ATLANTIC POWER CORP
Form 10-Q
May 11, 2011

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended March 31, 2011

OR

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

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

ATLANTIC POWER CORPORATION

(Exact name of registrant as specified in its charter)

British Columbia, Canada	**55-0886410**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
200 Clarendon Street, Floor 25 Boston, MA	**02116**
(Address of principal executive offices)	(Zip code)

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes 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 May 10, 2011 was 68,531,901.

ATLANTIC POWER CORPORATION

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THREE MONTHS ENDED MARCH 31, 2011

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GENERAL

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

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

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PART I FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(In thousands of U.S. dollars)

	March 31, 2011 (unaudited)	December 31, 2010
Assets		
Current assets:		
Cash and cash equivalents	$ 28,258	$ 45,497
Restricted cash	23,268	15,744
Accounts receivable	19,781	19,362
Note receivable related party (Note 14)	17,671	22,781
Current portion of derivative instruments asset (Notes 8 and 9)	9,340	8,865
Prepayments, supplies, and other	8,583	8,480
Refundable income taxes	2,079	1,593
Total current assets	108,980	122,322
Property, plant, and equipment, net	284,018	271,830
Transmission system rights	186,171	188,134
Equity investments in unconsolidated affiliates (Note 4)	294,231	294,805
Other intangible assets, net	82,933	88,462
Goodwill	12,453	12,453
Derivative instruments asset (Notes 8 and 9)	22,461	17,884
Other assets	16,554	17,122
Total assets	$ 1,007,801	$ 1,013,012
Liabilities		
Current Liabilities:		
Accounts payable and accrued liabilities	$ 22,857	$ 20,530
Current portion of long-term debt (Note 6)	24,394	21,587
Current portion of derivative instruments liability (Notes 8 and 9)	8,940	10,009
Interest payable on convertible debentures (Note 7)	3,759	3,078
Dividends payable	6,430	6,154
Other current liabilities	124	5
Total current liabilities	66,504	61,363
Long-term debt (Note 6)	240,692	244,299
Convertible debentures (Note 7)	210,005	220,616
Derivative instruments liability (Notes 8 and 9)	20,214	21,543
Deferred income taxes	31,632	29,439
Other non-current liabilities	1,949	2,376
Commitments and contingencies (Note 15)		

Equity		
Common shares, no par value, unlimited authorized shares; 68,530,369 and 67,118,154 issued and outstanding at March 31, 2011 and December 31, 2010, respectively	642,453	626,108
Accumulated other comprehensive loss (Note 9)	527	255
Retained deficit	(209,528)	(196,494)
Total Atlantic Power Corporation shareholders' equity	433,452	429,869
Noncontrolling interest	3,353	3,507
Total equity	436,805	433,376
Total liabilities and equity	$ 1,007,801	$ 1,013,012

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

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

(Unaudited)

	Three months ended March 31, 2011	Three months ended March 31, 2010
Project revenue:		
Energy sales	$ 18,502	$ 15,913
Energy capacity revenue	27,138	23,194
Transmission services	7,644	7,644
Other	381	470
	53,665	47,221
Project expenses:		
Fuel	17,068	16,157
Operations and maintenance	8,833	5,041
Project operator fees and expenses	2,239	919
Depreciation and amortization	10,879	10,071
	39,019	32,188
Project other income (expense):		
Change in fair value of derivative instruments (Notes 8 and 9)	3,561	(12,194)
Equity in earnings of unconsolidated affiliates (Note 4)	1,311	5,436
Interest expense, net	(4,647)	(4,411)
Other expense, net	(2)	
	223	(11,169)
Project income	14,869	3,864
Administrative and other expenses (income):		
Administration	4,054	4,100
Interest expense, net	3,968	2,794
Foreign exchange gain (Note 9)	(658)	(1,792)
	7,364	5,102
Income (loss) from operations before income taxes	7,505	(1,238)
Income tax expense	1,523	4,873
Net income (loss)	5,982	(6,111)
Net loss attributable to noncontrolling interest	(154)	(48)
Net income (loss) attributable to Atlantic Power Corporation	$ 6,136	$ (6,063)
Net income (loss) per share attributable to Atlantic Power Corporation shareholders: (Note 12)		
Basic	$ 0.09	$ (0.10)
Diluted	$ 0.09	$ (0.10)

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(In thousands of U.S. dollars)

(Unaudited)

	Three months ended March 31, 2011	Three months ended March 31, 2010
Cash flows from operating activities:		
Net income (loss)	$ 5,982	$ (6,111)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	10,879	10,071
Long-term incentive plan expense	825	1,420
Equity in earnings from unconsolidated affiliates	(1,311)	(5,436)
Distributions from unconsolidated affiliates	1,450	1,334
Unrealized foreign exchange loss (gain)	1,878	(623)
Change in fair value of derivative instruments	(3,561)	12,194
Change in deferred income taxes	2,011	4,829
Change in other operating balances		
Accounts receivable	(419)	350
Prepayments, refundable income taxes and other assets	176	(372)
Accounts payable and accrued liabilities	1,937	1,276
Other liabilities	500	1,907
Net cash provided by operating activities	20,347	20,839
Cash flows (used in) provided by investing activities:		
Acquisitions and investments, net of cash acquired		324
Change in restricted cash	(7,524)	(7,526)
Proceeds from related party loan repayment	5,110	
Biomass development costs	(308)	(317)
Purchase of property, plant and equipment	(15,393)	(319)
Net cash used in investing activities	(18,115)	(7,838)
Cash flows (used in) provided by financing activities:		
Repayment of project-level debt	(3,400)	(2,700)
Proceeds from project-level borrowings	2,781	
Dividends paid	(18,852)	(15,795)
Net cash used in financing activities	(19,471)	(18,495)
Net decrease in cash and cash equivalents	(17,239)	(5,494)
Cash and cash equivalents at beginning of period	45,497	49,850
Cash and cash equivalents at end of period	$ 28,258	$ 44,356
Supplemental cash flow information		
Interest paid	$ 4,659	$ 1,450
Income taxes paid (refunded), net	$ 14	$ (26)

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Basis of presentation and summary of significant accounting policies

Overview

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

The interim consolidated financial statements have been prepared in accordance with the Securities and Exchange Commission ("SEC") regulations for interim financial information and with the instructions to Form 10-Q. The following notes should be read in conjunction with the accounting policies and other disclosures as set forth in the notes to our financial statements in our Annual Report on Form 10-K for the year ended December 31, 2010. Interim results are not necessarily indicative of results for the full year.

In our opinion, the accompanying unaudited interim consolidated financial statements contain all material adjustments consisting of normal and recurring accruals necessary to present fairly our consolidated financial position as of March 31, 2011, the results of operations for the three month periods ended March 31, 2011 and 2010, and our cash flows for the three month periods ended March 31, 2011 and 2010.

Use of estimates:

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Reclassifications:

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

Recently issued accounting standards:

Adopted

In December 2010, the FASB issued changes to the disclosure of pro forma information for business combinations. These changes clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Also, the existing supplemental pro forma disclosures were expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. We adopted these changes beginning January 1, 2011. Upon adoption, we determined these changes did not impact the consolidated financial statements.

