the planned outages at Chambers and Gregory in 2009. Each of the projects with reduced availability was nevertheless able to achieve substantially all of their respective capacity payments as a result of contract terms that provide for certain levels of planned and unplanned outages.

Table of Contents

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 recontracted 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 $18.8 million for the nine months ended September 30, 2010 over the comparable period in 2009. The change from the prior year is primarily attributable to a significant decrease in cash interest expense as a result of our common share conversion in November 2009, which eliminated Cdn$348 million of outstanding subordinated notes. The positive change in operating cash flow attributable to the reduced interest expense was partially offset by a $4.5 million decrease in distributions from our Orlando project and no distributions in 2010 from our Selkirk project, both of which are equity method investments. The decrease in distributions from Orlando was the result of a one-time receipt of insurance proceeds in 2009 related to an unplanned outage that occurred in 2008. The Selkirk project is currently not making distributions to partners as a result of restrictions in its non-recourse project-level debt. We expect to resume receiving distributions from Selkirk in late 2011 or early 2012.

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 months ended September 30, 2010 were $65.3 million compared to $12.3 million for the nine months ended September 30, 2009. We acquired a 27.6% equity interest in Idaho Wind for $38.9 million and approximately $3.0 million in transaction costs. In addition, we loaned $12.8 million to Idaho Wind to temporarily fund a portion of construction costs at the project.

Cash Flow from Financing Activities

Cash used in financing activities for the nine months ended September 30, 2010 resulted in a net outflow of $39.2 million compared to a net outflow of $49.2 million for the same period in 2009. The change from the prior year is primarily attributable to a significant increase in dividends paid of approximately $29.5 million and a $4.1 million increase in project-level debt payments due to escalation payments included in the debt agreements. We completed our common share conversion in November 2009. As a result, Cdn$348 million of subordinated notes were extinguished and our entire monthly distribution to shareholders is now paid in the form of a dividend as opposed to the monthly distribution being split between a subordinated notes interest payment and a common share dividend during the nine months ended September 30, 2009. This increase in dividends and interest payments paid was offset by the proceeds of $20 million from a borrowing under our revolving credit facility that was used to partially fund our investment in Idaho Wind in July 2010.

Table of Contents

Cash Available for Distribution

Prior to our conversion to a common share structure, holders of our IPSs received monthly cash distributions in the form of interest payments on subordinated notes and dividends on common shares. Subsequent to the conversion, holders of common shares receive the same monthly cash distributions of Cdn$1.094 per year in the form of a dividend on the new common shares. The payout ratio for the three and nine month periods ended September 30, 2010 is consistent with our expected payout ratio for the full year 2010 of slightly more than 100%. The expected full-year payout ratio is slightly higher than our previous guidance in part due to dividends paid on a higher number of common shares outstanding following our public offering completed in October 2010.

From an overall cash flow perspective, we have received $2.0 million of proceeds from the sale of our interest in the Rumford project in November 2010 and expect to receive approximately $3 million to $4 million in distributions of restricted cash from our projects in the fourth quarter of 2010 as a result of more efficient management of project working capital. However, both the proceeds from Rumford and the restricted cash releases are classified as cash flows from investing activities in our consolidated statements of cash flows. Because only operating cash flows are included in the definition of cash available for distribution, these positive investing cash inflows will not be reflected as an increase in cash available for distribution or as a benefit to the presentation of the payout ratio. Cash Available for Distribution increased by $3.1 million for the three months ended September 30, 2010 from the 2009 period and decreased by $10.8 million for the nine months ended September 30, 2010 from the 2009 period as set forth in the following table:

(unaudited)	Three months ended September 30,		Nine months ended September 30,	
(in thousands of U.S. dollars, except as otherwise stated)	**2010**	**2009**	**2010**	**2009**
Cash flows from operating activities[1]	27,695	14,371	63,673	44,895
Project-level debt repayments	(2,700)	(1,270)	(11,841)	(7,684)
Interest on IPS portion of subordinated notes[2]		8,879		24,957
Purchases of property, plant and equipment	(557)	(708)	(2,077)	(1,641)
Cash Available for Distribution[3]	24,438	21,272	49,755	60,527
Interest on subordinated notes		8,879		24,957
Dividends on common shares	15,904	6,438	47,618	18,110
Total distributions to shareholders	15,904	15,317	47,618	43,067
Payout ratio	65%	72%	96%	71%
Expressed in Cdn$				
Cash Available for Distribution	25,404	23,349	51,552	70,763
Total common share distributions	16,556	16,557	49,639	49,791

(1) Beginning in the first quarter of 2010, changes in restricted cash in the consolidated statement of cash flows has been reported as an investing activity to reflect the use of the restricted cash in the current period. In previous periods, changes in restricted cash were reported as cash flow from operating activities. The prior period amounts have been reclassified to conform with the current year presentation. This reclassification does not impact the consolidated balance sheet or the consolidated statements of operations. We have changed the classification of restricted cash because the revised presentation is more widely used by companies in our industry.

