ATLANTIC POWER CORP
Form 10-Q
November 05, 2012

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-Q

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

For the quarterly period ended September 30, 2012

OR

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

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

ATLANTIC POWER CORPORATION

(Exact name of registrant as specified in its charter)

British Columbia, Canada (State or other jurisdiction of incorporation or organization)	**55-0886410** (I.R.S. Employer Identification No.)
One Federal Street, Floor 30 **Boston, MA** (Address of principal executive offices)	**02110** (Zip code)

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

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

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

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

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

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

The number of shares outstanding of the registrant's Common Stock as of November 1, 2012 was 119,333,349.

ATLANTIC POWER CORPORATION

FORM 10-Q

THREE AND NINE MONTHS ENDED SEPTEMBER 30, 2012

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GENERAL

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

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

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PART I FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS AND NOTES

ATLANTIC POWER CORPORATION

CONSOLIDATED BALANCE SHEETS

(in thousands of U.S. dollars)

	September 30, 2012 (unaudited)	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 42,872	$ 60,651
Restricted cash	112,633	21,412
Accounts receivable	80,190	79,008
Current portion of derivative instruments asset (Notes 6 and 7)	10,792	10,411
Inventory	20,105	18,628
Prepayments and other current assets	27,751	7,615
Assets held for sale (Note 11)	203,111	
Refundable income taxes	3,646	3,042
Total current assets	501,100	200,767
Property, plant, and equipment, net of accumulated depreciation of $168.4 million and $116.3 million at September 30, 2012 and December 31, 2011, respectively	1,730,765	1,388,254
Transmission system rights, net of accumulated amortization of $51.4 million at December 31, 2011		180,282
Equity investments in unconsolidated affiliates (Note 3)	432,525	474,351
Other intangible assets, net of accumulated amortization of $155.0 million and $90.2 million at September 30, 2012 and December 31, 2011, respectively	557,356	584,274
Goodwill	334,668	343,586
Derivative instruments asset (Notes 6 and 7)	14,236	22,003
Other assets	73,345	54,910
Total assets	$ 3,643,995	$ 3,248,427
Liabilities		
Current Liabilities:		
Accounts payable	$ 13,997	$ 18,122
Accrued interest	29,453	19,916
Other accrued liabilities	82,690	43,968
Revolving credit facility (Note 4)	20,000	58,000
Current portion of long-term debt (Note 4)	303,890	20,958
Current portion of derivative instruments liability (Notes 6 and 7)	42,440	20,592
Dividends payable	11,627	10,733
Liabilities associated with assets held for sale (Note 11)	157,420	
Other current liabilities	4,014	165
Total current liabilities	665,531	192,454
Long-term debt (Note 4)	1,225,661	1,404,900
Convertible debentures (Note 5)	326,067	189,563
Derivative instruments liability (Notes 6 and 7)	103,411	33,170

Deferred income taxes		161,266		182,925
Power purchase and fuel supply agreement liabilities, net of accumulated amortization of $3.5 million and $1.4 million at September 30, 2012 and December 31, 2011, respectively		45,265		71,775
Other non-current liabilities		63,996		57,859
Commitments and contingencies (Note 14)				
Total liabilities		2,591,197		2,132,646
Equity				
Common shares, no par value, unlimited authorized shares; 119,294,718 and 113,526,182 issued and outstanding at September 30, 2012 and December 31, 2011, respectively		1,286,399		1,217,265
Preferred shares issued by a subsidiary company		221,304		221,304
Accumulated other comprehensiveincome (loss)		17,253		(5,193)
Retained deficit		(474,489)		(320,622)
Total Atlantic Power Corporation shareholders' equity		1,050,467		1,112,754
Noncontrolling interest		2,331		3,027
Total equity		1,052,798		1,115,781
Total liabilities and equity	$	3,643,995	$	3,248,427

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF OPERATIONS

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

(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2012	**2011**	**2012**	**2011**
Project revenue:				
Energy sales	$ 72,033	$ 17,104	$ 218,883	$ 53,471
Energy capacity revenue	68,354	27,070	193,911	81,859
Other	14,112	521	51,036	1,153
	154,499	44,695	463,830	136,483
Project expenses:				
Fuel	58,565	14,818	176,176	46,202
Operations and maintenance	35,848	8,124	111,027	25,618
Depreciation and amortization	38,542	8,880	111,219	26,705
	132,955	31,822	398,422	98,525
Project other income (expense):				
Change in fair value of derivative instruments (Notes 6 and 7)	17,213	(11,484)	(40,953)	(12,497)
Equity in earnings of unconsolidated affiliates (Note 3)	4,000	2,374	12,420	5,647
Interest expense, net	(4,211)	(1,576)	(12,637)	(4,832)
Other expense, net	(567)	(7)	(538)	(40)
	16,435	(10,693)	(41,708)	(11,722)
Project income	37,979	2,180	23,700	26,236
Administrative and other expenses (income):				
Administration	6,309	11,839	21,992	20,379
Interest, net	25,829	3,337	69,269	10,815
Foreign exchange loss (Note 7)	7,659	21,576	4,440	20,383
Other expense (income), net	272		(5,728)	
	40,069	36,752	89,973	51,577
Loss from continuing operations before income taxes	(2,090)	(34,572)	(66,273)	(25,341)
Income tax expense (benefit) (Note 8)	3,166	(5,323)	(19,076)	(12,900)
Loss from continuing operations	(5,256)	(29,249)	(47,197)	(12,441)
Income from discontinued operations, net of tax (Note 11)	773	1,271	1,444	3,514
Net loss	(4,483)	(27,978)	(45,753)	(8,927)
Net income (loss) attributable to noncontrolling interest	2,963	(78)	9,071	(349)
Net loss attributable to Atlantic Power Corporation	$ (7,446)	$ (27,900)	$ (54,824)	$ (8,578)
Net loss per share attributable to Atlantic Power Corporation shareholders: (Note 10)				
Basic	$ (0.06)	$ (0.40)	$ (0.47)	$ (0.13)
Diluted	$ (0.06)	$ (0.40)	$ (0.47)	$ (0.13)

Weighted average number of common shares outstanding: (Note 10)				
Basic	119,011	68,910	115,437	68,384
Diluted	119,011	68,910	115,437	68,384

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

(in thousands of U.S. dollars)

(Unaudited)

	Three months ended September 30,		Nine months ended September 30,	
	2012	**2011**	**2012**	**2011**
Net loss	$ (4,483)	$ (27,978)	$ (45,753)	$ (8,927)
Other comprehensive income (loss), net of tax:				
Unrealized loss on hedging activities	(300)	(1,495)	(833)	(2,257)
Net amount reclassified to earnings	216	253	672	784
Net unrealized losses on derivatives	(84)	(1,242)	(161)	(1,473)
Foreign currency translation adjustments	19,301		22,608	
Other comprehensive income, net of tax	19,217	(1,242)	22,447	(1,473)
Comprehensive income (loss)	14,734	(29,220)	(23,306)	(10,400)
Less: Comprehensive (income) loss attributable to noncontrolling interest	2,963	(78)	9,071	(349)
Comprehensive income (loss) attributable to Atlantic Power Corporation	$ 11,771	$ (29,142)	$ (32,377)	$ (10,051)

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands of U.S. dollars)

(Unaudited)

	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Cash flows from operating activities:		
Net loss	$ (45,753)	$ (8,927)
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	117,464	32,711
Long-term incentive plan expense	2,344	2,257
Loss on the disposal of property, plant and equipment and other charges	840	
Impairment charge on equity investment	3,000	
Gain on sale of equity investments	(578)	
Equity in earnings from unconsolidated affiliates	(14,842)	(5,647)
Distributions from unconsolidated affiliates	26,821	15,542
Unrealized foreign exchange loss	21,552	28,175
Change in fair value of derivative instruments	40,953	12,497
Change in deferred income taxes	(24,278)	(10,315)
Change in other operating balances		
Accounts receivable	(2,873)	258
Prepayments, refundable income taxes and other assets	(18,656)	(570)
Accounts payable and accrued liabilities	14,855	1,536
Other liabilities	3,267	(1,178)
Cash provided by operating activities	124,116	66,339
Cash flows used in investing activities:		
Change in restricted cash	(105,494)	(12,379)
Proceeds from sale of equity investments	27,925	8,500
Cash paid for equity investment	(264)	
Proceeds from related party loan		15,455
Biomass development costs	(372)	(753)
Construction in progress	(336,153)	(78,256)
Purchase of property, plant and equipment	(1,172)	(814)
Cash used in investing activities	(415,530)	(68,247)
Cash flows provided by (used in) financing activities:		
Proceeds from issuance of convertible debentures	130,000	
Proceeds from issuance of equity, net of offering costs	67,692	
Proceeds from project-level debt	261,226	65,374
Repayment of project-level debt	(12,050)	(13,166)
Payments for revolving credit facility borrowings	(60,800)	
Proceeds from revolving credit facility borrowings	22,800	
Deferred financing costs	(25,339)	
Dividends paid	(108,152)	(57,543)
Cash provided by (used in) financing activities	275,377	(5,335)
Net decrease in cash and cash equivalents	(16,037)	(7,243)
Less cash at discontinued operations	(1,742)	
Cash and cash equivalents at beginning of period	60,651	45,497

Cash and cash equivalents at end of period	$ 42,872	$ 38,254
Supplemental cash flow information		
Interest paid	$ 77,738	$ 21,567
Income taxes paid (refunded), net	$ 3,145	$ (352)
Accruals for construction in progress	$ 40,097	$ 19,547

See accompanying notes to consolidated financial statements.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1. Basis of presentation and summary of significant accounting policies

Overview

Atlantic Power Corporation is a power generation and infrastructure company with a portfolio of assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers under long-term power purchase agreements ("PPAs"), 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 3,351 megawatts ("MW") in which our ownership interest is approximately 2,118 MW. Our current portfolio consists of interests in 30 operational power generation projects across 11 states in the United States and two provinces in Canada and an 84 mile 500-kilovolt electric transmission line located in California. In addition, we have one 53 MW biomass project under construction in Georgia and one approximately 300 MW wind project under construction in Oklahoma. Atlantic Power also owns a majority interest in Rollcast Energy, a biomass power plant developer in North Carolina. Twenty-three of our projects are wholly owned subsidiaries.

Atlantic Power is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange under the symbol "ATP" and on the New York Stock Exchange under the symbol "AT." Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at One Federal Street, Floor 30, Boston, Massachusetts, 02110, USA. Our telephone number in Boston is (617) 977-2400 and the address of our website is www.atlanticpower.com. Information contained on Atlantic Power's website or that can be accessed through its website is not incorporated into and does not constitute a part of this Quarterly Report on Form 10-Q. Atlantic Power has included its website address only as an inactive textual reference and does not intend it to be an active link to its website. We make available, free of charge, on our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act"), as soon as reasonably practicable after we electronically file such material with, or furnish it to, the Securities and Exchange Commission ("SEC"). Additionally, we make available on our website our Canadian securities filings, which are not incorporated by reference into our Exchange Act filings.

The interim consolidated financial statements have been prepared in accordance with the SEC regulations for interim financial information and with the instructions to Form 10-Q. The following notes should be read in conjunction with the accounting policies and other disclosures as set forth in the notes to our financial statements in our Annual Report on Form 10-K for the year ended December 31, 2011. Interim results are not necessarily indicative of results for the full year.

In our opinion, the accompanying unaudited interim consolidated financial statements present fairly our consolidated financial position as of September 30, 2012, the results of operations and comprehensive income for the three and nine month periods ended September 30, 2012 and 2011, and our cash flows for the nine month periods ended September 30, 2012 and 2011. In the opinion of management, all adjustments (consisting of normal recurring accruals and other adjustments) considered necessary for a fair presentation have been included.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Use of estimates

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the valuation of shares associated with our Long-Term Incentive Plan ("LTIP") and the fair value of financial instruments and derivatives. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. See "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations Critical Accounting Policies and Estimates" in our Annual Report on Form 10-K for the year ended December 31, 2011. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

Recently issued accounting standards

Adopted

On January 1, 2012, we adopted changes issued by the Financial Accounting Standards Board ("FASB") to conform existing guidance regarding fair value measurement and disclosure between GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio; application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. The adoption of these changes had no impact on our consolidated financial statements.

On January 1, 2012, we adopted changes issued by the FASB to the presentation of comprehensive income. These changes give an entity the option to present the total of comprehensive income, the components of net income, and the components of other comprehensive income either in a single continuous statement of comprehensive income or in two separate but consecutive statements; the option to present components of other comprehensive income as part of the statement of changes in

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

shareholders' equity was eliminated. The items that must be reported in other comprehensive income or when an item of other comprehensive income must be reclassified to net income were not changed. Additionally, no changes were made to the calculation and presentation of earnings per share. We elected to present the two-statement option. Other than the change in presentation, the adoption of these changes had no impact on our consolidated financial statements.

Issued

In July 2012, the FASB issued changes to the testing of indefinite-lived intangible assets for impairment, similar to the goodwill changes issued in September 2011. These changes provide an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of an indefinite-lived intangible asset is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions; industry and market considerations; cost factors; overall financial performance; and other relevant entity-specific events. If an entity elects to perform a qualitative assessment and determines that an impairment is more likely than not, the entity is then required to perform the existing two-step quantitative impairment test, otherwise no further analysis is required. An entity also may elect not to perform the qualitative assessment and, instead, proceed directly to the two-step quantitative impairment test. These changes become effective for us for any indefinite-lived intangible asset impairment test performed on January 1, 2013 or later, although early adoption is permitted. We do not expect the adoption of these changes to have an impact on our consolidated financial statements.

2. Acquisitions and divestitures

2012 Acquisitions

On January 31, 2012, Atlantic Oklahoma Wind, LLC ("Atlantic OW"), a Delaware limited liability company and our wholly owned subsidiary, entered into a purchase and sale agreement with Apex Wind Energy Holdings, LLC, a Delaware limited liability company ("Apex"), pursuant to which Atlantic OW acquired a 51% interest in Canadian Hills Wind, LLC, an Oklahoma limited liability company ("Canadian Hills") for a nominal sum. Canadian Hills is the owner of a 298.45 MW wind energy project under construction in the state of Oklahoma.

On March 30, 2012, we completed the purchase of an additional 48% interest in Canadian Hills for a nominal amount, bringing our total interest in the project to 99%. Apex retained a 1% interest in the project. At the time, we also closed a $310 million non-recourse, project-level construction financing facility for the project, which includes a $290 million construction loan and a $20 million 5-year letter of credit facility. The construction loan is structured to be repaid by a tax equity investment when Canadian Hills commences commercial operations.

On October 31, 2012, the Canadian Hills project entered into an equity contribution agreement with four entities for their commitment of a tax equity investment in the project totalling $225.0 million in exchange for Class B equity interests in Canadian Hills which will be funded on date of commercial operations. We are actively pursuing additional tax equity investors to fund the remaining estimated $47.0 million needed to pay down the existing construction loan. If we are unable to subscribe

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Acquisitions and divestitures (Continued)

additional investors, we will fund the remaining portion with either cash on hand or proceeds from our senior credit facility and will become an additional tax equity investor in the project owning the remaining Class B equity interest in Canadian Hills. In July 2012 we funded approximately $190.0 million of our equity contribution (net of financing costs). The acquisition of Canadian Hills was accounted for as an asset purchase and is consolidated in our consolidated balance sheet at September 30, 2012.

2012 Divestitures

On August 2, 2012, we entered into a purchase and sale agreement for the sale of our 50% ownership interest in the Badger Creek project. On September 4, 2012, the transaction closed and we received gross proceeds of $3.7 million. As a result of the pending sale, we recorded an impairment charge in the second quarter of 2012 of $3.0 million in equity in earnings from unconsolidated affiliates in the consolidated statements of operations.

On February 16, 2012, we entered into an agreement with Primary Energy Recycling Corporation ("Primary Energy" or "PERC"), whereby PERC agreed to purchase our 7,462,830.33 common membership interests in Primary Energy Recycling Holdings, LLC ("PERH") (14.3% of PERH total interests) for approximately $24.2 million, plus a management agreement termination fee of approximately $6.0 million, for a total sale price of $30.2 million. The transaction closed in May 2012 and we recorded a $0.6 million gain on sale of our equity investment.

