ATLANTIC POWER CORP
Form 10-K
March 01, 2013

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 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	**55-0886410**
(State of Incorporation)	(I.R.S. Employer Identification No.)
One Federal St, Floor 30	
Boston, MA	**02110**
(Address of Principal Executive Offices)	(Zip Code)

(617) 977-2400
(Registrant's Telephone Number, Including Area Code)

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
Common Shares, no par value per share	The New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: **None**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ý No o

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes o No ý

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 Website, 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). ý Yes o No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. 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.

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

As of June 30, 2012, the aggregate market value of the voting and nonvoting common equity held by non-affiliates of the registrant was $1.4 billion based upon the last reported sale price on the New York Stock Exchange. For purposes of the foregoing calculation only, all directors and executive officers of the registrant have been deemed affiliates.

As of February 27, 2013, 119,493,154 of the registrant's Common Shares were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's definitive Proxy Statement for its 2013 Annual Meeting of Shareholders, to be filed not later than 120 days after the end of the registrant's fiscal year, are incorporated by reference into Items 10 through 14 of Part III of this Annual Report on Form 10-K.

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PART I

As used herein, the terms "Atlantic Power," the "Company," "we," "our," and "us" refer to Atlantic Power Corporation, together with those entities owned or controlled by Atlantic Power Corporation, unless the context indicates otherwise. All references to "Cdn$" and "Canadian dollars" are to the lawful currency of Canada and references to "$," "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.

FORWARD-LOOKING INFORMATION

Certain statements in this Annual Report on Form 10-K 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 Annual Report on Form 10-K 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 our ability to fund anticipated dividend level;
- 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 Annual Report on Form 10-K. Such forward-looking statements are based on a number of assumptions which may prove to be incorrect, including, but not limited to the assumption that the projects will operate and perform in accordance with our expectations. Many of these risks and uncertainties can affect our actual results and could cause our actual results to differ materially from those expressed or implied in any forward-looking statement made by us or on our behalf.

Forward-looking statements involve significant risks and uncertainties, should not be read as guarantees of future performance or results, and will not necessarily be accurate indications of whether or not or the times at or by which such performance or results will be achieved. In addition, a number of factors could cause actual results to differ materially from the results discussed in the forward-looking statements, including, but not limited to, the factors described under *Item 1A Risk Factors*. Our business is both highly competitive and subject to various risks.

These risks include, without limitation:

- the expiration or termination of power purchase agreements;
- the dependence of our projects on their electricity, thermal energy and transmission services customers;
- exposure of certain of our projects to fluctuations in the price of electricity or natural gas;

projects not operating according to plan;

the dependence of our projects on third-party suppliers;

the effects of weather, which affects demand for electricity as well as operating conditions;

the dependence of our windpower projects on suitable wind and associated conditions;

U.S., Canadian and/or global economic conditions and uncertainty;

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- risks beyond our control, including but not limited to acts of terrorism or related acts of war, geopolitical crisis, natural disasters or other catastrophic events;
- the adequacy of our insurance coverage;
- the impact of significant energy, environmental and other regulations on our projects;
- increased competition, including for acquisitions;
- our limited control over the operation of certain minority owned projects;
- transfer restrictions on our equity interests in certain projects;
- construction risks;
- labor disruptions;
- our ability to retain, motivate and recruit executives and other key employees;
- unstable capital and credit markets;
- our indebtedness and financing arrangements; and
- changes in our creditworthiness.

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 Annual Report on Form 10-K are based upon what are believed to be reasonable assumptions, investors cannot be assured that actual results will be consistent with these forward-looking statements, and the differences may be material. Certain statements included in this Annual Report on Form 10-K 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 Annual Report on Form 10-K. These forward-looking statements are made as of the date of this Annual Report on Form 10-K and, except as expressly required by applicable law, we assume no obligation to update or revise them to reflect new events or circumstances.

ITEM 1. BUSINESS

OVERVIEW

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. As of December 31, 2012, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 3,366 megawatts ("MW") in which our aggregate ownership interest is approximately 2,117 MW. These totals exclude projects designated as held for sale at December 31, 2012 and our 40% interest in the Delta-Person generating station ("Delta-Person") for which we entered into an agreement to sell in December 2012. On January 30, 2013, we and certain of our subsidiaries entered into an agreement to sell our interests in the Auburndale Power Partners, L.P. ("Auburndale"), Lake CoGen, Ltd. ("Lake") and Pasco CoGen, Ltd. ("Pasco") projects (collectively, the "Florida Projects"). We expect to enter into a purchase and sale agreement in the remaining part of the first quarter of 2013 to sell our 100% interest in our Path 15 Transmission project ("Path 15"). Our current portfolio of continuing operations consists of interests in twenty-nine operational power generation projects across eleven states in the United States and two provinces in Canada. In addition, we have one 53 MW biomass project under construction in Georgia. Recently we acquired a wind and solar development company, Ridgeline Energy Holdings, Inc. ("Ridgeline"), located in Seattle, Washington, which will enhance our ability to develop, construct, and operate wind and solar energy projects across the United States and Canada. We also own a majority interest in Rollcast Energy Inc. ("Rollcast"), a biomass power plant developer in North Carolina. Twenty-three of our projects are wholly owned subsidiaries. In the fourth quarter of 2012, we entered into a purchase and sale agreement for the sale of our 40% interest in Delta-Person, acquired a 100% interest in Ridgeline, achieved commercial operations at Canadian Hills Wind, LLC ("Canadian Hills") and issued debentures in a public offering.

The following charts show, based on MW, the diversification of our portfolio of continuing operations by geography, segment and breakdown by the fuel type:

We sell the capacity and energy from our power generation projects under PPAs to a variety of utilities and other parties. Under the PPAs, which have expiration dates ranging from August 2013 to 2037, we receive payments for electric energy sold to our customers (known as energy payments), in addition to payments for electric generation capacity (known as capacity payments). We also sell steam from a number of our projects to industrial purchasers under steam sales agreements. Sales of electricity are generally higher during the summer and winter months, when temperature extremes create demand for either summer cooling or winter heating.

Our power generation projects generally have long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the fuel supply and transportation arrangements correspond to the term of the relevant PPAs and many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is no pass-through of fuel costs, we often attempt to mitigate the market price risk of changing commodity costs through the use of hedging strategies.

We directly operate and maintain more than half of our power generation projects. We also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including Colorado Energy Management ("CEM"), Power Plant Management Services ("PPMS") and Delta Power Services ("DPS"). Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

HISTORY OF OUR COMPANY

Atlantic Power Corporation is a corporation continued under the laws of British Columbia, Canada, which was incorporated in 2004. We used the proceeds from our initial public offering on the Toronto Stock Exchange ("TSX") in November 2004 to acquire a 58% interest in Atlantic Power Holdings, LLC (now Atlantic Power Holdings, Inc., which we refer to herein as "Atlantic Holdings") from two private equity funds managed by ArcLight Capital Partners, LLC ("ArcLight") and from Caithness Energy, LLC ("Caithness"). Until December 31, 2009, we were externally managed under an agreement with Atlantic Power Management, LLC, an affiliate of ArcLight. We agreed to pay ArcLight an aggregate of $15 million to terminate its management agreement with us, satisfied by a payment of $6 million on the termination date of December 31, 2009, and additional payments of $5 million, $3 million and $1 million on the respective first, second and third anniversaries of the termination date. We have now paid all amounts owed to ArcLight in connection with the termination of the management agreement. In connection with the termination of the management agreement, we hired all of the then-current employees of Atlantic Power Management and entered into employment agreements with its three officers.

At the time of our initial public offering, our publicly traded security was an Income Participating Security ("IPS"), each of which was comprised of one common share and a subordinated note. In November 2009, our shareholders approved a conversion from the IPS structure to a traditional common share structure in which each IPS was exchanged for one new common share and each old common share that did not form a part of an IPS was exchanged for approximately 0.44 of a new common share.

Our common shares trade on the TSX under the symbol "ATP" and began trading on the New York Stock Exchange ("NYSE") under the symbol "AT" on July 23, 2010.