(2) Prior to the common share conversion in November 2009, a portion of our monthly distribution to IPS holders was paid in the form of interest on the subordinated notes comprising a part of the

Table of Contents

IPSs. Subsequent to the conversion, the entire monthly cash distribution is paid in the form of a dividend on our common shares.

(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 Financial Information".

Outlook

Based on year-to-date results and our projections for the remainder of the year, we continue to expect to receive distributions from our projects in the range of $75 million to $80 million for the full year 2010. At the corporate-level, we expect a net cash tax refund in 2010 in the range of $7 million to $9 million, compared to insignificant net cash taxes in 2009. Included in 2010 corporate-level costs will be the $5 million payment under the terms of the management agreement termination, down from the $6 million payment in 2009.

Looking ahead to 2011, we expect overall levels of operating cash flow to be improved over projected 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 agreement termination are expected to be partially offset by the absence of a cash tax refund in 2011. 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 increased distributions from Selkirk following the final payment of its non-recourse project-level debt in 2012.

The following one-time items and contract expirations comprise the most significant of the decreases in projected 2010 project distributions compared to 2009.

- Final insurance proceeds received in 2009 at Orlando due to the unplanned outage in early 2008.
- Increase in debt principal payments in 2010 for Auburndale project level debt.
- Resolution in 2009 of the landowner litigation over right-of-way issues at Path 15, which resulted in $6 million being released from the construction reserve account.
- Final payment related to Pasco's prior PPA that expired at the end of 2008 which was received in early 2009.

In 2009, the following five projects comprised approximately 86% of project distributions received: Auburndale, Lake, Orlando, Path 15 and Pasco. For 2010, we expect these same five projects to contribute approximately 90% of total project distributions.

In addition to the items above, the following is a summary of other projections for project distributions in 2010 and beyond:

Lake

The Lake project is exposed to changes in natural gas prices from the expiration of its natural gas supply contract on June 30, 2009 through the expiration of its PPA in July, 2013. We have executed a hedging strategy to mitigate this exposure by periodically entering into financial swaps that effectively fix the forward price of natural gas expected to be purchased at the project. We have taken advantage of the low market price of natural gas to make significant progress in our natural gas hedging strategy. These hedges are summarized in "Quantitative and Qualitative Disclosures About Market Risk" in this Form 10-Q. We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Lake in 2011 and 2013, but do not intend to execute additional hedges at Lake for 2010 or 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 a specific utility plant in Florida, the Crystal River facility. 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 $27 million to $29 million in 2010. In 2011 and 2012, expected distributions from Lake are expected to be $30 million to $34 million per year. The increases in 2011 and 2012 are primarily due to higher contractual capacity and energy revenue and lower 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 2010 through 2013, when the project's current PPA expires. Distributions received from Auburndale in the 2010 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 coal costs 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 gas 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 "Quantitative and Qualitative Disclosures About Market Risk" in this Form 10-Q. The 2010 and 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.

Chambers

As previously reported, the reduced cash flows resulted in the project not meeting cash flow coverage ratio tests in its non-recourse debt, so we received no distributions from Chambers in 2009 or the first nine months of 2010. The Chambers project did meet the cash flow coverage ratio for its non-recourse debt as of September 30, 2010 and Epsilon Power Partners, the project's holding company received a distribution from the project of $2.8 million in October 2010. However, the required cash flow coverage ratio on the holding company debt at Epsilon has not been achieved and, as a result, cash is temporarily trapped at Epsilon. Based on our current projections, Epsilon will continue receiving distributions from the project in 2011 based on meeting the required debt service coverage ratios and we expect the trapped cash to be released from Epsilon in late 2011.

Table of Contents

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.

With the exception of our commitment to the construction of Piedmont Green Power, we do not expect any material unusual requirements for cash outflows for the remainder of 2010 and 2011 for capital expenditures or other required investments. We expect to contribute a total of $75.0 million to fund the equity portion of the construction costs for Piedmont. Approximately $40.0 million of this amount is expected to be contributed in the fourth quarter of 2010, with the balance paid in the first quarter of 2011. In addition, there are no debt instruments with significant maturities or refinancing requirements in 2010 and 2011. See "Outlook" above for information about changes in expected distributions from our projects in 2010 and beyond.