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

In 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. We adopted these changes beginning January 1, 2011. We determined that the adoption of these changes did not impact the consolidated financial statements, as our projects do not currently have any such arrangements with their customers.

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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

2. Comprehensive income (loss)

The following table summarizes the components of comprehensive income (loss), net of tax of $480 and ($11), respectively, for the three months ended March 31, 2011 and 2010:

	Three months ended March 31,	
	2011	**2010**
Net income (loss)	$ 5,982	$ (6,111)
Unrealized gain (loss) on hedging activity	721	(16)
Comprehensive income (loss)	$ 6,703	$ (6,127)

3. Acquisitions and divestitures

(a) Topsham

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

4. Equity method investments

The following summarizes the operating results for the three months ended March 31, 2011 and 2010, respectively, for our equity earnings interest in our equity method investments:

	Three-months ended March 31,	
	2011	**2010**
Revenue		
Chambers	13,269	15,416
Badger Creek	3,316	3,886
Gregory	7,181	8,866
Orlando	9,926	10,439
Selkirk	10,902	13,479
Other	1,821	664
	46,415	52,750
Project expenses		
Chambers	9,380	10,266
Badger Creek	2,983	3,470
Gregory	6,630	8,224
Orlando	9,463	10,047
Selkirk	12,659	12,828
Other	1,428	590
	42,543	45,425
Project other income (expense)		
Chambers	(427)	(907)
Badger Creek		6
Gregory	(38)	207
Orlando	(30)	(33)
Selkirk	(1,636)	(1,098)
Other	(430)	(64)
	(2,561)	(1,889)
Project income (loss)		
Chambers	3,462	4,243
Badger Creek	333	422
Gregory	513	849
Orlando	433	359
Selkirk	(3,393)	(447)
Other	(37)	10
	1,311	5,436

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

5. Accumulated depreciation and amortization

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

	March 31, 2011	December 31, 2010
Property, plant and equipment	$ 95,067	$ 91,851
Transmission system rights	45,498	43,535
Other intangible assets	62,730	57,000

6. Long-term debt

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

	March 31, 2011	December 31, 2010
Project debt, interest rates ranging from 5.1% to 9.0% maturing through 2028	$ 253,962	$ 254,581
Purchase accounting fair value adjustments	11,124	11,305
Less: current portion of long-term debt	(24,394)	(21,587)
Long-term debt	$ 240,692	$ 244,299

Project-level debt is secured by the respective project and its contracts with no other recourse to us. The loans have certain financial covenants that must be met. At March 31, 2011, all of our projects were in compliance with the covenants contained in project-level debt. However, the holding company for our investment in the Chambers project, Epsilon Power Partners, as well as the Selkirk and Delta-Person projects had not achieved the levels of debt service coverage ratios required by the project-level debt arrangements as a condition to make distributions and were therefore restricted from making distributions to us.

As of March 31, 2011 the inception to date balance on the Piedmont construction debt funded by the bridge loan was $2.8 million.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

7. Convertible debentures

The following table contains details related to outstanding convertible debentures during the three month period ended March 31, 2011:

	6.5% Debentures due 2014	6.25% Debentures due 2017	5.6% Debentures due 2017
Balance at December 31, 2010 (Cdn$)	55,801	83,124	80,500
Principal amount converted (Cdn$)	(7,685)	(8,119)	
Balance at March 31, 2011 (Cdn$)	48,116	75,005	80,500
Balance at March 31, 2011 (US$)	49,625	77,357	83,023
Common shares issued on conversion	619,752	624,535	

Aggregate interest expense related to the convertible debentures was $3.4 million and $2.3 million for the three-month periods ended March 31, 2011 and 2010, respectively.

8. Fair value of financial instruments

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

	March 31, 2011			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 28,258	$	$	$ 28,258
Restricted cash	23,268			23,268
Derivative instruments asset		31,801		31,801
Total	$ 51,526	$ 31,801	$	$ 83,327
Liabilities:				
Derivative instruments liability	$	$ 29,154	$	$ 29,154
Total	$	$ 29,154	$	$ 29,154

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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

8. Fair value of financial instruments (Continued)

The fair value of our derivative instruments are based on price quotes from brokers in active markets who regularly facilitate those transactions and we believe such price quotes are executable. 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 March 31, 2011, the credit reserve resulted in a $0.1 million net increase in fair value, which is comprised of a $0.3 million pre-tax gain in other comprehensive income offset by a $0.1 million loss in change in fair value of derivative instruments and a $0.1 million loss in foreign exchange. As of December 31, 2010, the credit reserve resulted in a $0.6 million net increase in fair value, which is comprised of a $0.2 million pre-tax gain in other comprehensive income and a $0.5 million gain in change in fair value of derivative instruments offset by a $0.1 million loss in foreign exchange.

9. Accounting for derivative instruments and hedging activities

Fair value of derivative instruments

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

	March 31, 2011	
	Derivative Assets	**Derivative Liabilities**
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 2,107
Interest rate swaps long-term		2,041
Total derivative instruments designated as cash flow hedges		4,148
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		2,253
Interest rate swaps long-term	4,708	1,765
Foreign currency forward contracts current	9,340	
Foreign currency forward contracts long-term	17,545	
Natural gas swaps current		4,580
Natural gas swaps long-term	208	16,408
Total derivative instruments not designated as cash flow hedges	31,801	25,006
Total derivative instruments	$ 31,801	$ 29,154

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

	December 31, 2010	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 2,124
Interest rate swaps long-term		2,626
Total derivative instruments designated as cash flow hedges		4,750
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		1,286
Interest rate swaps long-term	3,299	2,000
Foreign currency forward contracts current	8,865	
Foreign currency forward contracts long-term	14,585	
Natural gas swaps current		6,599
Natural gas swaps long-term		16,917
Total derivative instruments not designated as cash flow hedges	26,749	26,802
Total derivative instruments	$ 26,749	$ 31,552

Natural gas swaps

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

In October 2010, we entered into natural gas swaps that are effective in 2014 and 2015. The natural gas swaps are related to our 50% share of expected fuel purchases at our 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 represent approximately 25% of our share of the expected natural gas purchases at the project during 2014 and 2015. These swap agreements were entered into by Atlantic Power Corporation and not at the project level. Orlando is accounted for under the equity method of accounting.

Our strategy to mitigate the future exposure to changes in natural gas prices at Lake, Auburndale and Orlando 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.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 agreement effectively converted the floating rate debt to a fixed interest rate of 3.12%. The notional amount of the swap matches the outstanding principal balance over the remaining life of Auburndale's debt. The interest rate swap was executed in November 2009 and expires on November 30, 2013.

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate at 5.90% from February 20, 2008 to February 15, 2011, 6.02% from February 16, 2011 to February 15, 2015, 6.14% from February 16, 2015 to February 15, 2019, 6.26% from February 16, 2019 to February 15, 2023, and 6.38% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies and is designated as a cash flow hedge, is effective through June 2025.

