ATLANTIC POWER CORP
Form 10-Q
August 08, 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 June 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 August 3, 2012 was 119,248,868.

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ATLANTIC POWER CORPORATION

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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)

	June 30, 2012 (unaudited)	December 31, 2011
Assets		
Current assets:		
Cash and cash equivalents	$ 62,693	$ 60,651
Restricted cash	19,139	21,412
Accounts receivable	58,702	79,008
Current portion of derivative instruments asset (Notes 6 and 7)	7,402	10,411
Inventory	18,908	18,628
Prepayments and other current assets	26,582	10,657
Total current assets	193,426	200,767
Property, plant, and equipment, net of accumulated depreciation of $150.0 million and $116.3 million at June 30, 2012 and December 31, 2011, respectively	1,609,672	1,388,254
Transmission system rights, net of accumulated amortization of $55.3 million and $51.4 million at June 30, 2012 and December 31, 2011, respectively	176,356	180,282
Equity investments in unconsolidated affiliates (Note 3)	450,175	474,351
Other intangible assets, net of accumulated amortization of $133.2 million and $90.2 million at June 30, 2012 and December 31, 2011, respectively	572,571	584,274
Goodwill	343,586	343,586
Derivative instruments asset (Notes 6 and 7)	12,145	22,003
Other assets	70,669	54,910
Total assets	$ 3,428,600	$ 3,248,427
Liabilities		
Current Liabilities:		
Accounts payable	$ 19,379	$ 18,122
Accrued interest	18,482	19,916
Other accrued liabilities	66,949	43,968
Revolving credit facility (Note 4)	20,000	58,000
Current portion of long-term debt (Note 4)	309,336	20,958
Current portion of derivative instruments liability (Notes 6 and 7)	46,210	20,592
Dividends payable	10,700	10,733
Other current liabilities	3,021	165
Total current liabilities	494,077	192,454
Long-term debt (Note 4)	1,361,850	1,404,900
Convertible debentures (Note 5)	189,342	189,563
Derivative instruments liability (Notes 6 and 7)	112,135	33,170
Deferred income taxes	157,105	182,925
	45,339	71,775

Power purchase and fuel supply agreement liabilities, net of accumulated amortization of $2.5 million and $1.4 million at June 30, 2012 and December 31, 2011, respectively		
Other non-current liabilities	61,266	57,859
Commitments and contingencies (Note 12)		
Total liabilities	2,421,114	2,132,646
Equity		
Common shares, no par value, unlimited authorized shares; 113,681,691 and 113,526,182 issued and outstanding at June 30, 2012 and December 31, 2011, respectively	1,218,233	1,217,265
Preferred shares issued by a subsidiary company	221,304	221,304
Accumulated other comprehensive loss	(1,964)	(5,193)
Retained deficit	(432,776)	(320,622)
Total Atlantic Power Corporation shareholders' equity	1,004,797	1,112,754
Noncontrolling interest	2,689	3,027
Total equity	1,007,486	1,115,781
Total liabilities and equity	$ 3,428,600	$ 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 June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
Project revenue:				
Energy sales	$ 70,882	$ 17,865	$ 146,850	$ 36,367
Energy capacity revenue	63,039	27,651	125,557	54,789
Transmission services	6,363	7,491	13,524	15,135
Other	14,961	251	36,924	632
	155,245	53,258	322,855	106,923
Project expenses:				
Fuel	55,512	14,316	117,611	31,384
Operations and maintenance	46,100	7,801	77,600	18,873
Depreciation and amortization	40,364	10,924	76,832	21,803
	141,976	33,041	272,043	72,060
Project other income (expense):				
Change in fair value of derivative instruments (Notes 6 and 7)	(44)	(4,574)	(58,166)	(1,013)
Equity in earnings of unconsolidated affiliates (Note 3)	5,473	1,962	8,420	3,273
Interest expense, net	(6,999)	(4,543)	(14,032)	(9,190)
Other income (expense), net	14	(31)	29	(33)
	(1,556)	(7,186)	(63,749)	(6,963)
Project income (loss)	11,713	13,031	(12,937)	27,900
Administrative and other expenses (income):				
Administration	8,086	4,671	15,919	8,725
Interest, net	21,414	3,510	43,450	7,478
Foreign exchange gain (Note 7)	(4,205)	(535)	(3,219)	(1,193)
Other income, net	(6,000)		(6,000)	
	19,295	7,646	50,150	15,010
Income (loss) from operations before income taxes	(7,582)	5,385	(63,087)	12,890
Income tax benefit (Note 8)	(5,526)	(7,684)	(21,817)	(6,161)
Net income (loss)	(2,056)	13,069	(41,270)	19,051
Net income (loss) attributable to noncontrolling interest	3,030	(117)	6,108	(271)
Net income (loss) attributable to Atlantic Power Corporation	$ (5,086)	$ 13,186	$ (47,378)	$ 19,322
Net income (loss) per share attributable to Atlantic Power Corporation shareholders: (Note 10)				
Basic	$ (0.04)	$ 0.19	$ (0.42)	$ 0.28
Diluted	$ (0.04)	$ 0.18	$ (0.42)	$ 0.28
Weighted average number of common shares outstanding: (Note 10)				
Basic	113,682	68,573	113,630	68,116

Diluted	113,682	68,884	113,630	68,543

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)

	Atlantic Power Corporation Three months ended June 30,		Noncontrolling Interests Three months ended June 30,		Total Three months ended June 30,	
	2012	2011	2012	2011	2012	2011
Net (loss) income	$ (2,056)	$ 13,069	$ 3,030	$ (117)	$ (5,086)	$ 13,186
Other comprehensive income, net of tax:						
Unrealized loss on hedging activities	(548)	(762)			(548)	(762)
Net amount reclassified to earnings	226	259			226	259
Net unrealized losses on derivatives	(322)	(503)			(322)	(503)
Foreign currency translation adjustments	(13,858)				(13,858)	
Total other comprehensive income, net of tax	(14,180)	(503)			(14,180)	(503)
Comprehensive income (loss)	$ (16,236)	$ 12,566	$ 3,030	$ (117)	$ (19,266)	$ 12,683

	Atlantic Power Corporation Six months ended June 30,		Noncontrolling Interests Six months ended June 30,		Total Six months ended June 30,	
	2012	2011	2012	2011	2012	2011
Net (loss) income	$ (41,270)	$ 19,051	$ 6,108	$ (271)	$ (47,378)	$ 19,322
Other comprehensive income, net of tax:						
Unrealized loss on hedging activities	(533)	(762)			(533)	(762)
Net amount reclassified to earnings	457	531			457	531
Net unrealized losses on derivatives	(76)	(231)			(76)	(231)
Foreign currency translation adjustments	3,306				3,306	
Total other comprehensive income, net of tax	3,230	(231)			3,230	(231)
Comprehensive income (loss)	$ (38,040)	$ 18,820	$ 6,108	$ (271)	$ (44,148)	$ 19,091

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)

	Six months ended June 30, 2012	Six months ended June 30, 2011
Cash flows from operating activities:		
Net income (loss)	$ (41,270)	$ 19,051
Adjustments to reconcile to net cash provided by operating activities:		
Depreciation and amortization	76,832	21,803
Long-term incentive plan expense	1,475	1,639
Impairment charge on equity investment	3,000	
Gain on sale of equity investments	(578)	
Equity in earnings from unconsolidated affiliates	(10,842)	(3,273)
Distributions from unconsolidated affiliates	8,719	11,584
Unrealized foreign exchange loss	11,823	4,499
Change in fair value of derivative instruments	58,166	1,013
Change in deferred income taxes	(25,999)	(5,691)
Change in other operating balances		
Accounts receivable	20,306	(666)
Prepayments and other current assets	(14,102)	1,244
Accounts payable and accrued liabilities	(384)	(4,996)
Other liabilities	2,226	(1,492)
Net cash provided by operating activities	89,372	44,715
Cash flows used in investing activities:		
Change in restricted cash	2,273	(5,290)
Proceeds from sale of equity investments	24,225	8,500
Cash paid for equity investment	(264)	
Proceeds from related party loan		15,455
Biomass development costs	(200)	(587)
Construction in progress	(230,242)	(42,321)
Purchase of property, plant and equipment	(802)	(577)
Net cash used in investing activities	(205,010)	(24,820)
Cash flows provided by (used in) financing activities:		
Proceeds from project-level debt	255,242	29,890
Repayment of project-level debt	(9,325)	(10,341)
Payments for revolving credit facility borrowings	(60,800)	
Proceeds from revolving credit facility borrowings	22,800	
Deferred financing costs	(18,879)	
Dividends paid	(71,358)	(38,390)
Net cash provided by (used in) financing activities	117,680	(18,841)
Net increase in cash and cash equivalents	2,042	1,054
Cash and cash equivalents at beginning of period	60,651	45,497
Cash and cash equivalents at end of period	$ 62,693	$ 46,551
Supplemental cash flow information		

Interest paid	$	58,198	$	17,600
Income taxes paid (refunded), net	$	1,520	$	(436)
Accruals for construction in progress	$	25,534	$	

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 3,397 megawatts ("MW") in which our ownership interest is approximately 2,141 MW. Our current portfolio consists of interests in 31 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 298 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. 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.

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 June 30, 2012, the results of operations and comprehensive income for the three and six month periods ended June 30, 2012 and 2011, and our cash flows for the six month periods ended June 30, 2012 and 2011.