Credit facility

We maintain a credit facility with a capacity of $100 million, $50 million of which may be utilized for letters of credit. The credit facility matures in August 2012.

The credit facility bears interest at the London Interbank Offered Rate ("LIBOR") plus an applicable margin between 1.50% and 3.25% that varies based on the credit statistics of one of our subsidiaries. As of September 30, 2010, the applicable margin was 1.50%. As of September 30, 2010, $38.9 million was allocated, but not drawn, to support letters of credit for contractual credit support at seven of our projects. In June 2010, we borrowed $20 million under the credit facility and used the proceeds to partially fund the acquisition of Idaho Wind in July 2010. In October 2010, we repaid the $20 million borrowing with proceeds from our common stock and convertible debt offerings.

We must meet certain financial covenants under the terms of the credit facility, which are generally based on the cash flow coverage ratios and also require us to report indebtedness ratios to the bank. 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.

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, for gross proceeds of $52.8 million. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The Debentures initially had a maturity date of October 31, 2011 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. In connection with our conversion to a common share structure on November 27, 2009, the holders of the 2006 Debentures approved an amendment to increase the annual interest rate from 6.25% to 6.50% and separately, an extension of the maturity date from October 2011 to October 2014. In September 2010 and October 2010 Cdn$12,000 and Cdn$1,024,000 of the 2006 debentures, respectively, were converted to 967 and 82,580 common shares, respectively.

Table of Contents

In December 2009, we issued, in a public offering, Cdn$86.25 million aggregate principal amount of 6.25% convertible debentures, which we refer to as the 2009 Debentures, for gross proceeds of $71.4 million. 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. In August 2010 and November 2010 Cdn$17,000 and Cdn$137,000, respectively, of the 2009 debentures were converted to 1,307 and 10,538 common shares, respectively.

In October 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of convertible unsecured subordinated debentures at price of Cdn$1,000 per debenture, including Cdn$10.5 million aggregate principal amount of debentures pursuant to the exercise in full of the underwriters' over-allotment option. The debentures bear interest at a rate of 5.60% per year, and 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 (equivalent to US$18.03 per common share).

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, 2010 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, 2010, the covenants at the Selkirk and Delta-Person projects and at Epsilon Power Partners are temporarily preventing those projects from making cash distributions to us. We expect Delta-Person and Epsilon Power Partners to resume cash distributions in 2011 and Selkirk to resume distributions in 2012. All project-level debt is non-recourse to us and substantially all of the 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. From January 1 to October 31, 2010, we have contributed approximately $3.1 million to Epsilon Power Partners for debt service payments on the holding company debt, but do not anticipate any additional required contributions to Epsilon.

Table of Contents

The range of interest rates presented represents the rates in effect at September 30, 2010. The amounts listed below are in thousands of U.S. dollars, except as otherwise stated.

	Range of Interest Rates	Total Remaining Principal Repayments	2010	2011	2012	2013	2014	Thereafter
Consolidated Projects:								
Epsilon Power Partners	7.40%	$ 36,732	$ 250	$ 1,500	$ 1,500	$ 3,000	$ 5,000	$ 25,482
Path 15	7.9% - 9.0%	157,608	3,740	7,987	8,667	9,402	8,065	119,747
Auburndale	5.10%	24,150	2,450	9,800	7,000	4,900		
Total Consolidated Projects		218,490	6,440	19,287	17,167	17,302	13,065	145,229
Equity Method Projects:								
Chambers	0.4% - 7.2%	77,807	2,763	11,294	12,176	10,783	5,780	35,012
Delta-Person	2.0%	10,587	268	1,130	1,212	1,300	1,394	5,282
Selkirk	9.0%	20,999	4,206	10,948	5,845			
Gregory	1.8% - 7.5%	14,824	541	1,901	2,044	2,205	2,385	5,748
Total Equity Method Projects		124,217	7,778	25,273	21,277	14,288	9,559	46,042
Total Project-Level Debt		$ 342,707	$ 14,218	$ 44,560	$ 38,444	$ 31,590	$ 22,624	$ 191,271

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, 2010, restricted cash at the consolidated projects totaled $22.3 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.

In 2010, several of the projects have planned outages to complete maintenance work. The level of maintenance and capital expenditures is reduced from 2009. In the second quarter, Selkirk completed a minor inspection of one of its combustion turbines, with costs and lost margin largely covered by reserves and gas resales proceeds, respectively. Selkirk's planned major overhaul of a steam turbine has been postponed to 2011 due to maintaining a high steam quality. In the second quarter, Chambers completed its scheduled outage to inspect and complete customary repairs on one boiler. Due to the facility's low dispatch, the planned outage of its other boiler originally scheduled for the fourth quarter, has been postponed to 2011. At Orlando, a minor gas turbine inspection was completed in May, the cost of which was largely covered under its long-term maintenance agreement with the gas turbine manufacturer. In the fourth quarter, Auburndale will conduct an inspection of one of the facility's combustion turbines, which is covered by its long-term service agreement, in conjunction with other maintenance work.