We executed two interest rate swaps at our consolidated Piedmont project to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreements are not designated as hedges and changes in their fair market value are recorded in the consolidated statements of operations. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.75% from March 31, 2011 to February 29, 2016. From February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.47%. The swap continues at the fixed rate of 4.47% from the maturity of the debt in November 2017 until November 2030. The notional amounts of the interest rate swap agreements match the estimated outstanding principal balance of Piedmont's cash grant bridge loan and the construction loan facility which will convert to a term loan. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively.

Impact of derivative instruments on the consolidated income statements

Unrealized gains (losses) on interest rate swaps designated as cash flow hedges have been recorded in shareholders' equity as a gain in other comprehensive income of $1.2 million and $0.2 million for the three-month periods ended March 31, 2011 and 2010, respectively. Realized losses on these interest rate swaps of $0.6 million and $0.2 million were recorded in interest expense, net for the three-month periods ended March 31, 2011 and 2010, respectively.

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, prior to July 1, 2009 when hedge accounting for these natural gas swaps was discontinued prospectively. Amortization of the gain (loss) of $0.1 million and $(0.4) million, was recorded in change in fair value of derivative instruments for the three-month periods ended March 31, 2011 and 2010, respectively.

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.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

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 March 31, 2011	Three months ended March 31, 2010
Natural gas swaps	Fuel	$ 2,476	$ 1,818
Foreign currency forwards	Foreign exchange gain	(2,537)	(1,169)
Interest rate swaps	Interest, net	976	475

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 gains and (losses) resulting from changes in the fair value of derivative financial instruments that are not designated as cash flow hedges:

	Three months ended March 31, 2011	Three months ended March 31, 2010
Change in fair value of derivative instruments:		
Interest rate swaps	$ 678	$ (46)
Natural gas swaps	2,883	(12,148)
	$ 3,561	$ (12,194)

Volume of forecasted transactions

We entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the normal purchases and normal sales exception as of March 31, 2011:

	Units	March 31, 2011
Interest rate swaps	Interest (US$)	$ 63,732
Currency forwards	Dollars (Cdn$)	$ 201,800
Natural gas swaps	Natural Gas (Mmbtu)	14,580

Foreign currency forward contracts

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as we generate cash flow in U.S. dollars but pay dividends to shareholders and interest on convertible debentures predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge approximately 86% of our expected dividend and convertible debenture interest payments through 2013. Changes in the fair value of the forward contracts partially offset foreign exchange gain or losses on the U.S. dollar equivalent of our Canadian dollar obligations. The forward contracts consist of (1) monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

Cdn$1.134 per U.S. dollar and (2) purchases in both April and October 2011 of Cdn$1.9 million at an exchange rate of Cdn$1.1075 per U.S. dollar.

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

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 is $26.9 million and $23.4 million at March 31, 2011 and December 31, 2010, respectively. 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-month periods ended March 31, 2011 and 2010:

	Three months ended March 31, 2011	Three months ended March 31, 2010
Unrealized foreign exchange (gain) loss:		
Convertible debentures	$ 5,314	$ (541)
Forward contracts and other	(3,436)	(82)
	1,878	(623)
Realized foreign exchange gains on forward contract settlements	(2,536)	(1,169)
	$ (658)	$ (1,792)

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 March 31, 2011:

Convertible debentures, at carrying value	$ 21,001
Foreign currency forward contracts	$ (22,539)

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

For the three month period ended March 31, 2011	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at December 31, 2010	$ (427)	$ 682	$ 255
Change in fair value of cash flow hedges	721		721
Realized from OCI during the period	(360)	(89)	(449)
Accumulated OCI balance at March 31, 2011	$ (66)	$ 593	$ 527

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

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

For the three month period ended March 31, 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	116		116
Realized from OCI during the period	(132)	248	116
Accumulated OCI balance at March 31, 2010	$ (554)	$ (73)	$ (627)

10. Income taxes

The difference between the actual tax expense of $1.5 million for the three months ended March 31, 2011 and the expected income tax expense, based on a the Canadian enacted statutory rate of 26.5%, of $2.0 million is primarily due to an increase in the valuation allowance and various other permanent differences.

	Three months ended March 31, 2011	Three months ended March 31, 2010
Current income tax expense (benefit)	$ (488)	$ 44
Deferred tax expense (benefit)	2,011	4,829
Total income tax expense (benefit)	$ 1,523	$ 4,873

Valuation Allowance

As of March 31, 2011, we have recorded a valuation allowance of $79.1 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 three months ended March 31, 2011:

	Units	Grant Date Weighted-Average Fair Value per Unit
Outstanding at December 31, 2010	600,981	$ 10.28
Granted	153,094	$ 15.00
Additional shares from dividends	11,226	$ 10.19
Vested	(263,523)	$ 9.40
Outstanding at March 31, 2011	501,778	$ 11.97

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

11. Long-Term Incentive Plan (Continued)

Certain awards have a market condition based on our total shareholder return during the performance period compared to a group of peer companies. See further details as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2010.

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

	Three months ended March 31, 2011
Weighted average risk free rate of return	0.80%
Dividend yield	7.5%
Expected volatility Company	25.0%
Expected volatility peer companies	15.0 85.0%
Weighted average remaining measurement period	1.19 years

12. Basic and diluted earnings (loss) per share

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include shares that would be issued if all of the convertible debentures were converted into shares at January 1, 2011. Dilutive potential shares also include the weighted average number of 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 months ended March 31, 2010, diluted earnings per share are equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive.

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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 (loss) and potentially dilutive shares utilized in the per share calculation for the three-month periods ended March 31, 2011 and 2010:

	Three months ended March 31, 2011	Three months ended March 31, 2010
Numerator:		
Net income (loss) attributable to Atlantic Power Corporation	$ 6,136	$ (6,063)
Add: interest expense for potentially dilutive convertible debentures, net[1]		
Diluted net income (loss) attributable to Atlantic Power Corporation	$ 6,136	$ (6,063)

(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 March 31, 2011	Three months ended March 31, 2010
Denominator:		
Basic shares outstanding	67,654	60,404
Dilutive potential shares:		
Convertible debentures	14,809	11,473
LTIP notional units	517	394
Potentially dilutive shares	82,980	72,271
Diluted EPS	$ 0.09	$ (0.10)

Potentially dilutive shares from convertible debentures have been excluded from fully diluted shares in the three-month period ended March 31, 2011 because its impact would be anti-dilutive.

Potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units have been excluded from fully diluted shares in the three-month period ended March 31, 2010 because its impact would be anti-dilutive.