On November 5, 2011, we directly and indirectly acquired all of the issued and outstanding limited partnership units of Capital Power Income L.P., which was renamed Atlantic Power Limited Partnership on February 1, 2012 (the "Partnership"), in exchange for Cdn$506.5 million in cash and 31.5 million of our common shares. The Partnership's portfolio consisted of 19 wholly-owned power generation assets located in both Canada and the United States, a 50.15% interest in a power generation asset in the state of Washington, and a 14.3% common ownership interest in Primary Energy Recycling Holdings, LLC ("PERH"). At the acquisition date, the transaction increased the net generating capacity of our projects by 143% from 871 MW to approximately 2,116 MW. We did not purchase two of the Partnership's assets located in North Carolina. After this transaction, we remained headquartered in Boston, Massachusetts and added offices in Chicago, Illinois, Toronto, Ontario, and Richmond, British Columbia. Additionally, the Capital Power Corporation employees that operated and maintained the Partnership assets and most of those who provided management support of operations, accounting, finance, and human resources became employees of Atlantic Power.

In January 2012, we acquired a 51% interest in Canadian Hills, the owner of a 300 MW wind farm project in Oklahoma for a nominal sum. In March 2012, we increased our ownership in Canadian Hills to 99% for a nominal sum. We made an additional $193 million capital contribution to Canadian Hills in July 2012. In December 2012, the project received tax equity investments in aggregate of $225 million from a consortium of four institutional tax equity investors along with an approximately $44 million of our tax equity investment, which we expect to syndicate with additional tax equity investors in the first half of 2013, although no assurances can be provided regarding our ability to syndicate the investment on acceptable terms or at all, or the timing of any such syndication. The project's outstanding construction loan was repaid from the tax equity proceeds, decreasing the project's short-term debt by $265 million. Canadian Hills achieved commercial operations on December 22, 2012. We will oversee the ongoing operation of Canadian Hills and will act as its asset manager.

On December 31, 2012, we acquired Ridgeline, a wind and solar development company, which added interests in three wind projects totaling 150 net MW. The Ridgeline acquisition strengthened our ability to execute development stage projects which is one of our target growth areas. Ridgeline has an active wind and solar development pipeline which currently consists of more than 10 projects in the U.S. totaling in excess of 600 MW. As part of the acquisition, we will integrate Ridgeline's team of over 30 employees, which has a broad set of competencies essential for the successful identification, resource

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assessment, development (including permitting), construction and operation of large-scale renewable power projects. This team will also assist our assessment and pursuit of other renewable acquisitions and in managing our growing renewable energy portfolio.

In May of 2012, we sold our 14.3% interest in PERH for $24.2 million, plus a management agreement termination fee of approximately $6.0 million, for a total sale price of $30.2 million and on September 4, 2012, we sold our 50% interest in Badger Creek for proceeds of approximately $3.7 million. In December 2012 we also entered into a purchase and sale agreement for the sale of our 40% interest in Delta-Person for approximately $9.0 million. The Delta-Person transaction is expected to close in the third quarter of 2013. On January 30, 2013, we and certain of our subsidiaries entered into an agreement to sell our interests in the Florida Projects for a purchase price, including working capital adjustments, of approximately $136 million. The sale of the Florida Projects is subject to customary closing conditions and approvals, including approval from the Federal Energy Regulatory Commission ("FERC"), and is expected to close in the remaining part of the first quarter of 2013. We have also been conducting a sale process for our 100% ownership interest in Path 15. We expect to enter into a purchase and sale agreement to sell Path 15 in the remaining part of the first quarter of 2013. The sale would be expected to close in the first half of 2013.

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, 30th Floor, Boston, Massachusetts 02110 USA. Our telephone number in Boston is (617) 977-2400 and the address of our website is *www.atlanticpower.com.* Information contained on our website or that can be accessed through our website is not incorporated into and does not constitute a part of this Annual Report on Form 10-K. We have included our website address only as an inactive textual reference and do not intend it to be an active link to our website. We make available, free of charge, on our website our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to those reports filed or furnished pursuant to Section 13(a) or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") as soon as reasonably practicable after we electronically file such material with, or furnish it to, the SEC. Additionally, we make available on our website, our Canadian securities filings. The public may read and copy any materials we file with the SEC at the SEC's Public Reference Room at 100 F Street, NE, Washington, DC 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC at www.sec.gov. We are not a foreign private issuer, as defined in Rule 3b-4 under the Exchange Act.

OUR COMPETITIVE STRENGTHS

We believe we distinguish ourselves from other independent power producers through the following competitive strengths:

Diversified projects. Our power generation projects have an aggregate gross electric generation capacity of approximately 3,366 MW, and our net ownership interest in these projects is approximately 2,117 MW. These projects are diversified by fuel type, electricity and steam customers, project operators and geography. The majority are located in California, the U.S. Mid-Atlantic, New York and the provinces of Ontario and British Columbia. Additionally, we have a 53 MW biomass project under construction in Georgia.

Experienced management team. Our management team has a depth of experience in commercial power operations and maintenance, project development, asset management, mergers and acquisitions, capital raising and financial controls. Our network of industry contacts and our reputation allow us to see proprietary acquisition opportunities on a regular basis.

Stability of project cash flow. Many of our power generation projects currently in operation have been in operation for over ten years. Cash flows from each project are generally supported by PPAs with investment-grade utilities and other creditworthy counterparties. We aim to stabilize operating margins through a combination of a project's PPAs, fuel supply agreements and/or commodity hedges.

Access to capital. Our shares are publicly traded on the NYSE and the TSX. We have a history of successfully raising capital through public offerings of equity and debt securities in Canada and the United States, issuing public convertible debentures in Canada and notes in the United States. We have also issued securities by way of private placement in the United States and Canada. In addition, we have used non-recourse project-level financing as a source of capital. Project-level financing can be attractive as it typically has a lower cost than equity, is non-recourse to Atlantic Power and amortizes over the term of the project's PPA. Having significant experience in accessing all of these markets provides flexibility such that we can pursue transactions in the most cost-effective market at the time capital is needed.

Strong in-house operations team complemented by leading third-party operators. We operate and maintain 20 of our power generation projects, which represent 65% of our portfolio's generating capacity, and the remaining 9 generation projects are operated by third-parties, which are recognized leaders in the independent power business. CEM, PPMS and DPS operate projects representing approximately 14%, 8% and 5%, respectively, of the net electric generation capacity of our power generation projects. No other operator is responsible for the operation of projects representing more than 3% of the net electric generation capacity of our power generation projects.

OUR OBJECTIVES AND BUSINESS STRATEGY

Our corporate strategy is to increase the value of the company through accretive acquisitions in North American markets while generating stable, contracted cash flows from our existing assets. In order to achieve these objectives, we intend to focus on enhancing the operating and financial performance of our current projects and pursuing additional accretive acquisitions primarily in the electric power industry in the United States and Canada.

Organic growth

Since the time of our initial public offering on the TSX in late 2004, we have twice acquired the interest of another partner in one of our existing projects and will continue to look for additional such opportunities. We intend to enhance the operation and financial performance of our projects through:

- achievement of improved operating efficiencies, output, reliability and operation and maintenance costs through the upgrade or enhancement of existing equipment or plant configurations;
- optimization of commercial arrangements such as PPAs, fuel supply and transportation contracts, steam sales agreements, operations and maintenance agreements and hedge agreements; and
- expansion of existing projects.

Development and construction

We have invested and may invest in the future in energy-related projects, utility projects and infrastructure projects, as well as make additional investments in development stage projects or companies where the prospects for creating long-term predictable cash flows are attractive. In 2010, we purchased a 60% interest in Rollcast, a biomass developer located in North Carolina with a pipeline of development projects, in which we have the option but not the obligation to invest capital. In 2012, we

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acquired a 100% ownership interest in Ridgeline. With the acquisition of Ridgeline, we added an experienced development and operations team to enhance our ability to pursue future greenfield development and operate existing renewable assets, as well as a pipeline of renewable development projects. We continue to assess development companies with strong late-stage development projects, and believe that there are also opportunities in the market to enter into joint ventures with strong development teams.