Off-Balance Sheet Arrangements

As of September 30, 2010, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

60

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 are 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 Lake project's operating margin is exposed to changes in the market price of natural gas from the expiration of its natural gas supply contract on June 30, 2009 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 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.

We have executed a strategy to mitigate the future exposure to changes in natural gas prices at Lake and Auburndale by periodically entering into financial swaps that effectively fix the price of natural gas required at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value. Changes in the fair value of the natural gas swaps, at Lake and Auburndale, through June 30, 2009 were recorded in other comprehensive income (loss) as they were designated as a hedge of the risk associated with changes in market prices of natural gas. As of July 1, 2009, these natural gas swap hedges were de-designated and the changes in their fair value are recorded in change in fair value of derivative instruments in the consolidated statements of operations.

In 2011, projected cash distributions at Auburndale 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. In 2011, 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 unhedged 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 $2.5 million for every $0.25/Mmbtu change in the projected price of coal.

Table of Contents

The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndaleas of November 10, 2010:

	2010	2011	2012	2013
Portion of gas volumes currently hedged:				
Lake:				
Contracted				
Financially hedged	80%	78%	90%	65%
Total	80%	78%	90%	65%
Auburndale:				
Contracted	80%	80%	40%	0%
Financially hedged	15%	13%	32%	79%
Total	95%	93%	72%	79%
Average price of financially hedged volumes (per Mmbtu)				
Lake	$ 7.11	$ 6.52	$ 6.90	$ 7.05
Auburndale	$ 6.30	$ 6.68	$ 6.51	$ 6.92

On October 18, 2010, we entered into natural gas swaps that are effective in 2014 and 2015. The natural gas swaps are related to expected fuel purchases attributable to our 50% share of the Orlando project as its operating margin is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. These financial swaps effectively fix the price of 1.2 million Mmbtu of natural gas at the Orlando Project at a weighted average price of $5.76/Mmbtu and represents approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015.

We expect cash distributions from Orlando to increase significantly following the expiration of the project's gas contract at the end of 2013 because 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 current gas contract.

Foreign Currency Exchange Risk

We use forward foreign currency contracts to manage our exposure to changes in foreign exchange rates as we earn our income in the U.S. dollars but pay dividends to shareholders in Canadian dollars. Since our inception, we have had an established hedging strategy for the purpose of reinforcing 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 sufficient to make monthly dividend payments at the current annual dividend level of Cdn$1.094 per common share, as well as interest payments on the 2009 Debentures, through December 2013. Changes in the fair value of the forward contracts partially offset foreign exchange gains or losses on the U.S. dollar equivalent of our Canadian dollar obligations.

In addition to the forward contracts discussed above that settle on a monthly basis, we executed forward contracts to purchase Canadian dollars at fixed rates of exchange sufficient to make semi-annual payments on the 2006 Debentures. The contracts provide for the purchase of Cdn$1.9 million in April and in October of each year through 2011 at a rate of 1.1075 Canadian dollars per U.S. dollar.

It is our intention to periodically consider extending the length of these forward contracts. In addition, we will consider executing additional foreign currency forward contracts to hedge expected additional dividend and interest payments associated with the common shares and convertible debentures issued in our October 2010 public offering.

Table of Contents

The foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and the estimation of the counter-party's credit risk. 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, 2010 and 2009:

	Three months ended September 30,		Nine months ended September 30,	
	2010	**2009**	**2010**	**2009**
Unrealized foreign exchange (gain) loss:				
Subordinated notes and convertible debentures	$ 4,886	$ 33,625	$ 2,381	$ 51,282
Forward contracts and other	(5,716)	(19,389)	1,988	(27,416)
	(830)	14,236	4,369	23,866
Realized foreign exchange gains on forward contract settlements	(1,423)	(1,708)	(4,190)	(1,832)
	$ (2,253)	$ 12,528	$ 179	$ 22,034

The following table illustrates the impact on 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, 2010:

Convertible debentures	$ 14,210
Foreign currency forward contracts	$ 25.245

Interest Rate Risk

The impact of changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 90% 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.

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 $0.8 million.

Table of Contents

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.

Table of Contents

PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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, 2010 that are expected to have a material impact on our financial position or results of operations.