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

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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. 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 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.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

2. Acquisitions and divestitures

2012 Acquisition

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 the Canadian Hills for a nominal amount, bringing our total interest in the project to 99%. Apex retained a 1% interest in the project. We also closed on 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, in which we are actively pursuing, when Canadian Hills commences commercial operations. We have invested approximately $190 million of equity (net of financing costs) following the closing of our convertible debentures and equity offering on July 5, 2012 (see Note 13 for further information). The acquisition of Canadian Hills was accounted for as an asset purchase and is consolidated in our consolidated balance sheet at June 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. At close, expected in the third quarter, we will receive gross proceeds of $3.7 million. As a result of the pending sale, we recorded an impairment charge of $3.0 million in equity in earnings from unconsolidated affiliates in the consolidated statements of operations for the three and six month periods ended June 30, 2012. We do not anticipate recording additional gains or losses at the time of the transaction close.

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 $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 in equity in earnings of unconsolidated affiliates in the consolidated statements of operations for the three and six month periods ended June 30, 2012. The $6.0 million management termination fee was recorded in other income, net in the consolidated statements of operations for the three and six month periods ended June 30, 2012.

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 six months ended June 30, 2012 and 2011, respectively, for earnings in our equity method investments:

	Three months ended June 30,		Six months ended June 30,	
	2012	2011	2012	2011
Revenue				
Chambers	$ 14,725	$ 13,009	$ 27,952	$ 26,278
Badger Creek	1,091	1,334	2,270	4,655
Gregory	4,637	7,633	8,952	14,814
Orlando	10,957	9,375	21,769	19,302
Selkirk	11,547	12,961	23,609	23,861
Other	10,571	3,132	22,304	4,952
	53,528	47,444	106,856	93,862
Project expenses				
Chambers	8,749	9,545	18,502	18,925
Badger Creek	1,003	1,414	2,140	4,398
Gregory	4,350	6,900	10,130	13,530
Orlando	10,205	9,605	20,298	19,068
Selkirk	10,724	12,631	21,059	25,289
Other	10,244	2,366	18,638	3,795
	45,275	42,461	90,767	85,005
Project other income (expense)				
Chambers	(422)	(663)	(1,615)	(1,090)
Badger Creek	(3,004)	(7)	(3,008)	(11)
Gregory	(143)	(194)	(226)	(231)
Orlando	(20)	(13)	(34)	(44)
Selkirk	2,252	(929)	2,187	(2,566)
Other	(1,443)	(1,215)	(4,973)	(1,642)
	(2,780)	(3,021)	(7,669)	(5,584)
Project income (loss)				
Chambers	5,554	2,801	7,835	6,263
Badger Creek	(2,916)	(87)	(2,878)	246
Gregory	144	539	(1,404)	1,053
Orlando	732	(243)	1,437	190
Selkirk	3,075	(599)	4,737	(3,994)
Other	(1,116)	(449)	(1,307)	(485)
	5,473	1,962	8,420	3,273

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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:

	June 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)	206,262	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	34,232	34,982	7.40%
Path 15 senior secured bonds	142,005	145,879	7.90% 9.00%
Auburndale term loan, due 2013	8,400	11,900	5.10%
Cadillac term loan, due 2025	39,031	40,231	6.02% 8.00%
Piedmont construction loan, due 2013	117,285	100,796	Libor plus 3.50%
Canadian Hills construction loan, due 2013	238,754		Libor plus 3.00%
Purchase accounting fair value adjustments	10,217	10,580	
Less current maturities[(1)]	(309,336)	(20,958)	
Total long-term debt	$ 1,361,850	$ 1,404,900	

(1) Current maturities in 2012 include $238.8 million of construction loan debt related to the Canadian Hills project. This facility is expected to be repaid in late 2012 by tax equity funding.

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 have 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 Curtis Palmer's ability 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, a wholly-owned subsidiary of Atlantic Power Limited Partnership (the "Partnership"). 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 have agreed to waive certain defaults or events of default that they alleged

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

4. Long-term debt (Continued)

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 June 30, 2012, all of our projects were in compliance with the covenants contained in project-level debt. However, our Epsilon Power Partners, Idaho Wind, 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.

Senior Credit Facility

As of June 30, 2012, $20.0 million was drawn on the senior credit facility and $138.9 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects. The applicable margin was 2.75%.

5. Convertible debentures

The following table contains details related to outstanding convertible debentures:

(In thousands, except for share amounts)	6.5% Debentures due October 2014	6.25% Debentures due March 2017	5.6% Debentures due June 2017	Total
Balance at December 31, 2011 (Cdn$)	44,853	67,433	80,500	192,786
Principal amount converted to equity (Cdn$)	(13)			(13)
Balance at June 30, 2012 (Cdn$)	44,840	67,433	80,500	192,773
Balance at June 30, 2012 (US$)	44,043	66,234	79,065	189,342
Common shares issued on conversion during the six-months ended June 30, 2012	1,048			1,048

Aggregate interest expense related to the convertible debentures was $2.8 million and $3.0 million for the three-month periods ended June 30, 2012 and 2011, respectively, and $5.7 million and $6.4 million for the six-month periods ended June 30, 2012 and 2011, respectively.

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 June 30, 2012 and December 31, 2011. Financial

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

6. Fair value of financial instruments (Continued)

assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

	June 30, 2012			
	Level 1	Level 2	Level 3	Total
Assets:				
Cash and cash equivalents	$ 62,693	$	$	$ 62,693
Restricted cash	19,139			19,139
Derivative instruments asset		19,547		19,547
Total	$ 81,832	$ 19,547	$	$ 101,379
Liabilities:				
Derivative instruments liability	$	$ 158,345	$	$ 158,345
Total	$	$ 158,345	$	$ 158,345

	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 June 30, 2012, the credit valuation adjustments resulted in a $20.7 million net increase in fair value, which consists of a $1.3 million pre-tax gain in other comprehensive income and a $19.4 million gain in change in fair value of derivative instruments. 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 gain in other comprehensive income and a $5.1 million gain in change in fair value of derivative instruments, offset by a $0.2 million loss in foreign exchange.

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 certain contracts designated as cash flow hedges, we defer the effective portion of the change in fair value of the derivatives to accumulated other comprehensive income (loss), 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 purchase agreements and 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.

On May 9, 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 June 30, 2012. Changes in the fair market value of the contract are recorded in the consolidated statement of operations.

We have recorded a $1.2 million unrealized loss and a $59.1 million unrealized loss for the three and six months ended June 30, 2012, respectively, related to our gas purchase agreements accounted for as derivative financial instruments.

Natural gas swaps

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

The Lake project's operating margin is exposed to changes in natural gas spot market prices through the expiration of its PPA on July 31, 2013. The Auburndale project purchased natural gas under a fuel supply agreement that provided approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% was previously purchased at spot market prices and therefore the project's operating margin was exposed to changes in natural gas prices for that

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

portion of its gas requirements. Beginning on July 1, 2012, the project's operating margin is exposed to changes in natural gas prices for 100% of its natural gas requirements until the termination of its PPA at the end of 2013. Our strategy is to mitigate the future exposure to changes in natural gas prices at Orlando, Lake and Auburndale consists of periodically entering into financial swaps that effectively fix the price of natural gas expected to be purchased at these projects. These natural gas swaps are derivative financial instruments and are recorded in the consolidated balance sheet at fair value and the changes in their fair market value are recorded in the consolidated statement of operations.

Interest rate swaps

The Cadillac project has an interest rate swap agreement that effectively fixes the interest rate 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 is 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 is 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 February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.47%. The swap continues at the fixed rate of 4.47% from the maturity of the debt in November 2017 until November 2030. The notional amounts of the interest rate swap agreements match the estimated outstanding principal balance of Piedmont's cash grant bridge loan and the construction loan facility that will convert to a term loan. The interest rate swaps expire on February 29, 2016 and November 30, 2030, respectively. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

Our wholly owned subsidiary, Epsilon Power Partners, 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.

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

Foreign currency forward contracts

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as we generate cash flow in U.S. dollars and Canadian dollars but pay dividends to shareholders and interest on 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 approximately 79% 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 June 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$1.13 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 normal purchases and normal sales exception as of June 30, 2012 and December 31, 2011:

	Units	June 30, 2012	December 31, 2011
Natural gas swaps	Natural Gas (Mmbtu)	12,130	14,140
Gas Purchase Agreements	Natural Gas (GJ)	53,315	33,957
Interest Rate Swaps	Interest (US$)	50,010	52,711
Currency forwards	Cdn$	220,028	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:

	June 30, 2012	
	Derivative Assets	Derivative Liabilities
Derivative instruments designated as cash flow hedges:		
Interest rate swaps current	$	$ 1,700
Interest rate swaps long-term		5,116
Total derivative instruments designated as cash flow hedges		6,816
Derivative instruments not designated as cash flow hedges:		
Interest rate swaps current		2,618
Interest rate swaps long-term		11,077
Foreign currency forward contracts current	7,569	167
Foreign currency forward contracts long-term	12,253	108
Natural gas swaps current		21,142
Natural gas swaps long-term		11,283
Gas purchase agreements current		21,033
Gas purchase agreements long-term		84,376
Total derivative instruments not designated as cash flow hedges	19,822	151,804
Total derivative instruments	$ 19,822	$ 158,620

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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	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 June 30, 2012	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at March 31, 2012	$ (1,402)	$ 264	$ (1,138)
Change in fair value of cash flow hedges	(548)		(548)
Realized from OCI during the period	283	(57)	226
Accumulated OCI balance at June 30, 2012	$ (1,667)	$ 207	$ (1,460)