When these development opportunities arise, we have the ability and experience to manage the construction process. During 2012, Canadian Hills became our first construction project to achieve commercial operations. Canadian Hills is a 300 MW wind farm in the state of Oklahoma that was purchased as a late stage development project from Apex Wind Energy Holdings, LLC ("Apex"). Piedmont, our 53 MW biomass project under construction in Georgia is expected to achieve commercial operations late in the first quarter of 2013. Piedmont was developed by our affiliate Rollcast.

Acquisition and investment strategy

We believe that new electricity generation projects will continue to be required in the United States and Canada as a result of growth in electricity demand, transmission constraints and the retirement of older generation projects due to obsolescence or environmental concerns. In addition, renewable portfolio standards in over 31 states as well as renewables initiatives in several provinces have greatly facilitated attractive PPAs and financial returns for significant renewable project opportunities. We also team with experienced development companies to acquire pipelines of late stage development investment opportunities. There is also a very active secondary market for the purchase and sale of existing projects. We intend to expand our operations by making accretive acquisitions with a focus on power generation facilities in the United States and Canada.

Our management has significant experience in the independent power industry and we believe that our experience, reputation and industry relationships will continue to provide us with enhanced access to future acquisition opportunities on a proprietary basis.

Extending PPAs following their expiration

PPAs in our portfolio have expiration dates ranging from August 2013 to 2037. In each case, we plan for expirations by evaluating various options in the market. New arrangements may involve responses to utility solicitations for capacity and energy, direct negotiations with the original purchasing utility for PPA extensions, "reverse" request for proposals by the projects to likely bilateral counterparty arrangements with creditworthy energy trading firms for tolling agreements, full service PPAs or the use of derivatives to lock in value. 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. See Item 1A. Risk Factors Risk Related to Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition. We do not assume that revenues or operating margins under existing PPAs will necessarily be sustained after PPA expirations, since most original PPAs included capacity payments related to return of and return on original capital invested, and counterparties or evolving regional electricity markets may or may not provide similar payments under new or extended PPAs.

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ASSET MANAGEMENT

Our asset management strategy is to ensure that our projects receive appropriate preventative and corrective maintenance and incur capital expenditures, if required, to provide for their safety, efficiency, availability and longevity. We also proactively look for opportunities to optimize power, fuel supply and other agreements to deliver strong and predictable financial performance. In conjunction with our acquisition of the Partnership, the personnel that operated and maintained the Partnership's assets became employees of Atlantic Power. The staff at each of the facilities has extensive experience in managing, operating and maintaining the assets. Personnel at Capital Power Corporation regional offices that provided support in operations management, environmental health and safety, and human resources also joined Atlantic Power. As a result of the Ridgeline acquisition, we have added over thirty employees with extensive experience in renewable project development, construction and operations. In combination with the existing staff of Atlantic Power, we have a dedicated and experienced operations and commercial management organization that is well regarded in the energy industry.

For operations and maintenance services at the 9 projects in our portfolio which we do not operate, we partner with recognized leaders in the independent power business. Most of our third-party operated projects are managed by CEM, PPMS and DPS, all of whom are experienced, well regarded energy infrastructure management services companies. In addition, employees of Atlantic Power with significant experience managing similar assets are involved in all significant decisions with the objective of proactively identifying value-creating opportunities such as contract renewals or restructurings, asset-level refinancings, add-on acquisitions, divestitures and participation at partnership meetings and calls.

CEM is an energy infrastructure management company specializing in operations and maintenance, asset management and construction management for independent power producers and investors. With over 25 years of experience in operations and maintenance management, CEM focuses on revenue growth through continuous operational improvement and advanced maintenance concepts. Clients of CEM include independent power producers, municipalities and plant developers. CEM operates our Manchief facility.

PPMS is a management services company focused on providing senior level energy industry expertise to the independent power market. Founded in 2006, PPMS provides management services to a large portfolio of solid fuel and gas-fired generating stations including our Selkirk and Chambers facilities.

DPS, a subsidiary of Babcock and Wilcox Power Generation Group, Inc., is a power plant management services company that provides day-to-day operations, plant maintenance, and management of complex financial and regulatory issues. DPS operates our Cadillac and Gregory projects and will operate Piedmont upon achieving commercial operations.

OUR ORGANIZATION AND SEGMENTS

The following tables outline by segment our portfolio of power generating and transmission assets in operations and under construction as of February 27, 2012, including our interest in each facility. We believe our 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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As a result of our acquisition of the Partnership we revised our reportable business segments during the fourth quarter of 2011. The new operating segments are Northeast, Southeast, Northwest, Southwest and Un-allocated Corporate. Our financial results for the years ended December 31, 2012, 2011 and 2010 have been presented to reflect these changes in operating segments. We revised our segments to align with changes in management's resource allocation and assessment of performance. These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure and costs of being a public registrant. These costs are not allocated to the operating segments when determining segment profit or loss. Un-allocated Corporate also includes Rollcast, a 60% owned company, which develops, owns and operates renewable power plants that use wood or biomass fuel and Ridgeline, which develops and operates wind and solar power projects.

The sections below provide descriptions of our projects as they are aligned in our segment reporting structure for financial reporting purposes.

See Note 20 to the consolidated financial statements for information on revenue from external customers, Project Adjusted EBITDA (a non-GAAP measure), total assets by segment and revenue and total assets by geography.

Northeast Segment

Our Northeast segment accounted for 50.1%, 63.0% and 100.0% of consolidated revenue in 2012, 2011 and 2010, respectively and total net generation capacity of 497 MW at December 31, 2012. Ontario Electricity Financial Corp ("OEFC") and Niagara Mohawk Power Corporation accounted for 69.2% and 15.5% of total revenues, respectively, from the Northeast segment for the year ended December 31, 2012.

The table below provides the revenue and project income (loss) for the Northeast segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Project Income (Loss) by Segment for additional details on our project income (loss).

	Revenue ($ in thousands)	Project (loss) income ($ in thousands)
2012	$ 221,043	$ (23,147)
2011	58,201	10,939
2010	596	6,994

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Set forth below is a list of our Northeast projects in operation:

Project	Location	Fuel	Gross MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)[5]
Cadillac	Michigan	Biomass	40	100.00%	40	Consumers Energy	2028	BBB-
Chambers[4]	New Jersey	Coal	262	40.00%	89	Atlantic City Electric[1]	2024	BBB+
					16	DuPont	2024	A
Kenilworth	New Jersey	Natural Gas	30	100.00%	30	Merck, & Co., Inc.	2013[2]	AA
Curtis Palmer	New York	Hydro	60	100.00%	60	Niagara Mohawk Power Corperation	2027	A-
Selkirk[4]	New York	Natural Gas	345	17.7%[3]	15	Merchant	N/A	NR
					49	Consolidated Edison	2014	A-
Calstock	Ontario	Biomass	35	100.00%	35	Ontario Electricity Financial Corp	2020	AA-
Kapuskasing	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	2017	AA-
Nipigon	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	2022	AA-
North Bay	Ontario	Natural Gas	40	100.00%	40	Ontario Electricity Financial Corp	2017	AA-
Tunis	Ontario	Natural Gas	43	100.00%	43	Ontario Electricity Financial Corp	2014	AA-

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

(2)

The energy services agreement ("ESA") expired in July 2012 and has been extended on a month to month basis. We are currently in negotiations with Merck regarding a long-term extension of the ESA.

(3) Represents our residual interest in the project after all priority distributions are paid to us and the other partners.

(4) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

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

Southeast Segment

Our Southeast segment's continuing operations did not contribute to consolidated revenue in 2012, 2011 and 2010, respectively, as discussed below and accounted for total net generation capacity of 65 MW of our continuing operations at December 31, 2012.