ITEM 1A. RISK FACTORS

We have provided a summary of the various risk and uncertainties affecting our industry, business, results of operations and financial condition under the heading "Risk Factors" in our registration statement on Form 10 as filed with the Securities and Exchange Commission on July 21, 2010. In addition, we included the supplemental risk factor disclosure set forth below in our registration statements on Form S-1 as declared effective by the SEC on October 13, 2010. There have been no material changes to our risk factors from those disclosed in our Form 10 and as set forth below through the filing of this Quarterly Report on Form 10-Q.

Our projects are subject to significant environmental and other regulations

Our projects are subject to numerous and significant federal, state and local laws, including statutes, regulations, by-laws, guidelines, policies, directives and other requirements governing or relating to, among other things: air emissions; discharges into water; ash disposal; the storage, handling, use, transportation and distribution of dangerous goods and hazardous, residual and other regulated materials, such as chemicals; the prevention of releases of hazardous materials into the environment; the prevention, presence and remediation of hazardous materials in soil and groundwater, both on and off site; land use and zoning matters; and workers' health and safety matters. As such, the operation of our projects carries an inherent risk of environmental, health and safety liabilities (including potential civil actions, compliance or remediation orders, fines and other penalties), and may result in the projects being involved from time to time in administrative and judicial proceedings relating to such matters.

The Clean Air Act and related regulations and programs of the U.S. Environmental Protection Agency extensively regulate the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds emitted by power plants. Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In particular, the Environmental Protection Agency has promulgated regulations under the federal Clean Air Interstate Rule ("CAIR") requiring additional reductions in nitrogen oxides, or "$NO_{X,}$" and sulphur dioxide, or "$SO_{2,}$" emissions, beginning in 2009 and 2010 respectively, and has also promulgated regulations requiring reductions in mercury emissions from coal-fired electric generating units, beginning in 2010 with more substantial reductions in 2018. Moreover, certain of the states in which we operate have promulgated air pollution control regulations which are more stringent than existing and proposed federal regulations.

While CAIR was set aside by a court decision in 2008, that decision allowed the CAIR requirements to remain in place pending further rulemaking by the Environmental Protection Agency. On July 6, 2010, the Environmental Protection Agency proposed to replace CAIR by requiring 31 states and the District of Columbia to curb emissions of sulfur dioxide and nitrogen oxides from power plants through more aggressive state-by-state emissions budgets for nitrogen oxides and sulfur dioxide. Compliance with the proposed rule, which would take effect in 2012, may have a material adverse impact on our business, operations or financial condition.

Table of Contents

The Environmental Protection Agency intends to propose new mercury emissions standards for power plants by March 2011 and to have new standards in place by November 2011. Meeting these new standards at our coal-fired facilities may have a material adverse impact on our business, operations or financial condition.

The Resource Conservation and Recovery Act has historically exempted fossil fuel combustion wastes from hazardous waste regulation. However, in June 2010 the Environmental Protection Agency proposed two alternative sets of regulations governing coal ash. One set of proposed regulations would designate coal ash as "special waste" and bring coal ash under federal regulations governing hazardous solid waste under Subtitle C of the Resource Conservation and Recovery Act. Another set of proposed regulations would regulate coal ash as a non-hazardous solid waste. If the Environmental Protection Agency determines to regulate coal ash as a hazardous waste, our coal-fired facilities may be subject to increased compliance obligations and costs that may have a material adverse impact on our business, operations or financial condition.

Significant expenditures may be required for either capital expenditures or the purchase of emissions allowances under any or all of these programs to keep the projects compliant with environmental laws and regulations. The projects' PPAs do not allow for the pass through of emissions allowance or emission reduction capital expenditures, with the exception of Pasco. If it is not economical to make those expenditures it may be necessary to retire or mothball facilities, or restrict or modify our operations to comply with the more stringent standards.

Our projects have obtained environmental permits and other approvals that are required for their operations. Compliance with applicable environmental laws, regulations, permits and approvals and material future changes to them could materially impact our businesses. Although we believe the operations of the projects are currently in material compliance with applicable environmental laws, licenses, permits and other authorizations required for the operation of the projects and although there are environmental monitoring and reporting systems in place with respect to all the projects, there is no guarantee that more stringent laws will not be imposed, that there will not be more stringent enforcement of applicable laws or that such systems may not fail, which may result in material expenditures. Failure by the projects to comply with any environmental, health or safety requirements, or increases in the cost of such compliance, including as a result of unanticipated liabilities or expenditures for investigation, assessment, remediation or prevention, could result in additional expense, capital expenditures, restrictions and delays in the projects' activities, the extent of which cannot be predicted.