For the three month period ended June 30, 2011	Interest Rate Swaps	Natural Gas Swaps	Total
Accumulated OCI balance at March 31, 2011	$ (66)	$ 593	$ 527
Change in fair value of cash flow hedges	(762)		(762)
Realized from OCI during the period	349	(90)	259

Accumulated OCI balance at June 30, 2011	$ (479)	$ 503	$ 24

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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 six month period ended June 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	(533)		(533)
Realized from OCI during the period	570	(114)	456
Accumulated OCI balance at June 30, 2012	$ (1,667)	$ 207	$ (1,460)

For the six month period ended June 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	(762)		(762)
Realized from OCI during the period	710	(179)	531
Accumulated OCI balance at June 30, 2011	$ (479)	$ 503	$ 24

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 June 30, 2012	Three months ended June 30, 2011
Natural gas swaps	Fuel	$ 5,009	$ 2,055
Gas purchase agreements	Fuel	15,863	
Foreign currency forwards	Foreign exchange (gain) loss	(3,112)	(3,155)
Interest rate swaps	Interest, net	1,191	955

	Classification of (gain) loss recognized in income	Six months ended June 30, 2012	Six months ended June 30, 2011
Natural gas swaps	Fuel	$ 9,824	$ 4,531
Gas purchase agreements	Fuel	32,648	
Foreign currency forwards	Foreign exchange (gain) loss	(15,042)	(5,692)
Interest rate swaps	Interest, net	2,348	1,931

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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 June 30, 2012	Three months ended June 30, 2011
Natural gas swaps	Change in fair value of derivatives	$ 4,215	$ (1,237)
Gas purchase agreements	Change in fair value of derivatives	(1,237)	
Interest rate swaps	Change in fair value of derivatives	(3,022)	(3,337)
Total change in fair value of derivative instruments		$ (44)	$ (4,574)
Foreign currency forwards	Foreign exchange (gain) loss	$ 7,653	$ 1,303

	Classification of (gain) loss recognized in income	Six months ended June 30, 2012	Six months ended June 30, 2011
Natural gas swaps	Change in fair value of derivatives	$ 2,420	$ 1,646
Gas purchase agreements	Change in fair value of derivatives	(59,114)	
Interest rate swaps	Change in fair value of derivatives	(1,472)	(2,659)
Total change in fair value of derivative instruments		$ (58,166)	$ (1,013)
Foreign currency forwards	Foreign exchange (gain) loss	$ 12,863	$ (2,133)

8. Income taxes

The difference between the actual tax benefit of $5.5 million and $21.8 million for the three and six months ended June 30, 2012 and the expected income tax benefit, based on the Canadian enacted statutory rate of 25%, of $1.9 million and $15.8 million, respectively, is primarily due to permanent differences related to one of our projects and is partially offset by the increase in our valuation allowance.

	Three months ended June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
Current income tax expense (benefit)	$ 2,797	$ 18	$ 4,182	$ (470)
Deferred tax benefit	(8,323)	(7,702)	(25,999)	(5,691)
Total income tax benefit	$ (5,526)	$ (7,684)	$ (21,817)	$ (6,161)

ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Income taxes (Continued)

As of June 30, 2012, we have recorded a valuation allowance of $96.5 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 six months ended June 30, 2012:

	Units	Grant Date Weighted-Average Price per Unit
Outstanding at December 31, 2011	485,781	$ 11.49
Granted	209,009	$ 14.65
Forfeited	(28,932)	$ 13.91
Additional shares from dividends	18,111	$ 13.00
Vested	(231,687)	$ 10.10
Outstanding at June 30, 2012	452,282	$ 13.77

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 June 30, 2012 and December 31, 2011:

	June 30, 2012	December 31, 2011
Weighted average risk free rate of return	0.19 0.39%	0.15 0.28%
Dividend yield	8.80%	7.90%
Expected volatility Atlantic Power	19.4 23.5%	22.20%
Expected volatility peer companies	16.1 119.6%	17.3 112.9%
Weighted average remaining measurement period	1.67 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 the Shareholders on June 22, 2012. The 2012 Incentive Plan increases flexibility of the Compensation Committee to use various equity-based incentive awards as compensation tools to

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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 no new awards have been granted under the 2012 Incentive Plan. 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 six months ended June 30, 2012 and 2011:

	Three months ended June 30,		Six months ended June 30,	
	2012	**2011**	**2012**	**2011**
Numerator:				
Net income (loss) attributable to Atlantic Power Corporation	$ (5,086)	$ 13,186	$ (47,378)	$ 19,322
Denominator:				
Weighted average basic shares outstanding	113,682	68,573	113,630	68,116
Dilutive potential shares:				
Convertible debentures	13,251	14,055	13,251	14,430
LTIP notional units	474	311	480	427
Potentially dilutive shares	127,407	82,939	127,361	82,973
Diluted EPS	$ (0.04)	$ 0.18	$ (0.42)	$ 0.28

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 six months ended June 30, 2012 because their impact would be anti-dilutive. Potentially dilutive shares from convertible debentures have been excluded from fully diluted shares in the three and six month period ended June 30, 2011 because their impact would be anti-dilutive.

11. 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 six months ended June 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.

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Segment and geographic information (Continued)

These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes general and administrative activities that support the projects, executive offices, capital structure and costs of being a public registrant. 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 GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of project income to Project Adjusted EBITDA is included in the tables below.

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Three month period ended June 30, 2012:						
Operating revenues	$ 45,905	$ 47,461	$ 16,664	$ 44,558	$ 657	$ 155,245
Segment assets	1,180,033	434,269	784,195	987,712	42,391	3,428,600
Project Adjusted EBITDA	$ 22,413	$ 25,069	$ 12,417	$ 17,013	$ (4,132)	72,780
Change in fair value of derivative instruments	(1,572)	(1,058)			1	(2,629)
Depreciation and amortization	20,212	9,366	10,594	11,146	43	51,361
Interest, net	4,699	94	1,526	3,073	(91)	9,301
Other project (income) expense	255	14		2,689	76	3,034
Project (loss) income	(1,181)	16,653	297	105	(4,161)	11,713
Administration					8,086	8,086
Interest, net					21,414	21,414
Foreign exchange gain					(4,205)	(4,205)
Other income, net					(6,000)	(6,000)
Loss from operations before income taxes	(1,181)	16,653	297	105	(23,456)	(7,582)
Income tax benefit					(5,526)	(5,526)
Net income (loss)	$ (1,181)	$ 16,653	$ 297	$ 105	$ (17,930)	$ (2,056)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Segment and geographic information (Continued)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Three month period ended June 30, 2011:						
Operating revenues	$ 5,017	$ 40,660	$	$ 7,491	$ 90	$ 53,258
Segment assets	276,149	375,610	45,965	218,613	92,643	1,008,980
Project Adjusted EBITDA	$ 10,095	$ 22,670	$ 1,620	$ 8,626	$ (157)	$ 42,854
Change in fair value of derivative instruments	748	4,078				4,826
Depreciation and amortization	4,616	9,438	857	2,733	17	17,661
Interest, net	2,461	279	1,153	3,199	(4)	7,088
Other project (income) expense	230	14		5	(1)	248
Project (loss) income	2,040	8,861	(390)	2,689	(169)	13,031
Administration					4,671	4,671
Interest, net					3,510	3,510
Foreign exchange gain					(535)	(535)
Income from operations before income taxes	2,040	8,861	(390)	2,689	(7,815)	5,385
Income tax benefit					(7,684)	(7,684)
Net income (loss)	$ 2,040	$ 8,861	$ (390)	$ 2,689	$ (131)	$ 13,069

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Six month period ended June 30, 2012:						
Operating revenues	$ 112,831	$ 89,212	$ 31,964	$ 87,254	$ 1,594	$ 322,855
Segment assets	1,180,033	434,269	784,195	987,712	42,391	3,428,600
Project Adjusted EBITDA	$ 64,811	$ 46,743	$ 25,856	$ 35,777	$ (7,557)	165,630
Change in fair value of derivative instruments	56,444	(652)				55,792
Depreciation and amortization	37,659	18,738	21,020	23,803	86	101,306
Interest, net	9,437	263	2,622	5,881	(34)	18,169
Other project (income) expense	497	28	7	2,771	(3)	3,300
Project (loss) income	(39,226)	28,366	2,207	3,322	(7,606)	(12,937)
Administration					15,919	15,919
Interest, net					43,450	43,450
Foreign exchange gain					(3,219)	(3,219)
Other income, net					(6,000)	(6,000)
Loss from operations before income taxes	(39,226)	28,366	2,207	3,322	(57,756)	(63,087)

Income tax benefit					(21,817)	(21,817)
Net income (loss)	$ (39,226)	$ 28,366	$ 2,207	$ 3,322	$ (35,939)	$ (41,270)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Segment and geographic information (Continued)