The table below provides the revenue and project income (loss) for the Southeast segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Project Income (Loss) by Segment for additional details on our project income (loss). On January 30, 2013 we entered into an agreement to sell the Florida Projects and have therefore excluded their revenue and project income (loss) from the table as they are recorded in income from discontinued operations in the consolidated statements of operations for the years ended December 31, 2012, 2011 and 2010. Revenue for these projects totaled $188.0 million, $160.9 million and $163.2 million for the years ended December 31, 2012, 2011 and 2010, respectively. Project income for these projects totaled

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$13.6 million, $31.8 million and $19.5 million for the years ended December 31, 2012, 2011 and 2010, respectively.

	Revenue ($ in thousands)	Project (loss) income ($ in thousands)
2012	$	$ 267
2011		(13,074)
2010		5,171

Set forth below is a list of our Southeast projects in operation:

Project	Location	Fuel	Gross MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)[5]
Auburndale[1]	Florida	Natural Gas	155	100.00%	155	Progress Energy Florida	2013	BBB+
Lake[1]	Florida	Natural Gas	121	100.00%	121	Progress Energy Florida	2013	BBB+
Pasco[1]	Florida	Natural Gas	121	100.00%	121	Tampa Electric Company	2018	BBB+
Orlando[4]	Florida	Natural Gas	129	50.00%	46	Progress Energy Florida	2023	BBB+
					19	Reedy Creek Improvement District	2013[2]	A-[3]

(1) On January 30, 2013 we entered into an agreement to sell the Florida Projects.

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

(3) Fitch Ratings' credit ratings on Reedy Creek Improvement District bonds.

(4) Unconsolidated entity for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

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

Project under construction

Project	Location	Fuel	Gross MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)	Expected Year of Commercial Operations
Piedmont	Georgia	Biomass	54	98.0%	53	Georgia Power	2032	A	2013

Northwest Segment

Our Northwest segment accounted for 13.6%, 9.6% and 0.0% of consolidated revenue in 2012, 2011 and 2010, respectively and total net generation capacity of 480 MW at December 31, 2012. British Columbia Hydro and Power Authority ("BC Hydro") provided for 13.6% of total consolidated revenues and 100% of total revenues from the Northwest segment for the year ended December 31, 2012.

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The table below provides the revenue and project income (loss) for the Northwest segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Project Income (Loss) by Segment for additional details on our project income (loss).

	Revenue ($ in thousands)	Project (loss) income ($ in thousands)
2012	$ 59,814	$ (6,604)
2011	8,983	(862)
2010		326

Set forth below is a list of our Northwest projects in operation:

Project	Location	Fuel	Gross MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)[2]
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[1]	Idaho	Wind	183	27.56%	50	Idaho Power Co.	2030	BBB
Rockland Wind Farm	Idaho	Wind	80	50.00%	40	Idaho Power Co.	2036	BBB
Goshen North[1]	Idaho	Wind	125	12.50%	16	Southern California Edison	2030	BBB+
Meadow Creek	Idaho	Wind	120	100.00%	120	PacifiCorp	2032	A-
Frederickson[1]	Washington	Natural Gas	250	50.15%	50	Benton Co. PUD	2022	A+
					45	Grays Harbor PUD	2022	A
					30	Franklin, Co. PUD	2022	AA-
Koma Kulshan[1]	Washington	Hydro	13	49.80%	7	Puget Sound Energy	2037	BBB

(1) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

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

Southwest Segment

Our Southwest segment's continuing operations accounted for 35.9%, 27.1% and 0.0% of consolidated revenue in 2012, 2011 and 2010, respectively and total net generation capacity of 1,075 MW from continuing operations at December 31, 2012.

The table below provides the revenue and project income for the Southwest segment. See Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations Project Income (Loss) by Segment for additional details on our project income (loss). We expect to enter into an agreement to sell Path 15 in the remaining part of the first quarter of 2013 and have therefore excluded its revenue and project income from the table as they are recorded in income from discontinued operations in the consolidated statement of operation for the years ended December 31, 2012, 2011 and 2010, respectively. Revenue for Path 15 was $28.7 million, $30.1 million and

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$31.0 million for the years ended December 31, 2012, 2011 and 2010, respectively. Project income for Path 15 was $5.1 million, $7.6 million and $7.5 million for the years ended December 31, 2012, 2011 and 2010, respectively.

	Revenue ($ in thousands)	Project income ($ in thousands)
2012	$ 158,092	$ 11,259
2011	25,414	10
2010		2,911

Set forth below is a list of our Southwest projects in operation:

Project	Location	Type	MW	Economic Interest	Net MW	Primary Electric Purchasers	Power Contract Expiry	Customer Credit Rating (S&P)[(5)]
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[(1)]	California	Transmission	NA	100.00%	NA	Various through Cailfornia ISO	NA	BBB+ to A
Greeley[(4)]	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	NR
					100	Equistar Chemicals, LP	2023	BBB-
Delta-Person[(2)(3)]	New Mexico	Natural Gas	132	40.0%	53	Public Service Company of New Mexico	2020	BBB-
Canadian Hills	Oklahoma	Wind	300	99.0%	200	Southwestern Electric Power Company	2032	BBB
					49	Oklahoma Municipal Power Authority	2037	NR

					48	Grand River Dam Authority	2032	A
Gregory[3][4]	Texas	Natural Gas	400	17.10%	59	Fortis Energy Marketing & Trading	2013	A-
					9	Sherwin Alumina	2020	NR

(1) We expect to enter into an agreement to sell Path 15 in the remaining part of the first quarter. The sale would be expected to close in the first half of 2013.

(2) On December 7, 2012, we entered into an agreement to sell our 40% interest in Delta-Person. The sale is expected to close in the third quarter of 2013.

(3) Unconsolidated entities for which the results of operations are reflected in equity earnings of unconsolidated affiliates.

(4) We are currently considering various options regarding Greeley and Gregory for when the PPAs expire in August and December 2013, respectively.

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

POWER INDUSTRY OVERVIEW

Historically, the North American electricity industry was characterized by vertically-integrated monopolies. During the late 1980s, several jurisdictions began a process of restructuring by moving away from vertically integrated monopolies toward more competitive market models. Rapid growth in electricity demand, environmental concerns, increasing electricity rates, technological advances and other concerns prompted government policies to encourage the supply of electricity from independent power producers.

According to the North American Electric Reliability Council's ("NERC") Long-Term Reliability Assessment, published in November 2012, summer peak demand within the United States in the ten-year period from 2013 through 2022 is projected to increase at a compound annual growth rate of approximately 1.4%, while winter peak demand in Canada is projected to increase 1.3%. NERC's Reliability Assessment also projects increased dependence on natural gas and renewables for electricity capacity. The adoption of highly efficient combined-cycle technology and the economic viability of shale gas have made gas-fired generation the primary choice for new capacity with almost 100 gigawatts ("GW"), or approximately 50% of planned generation capacity expected over the next 10 years. The share of capacity from renewable resources will also continue to grow. In 2012, renewable generation made up 15.6% of all on-peak capacity resources and is expected to reach almost 17% percent in 2022.

The increase of gas and renewable capacity will be offset by large-scale retirements of coal-fired generation plants. NERC projects 71 GW of fossil-fired generation retirement by 2022, with over 90% retiring by 2017 primarily due to potential and existing federal environmental regulations and low natural gas prices.

The non-utility power generation industry

In the independent power generation sector, electricity is generated from a number of energy sources, including natural gas, coal, water, waste products such as biomass (e.g., wood, wood waste, agricultural waste), landfill gas, geothermal, solar and wind. Our 29 power generation projects in operation are non-utility electric generating facilities that operate in the North American electric power generation industry. The electric power industry is one of the largest industries in the United States, generating retail electricity sales of approximately $371 billion in 2011, based on information published by the Energy Information Administration in November 2012. A growing portion of the power produced in the United States and Canada is generated by non-utility generators. According to the Energy Information Administration, independent power producers represented approximately 35% of total net generation in 2011, the most recent year for which data are available. Independent power producers sell the electricity that they generate to electric utilities and other load-serving entities (such as municipalities and electric cooperatives) by way of bilateral contracts or open power exchanges. The electric utilities and other load-serving entities, in turn, generally sell this electricity to industrial, commercial and residential customers.