13. Segment and related information

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

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 Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

13. Segment and related information (Continued)

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 March 31, 2011:								
Operating revenues	$ 7,644	$ 21,782	$ 17,124	$ 2,520	$ 0	$ 4,595	$ 0	$ 53,665
Segment assets	215,019	102,926	108,409	37,991	145,450	338,068	59,938	1,007,801
Project Adjusted EBITDA	$ 6,570	$ 10,313	$ 8,490	$ (1,077)	$ 4,724	$ 6,973	$ 0	$ 35,993
Change in fair value of derivative instruments		(961)	(1,565)		(752)	494		(2,784)
Depreciation and amortization	1,973	4,959	2,290	757	836	6,622		17,437
Interest, net	2,992	313	(3)		1,386	1,552		6,240
Other project (income) expense					200	31		231
Project income	1,605	6,002	7,768	(1,834)	3,054	(1,726)		14,869
Interest, net							3,968	3,968
Administration							4,054	4,054
Foreign exchange gain							(658)	(658)
Other expense, net								
Income (loss) from operations before income taxes	1,605	6,002	7,768	(1,834)	3,054	(1,726)	(7,364)	7,505
Income tax expense (benefit)							1,523	1,523
Net income (loss)	$ 1,605	$ 6,002	$ 7,768	$ (1,834)	$ 3,054	$ (1,726)	$ (8,887)	$ 5,982

	Path 15	Auburndale	Lake	Pasco	Chambers	Other Project Assets	Un-allocated Corporate	Consolidated
Three month period ended March 31, 2010:								
Operating revenues	$ 7,644	$ 20,467	$ 16,241	$ 2,869	$	$	$	$ 47,221
Segment assets	223,467	126,191	118,320	41,693	142,216	7,131	217,659	876,677
Project Adjusted EBITDA	$ 7,053	$ 9,371	$ 7,313	$ 1,415	$ 5,988	$ 7,655	$	$ 38,795
Change in fair value of derivative instruments		4,212	7,935		(173)	546		12,520
Depreciation and amortization	2,099	4,948	2,269	746	837	5,487		16,386
Interest, net	3,146	471	(2)		1,676	487		5,778
Other project (income) expense					199	48		247
Project income	1,808	(260)	(2,889)	669	3,449	1,087		3,864
Interest, net							2,794	2,794
Administration							4,100	4,100
Foreign exchange gain							(1,792)	(1,792)
Other income, net								
Loss from operations before income taxes	1,808	(260)	(2,889)	669	3,449	1,087	(5,102)	(1,238)
Income tax expense (benefit)							4,873	4,873
Net loss	$ 1,808	$ (260)	$ (2,889)	$ 669	$ 3,449	$ 1,087	$ (9,975)	$ (6,111)

Progress Energy Florida and the California Independent System Operator ("CAISO") provide for 71.7% and 14.2%, respectively, of total consolidated revenues for the three months ended March 31, 2011 and 77.0% and 16.2% for the three months ended March 31, 2010. Progress Energy Florida purchases electricity from Auburndale and Lake, and the CAISO makes payments to Path 15.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

14. Related party transactions

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

During 2010, we made a short-term $22.8 million loan to Idaho Wind to provide temporary funding for construction of the project until a portion of the project-level construction financing is completed. Member loans will be paid down with a combination of excess proceeds from the federal stimulus grant after repaying the cash grant facility, funds from a third closing for additional debt and project cash flow. The federal stimulus grant is expected in June of 2011 and a third closing is expected by the end of the year. The outstanding loans bear interest at a prime rate plus 10% (13.25% as December 31, 2010). During the three-months ended March 31, 2011, we received $0.5 million in interest payments related to the member loans. As of May 10, 2011, $5.1 million of the loan has been repaid.

Prior to December 31, 2009, Atlantic Power was managed by Atlantic Power Management, LLC (the "Manager"), which was owned by two private equity funds managed by ArcLight. On December 31, 2009, we terminated our management agreements with the Manager and have agreed to pay the ArcLight funds an aggregate of $15 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. The remaining liability associated with the termination fee is recorded at its estimated fair value of $3.7 million at March 31, 2011. The contract termination liability is being accreted to the final amounts due over the term of these payments.

15. Commitments and contingencies

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

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 March 31, 2011 which are expected to have a material adverse impact on our financial position or results of operations.

16. Subsequent events

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

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

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

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

Such forward-looking statements reflect our current expectations regarding future events and operating performance and speak only as of the date of this Quarterly Report on Form 10-Q. Such forward-looking statements are based on a number of assumptions which may prove to be incorrect, including, but not limited to the assumption that the projects will operate and perform in accordance with our expectations. Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. A number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors discussed under "Risk Factors" included in the filings we make from time to time with the SEC. Our business is both competitive and subject to various risks.

These risks include, without limitation:

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

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

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capacity and energy prices or cash flows that are based on assumptions about future economic conditions and courses of action. Although the forward-looking statements contained in this Quarterly Report on Form 10-Q are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. Certain statements included in this Quarterly Report on Form 10-Q may be considered "financial outlook" for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this Quarterly Report on Form 10-Q.

These forward-looking statements are made as of the date of this Form 10-Q, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

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

The following discussion of the financial condition and results of operations of Atlantic Power Corporation should be read in conjunction with the interim consolidated financial statements and the related notes thereto included elsewhere in this Quarterly Report on Form 10-Q.

OVERVIEW

Atlantic Power Corporation owns and operates a diverse fleet of power generation and infrastructure assets in the United States. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements, which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 1,948 MW in which our ownership interest is approximately 871 MW. Our current portfolio consists of interests in 12 operational power generation projects across nine states, one biomass project under construction in Georgia, and a 500 kilovolt 84-mile electric transmission line located in California. Atlantic Power also owns a majority interest in Rollcast Energy, a biomass power plant developer with several projects under development.We sell the capacity and energy from our power generation projects under power purchase agreements (or "PPAs") with a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2011 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 many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is not a pass-through of fuel costs, we use a financial hedging strategy designed to mitigate the market price risk of fuel purchases.

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

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

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As of May 10, 2011, we had 68,531,901 common shares, Cdn$48.1 million ($50.4 million) principal amount of 6.50% convertible secured debentures due October 31, 2014 (the "2006 Debentures"), Cdn$75.0 million ($78.6 million) principal amount of 6.25% convertible debentures due March 15, 2017 (the "2009 Debentures"), and Cdn$80.5 million ($84.4 million) principal amount of 5.60% convertible debentures due June 30, 2017 (the "2010 Debentures" and together with the 2006 and 2009 Debentures, the "Debentures") outstanding. The 2006 Debentures, 2009 Debentures and 2010 Debentures are convertible at any time, at the option of the holder, into 80.645, 76.923 and 55.249, respectively, common shares per Cdn$1,000 principal amount of Debentures, representing a conversion price of Cdn$12.40, Cdn$13.00 and Cdn$18.10, respectively, per common share. Holders of common shares currently receive a monthly dividend at a current annual rate of Cdn$1.094 per common share.

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OUR POWER PROJECTS

The following table outlines our portfolio of power generating and transmission assets in operation and under construction as of May 10, 2011, including our interest in each facility. Management believes the portfolio is well diversified in terms of electricity and steam buyers, fuel type, regulatory jurisdictions and regional power pools, thereby partially mitigating exposure to market, regulatory or environmental conditions specific to any single region.