	Northeast	Southeast	Northwest	Southwest	Un-allocated Corporate	Consolidated
Six month period ended June 30, 2011:						
Operating revenues	$ 9,565	$ 82,087	$	$ 15,135	$ 136	$ 106,923
Segment assets	276,149	375,610	45,965	218,613	92,643	1,008,980
Project Adjusted EBITDA	$ 17,583	$ 42,257	$ 2,485	$ 17,127	$ (605)	$ 78,847
Change in fair value of derivative instruments	1,237	804			1	2,042
Depreciation and amortization	9,212	18,872	1,298	5,694	22	35,098
Interest, net	4,895	588	1,522	6,288	35	13,328
Other project (income) expense	431	45		3		479
Project (loss) income	1,808	21,948	(335)	5,142	(663)	27,900
Administration					8,725	8,725
Interest, net					7,478	7,478
Foreign exchange gain					(1,193)	(1,193)
Income from operations before income taxes	1,808	21,948	(335)	5,142	(15,673)	12,890
Income tax benefit					(6,161)	(6,161)
Net income (loss)	$ 1,808	$ 21,948	$ (335)	$ 5,142	$ (9,512)	$ 19,051

The tables below provide information, by country, about our consolidated operations for the three and six months ended June 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 June 30		Project Revenue Six Months Ended June 30	
	2012	2011	2012	2011
United States	$ 109,359	$ 53,258	$ 213,683	$ 106,923
Canada	45,886		109,172	
Total	$ 155,245	$ 53,258	$ 322,855	$ 106,923

	Property, Plant & Equipment, net June 30,	
	2012	2011
United States	$ 1,053,638	$ 308,851
Canada	556,034	
Total	$ 1,609,672	$ 308,851

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 June 30, 2012, and 26% and 23%, respectively, of total consolidated revenues for the six months ended June 30, 2012. PEF and the California Independent System Operator ("CAISO") provided approximately 69% and 14%, respectively, of total consolidated revenues for the three months ended June 30, 2011, and 70% and 14%, respectively, for the six months ended June 30, 2011. PEF purchases electricity from the Auburndale and Lake projects in the Southeast segment, OEFC purchases

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

11. Segment and geographic information (Continued)

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.

12. 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. The Company expects to be successful in sustaining its 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 June 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)

12. 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

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of June 30, 2012 which are expected to have a material adverse impact on our financial position or results of operations.

13. Subsequent Events

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 an aggregate net proceeds from the common share offering, after deducting the underwriting discounts and expenses, of approximately, $68.5 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") 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 have a conversion price of $17.25 per common share and are convertible into our common shares at a conversion rate of 57.9710 common shares per $1,000 principal amount of debentures. We used the proceeds to fund our equity commitment in Canadian Hills Wind, LLC.

14. Condensed consolidating financial information

As of June 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 June 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, Badger Power Generation I, LLC, Badger Power Generation, II, LLC, Badger Power Associates, LP, Atlantic Cadillac

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Condensed consolidating financial information (Continued)

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 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 LLC in accordance with Rule 3-10 under the SEC's Regulation S-X. The financial information may not necessarily be indicative of results of operations or financial position had the guarantor subsidiaries or Curtis Palmer LLC 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)

14. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING BALANCE SHEET

June 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	$ 61,023	$ (11)	$ 1,681	$	$ 62,693
Restricted cash	19,139				19,139
Accounts receivable	69,636	24,500	2,954	(38,388)	58,702
Prepayments and other current assets	43,696	1,170	8,026		52,892
Total current assets	193,494	25,659	12,661	(38,388)	193,426
Property, plant, and equipment, net	1,436,727	174,061		(1,116)	1,609,672
Transmission system rights	176,356				176,356
Equity investments in unconsolidated affiliates	4,464,936		392,064	(4,406,825)	450,175
Other intangible assets, net	409,256	163,315			572,571
Goodwill	285,358	58,228			343,586
Other assets	480,774		443,275	(841,235)	82,814
Total assets	$ 7,446,901	$ 421,263	$ 848,000	$ (5,287,564)	$ 3,428,600
Liabilities					
Current Liabilities:					
Accounts payable and accrued liabilities	$ 123,614	$ 7,826	$ 11,760	$ (38,388)	$ 104,812
Revolving credit facility			20,000		20,000
Current portion of long-term debt	309,336				309,336
Other current liabilities	49,229		10,700		59,929
Total current liabilities	482,179	7,826	42,460	(38,388)	494,077
Long-term debt	711,850	190,000	460,000		1,361,850
Convertible debentures			189,342		189,342
Other non-current liabilities	1,207,930	8,198	952	(841,235)	375,845
Equity					
Preferred shares issued by a subsidiary company	221,304				221,304
Common shares	4,192,702	215,239	1,218,233	(4,407,941)	1,218,233
Accumulated other comprehensive income (loss)	(1,964)				(1,964)
Retained deficit	630,211		(1,062,987)		(432,776)
Total Atlantic Power Corporation shareholders' equity	5,042,253	215,239	155,246	(4,407,941)	1,004,797

Noncontrolling interest	2,689				2,689
Total equity	5,044,942	215,239	155,246	(4,407,941)	1,007,486
Total liabilities and equity	$ 7,446,901	$ 421,263	$ 848,000	$ (5,287,564)	$ 3,428,600

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Three months ended June 30, 2012

(in thousands of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Project revenue:					
Total project revenue	$ 147,089	$ 8,306	$	$ (150)	$ 155,245
Project expenses:					
Fuel	55,512				55,512
Project operations and maintenance	44,312	1,500	388	(100)	46,100
Depreciation and amortization	36,523	3,841			40,364
	136,347	5,341	388	(100)	141,976
Project other income (expense):					
Change in fair value of derivative instruments	(44)				(44)
Equity in earnings of unconsolidated affiliates	5,473				5,473
Interest expense, net	(4,158)	(2,835)	(6)		(6,999)
Other income, net	14				14
	1,285	(2,835)	(6)		(1,556)
Project income	12,027	130	(394)	(50)	11,713
Administrative and other expenses (income):					
Administration expense	5,045		3,041		8,086
Interest, net	19,734		1,680		21,414
Foreign exchange loss	(2,443)		(1,762)		(4,205)
Other Income (loss)	(6,000)				(6,000)
	16,336		2,959		19,295
Income (loss) from operations before income taxes	(4,309)	130	(3,353)	(50)	(7,582)
Income tax expense (benefit)	(5,527)		1		(5,526)
Net income (loss)	1,218	130	(3,354)	(50)	(2,056)
Net loss attributable to noncontrolling interest	(177)				(177)
Net income attributable to preferred share dividends of a subsidiary company	3,207				3,207
Net income (loss) attributable to Atlantic Power Corporation	$ (1,812)	$ 130	$ (3,354)	$ (50)	$ (5,086)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

Six months ended June 30, 2012

(in thousands of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Project revenue:					
Total project revenue	$ 304,207	$ 18,923	$	$ (275)	$ 322,855
Project expenses:					
Fuel	117,611				117,611
Project operations and maintenance	74,379	3,136	260	(175)	77,600
Depreciation and amortization	69,228	7,604			76,832
	261,218	10,740	260	(175)	272,043
Project other income (expense):					
Change in fair value of derivative instruments	(58,166)				(58,166)
Equity in earnings of unconsolidated affiliates	8,420				8,420
Interest expense, net	(8,483)	(5,543)	(6)		(14,032)
Other income, net	29				29
	(58,200)	(5,543)	(6)		(63,749)
Project income	(15,211)	2,640	(266)	(100)	(12,937)
Administrative and other expenses (income):					
Administration expense	10,179		5,740		15,919
Interest, net	40,113		3,164	173	43,450
Foreign exchange loss	(1,310)		(1,909)		(3,219)
Other income (loss)	(6,000)				(6,000)
	42,982		6,995	173	50,150
Income (loss) from operations before income taxes	(58,193)	2,640	(7,261)	(273)	(63,087)
Income tax expense (benefit)	(21,818)		1		(21,817)
Net income (loss)	(36,375)	2,640	(7,262)	(273)	(41,270)
Net loss attributable to noncontrolling interest	(338)				(338)
Net income attributable to preferred share dividends of a subsidiary company	6,446				6,446
Net income (loss) attributable to Atlantic Power Corporation	$ (42,483)	$ 2,640	$ (7,262)	$ (273)	$ (47,378)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF COMPREHENSIVE INCOME

Three and six months ended June 30, 2012

(in thousands of U.S. dollars)

	Three months ended June 30, 2012				
	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net (loss) income	$ (1,812)	$ 130	$ (3,354)	$ (50)	$ (5,086)
Other comprehensive income, net of tax:					
Unrealized loss on hedging activities	(548)				(548)
Net amount reclassified to earnings	226				226
Net unrealized losses on derivatives	(322)				(322)
Foreign currency translation adjustments	(13,858)				(13,858)
Total other comprehensive income, net of tax	(14,180)				(14,180)
Comprehensive income (loss)	$ (15,992)	$ 130	$ (3,354)	$ (50)	$ (19,266)

	Six months ended June 30, 2012				
	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net (loss) income	$ (42,483)	$ 2,640	$ (7,262)	$ (273)	$ (47,378)
Other comprehensive income, net of tax:					
Unrealized loss on hedging activities	(533)				(533)
Net amount reclassified to earnings	457				457
Net unrealized losses on derivatives	(76)				(76)
Foreign currency translation adjustments	3,306				3,306
Total other comprehensive income, net of tax	3,230				3,230
Comprehensive income (loss)	$ (39,253)	$ 2,640	$ (7,262)	$ (273)	$ (44,148)

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ATLANTIC POWER CORPORATION

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)

(Unaudited)

14. Condensed consolidating financial information (Continued)

ATLANTIC POWER CORPORATION

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

Six months ended June 30, 2012

(in thousands of U.S. dollars)

	Guarantor Subsidiaries	Curtis Palmer	Atlantic Power	Eliminations	Consolidated Balance
Net cash provided by operating activities	$ (13,809)	$ 21	$ 103,160	$	$ 89,372
Cash flows used in investing activities:					
Acquisitions and investments, net of cash acquired	(66)		(198)		(264)
Proceeds from sale of equity investments	24,225				24,225
Construction in progress	(230,242)				(230,242)
Change in restricted cash	2,273				2,273
Biomass development costs	(200)				(200)
Purchase of property, plant and equipment	(785)	(17)			(802)
Net cash used in investing activities	(204,795)	(17)	(198)		(205,010)
Cash flows provided by financing activities:					
Repayment for long-term debt	(9,325)				(9,325)
Deferred finance costs	(10,179)		(8,700)		(18,879)
Proceeds from project-level debt	255,242				255,242
Payments for revolving credit facility borrowings	(30,800)		(30,000)		(60,800)
Proceeds from revolving credit facility borrowings	22,800				22,800
Dividends paid	(6,481)		(64,877)		(71,358)
Net cash provided by (used in) financing activities	221,257		(103,577)		117,680
Net increase in cash and cash equivalents	2,653	4	(615)		2,042
Cash and cash equivalents at beginning of period	58,370	(15)	2,296		60,651
Cash and cash equivalents at end of period	$ 61,023	$ (11)	$ 1,681	$	$ 62,693

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

These risks include, without limitation:

- 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 impact of significant environmental and other regulations on our projects;
- increased competition, including for acquisitions; and
- our limited control over the operation of certain minority owned projects.