COMPETITION

The power generation industry is characterized by intense competition, and we compete with utilities, industrial companies and other independent power producers. In recent years, there has been increasing competition among generators in an effort to obtain power sales agreements, and this competition has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins. In addition, many states and regions have aggressive demand side management programs designed to reduce current load and future local growth.

The U.S. power industry is continuing to undergo consolidation which may provide attractive acquisition and investment opportunities, although we believe that we will continue to confront significant competition for those opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments on attractive terms, if at all.

We compete for acquisition opportunities with numerous private equity, infrastructure and pension funds, Canadian and U.S. independent power firms, utility genco subsidiaries and other strategic and

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financial players. Our competitive advantages include our access to capital, experienced management team, diversified projects and stability of project cash flow.

INDUSTRY REGULATION

Overview

Our facilities and operations are subject to laws and regulations that govern, among other things, transactions by and with purchasers of power, including utility companies, the development and construction of generation facilities, the ownership and operations of generation facilities, access to transmission, and the geographical location, zoning, land use and operation aspects of our facilities and properties, including environmental matters.

In the United States, the power generation and sale aspects of our projects are primarily regulated by the FERC, although most of our projects benefit from the special provisions accorded to Qualifying Facilities ("QFs") or Exempt Wholesale Generators ("EWGs").

In Canada, electricity generation is subject primarily to provincial regulation. Our projects in British Columbia are thus subject to different regulatory regimes from our projects in Ontario.

Regulation generating projects

(i) United States

Eighteen of our power generating projects are QFs under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA") and related FERC regulations. A QF falls into one or both of two primary classes, both of which would facilitate one of PURPA's goals to more efficiently use fossil fuels to generate electricity than typical utility plants. The first class of QFs includes energy producers that generate power using renewable energy sources such as wind, solar, geothermal, hydro, biomass or waste fuels. The second class of QFs includes cogeneration facilities, which must meet specific fossil fuel efficiency requirements by producing both electricity and steam versus electricity only.

The generating projects with QF status and which are currently party to a PPA with a utility or have been granted authority to charge market-based rates are exempt from FERC rate-making authority. The FERC has granted seven of the projects the authority to charge market-based rates based primarily on a finding that the projects lack market power. The projects with QF status are also exempt from state regulation respecting the rates of electric utilities and the financial or organizational regulation of electric utilities. However, state regulators review the prudency of utilities entering into PPAs entered into by QFs and the siting of the generation facilities. The majority of our generation is sold by QFs under PPAs that required approval by state authorities.

PURPA, as initially implemented by the FERC, generally required that vertically integrated electric utilities purchase power from QFs at their avoided costs. The Energy Policy Act of 2005 (the "EP Act of 2005"), however, established new limits on PURPA's requirement that electric utilities buy electricity from QFs to certain markets that lack competitive characteristics. The Delta-Person and Pasco projects are EWGs under the Public Utility Holding Company Act of 2005 ("PUHCA"). The projects with EWG status are also exempt from state regulation respecting the rates of electric utilities, and the projects with EWG and QF status are exempt from regulations under PUHCA.

Notwithstanding their status as QFs and EWGs, our projects remain subject to various aspects of FERC regulation, including those relating to power marketer status and to oversight of mergers, acquisitions and investments relating to utilities under the Federal Power Act, as amended by the EP Act of 2005. All of our projects are also subject to reliability standards developed and enforced by NERC. NERC is a self-regulatory non-governmental organization which has statutory responsibility to regulate bulk power system users, generation and transmission owners and operators through the adoption and enforcement of standards for fair, ethical and efficient practices.

Pursuant to its authority, NERC has issued, and the FERC has approved, a series of mandatory reliability standards. Users, owners and operators of the bulk power system can be penalized significantly for failing to comply with the FERC-approved reliability standards. We have designated our Manager of Operational and Regulatory Compliance to oversee compliance with liability standards and an outside law firm specializing in this area advises us on FERC and NERC compliance, including annual compliance training for relevant employees.

(ii) British Columbia, Canada

The vast majority of British Columbia's power is generated or procured by BC Hydro. BC Hydro is one of the largest electric utilities in Canada. BC Hydro is owned by the Province of British Columbia and is regulated by the British Columbia Utilities Commission (the "BCUC"), which is governed by the Utilities Commission Act (British Columbia) and is responsible for the regulation of British Columbia's public energy utilities including publicly owned and investor owned utilities (i.e. independent power producers).

BC Hydro is generally required to acquire all new power (beyond what it already generates from existing BC Hydro plants) from independent power producers.

All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by the BCUC as being "in the public interest." The BCUC may hold a hearing in this regard. Furthermore, the BCUC may impose conditions to be contained in agreements entered into by public utilities for electricity.

The BCUC has adopted the NERC standards as being applicable to, among others, all generators of electricity in British Columbia, including independent power producers. In addition, the BCUC has adopted a number of other standards, including the Western Electricity Coordinating Council ("WECC") standards. As a practical matter, WECC typically administers standards compliance on the BCUC's behalf.

The *Clean Energy Act,* which became law in British Columbia in 2010, sets out British Columbia's energy objectives. This Act states, among other things, that British Columbia aims to accelerate and expand the development of clean and renewable energy sources British Columbia to, among other things, achieve energy self-sufficiency by 2016, promote economic development and job creation and continue to work toward the reduction of greenhouse gas emissions. This Act also explicitly states that British Columbia will encourage the use of waste heat, biogas and biomass to reduce waste. This Act is consistent with the British Columbia Government Energy Plan, introduced in 2009, which favors clean and renewable energy sources such as hydroelectric, wind and wood waste electricity generation. BC Hydro is required to meet these objectives and submit reports to the BCUC updating on its progress.

Other provincial regulators in British Columbia having authority over independent power producers include the British Columbia Safety Authority, the Ministry of Environment and the Integrated Land Management Bureau.

(iii) Ontario, Canada

In Ontario, the Ontario Energy Board ("OEB") is an administrative tribunal with overall responsibility for the regulation and supervision of the natural gas and electricity industries in Ontario and with the authority to grant or renew, and set the terms for, licenses with respect to electricity generation facilities, including our projects. No person is permitted to generate electricity in Ontario without a license from the OEB.

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The OEB's general functions include:

- Determination of the rates charged for regulated services in the electricity sector;
- Licensing of market participants;
- Inspections, particularly with respect to compelling production of records and information;
- Formulation of rules to govern the conduct of participants in the electricity market;
- Market monitoring and reporting, including on anti-competitive practice;
- Consumer advocacy; and
- Enforcement and compliance.

The OEB has the authority effectively to modify licenses by adopting "codes" that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the OEB can result in fines. While the OEB provides reports to the Ontario Minister of Energy, it generally operates independently from the government. However, the Minister may issue policy directives (with Cabinet approval) concerning general policy and the objectives to be pursued by the OEB, and the OEB is required to implement such policy directives.

A number of other regulators and quasi-governmental entities play a role in electricity regulation in Ontario, including the Independent Electricity System Operator ("IESO"), Hydro One, the Electrical Safety Authority ("ESA"), OEFC and the Ontario Power Authority ("OPA").

The IESO is responsible for administering the wholesale electricity market and controlling Ontario's transmission grid. The IESO is a non-profit corporation whose directors are appointed by the government of Ontario. The IESO's "Market Rules" form the regulatory framework for the operation of Ontario's transmission grid and electricity market. The Market Rules require, among other things, that generators meet certain equipment and performance standards and certain system reliability obligations. The IESO may enforce the Market Rules by imposing financial penalties. The IESO may also terminate, suspend or restrict participatory rights.