2011 Divestiture

On February 28, 2011, we entered into a purchase and sale agreement with a third party for the purchase of our lessor interest in the Topsham project. The transaction closed on May 6, 2011 and we received proceeds of $8.5 million. No gain or loss was recorded on the sale.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

3. Equity method investments

The following summarizes the operating results for the three and nine months ended September 30, 2012 and 2011, respectively, for earnings in our equity method investments:

	Three months ended September 30,		Nine months ended September 30,	
	2012	**2011**	**2012**	**2011**
Project revenue				
Chambers	$ 12,196	$ 11,616	$ 40,148	$ 37,894
Badger Creek	1,087	1,415	3,357	6,070
Gregory	5,814	7,810	14,766	22,624
Orlando	11,081	10,549	32,850	29,851
Selkirk	12,248	14,020	35,857	37,881
Other	9,218	3,093	31,522	8,045
	51,644	48,503	158,500	142,365
Project expenses				
Chambers	9,564	9,107	28,066	28,032
Badger Creek	831	1,509	2,971	5,907
Gregory	5,262	7,007	15,392	20,537
Orlando	10,189	10,156	30,487	29,224
Selkirk	10,663	12,572	31,722	37,861
Other	11,585	2,617	30,223	6,412
	48,094	42,968	138,861	127,973
Project other income (expense)				
Chambers	139	(730)	(1,476)	(1,820)
Badger Creek	(156)	(9)	(3,165)	(20)
Gregory	(46)	(218)	(272)	(449)
Orlando	(24)	(13)	(58)	(57)
Selkirk	(671)	(33)	1,516	(2,599)
Other	1,208	(2,158)	(3,764)	(3,800)
	450	(3,161)	(7,219)	(8,745)
Project income (loss)				
Chambers	2,771	1,779	10,606	8,042
Badger Creek	100	(103)	(2,779)	143
Gregory	506	585	(898)	1,638
Orlando	868	380	2,305	570
Selkirk	914	1,415	5,651	(2,579)
Other	(1,159)	(1,682)	(2,465)	(2,167)
	4,000	2,374	12,420	5,647

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Long-term debt

Long-term debt consists of the following:

	September 30, 2012	December 31, 2011	Interest Rate
Recourse Debt:			
Senior unsecured notes, due 2018	$ 460,000	$ 460,000	9.00%
Senior unsecured notes, due June 2036 (Cdn$210,000)	213,588	206,490	5.95%
Senior unsecured notes, due July 2014	190,000	190,000	5.90%
Series A senior unsecured notes, due August 2015	150,000	150,000	5.87%
Series B senior unsecured notes, due August 2017	75,000	75,000	5.97%
Non-Recourse Debt:			
Epsilon Power Partners term facility, due 2019	33,857	34,982	7.40%
Path 15 senior secured bonds	(1)	145,879	7.90% 9.00%
Auburndale term loan, due 2013	6,650	11,900	5.10%
Cadillac term loan, due 2025	38,431	40,231	6.02% 8.00%
Piedmont construction loan, due 2013	123,270(2)	100,796	Libor plus 3.50%
Canadian Hills construction loan, due 2013	238,755(3)		Libor plus 3.00%
Purchase accounting fair value adjustments	(1)	10,580	
Less current maturities	(303,890)	(20,958)	
Total long-term debt	$ 1,225,661	$ 1,404,900	

Current maturities consist of the following:

	September 30, 2012	December 31, 2011	Interest Rate
Current Maturities:			
Epsilon Power Partners term facility, due 2019	$ 2,625	$ 1,500	7.40%
Path 15 senior secured bonds	(1)	8,667	7.90% 9.00%
Auburndale term loan, due 2013	5,425	7,000	5.10%
Cadillac term loan, due 2025	2,400	3,791	6.02% 8.00%
Piedmont construction loan, due 2013	54,685(2)		Libor plus 3.50%
Canadian Hills construction loan, due 2013	238,755(3)		Libor plus 3.00%
Total current maturities	$ 303,890	$ 20,958	

(1) During the three months ended September 30, 2012, we designated the Path 15 project as an asset held for sale. Accordingly, Path 15 senior secured bonds current maturities of $9.0 million and long term debt of $143.0 million, including a purchase accounting fair value adjustment of $10.0 million, are recorded as a component of liabilities associated with assets held for sale on the consolidated balance sheets at September 30, 2012. See Note 11 for further discussion.

(2) The terms of the Piedmont project-level debt financing include a $51.0 million bridge loan for approximately 95.0% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations, and an $82.0 million construction term loan. The

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Long-term debt (Continued)

$51.0 million bridge loan will be repaid in early 2013 and repayment of the expected $82.0 million term loan will commence in 2013.

(3) On October 31, 2012, the Canadian Hills project entered into an equity contribution agreement with four entities for their commitment of a tax equity investment in the project to be funded on date of commercial operations. The proceeds from our equity contribution, the tax equity investments and a draw on our senior credit facility will be used to pay down the construction loan at the completion of construction.

Notes of Atlantic Power (US) GP

On June 22, 2012, Atlantic Power, Atlantic Power (US) GP and certain other of our subsidiaries entered into an amendment to the Note Purchase and Parent Guaranty Agreement, dated as of August 15, 2007 (the "Note Purchase Agreement"), which governs the 5.87% senior guaranteed notes, Series A, due August 15, 2017 (the "Series A Notes") and the 5.97% senior guaranteed notes, Series B, due August 15, 2019 (the "Series B Notes" and collectively the "Notes") of Atlantic Power (US) GP. Under the amendment, we agreed: (i) that Atlantic Power and the existing and future guarantors of our 9.00% senior notes due November 2018 (the "Senior Notes"), our senior credit facility and refinancings thereof would provide guarantees of the Notes; (ii) to shorten the maturity of the Series A Notes from August 15, 2017 to August 15, 2015; (iii) to shorten the maturity of the Series B Notes from August 15, 2019 to August 15, 2017; (iv) to include an event of default that would be triggered if certain defaults occurred under the debt instruments of Atlantic Power and certain of its subsidiaries; and (v) to add certain covenants, including covenants that limit the ability of Curtis Palmer LLC ("Curtis Palmer"), a wholly-owned subsidiary of Atlantic Power Limited Partnership (the "Partnership") to incur debt or liens, make distributions other than in the ordinary course of business, prepay debt or sell material assets and our ability to sell Curtis Palmer. The parties entered into the amendment following a series of discussions concerning our acquisition of the Partnership. Although we believe that the acquisition of the Partnership was in full compliance with the terms and conditions of the Note Purchase Agreement, the holders of the Notes agreed to waive certain defaults or events of default that they alleged may have occurred as a result of our acquisition of the Partnership in return for Atlantic Power and its subsidiaries entering into the amendment.

Non-Recourse Debt

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The loans have certain financial covenants that must be met. At September 30, 2012, all of our projects were in compliance with the covenants contained in project-level debt. However, our Epsilon Power Partners, Delta-Person and Gregory 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. The non-recourse holding company debt relating to our investment in Chambers is held at Epsilon Power Partners, our wholly owned subsidiary.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Long-term debt (Continued)

Senior Credit Facility

As of September 30, 2012, $20.0 million was drawn on our senior credit facility and $135.5 million and Cnd$1.0 million were issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects. The applicable margin on our senior credit facility was 2.75% at September 30, 2012.

In connection with the continued evolution of the Company's strategy to focus on late-stage development and construction projects, and the possible disposition of certain projects, including our Florida projects, on November 2, 2012, we amended the senior credit facility in order to change certain financial and leverage ratio covenants and obtained certain waivers from our lenders in connection with certain of our projects. See Item 5. Other Information to this quarterly report on Form 10-Q for additional information.

5. Convertible debentures

The following table contains details related to outstanding convertible debentures:

(In thousands US$, except for share amounts)	6.5% Debentures due October 2014	6.25% Debentures due March 2017	5.6% Debentures due June 2017	5.75% Debentures due June 2019	Total
Balance at December 31, 2011	$ 44,103	$ 66,306	$ 79,154	$	$ 189,563
Issuance of convertible debentures				130,000	130,000
Principal amount converted to equity	(13)				(13)
Foreign exchange loss	1,516	2,279	2,722		6,517
Balance at September 30, 2012	$ 45,606	$ 68,585	$ 81,876	$ 130,000	$ 326,067
Common shares issued on conversion during the nine months ended September 30, 2012	1,048				1,048

Aggregate interest expense related to the convertible debentures was $4.9 million and $2.8 million for the three months ended September 30, 2012 and 2011, respectively, and $10.6 million and $9.3 million for the nine months ended September 30, 2012 and 2011, respectively.

On July 5, 2012, we issued, in a public offering, $130.0 million aggregate principal amount of 5.75% convertible unsecured subordinated debentures due June 30, 2019, (the "2012 Debentures") for net proceeds of $124.0 million. The 2012 Debentures pay interest semi-annually on June 30 and December 30 of each year beginning December 30, 2012. The 2012 Debentures are convertible into our common shares at an initial conversion rate of 57.9710 common shares per $1,000 principal amount of debentures. We used the proceeds to fund a portion of our equity commitment in Canadian Hills Wind, LLC.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Fair value of financial instruments

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of September 30, 2012 and December 31, 2011. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	September 30, 2012			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 42,872	$	$	$ 42,872
Restricted cash	112,633			112,633
Derivative instruments asset		25,028		25,028
Total	$ 155,505	$ 25,028	$	$ 180,533
Liabilities:				
Derivative instruments liability	$	$ 145,851	$	$ 145,851
Total	$	$ 145,851	$	$ 145,851

	December 31, 2011			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 60,651	$	$	$ 60,651
Restricted cash	21,412			$ 21,412
Derivative instruments asset		32,414		$ 32,414
Total	$ 82,063	$ 32,414	$	$ 114,477
Liabilities:				
Derivative instruments liability	$	$ 53,762	$	$ 53,762
Total	$	$ 53,762	$	$ 53,762

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

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of September 30, 2012, the credit valuation adjustments resulted in a $19.0 million net increase in fair value, which consists of a $1.3 million pre-tax increase in other comprehensive income and a $17.8 million increase in change in fair value of derivative instruments, offset by a $0.1 million increase to foreign exchange loss. As of December 31, 2011, the credit valuation adjustments resulted in a $5.8 million net increase in fair value, which consists of a $0.9 million pre-tax increase in other comprehensive income and a $5.1 million increase in change in fair value of derivative instruments, offset by a $0.2 million increase in foreign exchange loss.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

7. Accounting for derivative instruments and hedging activities

We recognize all derivative instruments on the balance sheet as either assets or liabilities and measure them at fair value each reporting period. For a certain limited number of contracts designated as cash flow hedges, we defer the effective portion of the change in fair value of the derivatives to accumulated other comprehensive income (loss), until the hedged transactions occur and are recognized in earnings. The ineffective portion of a cash flow hedge is immediately recognized in earnings.

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

Gas purchase agreements

On March 12, 2012, we discontinued the application of the normal purchase normal sales ("NPNS") exemption on gas purchase agreements at our North Bay, Kapuskasing and Nipigon projects. On that date, we entered into an agreement with a third party that resulted in the gas purchase agreements no longer qualifying for the NPNS exemption. The agreements at North Bay and Kapuskasing expire on December 31, 2016 and the agreements at Nipigon expire on December 31, 2012. These gas purchase agreements are derivative financial instruments and are recorded in the consolidated balance sheet at fair value and the changes in their fair market value are recorded in the consolidated statement of operations.

In May 2012, the Nipigon project entered into a long-term contract for the purchase of natural gas beginning on January 1, 2013 and expiring on December 31, 2022. This contract is accounted for as a derivative financial instrument and is recorded in the consolidated balance sheet at fair value at September 30, 2012. Changes in the fair market value of the contract are recorded in the consolidated statement of operations.

In May 2012, the Tunis project entered into a contract for the purchase of natural gas beginning on October 1, 2012 and expiring on March 31, 2013 and qualified for the NPNS exemption. On September 27, 2012, we discontinued the application of the NPNS exemption on this contract due to net settlements of a portion of the contract to a third party. As of September 30, 2012 this contract is accounted for as a derivative financial instrument and is recorded in the consolidated balance sheet at fair value. Changes in the fair market value of the contract are recorded in the consolidated statement of operations.

We have recorded a $10.0 million unrealized gain and a $49.1 million unrealized loss for the three and nine months ended September 30, 2012, respectively, related to our gas purchase agreements accounted for as derivative financial instruments.

Natural gas swaps

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

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. We have entered into natural gas swaps to effectively fix the price of 3.2 million Mmbtu of future natural gas purchases, or approximately 64% of our share of the expected natural gas purchases at the project during 2014 and 2015. We also entered into natural gas swaps to effectively fix the price of 1.3 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2016 and 2017.

The Lake project's operating margin is exposed to changes in natural gas spot market prices through the expiration of its PPA on July 31, 2013. We have entered into natural gas swaps to effectively fix the price of approximately 90% of the expected natural gas purchases at Lake for the remainder of 2012 and 83% of the expected natural gas purchases through July 31, 2013.

The Auburndale project's operating margin is exposed to changes in natural gas spot market prices through the expiration of its PPA at the end of 2013. We have entered into natural gas swaps to effectively fix the price of approximately 46% of the expected natural gas purchases at Auburndale for the remainder of 2012 and 79% of the expected natural gas purchases through December 31, 2013.

Interest rate swaps

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate on its non-recourse, project-level debt at 6.02% until February 15, 2015, 6.14% from February 16, 2015 to February 15, 2019, 6.26% from February 16, 2019 to February 15, 2023, and 6.38% thereafter. The notional amount of the interest rate swap agreement matches the outstanding principal balance over the remaining life of Cadillac's debt. This swap agreement, which qualifies for and is designated as a cash flow hedge, is effective through June 2025 and changes in the fair market value are recorded in accumulated other comprehensive income.

The Auburndale project hedged a portion of its exposure to changes in interest rates related to its variable-rate, non-recourse project-level debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 5.10%. The notional amount of the swap matches the outstanding principal balance over the remaining life of Auburndale's debt. This swap agreement is effective through November 30, 2013. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Auburndale debt agreement and changes in the fair market value are recorded in accumulated other comprehensive income.

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate, non-recourse debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.75% until February 29, 2016. From March 1, 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 that will convert to a term loan. The interest rate swaps were executed in the fourth quarter 2010 and expire on February 29, 2016 and November 30, 2030. The

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

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

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 and Canadian dollars but pay dividends to shareholders and interest on our Canadian dollar denominated convertible debentures and long-term debt 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 an average of approximately 78% of our expected dividend and convertible debenture interest payments through 2015. 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. At September 30, 2012, 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) contracts assumed in our acquisition of the Partnership with various expiration dates through December 2015 to purchase a total of Cdn$112.0 million at an average exchange rate of Cdn$1.130 per U.S. dollar. It is our intention to periodically consider extending the length or terminating these forward contracts.