Other factors, such as general economic conditions, including exchange rate fluctuations, also may have an effect on the results of our operations. Many of these risks and uncertainties can affect our actual results and could cause our actual results to differ materially from those expressed or implied in any forward-looking statement made by us or on our behalf.

Material factors or assumptions that were applied in drawing a conclusion or making an estimate set out in the forward-looking information include third party projections of regional fuel and electric 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

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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 accounting principles generally accepted in the United States of America ("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 3,397 megawatts ("MW") in which our aggregate ownership interest is approximately 2,141MW. Our current portfolio consists of interests in 31 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 298 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 no 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.

We directly operate and maintain more than half of our power generation fleet. We 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,

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Southwest and Un-allocated Corporate. Our financial results for the six months ended June 30, 2011 have been presented to reflect these changes in our operating segments.

RECENT DEVELOPMENTS

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. 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. The construction loan is structured to be repaid with a tax equity investment, in which we are actively pursuing, with institutional investors at the time Canadian Hills commences commercial operations.

In connection with the closing of the construction financing facility on March 30, 2012, we committed to invest approximately $190 million in equity (net of financing costs) to cover the balance of the construction and development costs, expected to be drawn following the final disbursement of the construction loan. We funded our equity commitment with the proceeds of our convertible debentures and common stock offerings on July 5, 2012. The sources of financing for our equity commitment will depend upon a variety of factors, including market conditions. We have received an approximately $360 million bridge facility commitment to provide flexibility in the timing of the tax equity.

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).

DuPont

As previously disclosed in our Annual Report on Form 10-K, the Chambers project 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 May 18, 2012, the court issued its final written opinion which ordered DuPont to pay Chambers a total of approximately $16.3 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 has paid the Chambers project the true-up settlement of this new pricing methodology for the period July 1, 2009 through June 30, 2011 of approximately $9.0 million. On July 13, 2012, DuPont has 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.

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

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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.

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 $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 in equity in earnings of unconsolidated affiliates in the consolidated statements of operations for the three and six month periods ended June 30, 2012. The $6.0 million management termination fee was recorded in other income, net in the consolidated statements of operations for the three and six month periods ended June 30, 2012.

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 an aggregate net proceeds from the common share offering, after deducting the underwriting discounts and expenses, of approximately, $68.5 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") 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 have a conversion price of $17.25 per common share and are convertible into our common shares at a conversion rate of 57.9710 common shares per $1,000 principal amount of debentures. We used the proceeds to fund our equity commitment in Canadian Hills Wind, LLC.

Badger Creek Sale

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. At close, expected in the third quarter, we will receive proceeds of $3.7 million. As a result of the pending sale, we recorded an impairment charge of $3.0 million in equity in earnings from unconsolidated affiliates in the consolidated statements of operations for the three and six month periods ended June 30, 2012. We do not anticipate recording additional gains or losses at the time of closing.

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 August 3, 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)
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	Natural Gas	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	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								
Badger Creek	California	Natural Gas	46	50.00%	23	Pacific Gas & Electric	2013	BBB+
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 Municial 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 expires on July 31, 2012, was extended by agreement with the purchaser through August 31, 2012. We are currently in negotiations with the purchaser regarding extension of the PPA.

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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 six months ended June 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)	Three months ended June 30, 2012	Three months ended June 30, 2011	Six months ended June 30, 2012	Six months ended June 30, 2011
Project revenue				
Northeast	$ 45,905	$ 5,017	$ 112,831	$ 9,565
Southeast	47,461	40,660	89,212	82,087
Northwest	16,664		31,964	
Southwest	44,558	7,491	87,254	15,135
Un-allocated Corporate	657	90	1,594	136
	155,245	53,258	322,855	106,923
Project expenses				
Northeast	50,255	3,272	97,432	6,966
Southeast	32,512	27,198	62,679	58,935
Northwest	16,148		30,095	
Southwest	38,195	2,310	72,613	5,357
Un-allocated Corporate	4,866	261	9,224	802
	141,976	33,041	272,043	72,060
Project other income (expense)				
Northeast	3,169	295	(54,625)	(791)
Southeast	1,704	(4,601)	1,833	(1,205)
Northwest	(219)	(390)	338	(335)
Southwest	(6,258)	(2,492)	(11,319)	(4,635)
Un-allocated Corporate	48	2	24	3
	(1,556)	(7,186)	(63,749)	(6,963)
Total project income (loss)				
Northeast	(1,181)	2,040	(39,226)	1,808
Southeast	16,653	8,861	28,366	21,947
Northwest	297	(390)	2,207	(335)
Southwest	105	2,689	3,322	5,143
Un-allocated Corporate	(4,161)	(169)	(7,606)	(663)
	11,713	13,031	(12,937)	27,900
Administrative and other expenses				
Administration	8,086	4,671	15,919	8,725
Interest, net	21,414	3,510	43,450	7,478
Foreign exchange gain	(4,205)	(535)	(3,219)	(1,193)
Other income, net	(6,000)		(6,000)	
Total administrative and other expenses	19,295	7,646	50,150	15,010
Income (loss) from operations before income taxes	(7,582)	5,385	(63,087)	12,890
Income tax benefit	(5,526)	(7,684)	(21,817)	(6,161)
Net income (loss)	(2,056)	13,069	(41,270)	19,051
Net income (loss) attributable to noncontrolling interest	3,030	(117)	6,108	(271)
Net income (loss) attributable to Atlantic Power Corporation shareholders	$ (5,086)	$ 13,186	$ (47,378)	$ 19,322

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 six months ended June 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 $13.0 million and $18.0 million for the three months ended June 30, 2012 and 2011, respectively. Cash Available for Distribution was $72.8 million and $34.6 million for the six months ended June 30, 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. See "Supplementary Non-GAAP Financial Information" and "Cash Available for Distribution" below for additional information.

Income (loss) from operations before income taxes for the three months ended June 30, 2012 and 2011 was $(7.6) million and $5.4 million, respectively. Income (loss) from operations before income taxes for the six months ended June 30, 2012 and 2011 was $(63.1) million and $12.9 million, respectively. See "Segment Analysis" below for additional information.

Segment Analysis

Northeast

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

	Three months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Northeast			
Project Income	$ (1,181)	$ 2,040	Not Meaningful ("NM")

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

Project income for the three months ended June 30, 2012 decreased $3.2 million from the comparable 2011 period primarily due to:

- a project loss of $7.2 million from the newly acquired North Bay, Kapuskasing and Nipigon projects. The project loss for these projects were impacted by the amortization associated with their intangible assets, as well as a $1.2 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives; and

- a project loss from the newly acquired Calstock project of $2.4 million as a result from a planned maintenance outage during the second quarter of 2012.

These decreases were partially offset by:

- increased project income of $3.7 million at Selkirk attributable to lower operations and maintenance costs, higher capacity revenue and a $2.9 million non-cash change in the fair value of gas supply agreements from the comparable 2011 period; and

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increased project income of $3.4 million at Chambers due to the collection of the $3.6 million DuPont partial settlement associated with the dispute of the electricity calculation under its PPA.

	Six months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Northeast			
Project Income	$ (39,226)	$ 1,808	NM

Six months ended June 30, 2012 compared with six months ended June 30, 2011

Project income for the six months ended June 30, 2012 decreased $41.0 million from the comparable 2011 period primarily due to:

a project loss of $56.3 million from the newly acquired North Bay, Kapuskasing and Nipigon projects. The project income for these projects were impacted by a $59.1 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 Curtis Palmer project of $2.6 million and Tunis project of $3.8 million;

increased project income of $2.1 million at Chambers due to the collection of the $3.6 million DuPont partial settlement associated with the dispute of the electricity calculation under its PPA; and

increased project income of $8.7 million at Selkirk attributable to lower operations and maintenance costs, higher capacity revenue and a $4.2 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 June 30,		
	2012	2011	% change 2012 vs. 2011
Southeast			
Project Income	$ 16,653	$ 8,861	88%

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

Project income for the three months ended June 30, 2012 increased $7.8 million from the comparable 2011 period primarily due to:

increased project income of $4.0 million at Auburndale primarily attributable to an increase of $2.7 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps; and

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increased project income of $3.9 million at Lake primarily attributable to an increase of $2.9 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps.