In November 2006, the IESO entered into a memorandum of understanding with NERC, in which it recognized NERC as the "electricity reliability organization" in Ontario. In addition, the IESO has also entered into a similar MOU with the Northeast Power Coordinating Council (the "NPCC"). IESO is accountable to NERC and NPCC for compliance with NERC and NPCC reliability standards. While IESO may impose Ontario-specific reliability standards, such standards must be consistent with, and at least as stringent as, NERC's and NPCC's standards.

The OPA was established in 2005 to, among other things, procure new electricity generation. As a result, the OPA enters into electricity generation contracts with electricity generators in Ontario from time to time. Although we are not presently party to any such contracts, we may seek to enter into such contracts if and when the opportunity arises.

Most of the operating assets of the entity formerly known as Ontario Hydro were transferred, in or around 1998, to Hydro One, IESO and a third company called Ontario Power Generation Inc. The remaining assets and liabilities were kept in OEFC. Once all of OEFC's debts (approximately $27.1 billion as of March 2011) have been retired, it will be wound up and its assets and liabilities will be transferred directly to the Government of Ontario.

The *Green Energy Act* became law in Ontario in 2009 renewable electricity generation technologies, including via a feed-in tariff program. This Act states that the Government of Ontario is, among other things, committed to fostering the growth of renewable energy projects, to removing barriers to and promoting opportunities for renewable energy projects and to promoting a green economy.

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Carbon emissions

In the United States, during the past several years government action addressing carbon emissions has been focused on the regional and state level. Beginning in 2009, the Regional Greenhouse Gas Initiative ("RGGI") was established in ten Northeast and Mid-Atlantic states as the first cap-and-trade program in the United States for CO_2 emissions. These states have varied implementation plans and schedules. The two states where we have project interests, New York and New Jersey, also provide cost mitigation for independent power projects with certain types of power contracts. At the end of 2011, New Jersey withdrew from the RGGI program. California's cap-and-trade program governing greenhouse gas emissions became effective for the electricity sector on January 1, 2013. Other states and regions in the United Sates are developing similar regulations and it is possible that federal climate legislation will be established in the future.

At the federal level, President Obama has identified climate change as one of the major priorities for his second term. The U.S. Environmental Protection Agency has taken several recent actions respecting CO_2 emissions, including issuance of a finding that such emissions endanger public health and welfare, its final regulations to require annual reporting of greenhouse gas emissions by certain source categories considered to be large emitters, its final regulations to establish emissions standards for new fossil fuel power plants, and its anticipated proposed regulations to establish emissions standards for existing fossil fuel power plants.

Additionally, more than half of the U.S. states and most Canadian provinces have set mandates requiring certain levels of renewable energy production and/or energy efficiency during target timeframes. This includes generation from wind, solar and biomass. In order to meet CO_2 reduction goals, changes in the generation fuel mix are forecasted to include a reduction in existing coal resources, higher reliance on natural gas and renewable energy resources and an increase in demand-side resources. Investments in new or upgraded transmission lines will be required to move increasing renewable generation from more remote locations to load centers.

Regulatory incentives

The U.S. regulatory environment has undergone significant changes in the last several years due to the creation of incentives for the addition of large amounts of new renewable energy generation and, in some cases, transmission. Certain U.S. and Canadian government policies support renewable power generation and other clean infrastructure technologies and enhance the economic feasibility of developing and operating energy projects in the regions in which we operate. The viability of our current and potential future renewable energy projects, including our windpower projects, is largely contingent on public policy mechanisms and favorable regulatory incentives, including production and investment tax credits, stimulus grants from the U.S. Treasury and other types of cash grants, loan guarantees, accelerated depreciation tax benefits, state renewable portfolio standards, and regional carbon trading plans. For example, the American Taxpayer Relief Act was passed by Congress on January 1, 2013 and signed into law by the President on January 2, 2013. This legislation extended production tax credits and investment tax credits for projects that start construction prior to January 1, 2014 and extended bonus depreciation for projects that are placed in service prior to January 1, 2014. Under present law, the production tax credits provide an income tax credit of 2.2 cents/kilowatt-hour for the production of electricity from utility-scale wind turbines. The EP Act of 2005 also provides incentives for various forms of electric generation technologies. Governments from time to time may renew their policies that support renewable energy and consider actions to make the policies less conducive to the development and operation of renewable energy facilities.

Certain of our projects are eligible to receive grants and similar government incentives for the construction of renewable energy facilities. We expect our Piedmont and Meadow Creek projects to receive stimulus grant proceeds from the U.S. Treasury in the first half of 2013. However, because such grant proceeds are subject to Congressional action, we cannot provide any assurances with respect to the timing, availability or amount, if any, of such grants. We have also reduced expectations regarding the value of renewable energy credits in certain renewable projects. Tax equity investors in Canadian Hills are eligible for the income tax credit from production tax credits. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects Our renewable energy projects are subject to uncertainties regarding regulatory incentives."

EMPLOYEES

As of February 27, 2013, we had 310 employees, 207 in the United States and 103 in Canada. Of our Canadian employees, 65 are covered by two collective bargaining agreements. During 2012, we did not experience any labor stoppages or labor disputes at any of our facilities.

ITEM 1A. RISK FACTORS

This section highlights specific risks that could affect our Company. You should carefully consider each of the following risks and all of the other information set forth in this Annual Report on Form 10-K. Based on the information currently known to us, we believe the following information identifies the most significant risk factors affecting our Company. However, the risks and uncertainties described below are not the only ones related to our business and are not necessarily listed in the order of their importance. Additional risks and uncertainties not presently known to us or that we currently believe to be immaterial may also adversely affect our business.

If any of the following risks and uncertainties develops into actual events or if the circumstances described in the risks and uncertainties occur or continue to occur, these events or circumstances could have a material adverse effect on our business, results of operations or financial condition. These events could also have a negative effect on the trading price of our securities.

Risks Related to Our Business and Our Projects

The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition

Power generated by our projects, in most cases, is sold under PPAs that expire at various times. Currently, our PPAs are scheduled to expire between August 2013 and 2037. See Item 1. Business Our Organization and Segments for details about our projects' PPAs and related expiration dates. In addition, these PPAs may be subject to termination prior to expiration in certain circumstances, including default by the project. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly. It is possible that subsequent PPAs 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 and the value of the project may be impaired such that we would be required to record an impairment loss under applicable accounting rules. The loss of significant PPAs, or the breach by the other parties to such contracts that prevents us from fulfilling our obligations thereunder, could have a material adverse impact on our business, results of operations and financial condition.

Our projects depend on their electricity, thermal energy and transmission services customers and there is no assurance that these customers will perform their obligations or make required payments

Each of our projects relies on one or more PPAs, steam sales agreements or other agreements with one or more utilities or other customers for a substantial portion of its revenue. At times, we rely on a single customer or a limited number of customers to purchase all or a significant portion of a project's output. In 2012, the largest customers of our power generation projects, including projects recorded

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under the equity method of accounting, are Public Service Company of Colorado, Southwestern Electric, and OEFC which purchase approximately 18%, 10% and 9%, respectively, of the net electric generation capacity of our projects. If a customer stops purchasing output from our power generation projects or purchases less power than anticipated, such customer may be difficult to replace, if at all. Further concentration of our customers would increase our dependence on any one customer. Our cash flows and results of operations, including the amount of cash available to make payments on our indebtedness, are highly dependent upon customers under such agreements fulfilling their contractual obligations. There is no assurance that these customers will perform their contractual obligations or make required payments.

Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating margin of these projects and on our business, results of operations and financial condition

Those of our projects operating without a PPA or PPAs based on spot market pricing for some or all of their output will be exposed to fluctuations in the wholesale price of electricity. In addition, should any of the long-term PPAs expire or terminate, the relevant project will be required to either negotiate a new PPA or sell into the electricity wholesale market, in which case the prices for electricity will depend on market conditions at the time, which may not be favorable. The open market wholesale prices for electricity are very volatile. Long and short-term power prices may fluctuate substantially due to other factors outside of our control, including:

- changes in generation capacity in the electricity markets, including the addition of new supplies of power from existing competitors or new market entrants as a result of the development of new generation facilities, expansion of existing facilities or additional transmission capacity;
- electric supply disruptions, including plant outages and transmission disruptions;
- changes in power transmission infrastructure;
- fuel transportation capacity constraints;
- weather conditions;
- changes in the demand for power or in patterns of power usage;
- development of new fuels and new technologies for the production of power;
- development of new technologies for the production of natural gas;
- availability of competitively priced renewable fuel sources;
- available supplies of natural gas, crude oil and refined products, and coal;
- interest rate and foreign exchange rate fluctuation;
- availability and price of emission credits;

- geopolitical concerns affecting global supply of oil and natural gas;
- general economic conditions which impact energy consumption in areas where we operate; and
- power market, fuel market and environmental regulation and legislation.

We are also exposed to market power prices at the Selkirk, Morris and Chambers 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. At Morris, approximately 56% of the facility's capacity is

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currently not contracted. The facility can generate and sell this excess capacity into the grid at market prices. If market prices do not justify the increased generation, the project has no requirement to sell power at market. 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. As a result, fluctuations in the price of electricity may have a material adverse effect on the operating margins of these facilities and on our business, results of operations and financial condition.

Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects

The amount of energy generated at the projects is highly dependent on suppliers under certain fuel supply agreements fulfilling their contractual obligations. The loss of significant fuel supply agreements or an inability or failure by any supplier to meet its contractual commitments may adversely affect our results.

Upon the expiration or termination of existing fuel supply agreements, we or our project operators will have to renegotiate these agreements or may need to source fuel from other suppliers. We may not be able to renegotiate these agreements or enter into new agreements on similar terms. For example, 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. There can be no assurance as to availability of the supply or pricing of fuel under new arrangements, and it can be very difficult to accurately predict the future prices of fuel. If our suppliers are unable to perform their contractual obligations or we are unable to renegotiate our fuel supply agreements, we may seek to meet our fuel requirements by purchasing fuel at market prices, exposing us to market price volatility and the risk that fuel and transportation may not be available during certain periods at any price. Changes in market prices for natural gas, biomass, coal and oil may result from the following:

- weather conditions;
- seasonality;
- demand for energy commodities and general economic conditions;
- disruption or other constraints or inefficiencies of electricity, gas or coal transmission or transportation;
- additional generating capacity;
- availability and levels of storage and inventory for fuel stocks;
- natural gas, crude oil, refined products and coal production levels;
- changes in market liquidity;
- governmental regulation and legislation; and
- our creditworthiness and liquidity, and the willingness of fuel suppliers/transporters to do business with us.

Revenues earned by our projects may be affected by the availability, or lack of availability, of a stable supply of fuel at reasonable or predictable prices. The price we can obtain for the sale of energy may not rise at the same rate, or may not rise at all, to match a rise in fuel or delivery costs. To the extent possible, our projects attempt to match fuel cost setting mechanisms in supply agreements to energy payment formulas in the PPA and to provide for indexing or pass-through of fuel costs to 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 hedging strategies. To the extent that

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costs are not matched well to PPA energy payments, pass through of fuel costs is not allowed or hedging strategies are unsuccessful, increases in fuel costs may adversely affect our results of operation. This may have a material adverse effect on our business, results of operations and financial condition. Our energy payments at our Orlando project are subject to fluctuations as the energy payments are comprised of a fuel component based on the cost of coal consumed at a nearby coal-fired generating station.

Our projects may not operate as planned

The ability of our projects to meet availability requirements and generate the required amount of power to be sold to customers under the PPAs are primary determinants of the amount of cash that will be distributed from the projects to us, and that will in turn be available for dividends paid to our shareholders. There is a risk of equipment failure due to wear and tear, more frequent and/or larger than forecasted downtimes for equipment maintenance and repair, latent defect, design error or operator error, or force majeure events, among other things, which could adversely affect revenues and cash flow. Unplanned outages of generation facilities, including extensions of scheduled outages due to mechanical failures or other problems occur from time to time and are an inherent risk of our business. Unplanned outages typically increase our operation and maintenance expenses and may reduce our revenues or require us to incur significant costs as a result of obtaining replacement power from third parties in the open market to satisfy our obligations.

In general, our power generation projects transmit electric power to the transmission grid for purchase under the PPAs through a single step up transformer. As a result, the transformer represents a single point of vulnerability and may exhibit no abnormal behavior in advance of a catastrophic failure that could cause a temporary shutdown of the facility until a replacement transformer can be found or manufactured. To the extent that we suffer disruptions of plant availability and power generation due to transformer failures or for any other reason, there could be a material adverse effect on our business, results of operations and financial condition and the amount of cash available for dividends may be adversely affected.

We provide letters of credit under our $300 million senior secured revolving credit facility for contractual credit support at some of our projects. If the projects fail to perform under the related project-level agreements, the letters of credit could be drawn and we would be required to reimburse our senior lenders for the amounts drawn.

The effects of weather and climate change may adversely impact our business, results of operations and financial condition

Our operations are affected by weather, which affects demand for electricity. Temperatures above normal levels in the summer tend to increase summer cooling electricity demand and revenues, and temperatures below normal levels in the winter tend to increase winter heating electricity and gas demand and revenues. Moderate temperatures adversely affect the usage of energy and resulting revenues. To the extent that weather is warmer in the summer or colder in the winter than assumed, we may require greater resources to meet our contractual commitments. These conditions, which cannot be accurately predicted, may have an adverse effect on our business, results of operations and financial condition by causing us to seek additional capacity at a time when wholesale markets are tight or to seek to sell excess capacity at a time when markets are weak.

To the extent climate change contributes to the frequency or intensity of weather related events, our operations and planning process could be impacted, which may adversely impact our business, results of operations and financial condition.

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Revenues from windpower projects are highly dependent on suitable wind and associated weather conditions and in the absence of such suitable conditions, our wind energy projects may not meet anticipated production levels, which could adversely affect our forecasted revenues

We own interests in five windpower projects, which are subject to substantial risks. The energy and revenues generated at a wind energy project are highly dependent on climatic conditions, particularly wind conditions, which are variable and difficult to predict. Turbines will only operate within certain wind speed ranges that vary by turbine model and manufacturer, and there is no assurance that the wind resources at any given project site will fall within such specifications.

We base our investment decisions with respect to each wind energy project on the findings of wind studies conducted on-site before starting construction. However, actual climatic conditions at a project site, particularly wind conditions, may not conform to the findings of these wind studies, and, therefore, our wind energy projects may not meet anticipated production levels, which could adversely affect our forecasted revenues.

Revenues from hydropower projects are highly dependent on suitable precipitation and associated weather conditions and in the absence of such suitable conditions, our hydropower projects may not meet anticipated production levels, which could adversely affect our forecasted revenues.

We own interests in four hydropower projects, which are subject to substantial risks. The energy and revenues generated at a hydro energy project are highly dependent on climatic conditions, particularly precipitation patterns, which are variable and difficult to predict for any given year. We base our investment decisions with respect to each hydro energy project on the historical stream flow records for the area. However, actual climatic conditions in any given year may not meet the historical averages which would impair our ability to meet anticipated production levels, which could adversely affect our forecasted revenues.

U.S., Canadian and/or global economic conditions and uncertainty could adversely affect our business, results of operations and financial condition

Our business may be affected by changes in U.S., Canadian and/or global economic conditions, including inflation, deflation, interest rates, availability of capital, consumer spending rates and the effects of governmental initiatives to manage economic conditions. Uncertainty about global economic conditions may cause consumers to alter behaviors that may directly or indirectly reduce energy spending, which could have a material adverse effect on demand for our product. Volatility in the financial markets and the deterioration of national and global economic conditions may have a material adverse effect on our business, results of operations and financial condition.