Volume of forecasted transactions

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the NPNS exemption as of September 30, 2012 and December 31, 2011:

	Units	September 30, 2012	December 31, 2011
Natural gas swaps	Natural Gas (Mmbtu)	11,930	14,140
Gas Purchase Agreements	Natural Gas (GJ)	51,867	33,957
Interest Rate Swaps	Interest (US$)	48,450	52,711
Currency forwards	Cdn$	202,028	312,533

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Fair value of derivative instruments

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

	September 30, 2012	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1,469
Interest rate swaps long-term		5,391
Total derivative instruments designated as cash flow hedges		6,860
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		2,531
Interest rate swaps long-term		11,436
Foreign currency forward contracts current	10,299	
Foreign currency forward contracts long-term	13,942	
Natural gas swaps current		18,764
Natural gas swaps long-term	294	6,588
Gas purchase agreements current	493	19,676
Gas purchase agreements long-term		79,996
Total derivative instruments not designated as cash flow hedges	25,028	138,991
Total derivative instruments	$ 25,028	$ 145,851

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

	December 31, 2011 Derivative Assets	December 31, 2011 Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1,561
Interest rate swaps long-term		5,317
Total derivative instruments designated as cash flow hedges		6,878
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		2,587
Interest rate swaps long-term		9,637
Foreign currency forward contracts current	10,630	224
Foreign currency forward contracts long-term	22,224	221
Natural gas swaps current		16,439
Natural gas swaps long-term		18,216
Gas purchase agreements current		
Gas purchase agreements long-term		
Total derivative instruments not designated as cash flow hedges	32,854	47,324
Total derivative instruments	$ 32,854	$ 54,202

Accumulated other comprehensive income

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

For the three month period ended September 30, 2012	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at June 30, 2012	$ (1,667)	$ 207	$ (1,460)
Change in fair value of cash flow hedges	(300)		(300)
Realized from OCI during the period	274	(58)	216
Accumulated OCI balance at September 30, 2012	$ (1,693)	$ 149	$ (1,544)

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

Accumulated OCI balance at September 30, 2011	$	(1,630)	$	412	$	(1,218)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

For the nine month period ended September 30, 2012	**Interest Rate Swaps**	**Natural Gas Swaps**	**Total**
Accumulated OCI balance at December 31, 2011	$ (1,704)	$ 321	$ (1,383)
Change in fair value of cash flow hedges	(833)		(833)
Realized from OCI during the period	844	(172)	672
Accumulated OCI balance at September 30, 2012	$ (1,693)	$ 149	$ (1,544)

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

Impact of derivative instruments on the consolidated statements of operations

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

	Classification of (gain) loss recognized in income	**Three months ended September 30, 2012**	**2011**
Natural gas swaps	Fuel	$ 5,170	$ 1,744
Gas purchase agreements	Fuel	15,191	
Foreign currency forwards	Foreign exchange (gain) loss	(2,068)	(2,100)
Interest rate swaps	Interest, net	1,208	1,091

	Classification of (gain) loss recognized in income	**Nine months ended September 30, 2012**	**2011**
Natural gas swaps	Fuel	$ 14,994	$ 6,275
Gas purchase agreements	Fuel	47,839	
Foreign currency forwards	Foreign exchange (gain) loss	(17,110)	(7,792)
Interest rate swaps	Interest, net	3,556	3,022

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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

	Classification of (gain) loss recognized in income	Three months ended September 30, 2012	Three months ended September 30, 2011
Natural gas swaps	Change in fair value of derivatives	$ 7,463	$ (3,017)
Gas purchase agreements	Change in fair value of derivatives	10,022	
Interest rate swaps	Change in fair value of derivatives	(272)	(8,467)
Total change in fair value of derivative instruments		$ 17,213	$ (11,484)
Foreign currency forwards	Foreign exchange (gain) loss	$ (4,694)	$ 39,950

	Classification of (gain) loss recognized in income	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Natural gas swaps	Change in fair value of derivatives	$ 9,883	$ (1,372)
Gas purchase agreements	Change in fair value of derivatives	(49,093)	
Interest rate swaps	Change in fair value of derivatives	(1,743)	(11,125)
Total change in fair value of derivative instruments		$ (40,953)	$ (12,497)
Foreign currency forwards	Foreign exchange (gain) loss	$ 8,169	$ 37,817

8. Income taxes

The difference between the actual tax expense (benefit) of $3.2 million and $(19.1) million for the three and nine months ended September 30, 2012 and the expected income tax benefit, based on the Canadian enacted statutory rate of 25%, of $(0.5) million and $(16.6) million, respectively, is primarily due to higher tax rates in various tax jurisdictions, and various other permanent differences, partially offset by a change in the valuation allowance.

	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Current income tax expense (benefit)	$ 1,935	$ 104	$ 6,116	$ (366)
Deferred tax expense (benefit)	1,231	(5,427)	(25,192)	(12,534)
Total income tax expense (benefit)	$ 3,166	$ (5,323)	$ (19,076)	$ (12,900)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Income taxes (Continued)

As of September 30, 2012, we have recorded a valuation allowance of $98.4 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.

9. Employee Incentive Programs

Long-Term Incentive Program

The following table summarizes the changes in LTIP notional units during the nine months ended September 30, 2012:

	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2011	485,781	$ 11.49
Granted	226,752	$ 14.66
Forfeited	(28,932)	$ 13.63
Additional shares from dividends	27,579	$ 13.25
Vested	(231,687)	$ 10.10
Outstanding at September 30, 2012	479,493	$ 13.56

Certain awards have a market condition based on our total shareholder return during the performance period compared to a group of peer companies. Compensation expense for notional units granted in 2012 is recorded net of estimated forfeitures. See further details as disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011.

The calculation of simulated total shareholder return under the Monte Carlo model for the remaining time in the performance period for awards with market conditions included the following assumptions as of September 30, 2012 and December 31, 2011:

	September 30, 2012	December 31, 2011
Weighted average risk free rate of return	0.14 0.27%	0.15 0.28%
Dividend yield	7.80%	7.90%
Expected volatility Atlantic Power	14.0 19.9%	22.20%
Expected volatility peer companies	11.3 144.6%	17.3 112.9%
Weighted average remaining measurement period	1.43 years	0.87 years

Equity Incentive Plan

On April 23, 2012 the Board of Directors, upon the recommendation of the Compensation Committee, adopted the 2012 Equity Incentive Plan (the "2012 Incentive Plan"), which was approved by our shareholders on June 22, 2012. The 2012 Incentive Plan increases the flexibility of the Compensation Committee to use various equity-based incentive awards as compensation tools to

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

9. Employee Incentive Programs (Continued)

motivate our employees. Adoption of the 2012 Incentive Plan did not have any impact on previous award grants and 6,000 common shares have been granted under the 2012 Incentive Plan as of September 30, 2012. The 2012 Incentive Plan has an expiration date of June 22, 2022.

10. 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, 2012. 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.

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the three and nine months ended September 30, 2012 and 2011:

	Three months ended September 30,		Nine months ended September 30,	
	2012	**2011**	**2012**	**2011**
Numerator:				
Net income (loss) attributable to Atlantic Power Corporation	$ (7,446)	$ (27,900)	$ (54,824)	$ (8,578)
Denominator:				
Weighted average basic shares outstanding	119,011	68,910	115,437	68,384
Dilutive potential shares:				
Convertible debentures	20,459	13,718	15,672	14,190
LTIP notional units	481	415	477	363
Potentially dilutive shares	139,951	83,043	131,586	82,937
Diluted loss per share	$ (0.06)	$ (0.40)	$ (0.47)	$ (0.13)

Potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units have been excluded from fully diluted shares in the three and nine months ended September 30, 2012 and 2011 because their impact would be anti-dilutive.

11. Held for Sale Business

During the three months ended September 30, 2012, we classified our Path 15 project, which is a component of the Southwest segment, as a held for sale business based on our plan to sell the project within the next twelve months. Accordingly, the assets and liabilities of Path 15 have been classified separately as held for sale in the consolidated balance sheet at September 30, 2012 and the project's net income is recorded as income from discontinued operations in the consolidated statements of operations, net of tax for the three and nine months ended September 30, 2012 and 2011. The

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Held for Sale Business (Continued)

following table summarizes the revenue, income from operations and income tax expense of Path 15 for the three and nine months ended September 30, 2012 and 2011:

	Three months ended September 30,		Nine months ended September 30,	
	2012	2011	2012	2011
Revenue	$ 7,227	$ 7,638	$ 20,751	$ 22,773
Income from operations of discontinued businesses	1,261	2,074	2,356	5,733
Income tax expense	488	803	912	2,219
Income from operations of discontinued businesses, net of tax	$ 773	$ 1,271	$ 1,444	$ 3,514

Basic and diluted earnings per share related to income from discontinued operations was $0.01 and $0.02 for the three months ended September 30, 2012 and 2011, respectively and $0.01 and $0.05 for the nine months ended September 30, 2012 and 2011, respectively.

The components of assets and liabilities held for sale are set forth in the following table:

	September 30, 2012
Current assets:	
Cash and cash equivalents	$ 1,742
Restricted cash	14,273
Accounts receivable	1,691
Other current assets	664
	18,370
Non-current assets assets:	
Transmission system rights	174,393
Goodwill	8,918
Other assets	1,430
Assets held for sale	203,111
Current liabilities:	
Accounts payable and other accrued liabilities	$ 5,380
Current portion of long-term debt	9,028
	14,408
Long term liabilities	
Long-term debt	143,012
Liabilities held for sale	157,420

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

12. Equity

The following table provides a reconciliation of the beginning and ending equity attributable to shareholders of Atlantic Power Corporation, preferred shares issued by a subsidiary company, noncontrolling interest and total equity as of September 30, 2012 and 2011:

	Nine months ended September 30, 2012			
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Noncontrolling Interest	Total Equity
Balance at January 1	$ 891,450	$ 221,304	$ 3,027	$ 1,115,781
Net income (loss)	(54,824)	9,767	(696)	(45,753)
Realized and unrealized loss on hedging activities, net of tax	(162)			(162)
Foreign currency translation adjustment, net of tax	22,608			22,608
Common shares issuance, net of costs	67,777			67,777
Compensation expense for LTIP	1,344			1,344
Convertible debenture conversion	13			13
Dividends declared on common shares	(99,043)			(99,043)
Dividends declared on preferred shares of a subsidiary company		(9,767)		(9,767)
Balance at September 30	$ 829,163	$ 221,304	$ 2,331	$ 1,052,798

	Nine months ended September 30, 2011			
	Total Atlantic Power Corporation Shareholders' Equity	Preferred shares issued by a subsidiary company	Noncontrolling Interest	Total Equity
Balance at January 1	$ 429,869	$	$ 3,507	$ 433,376
Net loss	(8,578)		(349)	(8,927)
Realized and unrealized loss on hedging activities, net of tax	(1,473)			(1,473)
Compensation expense for LTIP	1,232			1,232
Convertible debenture conversion	21,730			21,730
Dividends declared on common shares	(57,064)			(57,064)
Balance at September 30	$ 385,716	$	$ 3,158	$ 388,874

On August 8, 2012, we announced the details of our Dividend Reinvestment Plan ("DRIP"). The DRIP allows eligible holders of common shares to reinvest their cash dividends to acquire additional common shares of Atlantic Power at a 3% discount to market price.

On July 5, 2012, we closed a public offering of 5,567,177 common shares, at a purchase price of $12.76 per common share and Cdn$13.10 per common share, for aggregate net proceeds, after deducting the underwriting discounts and expenses, of approximately $67.7 million.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and geographic information

We revised our reportable business segments during the fourth quarter of 2011 subsequent to our acquisition of the Partnership. The new operating segments are Northeast, Northwest, Southeast, Southwest and Un-allocated Corporate. Financial results for the three and nine months ended September 30, 2012 and 2011 have been presented to reflect the change in operating segments. We revised our segments to align with changes in management's resource allocation and assessment of performance. These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure and costs of being a public registrant in the United States and Canada. These costs are not allocated to the operating segments when determining segment profit or loss.

We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under U.S. generally accepted accounting principles ("GAAP") and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of project (loss) income to Project Adjusted EBITDA is included in the tables below.

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Three month period ended September 30, 2012:						
Operating revenues	$ 43,804	$ 48,194	$ 14,959	$ 47,734	$ (192)	$ 154,499
Segment assets	1,157,943	446,313	851,972	1,162,580	25,187	3,643,995
Project Adjusted EBITDA	$ 20,346	$ 23,150	$ 12,596	$ 23,440	$ (2,338)	$ 77,194
Change in fair value of derivative instruments	(10,160)	(7,187)				(17,347)
Depreciation and amortization	20,367	9,360	10,710	9,252	36	49,725
Interest, net	4,484	141	1,204	135	44	6,008
Other project (income) expense	258			156	415	829
Project (loss) income	5,397	20,836	682	13,897	(2,833)	37,979
Administration					6,309	6,309
Interest, net					25,829	25,829
Foreign exchange gain					7,659	7,659
Other income, net					272	272
Loss from continuing operations before income taxes	5,397	20,836	682	13,897	(42,902)	(2,090)
Income tax expense					3,166	3,166
Net loss	5,397	20,836	682	13,897	(46,068)	(5,256)
Income from discontinued operations				773		773
Net income (loss)	$ 5,397	$ 20,836	$ 682	$ 14,670	$ (46,068)	$ (4,483)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and geographic information (Continued)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Three month period ended September 30, 2011:						
Operating revenues	$ 4,933	$ 39,661	$	$	$ 101	$ 44,695
Segment assets	277,314	419,584	46,841	224,957	60,325	1,029,021
Project Adjusted EBITDA	$ 9,817	$ 21,635	$ 1,121	$ 1,523	$ (233)	$ 33,863
Change in fair value of derivative instruments	224	10,648			(1)	10,871
Depreciation and amortization	4,636	9,390	1,001	757	13	15,797
Interest, net	2,491	243	682	284	6	3,706
Other project (income) expense	1,300	12		1	(4)	1,309
Project (loss) income	1,166	1,342	(562)	481	(247)	2,180
Administration					11,839	11,839
Interest, net					3,337	3,337
Foreign exchange gain					21,576	21,576
Income from continuing operations before income taxes	1,166	1,342	(562)	481	(36,999)	(34,572)
Income tax benefit					(5,323)	(5,323)
Net loss	1,166	1,342	(562)	481	(31,676)	(29,249)
Income from discontinued operations				1,271		1,271
Net income (loss)	$ 1,166	$ 1,342	$ (562)	$ 1,752	$ (31,676)	$ (27,978)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Nine month period ended September 30, 2012:						
Operating revenues	$ 156,632	$ 137,406	$ 46,923	$ 121,674	$ 1,195	$ 463,830
Segment assets	1,157,943	446,313	851,972	1,162,580	25,187	3,643,995
Project Adjusted EBITDA	$ 85,156	$ 69,892	$ 38,453	$ 47,952	$ (9,645)	$ 231,808
Change in fair value of derivative instruments	46,283	(7,840)				38,443
Depreciation and amortization	58,028	28,099	31,730	28,902	37	146,796
Interest, net	13,922	404	3,833	412	(2)	18,569
Other project (income) expense	755	28		2,927	590	4,300
Project (loss) income	(33,832)	49,201	2,890	15,711	(10,270)	23,700
Administration					21,992	21,992
Interest, net					69,269	69,269
Foreign exchange gain					4,440	4,440

Other income, net					(5,728)	(5,728)
Loss from continuing operations before income taxes	(33,832)	49,201	2,890	15,711	(100,243)	(66,273)
Income tax benefit					(19,076)	(19,076)
Net loss	(33,832)	49,201	2,890	15,711	(81,167)	(47,197)
Income from discontinued operations				1,444		1,444
Net income (loss)	$ (33,832)	$ 49,201	$ 2,890	$ 17,155	$ (81,167)	$ (45,753)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and geographic information (Continued)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Nine month period ended September 30, 2011:						
Operating revenues	$ 14,498	$ 121,747	$	$	$ 238	$ 136,483
Segment assets	277,314	419,584	46,841	224,957	60,325	1,029,021
Project Adjusted EBITDA	$ 27,400	$ 63,892	$ 3,606	$ 4,894	$ (838)	$ 98,954
Change in fair value of derivative instruments	1,461	11,452				12,913
Depreciation and amortization	13,848	28,262	2,299	2,472	35	46,916
Interest, net	7,386	831	2,204	638	41	11,100
Other project (income) expense	1,731	57		5	(4)	1,789
Project (loss) income	2,974	23,290	(897)	1,779	(910)	26,236
Administration					20,379	20,379
Interest, net					10,815	10,815
Foreign exchange gain					20,383	20,383
Income from continuing operations before income taxes	2,974	23,290	(897)	1,779	(52,487)	(25,341)
Income tax benefit					(12,900)	(12,900)
Net loss	2,974	23,290	(897)	1,779	(39,587)	(12,441)
Income from discontinued operations				3,514		3,514
Net income (loss)	$ 2,974	$ 23,290	$ (897)	$ 5,293	$ (39,587)	$ (8,927)

The tables below provide information, by country, about our consolidated operations for the three and nine months ended September 30, 2012 and 2011. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

	Project Revenue Three Months Ended September 30, 2012	Project Revenue Three Months Ended September 30, 2011	Project Revenue Nine Months Ended September 30, 2012	Project Revenue Nine Months Ended September 30, 2011
United States	$ 109,177	$ 44,695	$ 309,336	$ 136,483
Canada	45,322		154,494	
Total	$ 154,499	$ 44,695	$ 463,830	$ 136,483

	Property, Plant and Equipment, net of accumulated depreciation September 30, 2012	Property, Plant and Equipment, net of accumulated depreciation September 30, 2011

United States	$ 1,164,340	$ 360,594
Canada	566,425	
Total	$ 1,730,765	$ 360,594

Progress Energy Florida ("PEF") and the Ontario Electricity Financial Corp ("OEFC") provided approximately 28% and 19%, respectively, of total consolidated revenues for the three months ended September 30, 2012, and 26% and 22%, respectively, of total consolidated revenues for the nine

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

13. Segment and geographic information (Continued)

months ended September 30, 2012. PEF and the California Independent System Operator ("CAISO") provided approximately 70% and 15%, respectively, of total consolidated revenues for the three months ended September 30, 2011, and 74% and 15%, respectively, for the nine months ended September 30, 2011. PEF purchases electricity from the Auburndale and Lake projects in the Southeast segment, OEFC purchases electricity from the Calstock, Kapuskasing, Nipigon, North Bay and Tunis projects in the Northeast segment and the CAISO makes payments to Path 15 in the Southwest segment.