	Six months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Southeast			
Project Income	$ 28,366	$ 21,947	29%

Six months ended June 30, 2012 compared with six months ended June 30, 2011

Project income for the six months ended June 30, 2012 increase $6.4 million from the comparable 2011 period primarily due to:

increased project income of $1.8 million at Auburndale primarily attributable to $1.3 million higher capacity revenues due to contractual escalation under the project's PPA as well as higher dispatch;

increased project income of $2.6 million at Lake primarily attributable to $1.0 million higher capacity revenues due to contractual escalation under the project's PPA and an increase of $2.1 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps; and

increased project income of $1.4 million at Pasco due to an unplanned replacement of gas turbine components and repairs during the comparable 2011 period.

Northwest

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

	Three months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Northwest			
Project Income	$ 297	$ (390)	NM

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

Project income for the three months ended June 30, 2012 increased $0.7 million from the comparable 2011 period primarily due to:

project income of $3.2 million from the newly acquired Mamquam project.

This increase was partially offset by:

project loss of $2.9 million from the newly acquired Williams Lake project resulting from a planned maintenance outage during the month of April.

	Six months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Northwest			
Project Income	$ 2,207	$ (335)	NM

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Six months ended June 30, 2012 compared with six months ended June 30, 2011

Project income for the six months ended June 30, 2012 increased $2.5 million from the comparable 2011 period primarily due to:

- project income of $3.9 million from the newly acquired Mamquam project; and

- project income of $0.9 million from the newly acquired Frederickson project.

These increases were partially offset by:

- project loss of $2.3 million from the newly acquired Williams Lake project resulting from a planned maintenance outage during the month of April.

Southwest

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

	Three months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Southwest			
Project Income	$ 105	$ 2,689	-96%

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

Project income for the three months ended June 30, 2012 decreased $2.6 million from the comparable 2011 period primarily due to:

- decreased project income of $2.8 million at Badger Creek which recorded a $3.0 million impairment charge in the second quarter of 2012; and

- decreased project income of $2.7 million at Path 15 due to $1.6 million in decreased revenue under the new rate agreement and higher operations & maintenance expense associated with an erosion control initiative.

These decreases were partially offset by:

- project income of $1.8 million from the newly acquired Morris project.

	Six months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Southwest			
Project Income	$ 3,322	$ 5,143	-35%

Six months ended June 30, 2012 compared with six months ended June 30, 2011

Project income for the six months ended June 30, 2012 decreased $1.8 million from the comparable 2011 period primarily due to:

- decreased project income of $3.1 million at Badger Creek which recorded a $3.0 million impairment charge in the second quarter of 2012;

decreased project income of $2.5 million at Path 15 due to $1.6 million in decreased revenue under the new rate agreement and higher operations & maintenance expense associated with an erosion control initiative; and

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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.

These decreases were partially offset by:

project income of $5.0 million from the newly acquired Morris project; and

project income of $2.2 million from the newly acquired Manchief project.

Un-allocated Corporate

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

	Three months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Un-Allocated Corporate			
Project loss	$ (4,161)	$ (169)	2362%
Administration	8,086	4,671	73%
Interest, net	21,414	3,510	510%
Foreign exchange loss (gain)	(4,205)	(535)	686%
Other income, net	(6,000)		
Total administrative and other expenses	19,295	7,646	152%
Income tax expense (benefit)	(5,526)	(7,684)	-28%

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

Total project loss for the three months ended June 30, 2012 increased $4.0 million from the comparable 2011 primarily due to general and administrative expenses associated with operating the newly acquired Partnership projects.

Total administrative and other expenses for the three months ended June 30, 2012 increased $11.7 million from the comparable 2011 primarily due to:

increased administration expense of $3.4 million primarily due to additional administration costs subsequent to the acquisition of the Partnership; and

increased interest expense of $17.9 million primarily due to issuance of the 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:

increased foreign exchange gain of $3.7 million primarily due to a $10.1 million increase in unrealized gains in the revaluation of instruments denominated in Canadian dollars offset by a $6.4 million increase in unrealized loss on foreign exchange forwards. The U.S. dollar to Canadian dollar exchange rate increased by 2.1% in the three months ended June 30, 2012 compared to a decrease of 0.5% in the comparable 2011 period; and

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 three months ended June 30, 2012 was $5.5 million. The difference between the actual tax benefit and the expected income tax benefit, based on the Canadian enacted

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statutory rate of 25%, of $1.9 million for the three months ended June 30, 2012 is primarily due to permanent differences related to one of our projects.

	Six months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Un-Allocated Corporate			
Project loss	$ (7,606)	$ (663)	1047%
Administration	15,919	8,725	82%
Interest, net	43,450	7,478	481%
Foreign exchange loss (gain)	(3,219)	(1,193)	170%
Other income, net	(6,000)		
Total administrative and other expenses	50,150	15,010	234%
Income tax expense (benefit)	(21,817)	(6,161)	254%

Six months ended June 30, 2012 compared with six months ended June 30, 2011

Total project loss for the six months ended June 30, 2012 increased $6.9 million from the comparable 2011 primarily due to general and administrative expenses associated with operating the newly acquired Partnership projects.

Total administrative and other expenses for the six months ended June 30, 2012 increased $35.1 million from the comparable 2011 primarily due to:

- increased administration expense of $7.2 million primarily due to additional administration costs subsequent to the acquisition of the Partnership; and

- increased interest expense of $36.0 million primarily due to issuance of the 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:

- increased foreign exchange gain of $2.0 million primarily due to a $7.7 million increase in unrealized gains in the revaluation of instruments denominated in Canadian dollars and a $9.3 million increase in realized gains on foreign exchange contract settlements, offset by a $15.0 million increase in unrealized loss on foreign exchange forward. The U.S. dollar to Canadian dollar exchange rate increased by 0.1% in the six months ended June 30, 2012 compared to a decrease of 3.0% in the comparable 2011 period; and

- 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 six months ended June 30, 2012 was $21.8 million. The difference between the actual tax benefit and the expected income tax benefit, based on the Canadian enacted statutory rate of 25%, of $15.8 million for the six months ended June 30, 2012 is primarily due to permanent differences related to one of our projects and is partially offset by the increase in our valuation allowance.

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

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

The primary factor influencing Cash Available for Distribution is cash distributions received from the projects. These distributions received are generally funded from Project Adjusted EBITDA generated by the projects, reduced by project-level debt service, 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 plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use unaudited Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of project income to Project Adjusted EBITDA is set out below 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)

	Three months ended June 30,		Six months ended June 30,	
	2012	**2011**	**2012**	**2011**
Project Adjusted EBITDA by individual segment				
Northeast	$ 22,413	$ 10,095	$ 64,811	$ 17,583
Southeast	25,069	22,670	46,743	42,257
Northwest	12,417	1,620	25,856	2,485
Southwest	17,013	8,626	35,777	17,127
Un-allocated Corporate	(4,132)	(157)	(7,557)	(605)
Total	72,780	42,854	165,630	78,847
Reconciliation to project income (loss)				
Depreciation and amortization	51,361	17,661	101,306	35,098
Interest expense, net	9,301	7,088	18,169	13,328
Change in the fair value of derivative instruments	(2,629)	4,826	55,792	2,042
Other (income) expense	3,034	248	3,300	479
Project income (loss)	11,713	13,031	(12,937)	27,900

Northeast

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

	Three months ended June 30,		
	2012	**2011**	**% change 2012 vs. 2011**
Northeast			
Project Adjusted EBITDA	$ 22,413	$ 10,095	NM

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

Project Adjusted EBITDA for the three months ended June 30, 2012 increased $12.3 million from the comparable 2011 period primarily due to:

- increased Project Adjusted EBITDA of $3.8 million at Chambers due to the collection of the $3.6 million DuPont partial settlement associated with the dispute of the electricity calculation under its PPA;

- Project Adjusted EBITDA of $6.8 million at the newly acquired Curtis Palmer project; and

- Project Adjusted EBITDA of $2.6 million at the newly acquired Nipigon project.

	Six months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Northeast			
Project Adjusted EBITDA	$ 64,811	$ 17,736	NM

Six months ended June 30, 2012 compared with six months ended June 30, 2011

Project Adjusted EBITDA for the six months ended June 30, 2012 increased $47.1 million from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $15.8 million at the newly acquired Curtis Palmer project;

- Project Adjusted EBITDA of $7.2 million at the newly acquired Nipigon project;

- Project Adjusted EBITDA of $6.4 million at the newly acquired Tunis project;

- increased Project Adjusted EBITDA of $5.0 million at Chambers due to the collection of the $3.6 million DuPont partial settlement associated with the dispute of the electricity calculation under its PPA; and

- increased Project Adjusted EBITDA of $4.0 million at Selkirk due to lower operating & maintenance costs and higher capacity revenue from the comparable 2011 period.

Southeast

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

	Three months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Southeast			
Project Adjusted EBITDA	$ 25,069	$ 22,670	11%

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

Project Adjusted EBITDA for the three months ended June 30, 2012 increased $2.4 million or 11% from the comparable 2011 period primarily due to:

- a $1.3 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.