Our projects are subject to regulation of CO_2 and other greenhouse gases

Ongoing public concerns about emissions of CO_2 and other greenhouse gases from power plants have resulted in the enactment of, and proposals for, laws and regulations at the federal, state and regional levels, some of which do or could apply to some of our project operations. For example, the multi-state CO_2 cap-and-trade program known as the Regional Greenhouse Gas Initiative applies to our fossil fuel facilities in the Northeast region. The Regional Greenhouse Gas Initiative program went into effect on January 1, 2009. CO_2 allocations are now a tradeable commodity, currently averaging in the $1.86 to $2.00/ton range. The State of Florida has conducted stakeholder meetings as part of the process of developing greenhouse gas emissions regulations, the most recent of which was in January 2009. Discussions indicate favoring a program similar to that of the Regional Greenhouse Gas Initiative.

California, New Mexico, Washington and other states are part of the Western Climate Initiative, which is developing a regional cap-and-trade program to reduce greenhouse gas emissions in the region to 15% below 2005 levels by 2020.

Table of Contents

In 2006, the State of California passed legislation initiating two programs to control/reduce the creation of greenhouse gases. The two laws, more commonly known as AB 32 and SB 1368, are currently in the regulatory rulemaking phase which will involve public comment and negotiations over specific provisions. Development towards the implementation of these programs continues.

Under AB 32 (the California Global Warming Act of 2006) the California Air Resources Board is required to adopt a greenhouse gas emissions cap on all major sources (not limited to the electric sector). In order to do so, it must adopt regulations for the mandatory reporting and verification of greenhouse gas emissions and to reduce state-wide emissions of greenhouse gases to 1990 levels by 2020. This will most likely require that electric generating facilities reduce their emissions of greenhouse gases or pay for the right to emit by the implementation date of January 1, 2012. The program has yet to be finalized and the decision as to whether allocations will be distributed or auctioned will be determined in the rulemaking process that is currently underway. Discussion to date favors an auction-based allocation program.

SB 1368 added the requirement that the California Energy Commission, in consultation with the California Public Utilities Commission (the "CPUC") and the California Air Resources Board establish greenhouse gas emission performance standards and implement regulations for power purchase agreements that exceed five years entered into prospectively by publicly-owned electric utilities. The legislation directs the California Energy Commission to establish the performance standard as one not exceeding the rate of greenhouse gas emitted per megawatt-hour associated with combined-cycle, gas turbine baseload generation, such as our Badger Creek project. Provisions are under consideration in the rulemaking to allow facilities that have higher CO_2 emissions to be able to negotiate PPA's for up to a five-year period or sell power to entities not subject to SB 1368.

In addition to the regional initiatives, legislation for the regulation of greenhouse gases has been introduced at the federal level and if passed, may eventually override the regional efforts with a national cap and trade program. Federal bills to create both a cap-and-trade allowance system and a renewable/efficiency portfolio standard have been introduced in both the house and senate. Separately, the U.S. Environmental Protection Agency has taken several recent actions to regulate greenhouse gas emissions.

The Environmental Protection Agency's recent actions include its finding of "endangerment" to public health and welfare from greenhouse gases, its issuance in September 2009 of the Final Mandatory Reporting of Greenhouse Gases Rule which requires large sources, including power plants, to monitor and report greenhouse gas emissions to the Environmental Protection Agency annually starting in 2011, and its publication in May 2010 of its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, to take effect in 2011, which requires large industrial facilities, including power plants, to obtain permits to emit, and to use best available control technology to curb emissions of, greenhouse gases.

In addition, the United States is actively participating in various international initiatives to reduce greenhouse gas emissions globally that may result in further regulatory developments in the United States.

The implementation of existing CO_2 and other greenhouse gas regulations, the introduction of new regulation, or other future regulatory developments may subject the Company to increased compliance obligations and costs that could have a material adverse impact on our business, operations or financial condition.

The projects are exposed to risks inherent in the use of derivative instruments

We and the projects may use derivative instruments, including futures, forwards, options and swaps, to manage commodity and financial market risks. In the future, the project operators could recognize financial losses on these arrangements as a result of volatility in the market values of the underlying commodities or if a counterparty fails to perform under a contract. If actively quoted market prices and pricing information from external sources are not available, the valuation of these contracts would involve judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

Most of these contracts are recorded at fair value with changes in fair value recorded currently in earnings, resulting in significant volatility in our income (as calculated in accordance with GAAP) that does not significantly affect current period cash flows or the underlying risk management purpose of the derivative instruments. As a result, we may be unable to accurately predict the impact that our risk management decisions may have on our quarterly and annual income (as calculated in accordance with GAAP).