14. Commitments and contingencies

Path 15

In February 2011, we filed a rate application with the Federal Energy Regulatory Commission ("FERC") to establish Path 15's revenue requirement at $30.3 million for the 2011-2013 period. On March 7, 2012, Path 15 filed a formal settlement agreement establishing a revenue requirement at $28.8 million with the Administrative Law Judge for review and certification to FERC for approval. The settlement was approved by the FERC on May 23, 2012.

IRS Examination

In 2011, the Internal Revenue Service ("IRS") began an examination of our federal income tax returns for the tax years ended December 31, 2007 and 2009. On April 2, 2012, the IRS issued various Notices of Proposed Adjustments. The principal area of the proposed adjustments pertain to the classification of U.S. real property in the calculation of the gain related to our 2009 conversion from the previous Income Participating Security structure to our current traditional common share structure.

We intend to vigorously contest these proposed adjustments, including pursuing all administrative and judicial remedies available to us. We expect to be successful in sustaining our positions with no material impact to our financial results. No accrual has been made for any contingency related to any of the proposed adjustments as of September 30, 2012.

Lake

Our Lake project is currently involved in a dispute with PEF 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 PEF. The Lake project has filed a claim against PEF in which we seek to confirm our contractual right to sell off-peak energy at the contractual price for such sales. PEF 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.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Commitments and contingencies (Continued)

Morris

On May 29, 2011, our Morris facility was struck by lightning. As a result, steam and electric deliveries were interrupted to our host Equistar. We believe the interruption constitutes a force majeure under the energy services agreement with Equistar. Equistar disputes this interpretation and has initiated arbitration proceedings under the agreement for recovery of resulting lost profits and equipment damage among other items. The agreement with Equistar specifically shields Morris from exposure to consequential damages incurred by Equistar and management expects our insurance to cover any material losses we might incur in connection with such proceedings, including settlement costs. Management will attempt to resolve the arbitration through settlement discussions, but is prepared to vigorously defend the arbitration on the merits.

Other

In addition to the other matters listed above, 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 probable and can be reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of September 30, 2012.

15. Guarantees and condensed consolidating financial information

In connection with the tax equity investments in our Canadian Hills project, we have expressly indemnified the investors for certain representations and warranties made by a wholly-owned subsidiary with respect to matters which we believe are remote and improbable to occur. The expiration dates of these guarantees vary from less than one year through the indefinite termination date of the project. Our maximum undiscounted potential exposure is limited to the amount of tax equity investment less the sum of cash distributions made to the investors and any net federal income tax benefits arising from production tax credits.

As of September 30, 2012 and December 31, 2011, we had $460.0 million of Senior Notes. These notes are guaranteed by certain of our wholly owned subsidiaries, or guarantor subsidiaries.

Unless otherwise noted below, each of the following guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of September 30, 2012:

Atlantic Power Limited Partnership, Atlantic Power GP Inc., Atlantic Power (US) GP, Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Atlantic Power Holdings, Inc., Atlantic Power Services Canada GP Inc., Atlantic Power Services Canada LP, Atlantic Power Services, LLC, Teton Power Funding, LLC, Harbor Capital Holdings, LLC, Epsilon Power Funding, LLC, Atlantic Auburndale, LLC, Auburndale LP, LLC, Auburndale GP, LLC, Atlantic Cadillac Holdings, LLC, Atlantic Idaho Wind Holdings, LLC, Atlantic Idaho Wind C, LLC, Baker Lake Hydro, LLC, Olympia Hydro, LLC, Teton East Coast Generation, LLC, NCP Gem, LLC, NCP Lake Power, LLC, Lake Investment, LP, Teton New Lake, LLC, Lake Cogen Ltd., Atlantic Renewables Holdings, LLC, Orlando Power Generation I, LLC, Orlando Power Generation II, LLC, NCP Dade Power, LLC, NCP Pasco LLC, Dade Investment, LP, Pasco Cogen, Ltd., Atlantic Piedmont

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

Holdings LLC, Teton Selkirk, LLC, Atlantic Oklahoma Wind, LLC, and Teton Operating Services, LLC.

The following condensed consolidating financial information presents the financial information of Atlantic Power, the guarantor subsidiaries, and Curtis Palmer in accordance with Rule 3-10 under the SEC's Regulation S-X. The principal elimination entries eliminate investments in subsidiaries and intercompany balances and transactions. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiaries or Curtis Palmer operated as independent entities.

In this presentation, Atlantic Power consists of parent company operations. Guarantor subsidiaries of Atlantic Power are reported on a combined basis. For companies acquired, the fair values of the assets and liabilities acquired have been presented on a push-down accounting basis.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING BALANCE SHEET

September 30, 2012

(in thousands of U.S. dollars)
(Unaudited)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Assets					
Current assets:					
Cash and cash equivalents	$ 42,510	$ (1,939)	$ 2,301	$	$ 42,872
Restricted cash	112,633				112,633
Accounts receivable	109,511	27,555	2,011	(58,887)	80,190
Prepayments, supplies, and other current assets	49,017	2,968	10,309		62,294
Asset held for sale	203,111				203,111
Total current assets	516,782	28,584	14,621	(58,887)	501,100
Property, plant, and equipment, net	1,558,898	173,034		(1,167)	1,730,765
Equity investments in unconsolidated affiliates	5,042,721		577,973	(5,188,169)	432,525
Other intangible assets, net	396,794	160,562			557,356
Goodwill	276,440	58,228			334,668
Other assets	483,253		447,380	(843,052)	87,581
Total assets	$ 8,274,888	$ 420,408	$ 1,039,974	$ (6,091,275)	$ 3,643,995
Liabilities					
Current Liabilities:					
Accounts payable and accrued liabilities	$ 139,566	$ 10,464	$ 34,997	$ (58,887)	$ 126,140
Revolving credit facility			20,000		20,000
Current portion of long-term debt	303,890				303,890
Other current liabilities	203,874		11,627		215,501
Total current liabilities	647,330	10,464	66,624	(58,887)	665,531
Long-term debt	575,661	190,000	460,000		1,225,661
Convertible debentures			326,067		326,067
Other non-current liabilities	1,207,579	8,261	1,150	(843,052)	373,938
Equity					
Preferred shares issued by a subsidiary company	221,304				221,304
Common shares	4,977,653	211,683	1,286,399	(5,189,336)	1,286,399
Accumulated other comprehensive income (loss)	17,253				17,253
Retained deficit	625,777		(1,100,266)		(474,489)

Total Atlantic Power Corporation shareholders' equity	5,841,987	211,683	186,133	(5,189,336)	1,050,467
Noncontrolling interest	2,331				2,331
Total equity	5,844,318	211,683	186,133	(5,189,336)	1,052,798
Total liabilities and equity	$ 8,274,888	$ 420,408	$ 1,039,974	$ (6,091,275)	$ 3,643,995

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Three months ended September 30, 2012

(in thousands of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Project revenue:					
Total project revenue	$ 150,006	$ 4,660	$	$ (167)	$ 154,499
Project expenses:					
Fuel	58,565				58,565
Project operations and maintenance	34,858	1,571	(466)	(115)	35,848
Depreciation and amortization	34,701	3,841			38,542
	128,124	5,412	(466)	(115)	132,955
Project other income (expense):					
Change in fair value of derivative instruments	17,213				17,213
Equity in earnings of unconsolidated affiliates	4,000				4,000
Interest expense, net	(1,409)	(2,802)			(4,211)
Other income, net	(567)				(567)
	19,237	(2,802)			16,435
Project income	41,119	(3,554)	466	(52)	37,979
Administrative and other expenses (income):					
Administration expense	4,174		2,135		6,309
Interest, net	20,374		5,456		25,829
Foreign exchange loss	4,474		3,185		7,659
Other Income (loss)	272				272
	29,293		10,776		40,069
Income (loss) from continuing operations before income taxes	11,826	(3,554)	(10,310)	(52)	(2,090)
Income tax expense	3,166				3,166
Net income (loss) from continuing operations	8,660	(3,554)	(10,310)	(52)	(5,256)
Net income from discontinued operations	773				773
Net income (loss)	9,433	(3,554)	(10,310)	(52)	(4,483)
Net income attributable to noncontrolling interest	2,963				2,963
	$ 6,470	$ (3,554)	$ (10,310)	$ (52)	$ (7,446)

Net income (loss) attributable to Atlantic Power Corporation	

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Nine months ended September 30, 2012

(in thousands of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Project revenue:					
Total project revenue	$ 440,689	$ 23,583	$	$ (442)	$ 463,830
Project expenses:					
Fuel	176,176				176,176
Project operations and maintenance	106,814	4,709	(206)	(290)	111,027
Depreciation and amortization	99,774	11,445			111,219
	382,764	16,154	(206)	(290)	398,422
Project other income (expense):					
Change in fair value of derivative instruments	(40,953)				(40,953)
Equity in earnings of unconsolidated affiliates	12,420				12,420
Interest expense, net	(4,286)	(8,345)	(6)		(12,637)
Other income, net	(538)				(538)
	(33,357)	(8,345)	(6)		(41,708)
Project income	24,568	(916)	200	(152)	23,700
Administrative and other expenses (income):					
Administration expense	14,118		7,874		21,992
Interest, net	60,476		8,620	173	69,269
Foreign exchange loss	3,163		1,277		4,440
Other income (loss)	(5,728)				(5,728)
	72,029		17,771	173	89,973
Loss from continuing operations before income taxes	(47,461)	(916)	(17,571)	(325)	(66,273)
Income tax benefit	(19,077)		1		(19,076)
Net loss from continuing operations	(28,384)	(916)	(17,572)	(325)	(47,197)
Income from discontinued operations, net of tax	1,444				1,444
Net loss	(26,940)	(916)	(17,572)	(325)	(45,753)
Net income attributable to noncontrolling interest	9,071				9,071
	$ (36,011)	$ (916)	$ (17,572)	$ (325)	$ (54,824)

Net loss attributable to Atlantic Power Corporation	

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF COMPREHENSIVE INCOME

Three and nine months ended September 30, 2012

(in thousands of U.S. dollars)

	Three months ended September 30, 2012				
	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net income (loss)	$ 6,470	$ (3,554)	$ (10,310)	$ (52)	$ (7,446)
Other comprehensive income (loss):					
Unrealized loss on hedging activities	(300)				(300)
Net amount reclassified to earnings	216				216
Net unrealized losses on derivatives	(84)				(84)
Foreign currency translation adjustments	19,301				19,301
Other comprehensive income, net of tax	19,217				19,217
Comprehensive income (loss)	$ 25,687	$ (3,554)	$ (10,310)	$ (52)	$ 11,771

	Nine months ended September 30, 2012				
	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net income (loss)	$ (36,011)	$ (916)	$ (17,572)	$ (325)	$ (54,824)
Other comprehensive income (loss):					
Unrealized loss on hedging activities	(833)				(833)
Net amount reclassified to earnings	672				672
Net unrealized losses on derivatives	(161)				(161)
Foreign currency translation adjustments	22,608				22,608
Other comprehensive income, net of tax	22,447				22,447
Comprehensive income (loss)	$ (13,564)	$ (916)	$ (17,572)	$ (325)	$ (32,377)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

15. Guarantees and condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Nine months ended September 30, 2012

(in thousands of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net cash provided by (used in) operating activities	$ (13,219)	$ (1,907)	$ 139,242	$	$ 124,116
Cash flows used in investing activities:					
Acquisitions and investments, net of cash acquired	193,155		(193,419)		(264)
Proceeds from sale of equity investments	27,925				27,925
Construction in progress	(336,153)				(336,153)
Change in restricted cash	(105,494)				(105,494)
Biomass development costs	(372)				(372)
Purchase of property, plant and equipment	(1,155)	(17)			(1,172)
Net cash used in investing activities	(222,094)	(17)	(193,419)		(415,530)
Cash flows provided by financing activities:					
Proceeds from issuance of convertible debentures			130,000		130,000
Net proceeds from issuance of equity			67,692		67,692
Repayment for long-term debt	(12,050)				(12,050)
Deferred finance costs	(10,179)		(15,160)		(25,339)
Proceeds from project-level debt	261,226				261,226
Payments for revolving credit facility borrowings	(30,800)		(30,000)		(60,800)
Proceeds from revolving credit facility borrowings	22,800				22,800
Dividends paid	(9,802)		(98,350)		(108,152)
Net cash provided by financing activities	221,195		54,182		275,377
Net increase in cash and cash equivalents	(14,118)	(1,924)	5		(16,037)
Less cash at discontinued operation	(1,742)				(1,742)
Cash and cash equivalents at beginning of period	58,370	(15)	2,296		60,651
Cash and cash equivalents at end of period	$ 42,510	$ (1,939)	$ 2,301	$	$ 42,872

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FORWARD-LOOKING INFORMATION

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

- the amount of distributions expected to be received from the projects;
- our ability to generate sufficient amounts of cash and cash equivalents to maintain our operations and meet obligations as they become due;
- expectations regarding completion of construction of certain projects; and
- the impact of legislative, regulatory, competitive and technological changes.

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

Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. In addition, a number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors discussed under "Risk Factors" included in the filings we make from time to time with the SEC. Our business is both highly competitive and subject to various risks.

These risks include, without limitation:

- general economic conditions, including exchange rate fluctuations;
- reductions in revenue, which could be substantial, 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 dependence of our projects on third-party suppliers;
- the dependence of our windpower projects on suitable wind and associated conditions;

the adequacy of our insurance coverage;

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

increased competition, including for acquisitions;

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

construction risks; and

labor disruptions.

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Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include third party projections of regional fuel and electric capacity and energy prices or cash flows that are based on assumptions about future economic conditions and courses of action. Although the forward-looking statements contained in this Quarterly Report on Form 10-Q are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. Certain statements included in this Quarterly Report on Form 10-Q may be considered "financial outlook" for the purposes of applicable securities laws, and such financial outlook may not be appropriate for purposes other than this Quarterly Report on Form 10-Q. These forward-looking statements are made as of the date of this Form 10-Q, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

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

The following discussion of the financial condition and results of operations of Atlantic Power should be read in conjunction with the interim consolidated financial statements and the related notes thereto included elsewhere in this Quarterly Report on Form 10-Q. All dollar amounts discussed below are in thousands of U.S. dollars, unless otherwise stated. The interim financial statements have been prepared in accordance with GAAP.

Overview of Our Business

Atlantic Power owns and operates a diverse fleet of power generation and infrastructure assets in the United States and Canada. Our power generation projects sell electricity to utilities and other large commercial customers largely under long-term power purchase agreements ("PPAs"), which seek to minimize exposure to changes in commodity prices. Our power generation projects in operation have an aggregate gross electric generation capacity of approximately 3,351 megawatts ("MW") in which our aggregate ownership interest is approximately 2,118 MW. Our current portfolio consists of interests in 30 operational power generation projects across 11 states in the United States and two provinces in Canada and a 500-kilovolt 84-mile electric transmission line located in California. In addition, we have one 53 MW biomass project under construction in Georgia and one approximately 300 MW wind project under construction in Oklahoma. We also own a majority interest in Rollcast Energy Inc., a biomass power plant developer in North Carolina. Twenty-three of our projects are wholly owned subsidiaries.