	Six months ended June 30,		
	2012	**2011**	**% change 2012 vs. 2011**
Southeast			
Project Adjusted EBITDA	$ 46,743	$ 42,257	11%

Six months ended June 30, 2012 compared with six months ended June 30, 2011

Project Adjusted EBITDA for the six months ended June 30, 2012 increased $4.5 million or 11% from the comparable 2011 period primarily due to:

- a $1.5 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;
- a $1.4 million increase in Project Adjusted EBITDA at Pasco, which had higher operations and maintenance expenses in the comparable 2011 period attributable to the unplanned replacement of gas turbine blades during a maintenance outage; and
- a $1.2 million increase in Project Adjusted EBITDA at Orlando which had higher operations and maintenance expenses in the comparable 2011 period due to a planned maintenance outage.

Northwest

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

	Three months ended June 30,		
	2012	**2011**	**% change 2012 vs. 2011**
Northwest			
Project Adjusted EBITDA	$ 12,417	$ 1,620	NM

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

Project Adjusted EBITDA for the three months ended June 30, 2012 increased $10.8 million from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $3.6 million from newly acquired Mamquam project;
- Project Adjusted EBITDA of $2.9 million from newly acquired Williams Lake project; and
- Project Adjusted EBITDA of $2.7 million from newly acquired Frederickson project.

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	Six months ended June 30, 2012	2011	% change 2012 vs. 2011
Northwest			
Project Adjusted EBITDA	$ 25,856	$ 2,485	NM

Six months ended June 30, 2012 compared with six months ended June 30, 2011

Project Adjusted EBITDA for the six months ended June 30, 2012 increased $23.4 million from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $4.8 million from newly acquired Mamquam project;
- Project Adjusted EBITDA of $9.3 million from newly acquired Williams Lake project; and
- Project Adjusted EBITDA of $5.8 million from newly acquired Frederickson project.

Southwest

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

	Three months ended June 30, 2012	2011	% change 2012 vs. 2011
Southwest			
Project Adjusted EBITDA	$ 17,013	$ 8,626	97%

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

Project Adjusted EBITDA for the three months ended June 30, 2012 increased $8.4 million or 97% from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $4.4 million from the newly acquired Naval Station, Naval Training Center and North Island projects;
- Project Adjusted EBITDA of $3.2 million from the newly acquired Manchief project; and
- Project Adjusted EBITDA of $2.7 million from the newly acquired Morris project.

These increases were partially offset by:

- decreased Project Adjusted EBITDA of $2.8 million at Path 15 due to $1.6 million in decreased revenue under the new rate agreement and higher operating & maintenance expense associated with an erosion control initiative.

	Six months ended June 30, 2012	2011	% change 2012 vs. 2011
Southwest			
Project Adjusted EBITDA	$ 35,777	$ 17,127	109%

Six months ended June 30, 2012 compared with six months ended June 30, 2011

Project Adjusted EBITDA for the six months ended June 30, 2012 increased $18.7 million or 109% from the comparable 2011 period primarily due to:

- Project Adjusted EBITDA of $7.5 million from the newly acquired Manchief project;

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Project Adjusted EBITDA of $6.8 million from the newly acquired Naval Station, Naval Training Center and North Island projects; and

Project Adjusted EBITDA of $6.7 million from the newly acquired Morris project.

These increases were partially offset by:

decreased Project Adjusted EBITDA of $2.7 million at Path 15 due to $1.6 million in decreased revenue under the new rate agreement and higher operating & maintenance expense associated with an erosion control initiative; and

decreased Project Adjusted EBITDA 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.

Generation and Availability

	Three months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Aggregate power generation (Net MWh)			
Northeast	536,697	241,622	122.1%
Southeast	587,415	468,565	25.4%
Northwest	312,351	46,417	572.9%
Southwest	583,764	132,227	341.5%
Total	2,020,227	888,831	127.3%
Weighted average availability			
Northeast	91.8%	91.0%	0.9%
Southeast	98.0%	98.4%	-0.4%
Northwest	95.2%	95.6%	-0.4%
Southwest	91.8%	92.8%	-1.0%
Total	93.2%	95.5%	-2.3%

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

Aggregate power generation for the three months ended June 30, 2012 increased 127.3% from the comparable 2011 period primarily due to:

increased generation in the Northeast segment primarily due to 387,385 MWh from the newly acquired Partnership projects, partially offset by a 49,574 MWh decrease at Selkirk due to lower dispatch from the comparable 2011 period;

increased generation in the Southeast segment attributable to an 111,571MWh increase at the Auburndale project that had off-peak generation in the second quarter of 2012 compared to none in the comparable 2011 period;

increased generation in the Northwest segment primarily due to 230,316 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 441,282 MWh from the newly acquired Partnership projects.

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Weighted average availability for the three months ended June 30, 2012 decreased 2.3% from the comparable 2011 period primarily due to:

decreased availability in the Southwest segment primarily due to the newly acquired Morris facility that had a minor maintenance outage in the second quarter of 2012.

	Six months ended June 30,		
	2012	2011	% change 2012 vs. 2011
Aggregate power generation (Net MWh)			
Northeast	1,201,890	449,261	167.5%
Southeast	1,046,687	898,890	16.4%
Northwest	560,399	69,408	707.4%
Southwest	1,164,156	290,611	300.6%
Total	3,973,132	1,708,170	132.6%
Weighted average availability			
Northeast	95.2%	85.8%	11.0%
Southeast	98.3%	98.8%	-0.5%
Northwest	94.2%	96.7%	-2.6%
Southwest	92.5%	93.7%	-1.2%
Total	94.7%	94.6%	0.1%

Six months ended June 30, 2012 compared with six months ended June 30, 2011

Aggregate power generation for the six months ended June 30, 2012 increased 132.6% from the comparable 2011 period primarily due to:

increased generation in the Northeast segment primarily due to 892,391 MWh from the newly acquired Partnership projects, partially offset by a 58,816 MWh decrease at Selkirk due to lower dispatch from the comparable 2011 period;

increased generation in the Southeast segment attributable to an 113,300 MWh increase at the Auburndale project that had off-peak generation in the second quarter of 2012 compared to no off-peak generation in the comparable 2011 period;

increased generation in the Northwest segment primarily due to 424,164 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 915,912 MWh from the newly acquired Partnership projects.

Weighted average availability for the six months ended June 30, 2012 increased 0.1% 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.

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Consolidated Cash Flows

At June 30, 2012, cash and cash equivalents increased $2.0 million from December 31, 2011 to $62.7 million. The increase in cash and cash equivalents was primarily due to $89.4 million provided by operating activities and $117.7 million of cash provided by financing activities, offset by $205.0 million of cash used in investing activities.

At June 30, 2011, cash and cash equivalents increased $1.1 million from December 31, 2010 to $46.6 million. The increase in cash and cash equivalents was due to by $44.7 million of cash provided by operating activities offset by $24.8 million used in investing activities and $18.8 million used in financing activities.

	Six months ended June 30,		$ Change
	2012	2011	2012 vs. 2011
Net cash provided by operating activities	$ 89,372	$ 44,715	$ 44,657
Net cash used in investing activities	(205,010)	(24,820)	(180,190)
Net cash provided by (used in) financing activities	117,680	(18,841)	136,521

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 $44.7 million for the six months ended June 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.

Investing Activities

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

Cash flows used in investing activities for the six months ended June 30, 2012 were $205.0 million compared to cash flows used in investing activities of $24.8 million for the comparable 2011 period. The change is primarily attributable to $230.2 million of construction in progress related to the Piedmont and Canadian Hills projects, partially offset by $24.2 million of proceeds from our sale of our interest in PERH.

Financing Activities

Cash provided by financing activities for the six months ended June 30, 2012 resulted in a net inflow of $117.7 million compared with an $18.8 million outflow for the comparable 2011 period. The change is primarily due to $255.2 million of proceeds from the Piedmont and Canadian Hills construction loans, partially offset by an increase in dividend payments attributable to shares issued in connection with the acquisition of the Partnership in the fourth quarter of 2011 and the dividend increase that was effective in November 2011, as well as repayments of borrowings under our revolving credit facility.

Cash Available for Distribution

Initially in 2011, holders of our common shares received a 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 dividend was 249% and 109% for the three months ended June 30, 2012 and 2011, respectively. The payout ratio associated with the dividend was 89% and 111% for the six months ended June 30, 2012 and 2011, respectively. The payout ratio for the six months ended June 30, 2012 was positively impacted by an increase in working capital associated with the Ontario plants acquired in the Partnership acquisition, the termination fee received on the management service contract as part of the sale of our interest in PERH, as well as reducing our combined foreign currency forward positions as a result of the acquisition, partially offset by interest payments associated with newly acquired debt from the Partnership acquisition. 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.

The table below presents our calculation of cash available for distribution for the three and six months ended June 30, 2012 and 2011:

	Three months ended June 30,		Six months ended June 30,	
(in thousands of U.S. dollars, except as otherwise stated)	**2012**	**2011**	**2012**	**2011**
Cash flows from operating activities	$ 22,880	$ 24,368	$ 89,372	$ 44,715
Project-level debt repayments	(6,600)	(6,941)	(9,325)	(10,341)
Purchases of property, plant and equipment	(86)	(238)	(802)	(546)
Transaction costs[1]		768		768
Dividends on preferred shares of a subsidiary company	(3,207)		(6,446)	
Cash Available for Distribution[2]	12,987	17,957	72,799	34,596
Total dividends to shareholders	32,275	19,550	65,055	38,542
Payout ratio	249%	109%	89%	111%
Expressed in Cdn$				
Cash Available for Distribution	13,119	17,376	73,211	33,793

(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.