If the values of these financial contracts change in a manner that we do not anticipate, or if a counterparty fails to perform under a contract, it could harm our financial condition, results of operations and cash flows. We have executed natural gas swaps to reduce our risks to changes in the market price of natural gas, which is the fuel consumed at many of our projects. Due to declining natural gas prices, we have incurred losses on these natural gas swaps. We execute these swaps only for the purpose of managing risks and not for speculative trading.

Our prior and current structure may be subject to additional U.S. federal income tax liability

Under our prior IPS structure, we treated the subordinated notes as debt for U.S. federal income tax purposes. Accordingly, we deducted the interest payments on the subordinated notes and reduced our net taxable income treated as "effectively connected income" for U.S. federal income tax purposes. Under our current structure, our subsidiaries that are incorporated in the United States are subject to U.S. federal income tax on their income at regular corporate rates (currently as high as 35%, plus state and local taxes), and our U.S. holding company will claim interest deductions with respect to the Intercompany Note in computing its income for U.S. federal income tax purposes. To the extent this interest expense is disallowed or is otherwise not deductible, the U.S. federal income tax liability of our U.S. holding company will increase, which could materially affect the after-tax cash available to distribute to us. While we received advice from our U.S. tax counsel, based on certain representations by us and our U.S. holding company and determinations made by our independent advisors, as applicable, that the subordinated notes and the Intercompany Note should be treated as debt for U.S. federal income tax purposes, it is possible that the Internal Revenue Service ("IRS") could successfully challenge those positions and assert that subordinated notes or the Intercompany Note should be treated as equity rather than debt for U.S. federal income tax purposes. In this case, the otherwise deductible interest on the subordinated notes or the Intercompany Note would be treated as non-deductible distributions and, in the case of the Intercompany Note, would be subject to U.S. withholding tax to the extent our U.S. holding company had current or accumulated earnings and profits. The determination of whether the subordinated notes and the U.S. holding company's indebtedness to us is debt or equity for U.S. federal income tax purposes is based on an analysis of the facts and circumstances. There is no clear statutory definition of debt for U.S. federal income tax purposes, and its characterization is governed by principles developed in case law, which analyzes numerous factors that are intended to identify the nature of the purported creditor's interest in the borrower. Furthermore, not all courts have applied this analysis in the same manner, and some courts have placed more emphasis on certain factors than other courts have. To the extent it were ultimately determined that our interest expenses on either the subordinated notes or the Intercompany Note were disallowed, our U.S. federal income tax liability for the applicable open tax years would materially increase, which could materially affect the after-tax cash available to us to distribute. Alternatively, the IRS could argue that the interest on the subordinated notes or the Intercompany Note exceeded or exceeds an arm's length rate, in which case only the portion of the interest expense that does not exceed an arm's length rate may be deductible and, in the case of the Intercompany Note, the remainder would be subject to U.S. withholding tax to the extent our U.S. holding company had current or accumulated earnings and profits. We have received advice from independent advisors that the interest rate on the subordinated notes and the Intercompany Note was and is, as applicable, commercially reasonable in the circumstances, but the advice is not binding on the IRS.

Furthermore, our U.S. holding company's deductions attributable to the interest expense on the Intercompany Note may be limited by the amount by which its net interest expense (the interest paid by our U.S. holding company on all debt, including the Intercompany Note, less its interest income) exceeds 50% of its adjusted taxable income (generally, U.S. federal taxable income before net interest expense, net operating loss carryovers, depreciation and amortization). Any disallowed interest expense may currently be carried forward to future years. Moreover, proposed legislation has been introduced, though not enacted, several times in recent years that would further limit the 50% of adjusted taxable income cap described above to 25% of adjusted taxable income, although recent proposals in the Fiscal Year Budget for 2010 would only apply the revised rules to certain foreign corporations that were expatriated. Furthermore, if our U.S. holding company does not make regular interest payments as required under the Intercompany Note, other limitations on the deductibility of interest under U.S. federal income tax laws could apply to defer and/or eliminate all or a portion of the interest deduction that our U.S. holding company would otherwise be entitled to with respect to the Intercompany Note.

Passive foreign investment company treatment

We do not believe that we are a passive foreign investment company, and we do not expect to become a passive foreign investment company. However, if we were a passive foreign investment company while a taxable U.S. holder held common shares, such U.S. holder could be subject to an interest charge on any deferred taxation and the treatment of gain upon the sale of our stock as ordinary income.

Market conditions and other factors may affect the value of our common shares

The trading price of our common shares will depend on many factors, which may change from time to time, including:

- conditions in the power generation markets and the energy markets generally;
- interest rates;
- the market for similar securities;
- government action or regulation;
- general economic conditions or conditions in the financial markets;
- our past and future dividend practice; and
- our financial condition, performance, creditworthiness and prospects.