We sell the capacity and energy from our power generation projects under PPAs with a number of utilities and other parties. Under the PPAs, which have expiration dates ranging from 2012 to 2037, we receive payments for electric energy delivered to our customers (known as energy payments), in addition to payments for electric generating capacity (known as capacity payments). We also sell steam from a number of our projects to industrial and commercial purchasers under steam sales agreements. The transmission system rights associated with our power transmission project entitle us to payments indirectly from the utilities that make use of the transmission line.

Our power generation projects generally have long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the term of the fuel supply and transportation arrangements corresponds to the term of the relevant PPAs, 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 an effective pass-through of fuel costs, we often attempt to mitigate the market price risk of changing commodity costs through the use of financial hedging strategies.

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We directly operate and maintain more than half of our power generation fleet. We, and the manager of our equity investments, also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including Caithness Energy, LLC, Colorado Energy Management, Power Plant Management Services and the Western Area Power Administration. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

We revised our reportable business segments during the fourth quarter of 2011 upon completion of the Partnership acquisition. The new operating segments are Northeast, Northwest, Southeast, Southwest and Un-allocated Corporate. Our financial results for the nine months ended September 30, 2012 have been presented to reflect these changes in our operating segments.

RECENT DEVELOPMENTS

Senior Credit Facility

In connection with the continued evolution of the Company's strategy to focus on late-stage development and construction projects, and the possible disposition of certain projects, including our Florida projects, on November 2, 2012, we amended the senior credit facility in order to change certain financial and leverage ratio covenants and obtained certain waivers from our lenders in connection with certain of our projects. See Item 5. Other Information to this quarterly report on Form 10-Q for additional information.

Canadian Hills

On January 31, 2012, Atlantic Oklahoma Wind, LLC ("Atlantic OW"), a Delaware limited liability company and a wholly owned subsidiary of Atlantic Power, entered into a purchase and sale agreement with Apex Wind Energy Holdings, LLC, a Delaware limited liability company ("Apex"), pursuant to which Atlantic OW acquired a 51% interest in Canadian Hills Wind, LLC, an Oklahoma limited liability company ("Canadian Hills") for a nominal sum. Canadian Hills is the owner of a 298.45 MW wind energy project under construction in the State of Oklahoma. Canadian Hills executed power PPAs for all of its output with Southwestern Electric Power Company (201.25 MW), Oklahoma Municipal Power Authority (49.2 MW), and Grand River Dam Authority (48 MW).

On March 30, 2012, we completed the purchase of an additional 48% interest in Canadian Hills for a nominal amount, bringing our total interest in the project to 99%. Apex retained a 1% interest in the project. At the time, we also closed a $310 million non-recourse, project-level construction financing facility for the project. The facility includes a $290 million construction loan and a $20 million 5-year letter of credit facility. Proceeds from the construction loan were used, in part, to repay Atlantic Power $29.3 million in member loans that were made to the project to fund construction prior to closing the construction financing facility. In connection with the closing of the construction financing facility, we committed to invest additional equity to cover the balance of the construction and development costs. We funded this equity commitment with the net proceeds from our July 5, 2012 public offering of common shares and convertible unsecured subordinated debentures. The net proceeds of our equity contribution was approximately $190.0 million. The acquisition of Canadian Hills was accounted for as an asset purchase and is consolidated in our consolidated balance sheet at September 30, 2012.

On October 31, 2012, the Canadian Hills project entered into an equity contribution agreement with four entities for the commitment of a tax equity investment in the project totalling $225.0 million in exchange for Class B equity interests in Canadian Hills which is to be funded on date of commercial operations. We are actively pursuing additional tax equity investors to fund the remaining estimated $47.0 million needed to pay down the existing construction loan. If we are unable to subscribe additional investors, we will fund the remaining portion with either cash on hand or proceeds from our senior credit facility and will become an additional tax equity investor in the project owning the remaining Class B equity interests in Canadian Hills.

Dividend Reinvestment Plan

On August 8, 2012, we announced the details of our Dividend Reinvestment Plan ("DRIP"). The DRIP allows eligible holders of common shares to reinvest their cash dividends to acquire additional common shares of Atlantic Power at a 3% discount to market price.

Common share and convertibles debenture offerings

On July 5, 2012, we closed a public offering of 5,567,177 common shares, at a purchase price of $12.76 per common share and Cdn$13.10 per common share, for aggregate net proceeds from the common share offering, after deducting the underwriting discounts and expenses, of approximately, $67.7 million. We also issued, in a public offering, $130.0 million aggregate principal amount of 5.75% convertible unsecured subordinated debentures due June 30, 2019, (the "2012 Debentures"), after deducting the underwriting discounts and offering expenses, for net proceeds of $124.0 million. The 2012 Debentures pay interest semi-annually on June 30 and December 30 of each year beginning December 30, 2012. The 2012 Debentures are convertible into our common shares at an initial conversion rate of 57.9710 common shares per $1,000 principal amount of debentures, subject to anti-dilution adjustments in certain circumstances. The 2012 Debentures may not be redeemed prior to June 30, 2015 (except in limited circumstances). After June 30, 2015, the 2012 Debentures may be redeemed by is, in whole or in part from time to time, upon certain conditions. Upon a change of control of the company, each holder may require that we purchase the 2012 Debentures upon the conditions set forth in the indenture governing the debentures. We used the net proceeds from the offerings to fund our equity commitment in Canadian Hills Wind, LLC.

Path 15

In February 2011, we filed a rate application with the Federal Energy Regulatory Commission ("FERC") to establish Path 15's revenue requirement at $30.3 million for the 2011-2013 period. On March 7, 2012, Path 15 filed a formal settlement agreement establishing a revenue requirement at $28.8 million with the Administrative Law Judge for review and certification to FERC for approval. The settlement was approved by the FERC on May 23, 2012. The new revenue requirement maintains the project's 13.5% regulated return on equity and will allow Path 15 to continue to make distributions consistent with our expectations through the 2013 rate period.

During the three months ended September 30, 2012, we classified our Path 15 project as a business held for sale based on our plan to sell the project within the next twelve months. Accordingly, the assets and liabilities of Path 15 have been classified separately as held for sale in the consolidated balance sheet at September 30, 2012 and the project's net income is recorded as income from discontinued operations, net of tax in the statement of operations for the three and nine months ended September 30, 2012 and 2011.

Badger Creek Sale

On August 6, 2012, we entered into a purchase and sale agreement for the sale of our 50% ownership interest in the Badger Creek project. On September 4, 2012, the transaction closed and we received gross proceeds of $3.7 million. During the second quarter of 2012, we recorded an impairment charge of $3.0 million which was recorded in equity in earnings from unconsolidated affiliates in the consolidated statements of operations.

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PERH Interest Sale

On February 16, 2012, we entered into an agreement with Primary Energy Recycling Corporation ("Primary Energy" or "PERC"), whereby PERC agreed to purchase our 7,462,830.33 common membership interests in Primary Energy Recycling Holdings, LLC ("PERH") (14.3% of PERH total interests) for approximately $24.2 million, plus a management agreement termination fee of approximately $6.0 million, for a total sale price of $30.2 million. The transaction closed in May 2012 and we recorded a $0.6 million gain on sale of our equity investment.

DuPont

As previously disclosed in our Annual Report on Form 10-K for the year ended December 31, 2011, Chambers filed suit against DuPont de Nemours & Company ("DuPont") for breach of the energy services agreement related to unpaid amounts associated with disputed price change calculations for electricity. On April 25, 2012, the court issued its written opinion which ordered DuPont to pay Chambers a total of approximately $15.7 million. This amount represents DuPont's electricity underpayments from January 2003 through June 2009, and interest through July 22, 2011. The court also ordered that from July 1, 2009 going forward, the pricing methodology should be calculated in accordance with the court's prior ruling on summary judgment. In June 2012, Dupont paid the Chambers project the true-up settlement of this new pricing methodology for the period July 1, 2009 through September 30, 2011 of approximately $9.0 million. On July 13, 2012, DuPont filed an appeal of this ruling and was granted a stay on paying any damages on the electricity under payment from January 2003 through June 2009 including interest.

OUR POWER PROJECTS

The table on the following page outlines our portfolio of power generating and transmission assets in operation and under construction as of November 1, 2012, 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.

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Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)[3]
Northeast Segment								
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	2028	BBB-
Chambers	New Jersey	Coal	262	40.00%	89	Atlantic City Elec.	2024	BBB+
					16	DuPont	2024	A
Kenilworth	New Jersey	Natural Gas	30	100.00%	30	Merck, & Co., Inc.	2012[1]	AA
Curtis Palmer	New York	Hydro	60	100.00%	60	Niagara Mohawk Power Corperation	2027	A-
Selkirk	New York	Natural Gas	345	17.70%	15	Merchant	N/A	N/R
					49	Consolidated Edison	2014	A-
Calstock	Ontario	Biomass	35	100.00%	35	Ontario Electricity Financial Corp	2020	AA-
Kapuskasing	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	2017	AA-
Nipigon	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	2022	AA-
North Bay	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	2017	AA-
Tunis	Ontario	Natural Gas	43	100.00%	43	Ontario Electricity Financial Corp	2014	AA-
Southeast Segment								
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 Company	2018	BBB+
Orlando	Florida	Natural Gas	129	50.00%	46	Progress Energy Florida	2023	BBB+
					19	Reedy Creek Improvement District(2)	2013	A-
Piedmont	Georgia	Biomass	54	98.0%	53	Georgia Power	2032	A
Northwest Segment								
Mamquam	British Columbia	Hydro	50	100.00%	50	British Columbia Hydro and Power Authority	2027	AAA
Moresby Lake	British Columbia	Hydro	6	100.00%	6	British Columbia Hydro and Power Authority	2022	AAA
Williams Lake	British Columbia	Biomass	66	100.00%	66	British Columbia Hydro and Power Authority	2018	AAA
Idaho Wind	Idaho	Wind	183	27.56%	50	Idaho Power Co.	2030	BBB
Rockland Wind Project	Idaho	Wind	80	30.00%	24	Idaho Power Co.	2036	BBB
Frederickson	Washington	Natural Gas	250	50.15%	125	Benton Co. PUD, Grays Harbor PUD, Franklin Co. PUD	2022	A
Koma Kulshan	Washington	Hydro	13	49.80%	7	Puget Sound Energy	2037	BBB
Southwest Segment								
Naval Station	California	Natural Gas	47	100.00%	47	San Diego Gas & Electric	2019	A
Naval Training Center	California	Natural Gas	25	100.00%	25	San Diego Gas & Electric	2019	A
North Island	California	Natural Gas	40	100.00%	40	San Diego Gas & Electric	2019	A

Oxnard	California	Natural Gas	49	100.00%	49	Southern California Edison	2020	BBB+
Path 15	California	Transmssion	N/A	100.00%	N/A	California Utilities via CAISO	N/A	BBB+ to A
Greeley	Colorado	Natural Gas	72	100%	72	Public Service Company of Colorado	2013	A-
Manchief	Colorado	Natural Gas	300	100%	300	Public Service Company of Colorado	2022	A-
Morris	Illinois	Natural Gas	177	100%	77	Merchant	N/A	N/R
					100	Equistar Chemicals, LP	2023	B+
Delta-Person	New Mexico	Natural Gas	132	40.0%	53	Public Service Company of New Mexico	2020	BBB-
Canadian Hills	Oklahoma	Wind	300	99.0%	200	Southwestern Electric Power Company	2032	BBB
					49	Oklahoma Municipal Power Authority	2037	N/R
					48	Grand River Dam Authority	2032	N/R
Gregory	Texas	Natural Gas	400	17.10%	59	Fortis Energy Marketing & Trading	2013	A-
					9	Sherwin Alumina	2020	N/R

(1) The Kenilworth PPA, which expired on July 31, 2012, was extended on a month-to month basis by agreement with the purchaser through November 30, 2012. We are currently in negotiations with the purchaser regarding the possible renewal of the PPA.

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

(3) Our customers are generally large utilities and other parties with investment-grade credit ratings. Customers that have assigned ratings at the top end of the range have, in the opinion of the rating agency, the strongest capability for payment of debt or payment of claims, while customers at the bottom end of the range have the weakest capacity. Agency ratings are subject to change, and there can be no assurance that a ratings agency will continue to rate the customers, and/or maintain their current ratings. A security rating is not a recommendation to buy, sell or hold securities, it may be subject to revision or withdrawal at any time by the rating agency, and each rating should be evaluated independently of any other rating. We cannot predict the effect that a change in the ratings of the customers will have on their liquidity or their ability to pay their debts.

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Consolidated Results of Operations

The following table and discussion is a summary of our consolidated results of operations for the three and nine months ended September 30, 2012 and 2011. The results of operations by segment are discussed in further detail following this consolidated overview discussion.

(in thousands of U.S. dollars, except as otherwise stated)	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Project revenue				
Northeast	$ 43,804	$ 4,933	$ 156,632	$ 14,498
Southeast	48,194	39,661	137,406	121,747
Northwest	14,959		46,923	
Southwest	47,734		121,674	
Un-allocated Corporate	(192)	101	1,195	238
	154,499	44,695	463,830	136,483
Project expenses				
Northeast	47,954	3,667	145,386	10,632
Southeast	35,298	27,807	97,976	86,742
Northwest	13,205		43,297	
Southwest	34,419		100,831	
Un-allocated Corporate	2,079	348	10,932	1,151
	132,955	31,822	398,422	98,525
Project other income (expense)				
Northeast	9,547	(100)	(45,078)	(892)
Southeast	7,940	(10,512)	9,771	(11,715)
Northwest	(1,072)	(562)	(736)	(897)
Southwest	582	481	(5,132)	1,779
Un-allocated Corporate	(562)		(533)	3
	16,435	(10,693)	(41,708)	(11,722)
Total project income (loss)				
Northeast	5,397	1,166	(33,832)	2,974
Southeast	20,836	1,342	49,201	23,290
Northwest	682	(562)	2,890	(897)
Southwest	13,897	481	15,711	1,779
Un-allocated Corporate	(2,833)	(247)	(10,270)	(910)
	37,979	2,180	23,700	26,236
Administrative and other expenses				
Administration	6,309	11,839	21,992	20,379
Interest, net	25,829	3,337	69,269	10,815
Foreign exchange gain	7,659	21,576	4,440	20,383
Other income, net	272		(5,728)	
Total administrative and other expenses	40,069	36,752	89,973	51,577
Loss from continuing operations before income taxes	(2,090)	(34,572)	(66,273)	(25,341)
Income tax expense (benefit)	3,166	(5,323)	(19,076)	(12,900)
Net loss from continuing operations	(5,256)	(29,249)	(47,197)	(12,441)
Income from discontinued operations, net of tax	773	1,271	1,444	3,514
Net loss	(4,483)	(27,978)	(45,753)	(8,927)
Net income (loss) attributable to noncontrolling interest	2,963	(78)	9,071	(349)

Net loss attributable to Atlantic Power Corporation shareholders	$ (7,446)	$ (27,900)	$ (54,824)	$ (8,578)

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Consolidated Overview

We have five reportable segments: Northeast, Southeast, Northwest, Southwest and Un-allocated Corporate. The consolidated results of operations are discussed below by reportable segment. The consolidated results of operations for the three and nine months ended September 30, 2012 include the results of operations from the Partnership, which was acquired on November 5, 2011.

Project income is the primary GAAP measure of our operating results and is discussed in "Segment Analysis" below. In addition, an analysis of non-project expenses impacting our results is set out in "Un-allocated Corporate" below.

Significant non-cash items, which are subject to potentially significant fluctuations, include: (1) the change in fair value of certain derivative financial instruments revalued at each balance sheet date (see "Item 3. 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 $28.3 million and $27.0 million for the three months ended September 30, 2012 and 2011, respectively. Cash Available for Distribution was $101.1 million and $61.6 million for the nine months ended September, 2012 and 2011, respectively. Cash Available for Distribution is a non-GAAP financial measure that we believe is a relevant supplemental measure of our ability to pay dividends to our shareholders. The most directly comparable GAAP measure is Cash flow from operating activities. For a reconciliation of Cash Available for Distribution to Cash flow from operating activities, see "Supplementary Non-GAAP Financial Information" and "Cash Available for Distribution".