Project Name	Location (State)	Type	Total MW	Economic Interest[(1)]	Net MW[(2)]	Electricity Purchaser	Power Contract Expiry	Customer S&P Credit Rating
Auburndale	Florida	Natural Gas	155	100.00%	155	Progress Energy Florida	2013	BBB+
Lake	Florida	Natural Gas	121	100.00%	121	Progress Energy Florida	2013	BBB+
Pasco	Florida	Natural Gas	121	100.00%	121	Tampa Electric Co.	2018	BBB
Chambers	New Jersey	Coal	262	40.00%	89	ACE[(3)]	2024	BBB+
					16	DuPont	2024	A
Path 15	California	Transmission	N/A	100.00%	N/A	California Utilities via CAISO[(4)]	N/A[(5)]	BBB+ to A[(6)]
Orlando	Florida	Natural Gas	129	50.00%	46	Progress Energy Florida	2023	BBB+
					19	Reedy Creek Improvement District	2013[(7)]	A1[(8)]
Selkirk	New York	Natural Gas	345	17.70%[(9)]	15	Merchant	N/A	N/R
					49	Consolidated Edison	2014	A-
Gregory	Texas	Natural Gas	400	17.10%	59	Fortis Energy Marketing and Trading	2013	AA
					9	Sherwin Alumina	2020	NR
Badger Creek	California	Natural Gas	46	50.00%	23	Pacific Gas & Electric	2012[(10)]	BBB+

Koma Kulshan	Washington	Hydro	13	49.80%	6	Puget Sound Energy	2037	BBB
Delta-Person	New Mexico	Natural Gas	132	40.00%	53	PNM	2020	BB-
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	2028	BBB-
Idaho Wind	Idaho	Wind	183	27.56%	50	Idaho Power Co.	2030	BBB
Piedmont(11)	Georgia	Biomass	54	98.00%	53	Georgia Power	2032	A

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

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

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

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

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

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

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

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

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

(10) Entered into a one-year interim agreement in April 2011 while details of a long-term agreement are worked out.

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

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RECENT DEVELOPMENTS

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

Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the three month periods ended March 31, 2011 and 2010. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

(Unaudited) (in thousands of U.S. dollars, except as otherwise stated)	Three months ended March 31, 2011	 2010
Project revenue		
Auburndale	$ 21,782	$ 20,467
Lake	17,124	16,241
Pasco	2,520	2,869
Path 15	7,644	7,644
Chambers		
Other Project Assets	4,595	
	53,665	47,221
Project expenses		
Auburndale	16,428	16,044
Lake	10,924	11,197
Pasco	4,354	2,200
Path 15	3,047	2,690
Chambers	1	
Other Project Assets	4,265	57
	39,019	32,188
Project other income (expense)		
Auburndale	648	(4,683)
Lake	1,568	(7,933)
Pasco		
Path 15	(2,992)	(3,146)
Chambers	3,055	3,449
Other Project Assets	(2,056)	1,144
	223	(11,169)
Total project income		
Auburndale	6,002	(260)
Lake	7,768	(2,889)
Pasco	(1,834)	669
Path 15	1,605	1,808
Chambers	3,054	3,449
Other Project Assets	(1,726)	1,087
	14,869	3,864
Administrative and other expenses		
Administration	4,054	4,100
Interest, net	3,968	2,794
Foreign exchange gain	(658)	(1,792)
Total administrative and other expenses	7,364	5,102
Income (loss) from operations before income taxes	7,505	(1,238)

Income tax expense		1,523		4,873
Net (loss) income		5,982		(6,111)
Net loss attributable to noncontrolling interest		(154)		(48)
Net income (loss) attributable to Atlantic Power Corporation shareholders	$	6,136	$	(6,063)

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Consolidated Overview

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

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

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

Cash available for distribution was $16.6 million and $17.8 million for the three months ended March 31, 2011 and 2010, respectively. See "Cash Available for Distribution" in this Form 10-Q for additional information.

Income (loss) from operations before income taxes for the three months ended March 31, 2011 and 2010, was $7.5 million and $(1.2) million, respectively. See "Project Income" below for additional information.

Three months ended March 31, 2011 compared with three months ended March 31, 2010

Project Income

Auburndale Segment

The increase in project income for our Auburndale segment of $6.3 million to $6.0 million in the three-month period ended March 31, 2011 from a loss of $(0.3) million in the comparable 2010 period is primarily attributable to the $5.2 million change in the benefit associated with the 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 changes in the market prices of natural gas. See Item 3, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments. Project revenue at Auburndale increased by $1.3 million in the three-month period ended March 31, 2011 due to favorable energy pricing compared to 2010, as well as the annual contractual escalation of capacity payments.

Lake Segment

Project income for our Lake segment increased $10.7 million to $7.8 million in the three-month period ended March 31, 2011, from a loss of $(2.9) million in the comparable 2010 period. The increase is primarily attributable to the $9.5 million change in the benefit associated with the 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 changes in the market prices of natural gas. See Item 3, "Quantitative and Qualitative Disclosures About Market Risk", for additional details about our derivative instruments and other financial instruments. Project revenue at Lake increased by $0.9 million in the three-month period ended March 31, 2011 due to the annual contractual escalation of capacity payments and increased energy sales, compared to 2010. In addition, fuel costs were lower due to the lower price on natural gas swaps.

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Pasco Segment

Project income for our Pasco segment decreased $2.5 million to a project loss of $(1.8) million in the three-month period ended March 31, 2011, from project income of $0.7 million in the comparable 2010 period. The decrease is due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine blades.

Path 15 Segment

Project income for our Path 15 segment decreased $0.2 million to $1.6 million in the three-month period ended March 31, 2011 from $1.8 million in the comparable 2010 period due to higher operation and maintenance costs associated with an erosion control initiative.

Chambers Segment

Project income for our Chambers segment, which is recorded under the equity method of accounting, decreased $0.3 million to $3.1 million in the three-month period ended March 31, 2011 from $3.4 million in the comparable 2010 period. The decrease in project income at Chambers is primarily attributable to higher maintenance costs associated with a planned outage in April 2011 and lower dispatch compared to 2010, partially offset by a $0.6 million benefit in the non-cash change in fair value of derivative instruments associated with its interest rate swaps.

Other Project Assets Segment

Project income for our Other Project Assets segment decreased $(2.8) million to a project loss of $(1.7) million for the three-period ended March 31, 2011 compared to project income of $1.1 million in 2010. The decrease was primarily a result of a $(2.9) million decrease in project income from our Selkirk project. This was due to a planned outage lasting longer than expected, resulting in a delay in the receipt of capacity payments until the second quarter. Project income was also reduced slightly due to the sale of the Topsham project which is no longer generating income, offset by project income generated from Cadillac and Idaho Wind.

Administrative and Other Expenses (Income)

Administration includes the costs of operating as a public company. Administration was consistent at $4.1 million for both the three-month periods ended March 31, 2011 and 2010.

Interest expense at the corporate level primarily relates to our convertible debentures. Interest expense, net increased $1.2 million to $4.0 million in the three-month period ended March 31, 2011 from $2.8 million in the comparable 2010 period. This increase is primarily due to the issuance of Cdn$80.5 million of convertible debentures in October of 2010.