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Liquidity and Capital Resources

Liquidity Position

(in thousands of U.S. dollars, except as otherwise stated)	June 30, 2012	December 31, 2011
Cash and cash equivalents	$ 62,693	$ 60,651
Restricted cash	19,139	21,412
Total	81,832	82,063
Revolving credit facility availability	141,120	134,700
Total liquidity	$ 222,952	$ 216,763

For the six months ended June 30, 2012, total liquidity, increased by $6.1 million due to higher revolving credit facility availability and cash and cash equivalents, offset by lower restricted cash balances. The increase in the revolving credit facility availability was primarily due to a $38.0 million reduction in the amount drawn on our credit facility. As of August 3, 2012, we have $20.0 million drawn on the credit facilities and $139.1 million outstanding in letters of credit, but not drawn, to support contractual credit requirements at several of our projects. Changes in cash and cash equivalent balances were previously discussed herein under the heading *Consolidated Cash Flows* above. Cash and cash equivalents at June 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 and project-level debt service. For projects that are consolidated, our share of these amounts is reflected as restricted cash on the consolidated balance sheet. Changes in restricted cash were previously discussed herein under *Investing Activities* above. At June 30, 2012, restricted cash at the consolidated projects totalled $19.1 million.

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

Sources of Liquidity

Our primary source of liquidity is distributions from our projects and availability under our revolving 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 2011 Form 10-K, 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 June 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 June 30, 2012, the covenants at the Gregory, Delta-Person, Idaho Wind and at Epsilon Power Partners are temporarily preventing those projects from making cash distributions to us. We expect to resume receiving distributions from Idaho Wind in the third quarter 2012, Gregory and Delta-Person in 2014 and Epsilon Power Partners in 2013. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the

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projects' PPAs. The non-recourse holding company debt relating to our investment in Chambers is held at Epsilon Power Partners, our wholly owned subsidiary.

The range of interest rates presented represents the rates in effect at June 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%	$ 34,232	$ 750	$ 3,000	$ 5,000	$ 5,750	$ 6,000	$ 13,732
Piedmont[1]	3.8% 5.20%	117,285		55,357	4,789	4,772	3,690	48,677
Canadian Hills[2]	3.30%	238,754	238,754					
Path 15	7.90% 9.00%	142,005	4,792	9,402	8,065	8,749	9,487	101,510
Auburndale	5.10%	8,400	3,500	4,900				
Cadillac	6.00% 8.00%	39,031	1,200	2,400	2,000	3,891	2,500	27,040
Curtis Palmer[3]	5.90%	190,000			190,000			
Total Consolidated Projects		769,707	248,996	75,059	209,854	23,162	21,677	190,959
Equity Method Projects:								
Chambers	0.70% 7.60%	58,279	6,352	10,783	5,780	5,213	5,447	24,704
Delta-Person	1.90%	8,602	422	1,300	1,394	1,495	1,604	2,387
Gregory	3.0% 6.6%	11,660	891	2,007	2,170	2,268	2,448	1,876
Rockland	6.4	26,006	335	368	445	529	583	23,746
Idaho Wind	2.3% 7.7%	50,048	1,212	2,198	2,364	2,554	2,511	39,209
Total Equity Method Projects		154,595	9,212	16,656	12,153	12,059	12,593	91,922
Total Project-Level Debt		$ 924,302	$ 258,208	$ 91,715	$ 222,007	$ 35,221	$ 34,270	$ 282,881

(1) As of June 30, 2012 the inception to date balance of $117.3 million on the Piedmont construction debt is funded by the related bridge loan of $51.0 million and $66.3 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 will be repaid in early 2013 and repayment of the expected $82.0 million term loan will 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 June 30, 2012. The facility is expected to be repaid in late 2012 by the tax equity funding.

(3) The Curtis Palmer Notes are not considered non-recourse project-level debt and these notes are guaranteed by the Partnership.

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.

With the exception of our equity contribution of approximately $190 million towards the construction of the Canadian Hills project, we do not expect any material unusual requirements for cash outflows for 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 $190 million equity offering and proceeds from tax equity investments from institutional investors.

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. 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 will conduct scheduled outages to complete major maintenance work. The level of maintenance and capital expenditures for our legacy portfolio of projects will 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. During the second quarter of 2012 the level of maintenance expense was substantial, including outage related work performed at the Calstock, Kapuskasing, North Bay, Selkirk, and Tunis facilities, and capital expenditures were minimal, which is customary.

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

In the second quarter of 2012, we incurred approximately $7.0 million in capital expenditures for the construction of our Piedmont biomass project. 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 late 2012 of approximately $207.0 million.

In the second quarter of 2012, we also incurred approximately $82.6 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 an expected completion in the fourth quarter of 2012.

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 June 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 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 and electricity 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 2014. The projected annual cash distributions at Tunis would change by approximately $2.8 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 40% of our share of the required 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 required 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 5 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 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 payments 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 purchased natural gas under a fuel supply agreement that provided approximately 80% of the project's fuel requirements at fixed prices through June 30, 2012. The remaining 20% was previously purchased at spot market prices and therefore the project's operating margin was exposed to changes in natural gas prices for that portion of its gas requirements. Beginning on July 1, 2012, the project's operating margin is exposed to changes in natural gas prices for 100% of its natural gas requirements until the termination of its PPA at the end of 2013.The annual projected cash distributions at Lake would change by approximately $0.8 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project. The annual projected cash distributions at Auburndale

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would change by approximately $0.4 million per $1.00/Mmbtu change in the price of natural gas based on the current level of un-hedged natural gas volumes at the project.

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 annual cash distributions from Lake and Auburndale combined would change by approximately $2.4 million for every $0.25/Mmbtu change in the projected price of coal.

The following table summarizes the hedge position related to natural gas needed to meet PPA requirements at Lake and Auburndale as of June 30, 2012 and August 3, 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

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 economical 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 in the near term 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

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located in the Northern Florida markets that are served primarily by PEF and Tampa Electric. Our Pasco facility also operates in Florida and completed a re-contracting when its 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 substantially lower cash flow than under the original agreement. We believe that the pricing for PPA extensions for our projects, such as the Auburndale and Lake projects whose 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 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 approximately 79% 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 June 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$1.13 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 six months ended June 30, 2012 and 2011:

	Three months ended June 30,		**Six months ended June 30,**	
	2012	**2011**	**2012**	**2011**
Unrealized foreign exchange (gain) loss:				
Convertible debentures and other	$ (8,746)	$ 1,317	$ (1,040)	$ 6,632
Forward contracts	7,653	1,303	12,863	(2,133)
	(1,093)	2,620	11,823	4,499
Realized foreign exchange gains on forward contract settlements	(3,112)	(3,155)	(15,042)	(5,692)
	$ (4,205)	$ (535)	$ (3,219)	$ (1,193)

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 June 30, 2012:

Convertible debentures, at carrying value	($ 19,626)
Foreign currency forward contracts	$ 22,370

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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 83% 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 a portion of its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Cadillac debt and changes in their fair market value are recorded in other comprehensive income. The interest rate swap expires on June 30, 2025.

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

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

After considering the impact of interest rate swaps, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at equity investments, by approximately $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, 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 six months ended June 30, 2012, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

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.

From time to time, Atlantic Power, its subsidiaries and the projects are parties to disputes and litigation that arise in the normal course of business. We assess our exposure to these matters and record estimated loss contingencies when a loss is likely and can be reasonably estimated. There are no matters pending as of June 30, 2012 that are expected to have a material impact on our financial position or results of operations.

ITEM 1A. RISK FACTORS

Other than as described below, 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 period ended March 31, 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 2. Management's Discussion and Analysis of Financial Condition and Results of Operations")).

Our revenue and cash flows may be reduced upon the expiration of our power purchase agreements

Power generated by our projects, in most cases, is sold under PPAs that expire at various times. Our current projects that have PPAs expiring in the near term are Kenilworth, Greeley, Gregory, Lake and Auburndale. 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. Alternatively, our projects may not be able to secure a new agreement and could be exposed to sell power at spot market prices. It is also possible that subsequent PPAs may not be available at prices that permit the operation of the project on a profitable basis. We believe that the pricing for PPA extensions for some of our projects, such as the Auburndale and Lake projects whose PPAs expire in

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2013, will be substantially lower than the current PPAs. See further discussion of our electricity commodity market risk in "Item 3. Quantitative and Qualitative Disclosures about Market Risk."

ITEM 6. EXHIBITS

Exhibit Number	Description
10.1	2012 Equity Incentive Plan (Incorporated by reference to Schedule B of the registrant's Definitive Proxy Statement filed with the SEC on April 30, 2012)
31.1*	Certification of Chief Executive Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
31.2*	Certification of Chief Financial Officer pursuant to Rule 13a-14(a) or Rule 15d-14(a) of the Securities Exchange Act of 1934
32.1**	Certification of Chief Executive Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
32.2**	Certification of Chief Financial Officer pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema.
101.CAL	XBRL Taxonomy Extension Calculation Linkbase.
101.DEF	XBRL Taxonomy Extension Definition Linkbase.
101.LAB	XBRL Taxonomy Extension Label Linkbase.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Filed herewith.

** Furnished herewith.

Indicates a management contract or any compensatory plan, contract or arrangement.

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: August 7, 2012	Atlantic Power Corporation		
	By:	/s/ LISA J. DONAHUE	
		Name:	Lisa J. Donahue
		Title:	*Interim Chief Financial Officer (Duly Authorized Officer and Principal Financial Officer)*