Loss from continuing operations before income taxes for the three months ended September 30, 2012 and 2011 was $(2.1) million and $(34.6) million, respectively. Loss from continuing operations before income taxes for the nine months ended September 30, 2012 and 2011 was $(66.3) million and $(25.3) million, respectively. See "Segment Analysis" below for additional information.

Segment Analysis

Northeast

The following table summarizes project income (loss) for our Northeast segment for the periods indicated:

	Three months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Northeast			
Project income	$ 5,397	$ 1,166	Not Meaningful ("NM")

Three months ended September 30, 2012 compared with three months ended September 30, 2011

Project income for the three months ended September 30, 2012 increased $4.2 million from the comparable 2011 period primarily due to:

- project income from the newly acquired Nipigon project of $2.8 million resulting primarily from a positive $2.1 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives; and

- increased project income of $1.9 million at Chambers due to lower operations and maintenance expenses. The project had a forced outage in July 2011.

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These increases were partially offset by:

a project loss from the newly acquired Curtis Palmer project of $3.6 million due to a seasonal decline in revenue.

	Nine months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Northeast			
Project income (loss)	$ (33,832)	$ 2,974	NM

Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

Project income (loss) for the nine months ended September 30, 2012 decreased $36.8 million from the comparable 2011 period primarily due to:

a project loss of $52.2 million from the newly acquired North Bay, Kapuskasing and Nipigon projects. The project income (loss)for these projects was impacted by a negative $45.3 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives.

These decreases were partially offset by:

project income from the newly acquired Tunis project of $4.9 million;

increased project income of $4.0 million at Chambers due to the collection of the $3.6 million DuPont partial settlement associated with the dispute of the electricity price calculation under its PPA and lower operations and maintenance expense; and

increased project income of $8.2 million at Selkirk attributable to lower operations and maintenance costs, higher capacity revenue and a positive $3.4 million non-cash change in the fair value of gas supply agreements from the comparable 2011 period.

Southeast

The following table summarizes project income for our Southeast segment for the periods indicated:

	Three months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Southeast			
Project income	$ 20,836	$ 1,342	NM

Three months ended September 30, 2012 compared with three months ended September 30, 2011

Project income for the three months ended September 30, 2012 increased $19.5 million from the comparable 2011 period primarily due to:

increased project income of $7.4 million at Piedmont attributable to an increase of $7.4 million related to the non-cash change in fair value of derivative instruments associated with its interest rate swaps;

increased project income of $7.2 million at Auburndale primarily attributable to an increase of $4.5 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as higher dispatch than the comparable 2011 period; and

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increased project income of $5.0 million at Lake primarily attributable to an increase of $4.5 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps.

	Nine months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Southeast			
Project income	$ 49,201	$ 23,290	111%

Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

Project income for the nine months ended September 30, 2012 increased $25.9 million or 111% from the comparable 2011 period primarily due to:

increased project income of $9.0 million at Auburndale primarily attributable to an increase of $4.5 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as higher dispatch than the comparable 2011 period;

increased project income of $8.4 million at Piedmont attributable to an increase of $8.4 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps; and

increased project income of $7.6 million at Lake primarily attributable to an increase of $6.6 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps.

Northwest

The following table summarizes project income (loss) for our Northwest segment for the periods indicated:

	Three months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Northwest			
Project income (loss)	$ 682	$ (562)	NM

Three months ended September 30, 2012 compared with three months ended September 30, 2011

Project income (loss) for the three months ended September 30, 2012 increased $1.2 million from the comparable 2011 period primarily due to:

project income of $1.8 million from the newly acquired Mamquam project.

	Nine months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Northwest			
Project income (loss)	$ 2,890	$ (897)	NM

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Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

Project income (loss) for the nine months ended September 30, 2012 increased $3.8 million from the comparable 2011 period primarily due to:

project income of $5.7 million from the newly acquired Mamquam project.

The increase was partially offset by:

project loss of $1.4 million from the newly acquired Williams Lake project resulting from additional amortization associated with the intangible assets resulting from the acquisition of the Partnership.

Southwest

The following table summarizes project income for our Southwest segment for the periods indicated:

	Three months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Southwest			
Project Income	$ 13,897	$ 481	NM

Three months ended September 30, 2012 compared with three months ended September 30, 2011

Project income for the three months ended September 30, 2012 increased $13.4 million from the comparable 2011 period primarily due to:

project income of $6.9 million from the newly acquired Naval Station, Naval Training Center and North Island projects; and

project income of $4.4 million from the newly acquired Oxnard project.

	Nine months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Southwest			
Project Income	$ 15,711	$ 1,779	NM

Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

Project income for the nine months ended September 30, 2012 increased $13.9 million from the comparable 2011 period primarily due to:

project income of $5.2 million from the newly acquired Morris project;

project income of $3.5 million from the newly acquired Manchief project; and

project income of $3.3 million from the newly acquired Oxnard project.

These increases were partially offset by:

decreased project income of $2.9 million at Badger Creek which recorded a $3.0 million impairment charge in the second quarter of 2012 and was sold in the third quarter of 2013; and

decreased project income of $2.5 million at Gregory attributable to higher operations and maintenance costs due to a planned outage during the first quarter of 2012 that was longer than anticipated.

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Un-allocated Corporate

The following table summarizes the results of operations for the Un-allocated Corporate segment for the periods indicated:

	Three months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Un-Allocated Corporate			
Project loss	$ (2,833)	$ (247)	NM
Administration	6,309	11,839	-47%
Interest, net	25,829	3,337	NM
Foreign exchange loss (gain)	7,659	21,576	-65%
Other income, net	272		NM
Total administrative and other expenses	40,069	36,752	9%
Income tax expense (benefit)	3,166	(5,323)	-159%

Three months ended September 30, 2012 compared with three months ended September 30, 2011

Total project loss for the three months ended September 30, 2012 increased $2.6 million from the comparable 2011 period primarily due to higher general and administrative expenses associated with operating the newly acquired Partnership projects.

Total administrative and other expenses for the three months ended September 30, 2012 increased $3.3 million from the comparable 2011 period primarily due to:

- increased interest expense of $22.5 million primarily due to the issuance of the $130 million principal amount of convertible debentures in the third quarter of 2012, issuance of $460 million principal amount of Senior Notes in the fourth quarter of 2011, as well as newly acquired debt assumed in our acquisition of the Partnership.

These increases were partially offset by:

- decreased administration expense of $5.5 million primarily due to a decrease in transaction related costs from the comparable period. The third quarter of 2011 included transaction costs related to the acquisition of the Partnership; and

- decreased foreign exchange loss of $13.9 million primarily due to a $44.6 million increase in unrealized gain on foreign exchange forward contracts offset by a $30.7 million increase in unrealized loss in the revaluation of instruments denominated in Canadian dollars. The U.S. dollar to Canadian dollar exchange rate was .9832 at September 30, 2012 and decreased by 3.4% in the three months ended September 30, 2012 compared to an increase of 8.7% in the comparable 2011 period.

Income tax expense for the three months ended September 30, 2012 was $3.2 million as compared to a $5.3 million benefit in the comparable 2011 period. The difference between the actual tax expense and the expected income tax benefit, based on the Canadian enacted statutory rate of 25%, of $0.5 million for the three months ended September 30, 2012 is primarily due to foreign currency

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translation, difference in tax rates in other countries, change in valuation allowance and various other permanent differences.

	Nine months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Un-Allocated Corporate			
Project loss	$ (10,270)	$ (910)	NM
Administration	21,992	20,379	8%
Interest, net	69,269	10,815	NM
Foreign exchange loss (gain)	4,440	20,383	-78%
Other income, net	(5,728)		NM
Total administrative and other expenses	89,273	51,577	74%
Income tax expense (benefit)	(19,076)	(12,900)	48%

Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

Total project loss for the nine months ended September 30, 2012 increased $9.4 million from the comparable 2011period primarily due to higher general and administrative expenses associated with operating the newly acquired Partnership projects.

Total administrative and other expenses for the nine months ended September 30, 2012 increased $37.7 million from the comparable 2011 period primarily due to:

- increased administration expense of $1.6 million primarily due to additional administration costs subsequent to the acquisition of the Partnership; and

- increased interest expense of $58.5 million primarily due to due to the issuance of the $130 million principal amount of convertible debentures in the third quarter of 2012, issuance of $460 million principal amount of Senior Notes in the fourth quarter of 2011, as well as newly acquired debt assumed in our acquisition of the Partnership.

These increases were partially offset by:

- decreased foreign exchange loss of $15.9 million primarily due to a $9.3 million increase in realized gain on foreign exchange contract settlements and a $29.6 million decrease in unrealized loss on foreign exchange forward contracts, offset by a $23.0 million increase in unrealized loss in the revaluation of instruments denominated in Canadian dollars. The U.S. dollar to Canadian dollar exchange rate was .9832 at September 30, 2012 and decreased by 3.3% in the nine months ended September 30, 2012 compared to an increase of 5.4% in the comparable 2011 period; and

- increased other income of $5.7 million, primarily due to the $6.0 million proceeds related to the management agreement termination fee received in the sale of our 14.3% equity investment in PERH.

Income tax benefit for the nine months ended September 30, 2012 was $19.01 million as compared to a $12.9 million benefit in the comparable 2011 period. The difference between the actual tax benefit and the expected income tax benefit, based on the Canadian enacted statutory rate of 25%, of $16.6 million for the nine months ended September 30, 2012 is primarily due to foreign currency translation, renewable energy grants received, change in valuation allowance, difference in tax rates in other countries and various other permanent differences.

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Supplementary Non-GAAP Financial Information

A key measure we use to evaluate the results of our business 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 cash flows from operating activities, the most directly comparable GAAP measure, 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, capital expenditures, dividends paid on preferred shares of a subsidiary company and adjusted for changes in project-level working capital and cash reserves. Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of project income to Project Adjusted EBITDA is set out below by segment under "Project Adjusted EBITDA." Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

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

	Three months ended September 30,		Nine months ended September 30,	
(unaudited)	**2012**	**2011**	**2012**	**2011**
Project Adjusted EBITDA by Segment				
Northeast	$ 20,346	$ 9,817	$ 85,156	$ 27,400
Southeast	23,150	21,635	69,892	63,892
Northwest	12,596	1,121	38,453	3,606
Southwest	23,440	1,523	47,952	4,894
Un-allocated Corporate	(2,338)	(233)	(9,645)	(838)
Total	77,194	33,863	231,808	98,954
Reconciliation to project income (loss)				
Depreciation and amortization	49,725	15,797	146,796	46,916
Interest expense, net	6,008	3,706	18,569	11,100
Change in the fair value of derivative instruments	(17,347)	10,871	38,443	12,913
Other (income) expense	829	1,309	4,300	1,789
Project income (loss)	37,979	2,180	23,700	26,236

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Northeast

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

	Three months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Northeast			
Project Adjusted EBITDA	$ 20,346	$ 9,817	107%

Three months ended September 30, 2012 compared with three months ended September 30, 2011

Project Adjusted EBITDA for the three months ended September 30, 2012 increased $10.5 million or 107% from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $3.1 million at the newly acquired Curtis Palmer project;
- Project Adjusted EBITDA of $3.0 million at the newly acquired Nipigon project; and
- Project Adjusted EBITDA of $2.0 million at the newly acquired Tunis project.

	Nine months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Northeast			
Project Adjusted EBITDA	$ 85,156	$ 27,400	NM

Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

Project Adjusted EBITDA for the nine months ended September 30, 2012 increased $57.8 million from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $18.9 million at the newly acquired Curtis Palmer project;
- Project Adjusted EBITDA of $10.2 million at the newly acquired Nipigon project;
- Project Adjusted EBITDA of $8.4 million at the newly acquired Tunis project;
- increased Project Adjusted EBITDA of $6.3 million at Chambers due to the collection of the $3.6 million DuPont partial settlement associated with the dispute of the electricity price calculation under its PPA, as well as lower operations and maintenance costs from the comparable period;
- Project Adjusted EBITDA of $4.2 million at the newly acquired North Bay project; and
- increased Project Adjusted EBITDA of $4.1 million at Selkirk due to lower operating and maintenance costs and higher capacity revenue from the comparable 2011 period.

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Southeast

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

	Three months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Southeast			
Project Adjusted EBITDA	$ 23,150	$ 21,635	7%

Three months ended September 30, 2012 compared with three months ended September 30, 2011

Project Adjusted EBITDA for the three months ended September 30, 2012 increased $1.5 million or 7% from the comparable 2011 period primarily due to:

a $2.6 million increase in Project Adjusted EBITDA at Auburndale primarily attributable to higher capacity revenues due to contractual escalation under the project's PPA as well as higher dispatch than the comparable 2011 period.

The increase was partially offset by:

decreased Project Adjusted EBITDA of $2.0 million at Pasco which had higher operations and maintenance expenses in the third quarter of 2012 due to the unplanned replacement of gas turbine blades during a maintenance outage.

	Nine months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Southeast			
Project Adjusted EBITDA	$ 69,892	$ 63,892	9%

Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

Project Adjusted EBITDA for the nine months ended September 30, 2012 increased $6.0 million or 9% from the comparable 2011 period primarily due to:

a $4.1 million increase in Project Adjusted EBITDA at Auburndale primarily attributable to higher capacity revenues due to contractual escalation under the project's PPA as well as higher dispatch than the comparable 2011 period.

Northwest

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

	Three months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Northwest			
Project Adjusted EBITDA	$ 12,596	$ 1,121	NM

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Three months ended September 30, 2012 compared with three months ended September 30, 2011

Project Adjusted EBITDA for the three months ended September 30, 2012 increased $11.5 million from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $2.3 million from the newly acquired Mamquam project;
- Project Adjusted EBITDA of $6.7 million from the newly acquired Williams Lake project; and
- Project Adjusted EBITDA of $2.0 million from the newly acquired Frederickson project.

	Nine months ended September 30, 2012	2011	% change 2012 vs. 2011
Northwest			
Project Adjusted EBITDA	$ 38,453	$ 3,606	NM

Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

Project Adjusted EBITDA for the nine months ended September 30, 2012 increased $34.8 million from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $7.1 million from the newly acquired Mamquam project;
- Project Adjusted EBITDA of $16.0 million from the newly acquired Williams Lake project;
- Project Adjusted EBITDA of $7.8 million from the newly acquired Frederickson project; and
- Project Adjusted EBITDA of $2.3 million from Rockland which became operational in the first quarter of 2012.

Southwest

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

	Three months ended September 30, 2012	2011	% change 2012 vs. 2011
Southwest			
Project Adjusted EBITDA	$ 23,440	$ 1,523	NM

Three months ended September 30, 2012 compared with three months ended September 30, 2011

Project Adjusted EBITDA for the three months ended September 30, 2012 increased $21.9 million from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $4.5 million from the newly acquired Naval Station project;

Project Adjusted EBITDA of $3.5 million from the newly acquired North Island project;

Project Adjusted EBITDA of $5.5 million from the newly acquired Oxnard project; and

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Project Adjusted EBITDA of $4.0 million from the newly acquired Manchief project.

	Nine months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Southwest			
Project Adjusted EBITDA	$ 47,952	$ 4,894	NM

Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

Project Adjusted EBITDA for the nine months ended September 30, 2012 increased $43.1 million from the comparable 2011 period primarily due to:

Project Adjusted EBITDA of $9.1 million from the newly acquired Naval Station project;

Project Adjusted EBITDA of $4.1 million from the newly acquired Naval Training Centre project;

Project Adjusted EBITDA of $4.0 million from the newly acquired North Island project;

Project Adjusted EBITDA of $11.5 million from the newly acquired Manchief project;

Project Adjusted EBITDA of $7.8 million from the newly acquired Morris project; and

Project Adjusted EBITDA of $6.6 million from the newly acquired Oxnard project.

These increases were partially offset by:

decreased Project Adjusted EBITDA of $2.7 million at Gregory attributable to higher operations and maintenance costs due to a planned outage during the first quarter of 2012 that was longer than anticipated.