Foreign exchange loss (gain) primarily reflects the unrealized impact of changes in foreign exchange rates on the U.S. dollar equivalent of our Canadian dollar-denominated obligations to holders of the convertible debentures. In addition, unrealized and realized gains and losses on our forward contracts for the purchase of Canadian dollars to satisfy these obligations and our dividends to shareholders are included in foreign exchange loss (gain). Unrealized gains and losses on our forward contracts are reclassified to realized gains and losses upon cash settlement of the contracts. Foreign exchange gain decreased $1.1 million to a $0.7 million gain in the three-month period ended 2011 compared to a $1.8 million gain in the comparable 2010 period. The U.S. dollar to Canadian dollar exchange rate increased by 2.6% during the three-month period ended March 31, 2011, compared to an increase of 3.5% in the comparable period in 2010. See Item 3 "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our management of foreign currency risk

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and the components of the foreign exchange gain recognized during the three-month period ended March 31, 2011 compared to the foreign exchange gain in the comparable 2010 period.

Supplementary Non-GAAP Financial Information

The key measure we use to evaluate the results of our projects is Cash Available for Distribution. Cash Available for Distribution is not a measure recognized under GAAP, does not have a standardized meaning prescribed by GAAP and therefore may not be comparable to similar measures presented by other issuers. We believe Cash Available for Distribution is a relevant supplemental measure of our ability to pay dividends to our shareholders. A reconciliation of net cash provided by operating activities to Cash Available for Distribution is set out below under "Cash Available for Distribution." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

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.

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

(unaudited)	Three months ended March 31, 2011	Three months ended March 31, 2010
Project Adjusted EBITDA by individual segment		
Auburndale	$ 10,313	$ 9,371
Lake	8,490	7,313
Pasco	(1,077)	1,415
Path 15	6,570	7,053
Chambers	4,724	5,988
Total	29,020	31,140
Other Project Assets		
Cadillac	1,747	
Piedmont	(29)	
Idaho Wind	806	
Badger Creek	760	736
Koma Kulshan	60	119
Orlando	1,891	1,801
Topsham		415
Delta Person	399	364
Gregory	772	855
Rumford		(8)
Selkirk	1,109	3,530
Rollcast	(467)	
Other	(75)	(157)
Total adjusted EBITDA from Other Project Assets segment	6,973	7,655
Project income		
Total adjusted EBITDA from all Projects	35,993	38,795
Depreciation and amortization	17,437	16,386
Interest expense, net	6,240	5,778
Change in the fair value of derivative instruments	(2,784)	12,520
Other (income) expense	231	247
Project income as reported in the statement of operations	$ 14,869	$ 3,864

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Reconciliation of Project Distributions (in thousands of U.S. dollars)
For the three months ended March 31, 2011

	Project Adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distributions received
Reportable Segments						
Auburndale	$ 10,313	$ (2,450)	$ (313)	$	$ (750)	$ 6,800
Chambers	4,724	(3,199)	(1,386)		(139)	
Lake	8,490		3	(257)	2,040	10,276
Pasco	(1,077)				1,732	655
Path 15	6,570		(2,990)		(3,580)	
Total Reportable Segments	29,020	(5,649)	(4,686)	(257)	(697)	17,731
Other Project Assets						
Cadillac	1,747	(575)	(654)	(62)	744	1,200
Piedmont	(29)				29	
Idaho Wind	806		(369)		105	542
Badger Creek	760				65	825
Delta Person	399	(268)	(59)		(72)	
Gregory	772	(377)	(38)	(12)	(345)	
Koma Kulshan	60				165	225
Orlando	1,891		1	(88)	(1,604)	200
Selkirk	1,109		(394)		(715)	
Topsham						
Rollcast	(467)		1		466	
Other	(75)		(42)	11	306	200
Total Other Project Assets Segment	6,973	(1,220)	(1,554)	(151)	(856)	3,192
Total all Segments	$ 35,993	$ (6,869)	$ (6,240)	$ (408)	$ (1,553)	$ 20,923

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Reconciliation of Project Distributions (in thousands of U.S. dollars)
For the three months ended March 31, 2010

	Project Adjusted EBITDA	Repayment of long-term debt	Interest expense, net	Capital expenditures	Change in working capital & other items	Project distributions received
Reportable Segments						
Auburndale	$ 9,371	$ (2,450)	$ (471)	$	$ (650)	$ 5,800
Chambers	5,988	(3,013)	(1,676)	(34)	(1,265)	
Lake	7,313		2	(274)	(1,011)	6,030
Pasco	1,415			(24)	(361)	1,030
Path 15	7,053		(3,146)		(3,907)	
Total Reportable Segments	31,140	(5,463)	(5,291)	(332)	(7,194)	12,860
Other Project Assets						
Badger Creek	736		6		92	834
Delta Person	364	(662)	(69)		367	
Gregory	855	(394)	206		(349)	318
Koma Kulshan	119				63	182
Orlando	1,801		(33)	(43)	(1,725)	
Rumford	(8)				8	
Selkirk	3,530		(600)		(2,930)	
Topsham	415				(415)	
Rollcast						
Other	(157)		3	(21)	175	
Total Other Project Assets Segment	7,655	(1,056)	(487)	(64)	(4,714)	1,334
Total all Segments	$ 38,795	$ (6,519)	$ (5,778)	$ (396)	$ (11,908)	$ 14,194

Project Operations Performance Three months ended March 31, 2011 compared with three months ended March 31, 2010

Aggregate Project Adjusted EBITDA decreased $2.8 million to $36.0 million in the three-month period ended March 31, 2011 from $38.8 million in the comparable 2010 period and included the following factors:

Project Adjusted EBITDA of $1.7 million at Cadillac, as the project was acquired in December 2010;

increased Project Adjusted EBITDA of $2.1 million at Lake and Auburndale due to increased contractual capacity payments under the project's PPA's and favorable energy prices; offset by

decreased Project Adjusted EBITDA of $2.5 million at Pasco primarily attributable to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine blades during a maintenance outage;

decreased Project Adjusted EBITDA of $2.4 million at Selkirk primarily attributable to lower capacity revenue. A planned outage was longer than expected, resulting in a delay in the receipt of capacity payments until the second quarter; and decreased Project Adjusted EBITDA of $1.3 million at Chambers attributable to higher maintenance costs associated with a planned outage in April and lower dispatch during the first quarter.

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Aggregate power generation for projects in operation at March 31, 2011 was 0.4% greater than the three-month period ended March 31, 2010. Generation during the three-month period ended March 31, 2011 compared to the comparable 2010 period was favorably impacted primarily by additional generation associated with the acquisition of Cadillac in the fourth quarter of 2010 and with Idaho Wind achieving commercial operation in the first quarter of 2011, as well as increased dispatch at Selkirk. The favorable variance was offset largely by lower generation at Chambers and Pasco due to reduced dispatch and by a planned major maintenance outage at Orlando in 2011.

The project portfolio achieved a weighted average availability of 93.8% for the three-month period ended March 31, 2011 compared to 98.2% in the 2010 period. The decrease in portfolio availability for the three-month period ended March 31, 2011 versus the prior period was primarily due to planned outages at Chambers and Selkirk and a forced outage at Delta-Person in the first quarter of 2011. 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.

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 decreased by $0.5 million for the three-month period ended March 31, 2011 over the comparable period in 2010. The changes from the prior period are consistent with and partially attributable to the changes in Project Adjusted EBITDA described above, as well as changes in working capital at both consolidated and unconsolidated affiliates.