Accordingly, the common shares may trade at a price lower than that at which they were purchased.

The market price and trading volume of our common shares may be volatile

The market price of our common shares may be volatile, particularly given the current economic environment. In addition, the trading volume in our common shares may fluctuate and cause significant price variations to occur. If the market price of our common shares declines significantly, you may be unable to resell your shares at or above the public offering price. The market price of our common shares may fluctuate or decline significantly in the future.

Table of Contents

Some of the factors that could negatively affect our share price or result in fluctuations in the price or trading volume of our common shares include:

- quarterly variations in our operating results or the quality of our assets;
- changes in applicable regulations or government action;
- operating results that vary from the expectations of management, securities analysts and investors;
- changes in expectations as to our future financial performance;
- announcements of innovations, new products, strategic developments, significant contracts, acquisitions and other material events by us or our competitors;
- changes in financial estimates or publication of research reports and recommendations by financial analysts or actions taken by rating agencies with respect to us or other companies in our industry;
- the operating and securities price performance of other companies that investors believe are comparable to us;
- changes in general market conditions, such as interest or foreign exchange rates, stock or commodity valuations, or volatility; and
- actions by our current shareholders, including sales of our common shares by existing shareholders and/or directors and executive officers.

Stock markets in general have experienced significant volatility over the past two years, and continue to experience significant price and volume volatility. As a result, the market price of our common shares may continue to be subject to similar market fluctuations that may be unrelated to our operating performance or prospects. Increased volatility could result in a decline in the market price of our common shares.

Present and future offerings of debt or equity securities, ranking senior to our common shares, may adversely affect the market price of our common shares

If we decide to issue debt or equity securities ranking senior to our common shares in the future it is likely that they will be governed by an indenture or other instrument containing covenants restricting our operating flexibility. Additionally, any convertible or exchangeable securities that we issue in the future may have rights, preferences and privileges more favorable than those of holders of our common shares and may result in dilution to holders of our common shares. We and, indirectly, our shareholders, will bear the cost of issuing and servicing such securities. Because our decision to issue debt or equity securities in any future offering will depend on market conditions and other factors beyond our control, we cannot predict or estimate the amount, timing or nature of our future offerings. Thus, holders of our common shares will bear the risk of our future offerings reducing the market price of our common shares and diluting the value of their share holdings in us.

The number of shares available for future sale could adversely affect the market price of our common shares

We cannot predict whether future issuances of our common shares or the availability of shares for resale in the open market will decrease the market price per common share. We may issue additional common shares, including securities that are convertible into or exchangeable for, or that represent the right to receive common shares. Sales of a substantial number of common shares in the public market or the perception that such sales might occur could materially adversely affect the market price of our common shares. Because our decision to issue securities in any future offering will depend on market

Table of Contents

conditions and other factors beyond our control, we cannot predict or estimate the amount, timing or nature of our future offerings. Thus, our shareholders bear the risk of our future offerings reducing the market price of our common shares and diluting their share holdings in us.

The the exercise of any options granted to directors, executive officers and other employees under our stock compensation plans, and other issuances of our common shares could have an adverse effect on the market price of our common shares, and the existence of options may materially adversely affect the terms upon which we may be able to obtain additional capital through the sale of equity securities. In addition, future sales of our common shares may be dilutive to existing shareholders.

The redemption of our outstanding debentures for or repayment of principal by issuing common shares may cause common shareholders dilution

We may determine to redeem outstanding debentures for common shares or to repay outstanding principal amounts thereunder at maturity of the debentures by issuing additional common shares. The issuance of additional common shares may have a dilutive effect on shareholders and an adverse impact on the price of our common shares.

Provisions of our articles of continuance could discourage potential acquisition proposals and could deter or prevent a change in control

We are governed by the Business Corporations Act (British Columbia). Our articles of continuance contain provisions that could have the effect of delaying, deferring or discouraging another party from acquiring control of our company by means of a tender offer, a proxy contest or otherwise. These provisions may make it more difficult for other persons, without the approval of our board of directors, to make a tender offer or otherwise acquire a substantial number of our common shares or to launch other takeover attempts that a shareholder might consider to be in his or her best interest. These provisions could limit the price that some investors might be willing to pay in the future for our common shares.

ITEM 6. EXHIBITS.

Exhibit Number	Description
31.1	Certification of Chief Executive Officer uprsuant 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

Table of Contents

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 10, 2010	Atlantic Power Corporation
	By: /s/ PATRICK J. WELCH
	Name: Patrick J. Welch
	Title: *Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*

Table of Contents

EXHIBIT INDEX

Exhibit Number	Description
31.1	Certification of Chief Executive Officer uprsuant 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