Generation and Availability by Segment

	Three months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Aggregate power generation (Net MWh)			
Northeast	581,350	245,245	137.0%
Southeast	563,848	455,410	23.8%
Northwest	286,977	28,657	NM
Southwest	684,919	149,889	NM
Total	2,117,094	879,201	140.8%
Weighted average availability			
Northeast	97.5%	85.8%	13.6%
Southeast	99.2%	97.1%	2.2%
Northwest	94.3%	99.1%	-4.8%
Southwest	96.8%	99.9%	-3.1%

Total	97.2%	94.9%	2.4%

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Three months ended September 30, 2012 compared with three months ended September 30, 2011

Aggregate power generation for the three months ended September 30, 2012 increased 140.8% from the comparable 2011 period primarily due to:

- increased generation in the Northeast segment primarily due to 380,025 MWh from the newly acquired Partnership projects, partially offset by a 37,820 MWh decrease at Selkirk due to lower dispatch from the comparable 2011 period;
- increased generation in the Southeast segment attributable to an 125,486 MWh increase at the Auburndale project that had off-peak generation in the third quarter of 2012 compared to no off-peak generation in the comparable 2011 period;
- increased generation in the Northwest segment primarily due to 242,141 MWh from the newly acquired Partnership projects as well as generation from Rockland which became operational in the first quarter of 2012; and
- increased generation in the Southwest segment primarily due to 541,639 MWh from the newly acquired Partnership projects, partially offset by a decrease at Badger which was sold in September 2012.

Weighted average availability for the three months ended September 30, 2012 increased to 97.2% or 2.4% from the comparable 2011 period primarily due to:

- increased availability in the Northeast segment primarily due to an increase at Chambers which had an outage in the comparable 2011 period.

	Nine months ended September 30,		
	2012	2011	% change 2012 vs. 2011
Aggregate power generation (Net MWh)			
Northeast	1,783,240	694,564	156.7%
Southeast	1,610,535	1,354,300	18.9%
Northwest	847,376	101,926	NM
Southwest	1,849,075	440,500	NM
Total	6,090,226	2,591,290	135.0%
Weighted average availability			
Northeast	96.0%	85.8%	11.9%
Southeast	98.6%	98.3%	0.3%
Northwest	94.2%	98.2%	-4.0%
Southwest	93.9%	95.7%	-1.9%
Total	95.6%	94.8%	0.8%

Nine months ended September 30, 2012 compared with nine months ended September 30, 2011

Aggregate power generation for the nine months ended September 30, 2012 increased 135.0% from the comparable 2011 period primarily due to:

- increased generation in the Northeast segment primarily due to 1,386,137 MWh from the newly acquired Partnership projects, partially offset by a 96,693 MWh decrease at Selkirk due to lower dispatch from the comparable 2011 period;

increased generation in the Southeast segment attributable to an 238,786 MWh increase at the Auburndale project that had off-peak generation in the third quarter of 2012 compared to no off-peak generation in the comparable 2011 period;

increased generation in the Northwest segment primarily due to 666,305 MWh from the newly acquired Partnership projects as well as generation from Rockland which became operational in the first quarter of 2012; and

increased generation in the Southwest segment primarily due to 1,457,551 MWh from the newly acquired Partnership projects.

Weighted average availability for the nine months ended September 30, 2012 increased to 95.6% or 0.8% from the comparable 2011 period primarily due to:

increased availability in the Northeast segment primarily due to increases at Chambers and Selkirk which had planned outages in the comparable 2011 period.

This increase was partially offset by:

decreased availability in the Southwest segment primarily due to a planned outage at Gregory in the first quarter of 2012 which was longer than anticipated.

Consolidated Cash Flows

At September 30, 2012, cash and cash equivalents decreased $16.0 million from December 31, 2011 to $42.9 million. The decrease in cash and cash equivalents was primarily due to $415.5 million of cash used in investing activities, offset by $124.1 million provided by operating activities and $275.4 million of cash provided by financing activities.

At September 30, 2011, cash and cash equivalents decreased $7.2 million from December 31, 2010 to $38.3 million. The decrease in cash and cash equivalents was due to $68.2 million used in investing activities and $5.3 million used in financing activities, offset by $66.3 million of cash provided by operating activities

	Nine months ended September 30,		$ Change
	2012	2011	2012 vs. 2011
Net cash provided by operating activities	$ 124,116	$ 66,339	$ 57,777
Net cash used in investing activities	(415,530)	(68,247)	(347,283)
Net cash provided by (used in) financing activities	275,377	(5,335)	280,712

Operating Activities

Our cash flow from the projects may vary from year to year based on working capital requirements and the operating performance of the projects, as well as changes in prices under the PPAs, fuel supply and transportation agreements, steam sales agreements and other project contracts, changes in regulated transmission rates and the transition to market or re-contracted pricing following the expiration of PPAs. Project cash flows may have some seasonality and the pattern and frequency of distributions to us from the projects during the year can also vary, although such seasonal variances do not typically have a material impact on our business.

Cash flows from operating activities increased by $57.8 million for the nine months ended September 30, 2012 over the comparable period in 2011. The change from the prior year is primarily attributable to the increases in Project Adjusted EBITDA noted above as well as an increase in distributions from equity method investments.

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Investing Activities

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

In July 2012 we raised approximately $190.0 million of net proceeds in new convertible debentures and equity offerings to fund our equity commitment in the Canadian Hills project. A portion of these funds was used to support the construction of the project and the remainder was placed in restricted cash accounts to be utilized during the remainder of the construction process.

Cash flows used in investing activities for the nine months ended September 30, 2012 were $415.5 million compared to cash flows used in investing activities of $68.2 million for the comparable 2011 period. The change is primarily attributable to $336.2 million of construction in progress related to the Piedmont and Canadian Hills projects and $105.5 million increase in restricted cash as noted above, partially offset by $27.9 million of proceeds from our sale of our interest in PERH and Badger Creek.

Financing Activities

Cash provided by financing activities for the nine months ended September 30, 2012 resulted in a net inflow of $275.4 million compared with a $5.3 million outflow for the comparable 2011 period. The change is primarily due to $124.8 million of proceeds from the July 2012 convertible debentures offering, $67.7 million of net proceeds from our July 2012 equity offering and $261.2 million of proceeds from the Piedmont and Canadian Hills construction loans. This increase was partially offset by an increase in dividend payments attributable to shares issued in connection with the July 2012 equity offering and the acquisition of the Partnership in the fourth quarter of 2011, the dividend increase that was effective November 2011, as well as repayments of borrowings under our senior credit facility.

Cash Available for Distribution

Initially in 2011, holders of our common shares received monthly cash dividends at an annual rate of Cdn$1.094 per share. This dividend was increased to an annual rate of Cdn$1.15 per share in November 2011 upon the closing of the Partnership acquisition. The payout ratio associated with the cash dividends declared was 120% and 70% for the three months ended September 30, 2012 and 2011 and 98% and 93% for the nine months ended September 30, 2012 and 2011, respectively. The payout ratio for the three months ended September 30, 2012 was negatively impacted as a result of the timing of contractual receipts with two off-takers at a number of our facilities. The collection of receivables occured during the first week in October and negatively impacted working capital for the quarter. The payout ratio for the nine months ended September 30, 2012 was positively impacted by the termination of the management service contract as part of the sale of our interest in PERH, the proceeds from the sale of Badger Creek as well as reducing our combined foreign currency forward positions as a result of the Partnership acquisition, partially offset by interest payments associated with newly acquired debt from the Partnership acquisition and the additional convertible debentures offered in July 2012. Due to the timing of working capital adjustments and the cash payments associated with our corporate level interest payments, our payout ratio will fluctuate from quarter to quarter. For example, the interest payments on the $460 million Senior Notes are due semi-annually (May and November) and will impact our payout ratios in the second and fourth quarters.

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The table below presents our calculation of cash available for distribution for the three and nine months ended September 30, 2012 and 2011, and the reconciliation to Cash flows from operating activities, the most directly comparable GAAP measure:

(unaudited) (in thousands of U.S. dollars, except as otherwise stated)	Three months ended September 30, 2012	Three months ended September 30, 2011	Nine months ended September 30, 2012	Nine months ended September 30, 2011
Cash flows from operating activities	$ 34,744	$ 21,624	$ 124,116	$ 66,339
Project-level debt repayments	(2,725)	(2,825)	(12,050)	(13,166)
Purchases of property, plant and equipment	(370)	(268)	(1,172)	(814)
Transaction costs[1]		8,470		9,238
Dividends on preferred shares of a subsidiary company	(3,321)		(9,767)	
Cash Available for Distribution[2]	28,328	27,001	101,127	61,597
Total cash dividends declared to shareholders	34,035	19,010	99,090	57,552
Payout ratio	120%	70%	98%	93%
Expressed in Cdn$				
Cash Available for Distribution	28,188	26,833	101,339	60,520
Total dividends declared to shareholders	34,288	18,874	99,637	56,259

(1) Represents business development costs associated with the acquisition of the Partnership.

(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" above.

Liquidity and Capital Resources

Liquidity Position

(in thousands of U.S. dollars, except as otherwise stated)	September 30, 2012	December 31, 2011
Cash and cash equivalents	$ 42,872	$ 60,651
Restricted cash	112,633	21,412
Total	155,505	82,063
Revolving credit facility availability	143,501	134,700
Total liquidity	$ 299,006	$ 216,763

For the nine months ended September 30, 2012, total liquidity, increased by $82.2 million due to higher availability under our senior credit facility and restricted cash, offset by lower cash and cash equivalents balances. The increase in the senior credit facility availability was primarily due to a $38.0 million reduction in the amount drawn on our senior credit facility. As of November 1, 2012, we have $20.0 million drawn on the senior credit facility and $135.3 million outstanding in letters of credit. Changes in cash and cash equivalent balances were previously discussed herein under the heading *Consolidated Cash Flows* above. Total liquidity excludes $1.7 million of cash and cash equivalents and $14.3 million of restricted cash from the Path 15 project which is recorded as an asset held for sale at September 30, 2012. Cash and cash equivalents at September 30, 2012 were predominantly held in money market funds invested in treasury securities.

The projects with project-level debt generally have reserve requirements to support payments for major maintenance costs, construction costs, and project-level debt service. Project-level debt agreements also contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. For projects that are consolidated, our share of these amounts is reflected as restricted cash on the consolidated balance sheet. Changes in restricted cash were previously discussed herein under *Investing Activities* above. At September 30, 2012, restricted cash at the consolidated projects totalled $112.6 million.

We believe existing cash, cash equivalents and marketable securities and funds generated from operations should be sufficient to meet our working capital and capital expenditure requirements, and meet our obligations for the next 12 months.

Sources of Liquidity

Our primary source of liquidity is distributions from our projects and availability under our senior credit facility. As described in Note 4, *Long-term debt* and Note 5, *Convertible debentures,* to this Form 10-Q and Note 9, *Long-term debt*, and Note 10, *Convertible debentures,* to our Annual Report on Form 10-K for the year ended December 31, 2011, our financing arrangements consist primarily of the senior credit facility, convertible debentures, senior notes of Atlantic Power, senior unsecured notes of the Partnership, senior unsecured notes of Atlantic Power (US) GP and non-recourse project level debt.

Project-Level Debt

The following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at September 30, 2012 and exclude any purchase accounting adjustments recorded to adjust the debt to its fair value at the time the project was acquired. Certain of the projects have more than one tranche of debt outstanding with different maturities, different interest rates and/or debt containing variable interest rates. Project-level debt agreements contain covenants that restrict the amount of cash distributed by the project if certain debt service coverage ratios are not attained. As of September 30, 2012, the covenants at the Gregory, Delta-Person 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 2013 and Gregory and Delta-Person in 2014. 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.

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The range of interest rates presented represents the rates in effect at September 30, 2012. The amounts listed below are in thousands of U.S. dollars, except as otherwise stated.

	Range of Interest Rates	Total Remaining Principal Repayments	2012	2013	2014	2015	2016	Thereafter
Consolidated Projects:								
Epsilon Power Partners	7.40%	$ 33,857	$ 375	$ 3,000	$ 5,000	$ 5,750	$ 6,000	$ 13,732
Piedmont[(1)]	3.80% 5.20%	123,270		55,357	4,789	4,772	3,690	54,662
Canadian Hills[(2)]	3.20%	238,755	238,755					
Path 15[(3)]	7.90% 9.00%	142,005	4,792	9,402	8,065	8,749	9,487	101,510
Auburndale	5.10%	6,650	1,750	4,900				
Cadillac	6.00% 8.00%	38,431	600	2,400	2,000	3,891	2,500	27,040
Curtis Palmer[(4)]	5.90%	190,000			190,000			
Total Consolidated Projects		772,968	246,272	75,059	209,854	23,162	21,677	196,944
Equity Method Projects:								
Chambers	0.60% 7.20%	55,201	3,274	10,783	5,780	5,213	5,447	24,704
Delta-Person	1.90%	8,281	101	1,300	1,394	1,495	1,604	2,387
Gregory	2.30% 7.70%	11,186	417	2,007	2,170	2,268	2,448	1,876
Rockland	6.40%	26,006	335	368	445	529	583	23,746
Idaho Wind	5.60%	49,633	797	2,198	2,364	2,554	2,511	39,209
Total Equity Method Projects		150,307	4,924	16,656	12,153	12,059	12,593	91,922
Total Project-Level Debt		$ 923,275	$ 251,196	$ 91,715	$ 222,007	$ 35,221	$ 34,270	$ 288,866

(1) As of September 30, 2012 the balance of $123.3 million on the Piedmont debt is funded by the related bridge loan of $51.0 million and $72.3 million funded by the construction loan that will convert to a term loan. The terms of the Piedmont project-level debt financing include a $51.0 million bridge loan for approximately 95.0% of the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations, and an $82.0 million construction term loan. The $51.0 million bridge loan is expected to be repaid in early 2013 and repayment of the expected $82.0 million term loan is scheduled to commence in 2013.

(2) Canadian Hills debt outstanding is funded by a $290.0 million construction loan of which $238.8 million has been drawn as of September 30, 2012. The facility is expected to be repaid in late 2012 by proceeds from our equity contribution, the tax equity investments and a draw on our senior credit facility. See " Recent Developments Canadian Hills."

(3) Path 15 is classified as an asset held for sale as of September 30, 2012. Accordingly, the outstanding debt is recorded as a component of liabilities associated with an asset held for sale on the consolidated balance sheet at September 30, 2012.

(4) The Curtis Palmer Notes are not considered non-recourse project-level debt as these notes are guaranteed by the Partnership. Interest expense associated with the Curtis Palmer notes are recorded as a component of project income.

Uses of Liquidity

Our requirements for liquidity and capital resources, other than operating our projects, consist primarily of dividend payments to our common shareholders and preferred shareholders of a subsidiary company, interest on our outstanding convertible debentures, Senior Notes and other corporate and project level debt and capital expenditures, including major maintenance and business development costs. We may fund future acquisitions with a combination of cash on hand, the issuance of additional corporate debt or equity securities and the incurrence of privately placed bank or institutional non-recourse operating level debt, although we can provide no assurances regarding the availability of public or private financing on acceptable terms or at all.

We do not expect any material, unusual requirements for cash outflows for the remainder of 2012 for capital expenditures or other required investments. In addition, there are no debt instruments, other than the construction loan for Canadian Hills, with significant maturities or refinancing requirements in 2012. We expect to pay down the construction loan facility at Canadian Hills with proceeds from our equity contribution as well as proceeds from the tax equity investments. See " Recent Developments Canadian Hills."

Capital and Major Maintenance Expenditures

Capital expenditures and maintenance expenses for the projects are generally paid at the project level using project cash flows and project reserves. Therefore, the distributions that we receive from the projects are made net of capital expenditures needed at the projects. The operating projects which we own consist of large capital assets that have established commercial operations. On-going capital expenditures for assets of this nature are generally not significant because most major expenditures relate to planned repairs and maintenance and are expensed when incurred.

We expect to reinvest approximately $30.0 million in 2012 in our project portfolio in the form of capital expenditures and major maintenance expenses. As explained above, this investment is generally paid at the project level. We believe one of the benefits of our diverse fleet is that plant overhauls and other major expenditures do not occur in the same year for each facility. Recognized industry guidelines and original equipment manufacturer recommendations allow us to predict major maintenance events and balance the funds necessary for these expenditures over time. Future capital expenditures and major maintenance expenses may exceed the level in 2012 as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

In 2012, several of our projects have or will conduct scheduled outages to complete major maintenance work. The level of maintenance and capital expenditures for our legacy portfolio of projects is expected to be consistent with prior years. However, overall maintenance and capital expenditures will be higher than in 2011 due to our acquisition of the Partnership project portfolio. There were no significant capital expenditures at our operating projects during the third quarter of 2012, but maintenance expenses were substantial, including outage related work performed at the Auburndale, Pasco, Tunis, Chambers, Kapuskasing, Nipigon, Morris and Selkirk facilities.