Cash Flow from Investing Activities

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

Cash flows used in investing activities for the three-month period ended March 31, 2011 were $18.1 million compared to cash flows used in investing activities of $7.8 million for the comparable 2010 period. We invested $15.1 million for the construction-in-progress for our Piedmont biomass project offset by the repayment of $5.1 million from our related-party loan to Idaho Wind.

Cash Flow from Financing Activities

Cash used in financing activities for the three-month period ended March 31, 2011 resulted in a net outflow of $19.5 million compared to a net outflow of $18.5 million for the same period in 2010. The change from the comparable period is primarily attributable to a $3.1 million increase in dividends paid due to a higher number of common shares outstanding compared to the first quarter 2010. Since the third quarter of 2010, Cdn$23.1 million of convertible debentures have converted to common stock.

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In addition, we issued common shares in a public offering in October 2010. The increase in dividends is partially offset by proceeds of $2.8 million of project-level debt related to our Piedmont biomass project.

Cash Available for Distribution

Holders of our common shares receive monthly cash distributions of Cdn$1.094 per year in the form of a dividend. The payout ratio for the three-month periods ended March 31, 2011 and 2010 was 114% and 89%, respectively.

The table below presents our calculation of cash available for distribution for the three-month periods ended March 31, 2011 and 2010:

(unaudited) **(in thousands of U.S. dollars, except as otherwise stated)**	**Three months ended March 31,** **2011**	 **2010**
Cash flows from operating activities	20,347	20,839
Project-level debt repayments	(3,400)	(2,700)
Purchases of property, plant and equipment[1]	(308)	(319)
Cash Available for Distribution[2]	16,639	17,820
Dividends on common shares	18,992	15,801
Total distributions to shareholders	18,992	15,801
Payout ratio	114%	89%
Expressed in Cdn$		
Cash Available for Distribution	16,407	18,540
Total common share distributions	18,623	16,527

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

(2) Cash Available for Distribution is not a recognized measure under GAAP and does not have any standardized meaning prescribed by GAAP. Therefore, this measure may not be comparable to similar measures presented by other companies. See "Supplementary Non-GAAP Financial Information".

Outlook

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

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

- lower fuel costs at the Lake project;
- resumption of distributions from the Chambers project;
- annual increase in contractual capacity payments from the Auburndale and Lake projects; and
- distributions from the recently acquired Cadillac and Idaho Wind projects

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

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

Lake

The Lake project is exposed to changes in natural gas prices from the expiration of its natural gas supply contract on June 30, 2009 through to the expiration of its PPA in July 2013 that are not passed through in its PPAs. 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. These hedges are summarized in Item 3, "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 2013, but do not intend to execute additional hedges at Lake for 2011 and 2012 because our natural gas exposure for those years is already substantially hedged.

The variable energy revenues in the Lake project's PPA are indexed, in part, to the price of coal consumed by 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 $30 million to $34 million in both 2011 and 2012. The increases in 2011 and 2012 over the $28.8 million of distributions in 2010 are primarily due to higher contractual capacity payments and lower hedged natural gas prices than in 2010.

Auburndale

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

The projected revenue from the Auburndale PPA contains a component related to the costs of coal consumed at the utility off-taker's Crystal River facility as described above for the Lake project. Because that mechanism does not pass through changes in the project's fuel costs, Auburndale's operating margin is exposed to changes in natural gas prices for approximately 20% of its natural gas requirements through the expiration of the project's gas supply contract. The remaining 80% of the project's fuel requirements are supplied under an agreement with fixed prices through its expiration in

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mid-2012. We have been executing a strategy to mitigate the future exposure to changes in natural gas prices at Auburndale by periodically entering into financial swaps that effectively fix the forward price of natural gas required at the project. These hedges are summarized in Item 3, "Quantitative and Qualitative Disclosures About Market Risk", in this Form 10-Q. The 2011 natural gas price exposure at Auburndale has been substantially hedged. We intend to continue, when appropriate, to evaluate opportunities to further mitigate natural gas price exposure at Auburndale in 2012 and 2013.

Orlando

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

Liquidity and Capital Resources

Overview

Our primary source of liquidity is distributions from our projects and availability under our revolving credit facility. A significant portion of the cash received from project distributions is used to pay dividends to our shareholders and interest on our outstanding convertible debentures. We may fund future acquisitions with a combination of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately-placed bank or institutional non-recourse operating level debt.

We believe that we will be able to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due.

We do not expect any additional material or unusual requirements for cash outflows for 2011 for capital expenditures or other required investments. We have contributed approximately $75.0 million to fund the equity portion of the construction costs for Piedmont. Approximately $59.0 million of this amount was contributed in the fourth quarter of 2010 and the remaining balance was paid in the quarter ending March 31, 2011. In addition, there are no debt instruments with significant maturities or refinancing requirements in 2011. See "Outlook" above for information about changes in expected distributions from our projects in 2011 and beyond.

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 1.5% and 3.25% that varies based on the credit statistics of one of our subsidiaries. As of March 31, 2011, the applicable margin was 1.5%. As of March 31, 2011, $48.6 million was allocated, but not drawn, to support letters of credit for contractual credit support at eight of our projects.

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 our lenders. 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.

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Convertible Debentures

In October 2006, we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.25% convertible secured debentures, which we refer to as the 2006 Debentures. In 2009 the holders agreed to change the rate to 6.50% and extend the maturity date to 2014. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The Debentures have a maturity date of October 31, 2014 and are convertible into approximately 80.6452 common shares per Cdn$1,000 principal amount of 2006 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per common share. The 2006 Debentures are secured by a subordinated pledge of our interest in certain subsidiaries and contain certain restrictive covenants. Through May 10, 2011, a cumulative Cdn$11.9 million of the 2006 Debentures have been converted to 0.96 million common shares. As of May 10, 2011 the 2006 Debentures balance is Cdn$48.1 million ($50.4 million).

In December 2009, we issued, in a public offering, Cdn$86.25 million aggregate principal amount of 6.25% convertible unsecured subordinated debentures, which we refer to as the 2009 Debentures. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year beginning September 15, 2010. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share. Through May 10, 2011, a cumulative Cdn$11.2 million of the 2009 Debentures have been converted to 0.86 million common shares. As of May 10, 2011 the 2009 Debentures balance is Cdn$75.0 million ($78.6 million).

In October 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of 5.60% convertible unsecured subordinated debentures, which we refer to as the 2010 Debentures. The 2010 Debentures pay interest semi-annually on June 30 and December 30 of each year beginning June 30, 2011. The 2010 Debentures mature on June 30, 2017, unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of debentures, representing an initial conversion price of approximately Cdn$18.10 per common share. As of May10, 2011 the 2010 debentures balance is Cdn$80.5 million ($84.4 million).

Project-level debt

The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at March 31, 2011 and exclude any purchase accounting adjustments recorded to adjust the debt to its fair value at the time the project was acquired. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project-level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. As of March 31, 2011, 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 to resume receiving distributions from Epsilon Power Partners in 2011 and Selkirk and Delta-Person in 2012. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. The non-recourse holding company debt relating to our investment in Chambers is held at Epsilon Power Partners, our wholly-owned subsidiary. For the three-month period ended March 31, 2011, we have contributed approximately $0.48 million to Epsilon Power Partners for debt service payments on the holding company debt but do not anticipate any additional required contributions to Epsilon.

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The range of interest rates presented represents the rates in effect at March 31, 2011. The amounts listed below are in thousands of U.S. dollars, except as otherwise stated.

	Range of Interest Rates	Total Remaining Principal Repayments	2011	2012	2013	2014	2015	Thereafter
Consolidated Projects:								
Epsilon Power Partners	7.40%	$ 36,107	$ 1,125	$ 1,500	$ 3,000	$ 5,000	$ 5,750	$ 19,732
Piedmont[(1)]	5.20%	2,781		2,781				
Path 15	7.9% - 9.0%	153,868	7,987	8,667	9,402	8,065	8,749	110,998
Auburndale	5.10%	19,250	7,350	7,000	4,900			
Cadillac	6.02% - 8.0%	41,956	1,725	3,791	2,400	2,000	2,500	29,540
Total Consolidated Projects		253,962	18,187	23,739	19,702	15,065	16,999	160,270
Equity Method Projects:								
Chambers	0.4% - 7.2%	72,222	8,471	12,176	10,783	5,780	5,213	29,799
Delta-Person	2.1%	10,253	862	1,212	1,300	1,394	1,495	3,990
Selkirk	9.0%	16,793	10,948	5,845				
Idaho Wind	2.8% - 13.3%	83,940	41,666	1,848	1,892	2,049	2,136	34,349
Gregory	1.8% - 7.5%	13,972	1,523	2,044	2,205	2,385	2,492	3,323
Total Equity Method Projects		197,180	63,470	23,125	16,180	11,608	11,336	71,461
Total Project-Level Debt		$ 451,142	$ 81,657	$ 46,864	$ 35,882	$ 26,673	$ 28,335	$ 231,731

(1) The Piedmont debt outstanding is the inception to date balance on the construction debt funded by the bridge loan. The terms of the Piedmont project-level debt refinancing include an $82.0 million construction and term loan and a $51.0 million bridge loan for approximately 95.0% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations. The $51.0 million bridge loan will be repaid in 2012 and repayment of the expected $82.0 million term loan will commence in 2013.

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 March 31, 2011, restricted cash at the consolidated projects totaled $23.3 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 2011, several of the projects have planned outages to complete maintenance work. The level of maintenance and capital expenditures is slightly higher than in 2010. During the first quarter of 2011, Selkirk completed a major inspection of its steam turbine generator and a minor inspection of one of its combustion turbines, with costs and lost margin largely covered by reserves and gas resales proceeds, respectively. Also in the first quarter of 2011, Chambers completed its scheduled outage to inspect and complete customary repairs on one boiler. At Orlando, a major gas turbine overhaul and major steam turbine overhaul were commenced in March, the cost of which was largely covered under its long-term maintenance agreement with the gas turbine manufacturer. In late March, Pasco commenced its scheduled spring outage to conduct regular maintenance as well as replace some components of the

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combustion turbine. A portion of the repair costs are covered under Pasco's service agreement with General Electric.

In the three-month period ended March 31, 2011, we incurred approximately $15.4 million in capital expenditures for the construction of our Piedmont biomass project. For the remainder of 2011, we expect to incur approximately $84.1 million in capital expenditures related to the Piedmont project, with total project costs through expected completion in late 2012 of approximately $207.0 million. The project is being funded with an $82.0 million construction loan which will convert to a term loan upon commercial operation, a $51.0 million bridge loan and approximately $75.0 million of equity contributed by Atlantic Power. The bridge loan will be repaid from the proceeds of a federal stimulus grant which is expected to be received two months after achieving commercial operation.

Off-Balance Sheet Arrangements

As of March 31, 2011, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

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

Fuel Commodity Market Risk

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

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

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 $0.5 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 un-hedged natural gas volumes at the project.

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

The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of March 31, 2011 and May 10, 2011:

As of March 31, 2011 and May 10, 2011	**2011**	**2012**	**2013**
Portion of gas volumes currently hedged:			
Lake:			
Contracted			
Financially hedged	78%	90%	83%
Total	78%	90%	83%
Auburndale:			
Contracted	80%	40%	0%
Financially hedged	13%	32%	79%
Total	93%	72%	79%
Average price of financially hedged volumes (per Mmbtu)			
Lake	$ 6.52	$ 6.90	$ 6.63
Auburndale	$ 6.68	$ 6.51	$ 6.92

In October 2010, we entered into natural gas swaps that are effective in 2014 and 2015. The natural gas swaps are related to our 50% share of expected fuel purchases at our 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 represent 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 both projected natural gas prices at that time and the prices in the natural gas swaps we have executed are lower than the price of natural gas being purchased under the project's gas contract.

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 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 mitigating the currency risk impact on the long-term sustainability of our dividends to shareholders. We have executed this strategy by entering into forward contracts to purchase Canadian dollars at fixed rates of exchange to hedge approximately 86% of our expected dividend and convertible debenture interest payments through 2013. Changes in the fair value of the forward contracts partially offset foreign exchange gains

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or losses on the U.S. dollar equivalent of our Canadian dollar obligations. The forward contracts consist of (1) monthly purchases through the end of 2013 of Cdn$6.0 million at an exchange rate of Cdn$1.134 per U.S. dollar and (2) purchases in both April and October 2011 of Cdn$1.9 million at an exchange rate of Cdn$1.1075 per U.S. dollar.

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

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-month periods ended March 31, 2011 and 2010:

	Three months ended March 31, 2011	Three months ended March 31, 2010
Unrealized foreign exchange (gain) loss:		
Convertible debentures	$ 5,314	$ (541)
Forward contracts and other	(3,436)	(82)
	1,878	(623)
Realized foreign exchange gains on forward contract settlements	(2,536)	(1,169)
	$ (658)	$ (1,792)

The following table illustrates the impact on the fair value of our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of March 31, 2011:

Convertible debentures, at carrying value	$ 21,001
Foreign currency forward contracts	$ (22,539)

Interest Rate Risk

Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 84% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

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

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

We executed two interest rate swaps at our consolidated Piedmont project to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreements are not designated as hedges and changes in their fair market value are recorded in the statements of operations. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively.

In 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 $1.1 million.

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.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

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

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of March 31, 2011 which are expected to have a material adverse impact on our financial position or results of operations.

ITEM 1A. RISK FACTORS

Except to the extent additional factual information disclosed elsewhere in this Quarterly Report on Form 10-Q relates to such risk factors (including, without limitation, the matters discussed in Part I, "Item 2-Management's Discussion and Analysis of Financial Condition and Results of Operations"), there were no material changes to the risk factors disclosed in Part I, "Item 1A. Risk Factors" of our Annual Report on Form 10-K for the year ended December 31, 2010.

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

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SIGNATURES

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

Date: May 11, 2011	Atlantic Power Corporation		
	By:	/s/ PATRICK J. WELCH	
		Name:	Patrick J. Welch
		Title:	*Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*