In all cases, maintenance outages occurred at such times that did not adversely impact the facilities' availability requirements under their respective PPAs.

In the third quarter of 2012, we incurred approximately $5.4 million in capital expenditures for the construction of our Piedmont biomass project which is close to commercial operation. In 2012, we expect to incur a total of approximately $35.2 million in capital expenditures related to the Piedmont project, with total project costs through expected completion in November 2012 of approximately $207.0 million.

In the third quarter of 2012, we also incurred approximately $113.9 million in capital expenditures for the construction of our Canadian Hills Wind project. We expect to incur approximately $470 million in total construction costs with expected completion late in the fourth quarter of 2012. See " Recent Developments Canadian Hills."

Recently Adopted and Recently Issued Accounting Guidance

See Note 1 to the consolidated financial statements in Part I Item 1 of this Form 10-Q.

Off-Balance Sheet Arrangements

As of September 30, 2012, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

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ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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 and electricity 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 passing through changes in fuel prices to the buyer of the energy.

The Tunis project is exposed to changes in natural gas prices under a combination of spot purchases and short-term contracts expiring in 2013 and 2014. The projected annual cash distributions at Tunis would change by approximately $2.6 million per $1.00/Mmbtu change in the price of natural gas based on the current level of natural gas volumes used by the project.

The operating margin at our 50% owned Orlando project is exposed to changes in natural gas prices following the expiration of its fuel contract at the end of 2013. We have entered into natural gas swaps in order to effectively fix the price of 3.2 million Mmbtu of future natural gas purchases representing approximately 64% of our share of the expected natural gas purchases at the project during 2014 and 2015. We also entered into natural gas swaps to effectively fix the price of 1.3 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2016 and 2017.

We expect cash distributions from Orlando to increase in a range between $14.0 to $18.0 million on average over the next five years following the expiration of the project's gas contract at the end of 2013. The reason for this increase in cash distributions is a result of the projected natural gas prices and the fact that the prices in our natural gas swaps that we have executed are lower than the price of natural gas being purchased under the project's current gas contract, as well as the annual escalation of capacity revenue under the existing PPA.

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's operating margin is exposed to changes in natural gas spot market prices through the expiration of its PPA at the end of 2013. The projected cash distributions for the remainder of 2012 and 2013 at Lake would change by approximately $0.1 million and $0.4 million, respectively, 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. Projected cash distributions for the remainder of 2012 and 2013 at Auburndale would change by approximately $0.4 million and $1.2 million, respectively, 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.

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The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of September 30, 2012 and November 2, 2012:

	2012	2013
Portion of gas volumes currently hedged:		
Lake:		
Contracted		
Financially hedged	90%	83%
Total	90%	83%
Auburndale:		
Contracted		
Financially hedged	46%	79%
Total	46%	79%
Average price of financially hedged volumes (per Mmbtu)		
Lake	$ 6.90	$ 6.63
Auburndale	$ 6.56	$ 6.92

Coal prices used in the energy 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 cash distributions for the remainder of 2012 and 2013 from Lake and Auburndale combined would change by approximately $0.5 million and $2.4 million, respectively, for every $0.25/Mmbtu change in the projected price of coal.

Electricity Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity prices when our projects operate with no PPA or projects that operate with PPAs that are based on spot market pricing. Our most significant exposure to market power prices is at the Chambers, Morris and Selkirk projects. At Chambers, our utility customer has the right to sell a portion of the plant's output into the spot power market if it is profitable to do so, and the Chambers project shares in the profits from these sales. In addition, during periods of low spot electricity prices the utility takes less generation, which negatively affects the project's operating margin. Our equity investment in the Chambers project is 40%. At Morris, the facility can sell approximately 100MW above the off-taker's demand into the grid at market prices. If market prices do not justify the increased generation the project has no requirement to sell power in excess of the off-taker's demand which can negatively impact operating margins. We own 100% of the Morris project. At Selkirk, approximately 23% of the capacity of the facility is not contracted and is sold at market prices or not sold at all if market prices do not support the profitable operation of that portion of the facility. Our equity investment in the Selkirk project is approximately 18%.

When a PPA expires or is terminated, it is possible that the price received by the project for power under subsequent arrangements may be reduced and in some cases, significantly. Our projects may not be able to secure a new agreement and could be exposed to sell power at spot market prices. It is possible that subsequent PPAs or the spot markets may not be available at prices that permit the operation of the project on a profitable basis. If this occurs, the affected project may temporarily or permanently cease operations. Our current exposure to these future agreements or spot market pricing is at the Kenilworth, Greeley, Gregory, Lake and Auburndale projects. Our most significant exposure to future cash flows is at our Lake and Auburndale projects. These projects are located in the Northern Florida markets that are served primarily by PEF and Tampa Electric. We have been through a similar PPA re-contracting experience in Florida with our Pasco plant for which the initial PPA expired at the end of 2008. Our Pasco project was able to enter into a new ten-year tolling agreement, but it provided

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substantially lower cash flow than under the original agreement. Although we cannot provide any assurance that we will be able to enter into PPA extensions for our projects, if we do enter into such extension, we believe that the pricing for PPA extensions for our projects, such as the Auburndale and Lake projects for which the PPAs expire in 2013, will be substantially lower than the current PPAs.

Foreign Currency Exchange Risk

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as many of our projects generate cash flow in U.S. dollars and Canadian dollars but we pay dividends to shareholders and interest on corporate level long-term debt and 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 utilizing cash flows from our projects that generate Canadian dollars and by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge an average of approximately 78% of our expected dividend, long-term debt and convertible debenture interest payments through 2015. 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. At September 30, 2012, 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) contracts assumed in our acquisition of the Partnership with various expiration dates through December 2015 to purchase a total of Cdn$112.0 million at an average exchange rate of Cdn$1.130 per U.S. dollar. It is our intention to periodically consider extending or terminating the length of these forward contracts.

The foreign exchange forward contracts are recorded at estimated fair value based on quoted market prices and the estimation of the counter-party's credit risk. Changes in the fair value of the foreign currency forward contracts are recorded in foreign exchange (gain) loss in the consolidated statements of operations.

The following table contains the components of recorded foreign exchange (gain) loss for the three and nine months ended September 30, 2012 and 2011:

	Three months ended September 30,		Nine months ended September 30,	
	2012	**2011**	**2012**	**2011**
Unrealized foreign exchange (gain) loss:				
Convertible debentures and other	$ 14,421	$ (16,274)	$ 13,381	$ (9,642)
Forward contracts	(4,694)	39,950	8,169	37,817
	9,727	23,676	21,550	28,175
Realized foreign exchange gains on forward contract settlements	(2,068)	(2,100)	(17,110)	(7,792)
Total foreign exchange loss	$ 7,659	$ 21,576	$ 4,440	$ 20,383

The U.S dollar to Canadian dollar exchange rate was .9832 at September 30, 2012. The following table illustrates the impact on the fair value of our financial instruments of a 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar as of September 30, 2012:

Convertible debentures denominated in Canadian dollars, at carrying value	$ (18,953)
Foreign currency forward contracts	$ 20,274

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Interest Rate Risk

Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 85% 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 and changes in their fair market value are recorded in other comprehensive income. The interest rate swap expires on November 30, 2013.

We have an interest rate swap at our consolidated Cadillac project to economically fix 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 and changes in their fair market value are recorded in other comprehensive income. The interest rate swap expires on September 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 expire on February 29, 2016 and November 30, 2030, respectively.

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

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 (loss). 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 net income (loss) 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 $3.4 million.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation 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 have evaluated our disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934, as of the end of the period covered by this report, and our principal executive officer and principal financial officer have concluded that these controls and procedures are effective.

Changes in Internal Control over Financial Reporting

There have been no changes in internal control over financial reporting during the nine months ended September 30, 2012, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Inherent Limitations of Disclosure Controls and Internal Control over Financial Reporting

Because of their inherent limitations, our disclosure controls and procedures and our internal control over financial reporting may not prevent material errors or fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. The effectiveness of our disclosure controls and procedures and our internal control over financial reporting is subject to risks, including that the control may become inadequate because of changes in conditions or that the degree of compliance with our policies or procedures may deteriorate.

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PART II OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

Our Lake project is currently involved in a dispute with PEF 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 PEF. 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. PEF 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 and our forward guidance for distributions does not include proceeds from off-peak sales, 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.

On May 29, 2011, our Morris facility was struck by lightning. As a result, steam and electric deliveries were interrupted to our host Equistar. We believe the interruption constitutes a force majeure under the energy services agreement with Equistar. Equistar disputes this interpretation and has initiated arbitration proceedings under the agreement for recovery of resulting lost profits and equipment damage among other items. The agreement with Equistar specifically shields Morris from exposure to consequential damages incurred by Equistar and management expects our insurance to cover any material losses we might incur in connection with such proceedings, including settlement costs. Management will attempt to resolve the arbitration through settlement discussions, but is prepared to vigorously defend the arbitration on the merits.

In addition to the other matters listed above, 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 probable and can be reasonably estimated. There are no matters pending as of September 30, 2012 that are expected to have a material impact on our financial position or results of operations.

ITEM 1A. RISK FACTORS

There were no additional 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, 2011, other than as set forth in "Part II. Item 1A. Risk Factors" in our Quarterly Report on Form 10-Q for the quarterly periods ended March 31, 2012 and June 30, 2012 (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 1. Financial Information, Note 14, *Commitments and Contingencies*," and "Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations")).

ITEM 5. OTHER INFORMATION

The following information set forth below was required to be disclosed under "*Item 1.01. Entry in a Material Definitive Agreement*" and "*Item 2.03. Creation of a Direct Financial Obligation or an Obligation under an Off-Balance Sheet Arrangement of a Registrant.*" of Form 8-K during the period covered by the Quarterly Report on Form 10-Q.

Senior Credit Facility

In connection with the continued evolution of the Company's strategy to focus on late-stage development and construction projects, and the possible disposition of certain projects, on November 2,

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2012 (the "*Effective Date*"), the Company entered into an Amended and Restated Credit Agreement (the "*Credit Agreement*") among the Company, and certain subsidiaries and its senior credit facility lenders. All capitalized terms used but not defined in this section have the meaning assigned to them in the Credit Agreement.

The Credit Agreement amends and restates the existing amended and restated credit agreement, dated as of November 4, 2011 (as amended, supplemented or modified from time to time), among the same parties, and provides for the amendments and consents described below.

The first change better accommodates construction stage projects with no historical financial performance. This change will allow the Company, in calculating its Total Leverage Ratio, to (a) exclude from Consolidated Total Net Debt any Non-Recourse Project Financing Indebtedness for a project that has not yet achieved Commercial Operations, subject to a cap of $350 million in the aggregate, and to use projections prepared by the Company in the calculation of Consolidated EBITDA once a project achieves Commercial Operations; and (b) exclude from the definition of Consolidated Total Net Debt, for non-wholly owned subsidiaries, the proportion of any Non-Recourse Project Finance Indebtedness that is in excess of the Company's ownership percentage.

The second change will accommodate the possibility of certain asset sales, including our Florida projects, by waiving a material disposition covenant and permitting inclusion of the disposed assets' trailing twelve months EBITDA for covenant calculations.

The third change is also aimed at accommodating the same possible asset sales by temporarily modifying the leverage covenant, allowing the Total Leverage Ratio limit under that scenario to be set at 7.50 to 1 through the fiscal quarter ending June 30, 2014, 7.25 to 1 for subsequent fiscal quarters ending on or before March 31, 2015 and 7.00 to 1 for all subsequent fiscal quarters; provided that if disposition proceeds do not exceed a certain level by a specified date, the total leverage ratio will revert to its prior level. Prior to this change, the Total Leverage Ratio limit was 6.50 to 1 as of the end of any fiscal quarter.

Pursuant to the Credit Agreement, the Company also obtained consent to (i) use proceeds from the Credit Agreement in an amount not to exceed $47.0 million to repay a portion of the construction loan for the Canadian Hills project; and (ii) incur unsecured indebtedness in an amount not to exceed $77.0 million in connection with a possible acquisition.

The description of the consents and amendments of the Credit Agreement contained herein is qualified in its entirety by reference to the Credit Agreement.

The following information set forth below was required to be disclosed under "*Item 8.01. Other Events.*" of Form 8-K during the period covered by the Quarterly Report on Form 10-Q.

Canadian Hills

As previously disclosed by the Company on January 31, 2012, Atlantic Oklahoma Wind, LLC ("Atlantic OW"), a Delaware limited liability company and a wholly owned subsidiary of Atlantic Power, entered into a purchase and sale agreement with Apex Wind Energy Holdings, LLC, a Delaware limited liability company ("Apex"), pursuant to which Atlantic OW acquired a 51% interest in Canadian Hills Wind, LLC, an Oklahoma limited liability company ("Canadian Hills") for a nominal sum. Canadian Hills is the owner of a 298.45 MW wind energy project under construction in the State of Oklahoma. Canadian Hills executed power PPAs for all of its output with Southwestern Electric Power Company (201.25 MW), Oklahoma Municipal Power Authority (49.2 MW), and Grand River Dam Authority (48 MW).

Also as previously disclosed, on March 30, 2012, we completed the purchase of an additional 48% interest in Canadian Hills for a nominal amount, bringing our total interest in the project to 99%. Apex retained a 1% interest in the project. At the time, we also closed a $310 million non-recourse, project-level construction financing facility for the project. The facility includes a $290 million construction loan and a $20 million 5-year letter of credit facility. Proceeds from the construction loan were used, in part, to repay Atlantic Power $29.3 million in member loans that were made to the project to fund construction prior to closing the construction financing facility. In connection with the closing of the construction financing facility, we committed to invest additional equity to cover the balance of the construction and development costs. We funded this equity commitment with the net proceeds from our July 5, 2012 public offering of common shares and convertible unsecured subordinated debentures. The net proceeds of our equity contribution was approximately $190.0 million. The acquisition of Canadian Hills was accounted for as an asset purchase and is consolidated in our consolidated balance sheet at September 30, 2012.

On October 31, 2012, the Canadian Hills project entered into an equity contribution agreement with four entities for the commitment of a tax equity investment in the project totalling $225.0 million in exchange for Class B equity interest in Canadian Hills which is to be funded on date of commercial operations. We are actively pursuing additional tax equity investors to fund the remaining estimated $47.0 million needed to pay down the existing construction loan. If we are unable to subscribe additional investors, we will fund the remaining portion with either cash on hand or proceeds from our senior credit facility and will become an additional tax equity investor in the project owning the remaining Class B equity interests in Canadian Hills.

ITEM 6. EXHIBITS

Exhibit Number	Description
10.3*	Purchase and sale agreement, dated as of January 31, 2012, between Atlantic Oklahoma Wind, LLC and Apex Wind Energy Holdings, LLC
10.4*	Amended and restated operating agreement, dated as of January 31, 2012, between Atlantic Oklahoma Wind, LLC and Apex Wind Energy Holdings, LLC
10.5*	Amended and restated operating agreement, dated as of March 30, 2012, between Atlantic Oklahoma Wind, LLC and Apex Wind Energy Holdings, LLC
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF	XBRL Taxonomy Extension Definition Linkbase.
101.LAB	XBRL Taxonomy Extension Label Linkbase.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

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* Filed herewith.

** Furnished herewith.

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XBRL information is furnished and not filed for purposes of Sections 11 and 12 of the Securities Act of 1933 and Section 18 of the Securities Exchange Act of 1934, and is not subject to liability under those sections, is not part of any registration statement or prospectus to which it relates and is not incorporated or deemed to be incorporated by reference into any registration statement, prospectus or other document.

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SIGNATURES

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

Date: November 5, 2012

Atlantic Power Corporation

By: /s/ TERRENCE RONAN

Name: Terrence Ronan

Title: *Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*