Financial markets have also recently been affected by concerns over U.S. fiscal policy, as well as the U.S. federal government's debt ceiling and federal deficit. These concerns have also renewed discussions relating to a potential downgrade of the long-term sovereign credit rating of the United States. Any actions taken by the U.S. federal government regarding the debt ceiling or the federal deficit or any action taken or threatened by ratings agencies, could significantly impact the global and U.S. economies and financial markets. Any such economic downturn could have a material adverse effect on our business, results of operations and financial condition.

Risks that are beyond our control, including but not limited to acts of terrorism or related acts of war, natural disasters, or other catastrophic events could have a material adverse effect on our business, results of operations and financial condition

Man-made events, such as acts of terror and governmental responses to acts of terror, could adversely affect general economic conditions, which could have a material impact on our business, results of operations and financial condition. Strategic targets, such as energy-related facilities, may be at greater risk of future terrorist activities than other domestic targets. Our projects may be targets of terrorist activities, as well as events occurring in response to or in connection with them, that could cause environmental repercussions and/or result in full or partial disruption of the ability of the projects to generate and/or transmit electricity. Any such environmental repercussions or other disruption could result in a significant decrease in revenues or significant reconstruction or remediation costs, which could have a material adverse effect on our business, results of operations and financial condition.

Our projects could also be impacted by natural disasters, such as earthquakes, floods, lightning activity, hurricanes, tropical storms, winter storms, tornadoes, wind, seismic activity, more frequent and more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, sea level rise and other related phenomena. Severe weather or other natural disasters could be destructive or otherwise disrupt our operations, which could result in increased costs. We maintain standard insurance against catastrophic losses, which are subject to deductibles, limits and exclusions, however, our insurance coverage may not be sufficient to cover all of our losses. Future significant weather related events could negatively affect our business, results of operations and financial condition. Additionally, natural disasters and other events that have an adverse effect on the economy in general may adversely affect our operations and our ability to raise capital.

Our business faces significant operating hazards, natural disaster risks and other hazards such as fire and explosions and insurance may not be sufficient to cover all losses

Our business involves significant operating hazards related to the generation of electricity, including hazards related to acquiring, transporting and unloading fuel, operating large pieces of rotating equipment, structural collapse, machinery failure, and delivering electricity to transmission and distribution systems. In addition, we are exposed to natural disaster risks and other hazards such as fire and explosions. These and other hazards can cause significant personal injury or loss of life, severe damage to and destruction of property, plant and equipment, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being named as a defendant in lawsuits asserting claims for substantial damages, including for environmental cleanup costs, personal injury and property damage and fines and/or penalties.

While we believe that the projects maintain an amount of insurance coverage that is adequate and similar to what would be maintained by a prudent owner/operator of similar facilities, and are subject to deductibles, limits and exclusions which are customary or reasonable given the cost of procuring insurance, current operating conditions and insurance market conditions, there can be no assurance that such insurance will continue to be offered on an economically feasible basis, nor that all events that could give rise to a loss or liability are insurable or insured, nor that the amounts of insurance will at all times be sufficient to cover each and every loss or claim that may occur involving our assets or operations of our projects. Any losses in excess of those covered by insurance, which may include a significant judgment against any project or project operator, the loss of a significant permit or other approval or the imposition of a significant fine or penalty, could have a material adverse effect on our business, results of operations, financial condition and future prospects and could adversely affect dividends to our shareholders.

Our operations are subject to the provisions of various energy laws and regulations

Our business is subject to extensive Canadian and U.S. federal, state, provincial and local laws and regulation. Compliance with the requirements under these various regulatory regimes may cause us to incur significant additional costs, and failure to comply with such requirements could result in the shutdown of the non-complying facility, the imposition of liens, fines and/or civil or criminal liability.

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Generally, in the United States, our projects are subject to regulation by the FERC regarding the terms and conditions of wholesale service and rates, as well as by state regulators regarding the prudency of utilities entering into PPAs entered into by QF projects and the siting of the generation facilities. The majority of our generation is sold by QF projects under PPAs that required approval by state authorities.

The EP Act of 2005 also limited the requirement that electric utilities buy electricity from QFs in certain markets that have certain competitive characteristics, potentially making it more difficult for our current and future projects to negotiate favorable PPAs with these utilities.

If any project were to lose its status as a QF, it would lose its ability to make sales to utilities on favorable terms. Such project may no longer be entitled to exemption from provisions of PUHCA of 2005 or from certain provisions of the Federal Power Act and state law and regulations. Loss of QF status could also trigger defaults under covenants to maintain that status in the PPAs and project-level debt agreements, and if not cured within allowed cure periods, could result in termination of agreements, penalties or acceleration of indebtedness under such agreements. In such event, our business, results of operations and financial condition could be negatively impacted.

Notwithstanding their status as QFs and EWGs, our facilities remain subject to numerous FERC regulations, including those relating to power marketer status, approval of mergers, acquisitions and investments relating to utilities, and mandatory reliability rules and regulations delegated to NERC. Any violation of these rules and regulations could subject us to significant fines and penalties and negatively impact our business, results of operations and financial condition.

The EP Act of 2005 and other federal and state programs also may provide incentives for various forms of electric generation technologies, which may subsidize our competitors. The U.S. regulatory environment has undergone significant changes in the last several years due to state and federal policies affecting wholesale competition and the creation of incentives for the addition of large amounts of new renewable energy generation and, in some cases, transmission. These changes are ongoing and we cannot predict the future design of the wholesale power markets or the ultimate effect that the changing regulatory environment will have on our business. In addition, in some of these markets, interested parties have proposed material market design changes, including the elimination of a single clearing price mechanism as well as proposals to re-regulate the markets. Other proposals to re-regulate may be made and legislative or other attention to the electric power market restructuring process may delay or reverse the deregulation process. If competitive restructuring of the electric power markets is reversed, discontinued, or delayed, or new law or other future regulatory developments are introduced, our business, results of operations and financial condition could be negatively impacted.

Generally, in Canada, our projects are subject to energy regulation primarily by the relevant provincial authorities. In addition, our projects are subject to Canada's corporate, commercial and other laws of general application to businesses. Our projects require licenses, permits and approvals which can be in addition to any required environmental permits. No assurance can be provided that we will be able to obtain, comply with and renew, as required, all necessary licenses, permits and approvals for these facilities. If we cannot comply with and renew as required all applicable licenses, permits and approvals, our business, results of operations and financial condition could be adversely affected.

The introductions of new laws, or other future regulatory developments, may have a material adverse impact on our business, operations or financial condition.

Risks with respect to the two Canadian provinces where we currently have projects are addressed further below.

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(i)

British Columbia

The Government of British Columbia has a number of specific statutes and regulations that govern the generation, transmission and distribution of electricity within British Columbia. Our projects in that province are subject to these laws. These statutes can be changed by act of the provincial legislature and the regulations may be changed by the provincial cabinet. Such changes could have a material effect on our projects.

The *Clean Energy Act*, which became law in British Columbia in 2010, sets out British Columbia's energy objectives, one of which is the generation of at least 93% of the electricity in British Columbia from clean or renewable resources. BC Hydro is required to submit resource plans outlining how it will meet these objectives and requires the province to be energy self-sufficient by 2016. BC Hydro is generally required to acquire all new power (beyond what it already generates from existing BC Hydro plants) from independent power producers. Two of our three British Columbia projects currently sell all of their electricity to BC Hydro, and the third project sells substantially all of its electricity to BC Hydro. Therefore, changes to BC Hydro's energy procurement policies and financial difficulties of or regulatory intervention in respect of BC Hydro and/or the province's energy objectives could impact the market for electricity generated by our British Columbia projects although BC Hydro is currently limited by regulation to undertaking efficiency improvements at its existing facilities and only undertaking development of new generation facilities/projects with BCUC approval. There is a risk that the regulatory regime could adversely affect the amount of power that BC Hydro purchases from our projects and the competitive environment or the price at which BC Hydro is willing to purchase power from our British Columbia projects

The *Utilities Commission Act* governs the BCUC, which is responsible for the regulation of British Columbia's public energy utilities, which include publicly owned and investor owned utilities (*i.e.,* independent power producers). All contracts for electricity supply, including those between independent power producers and BC Hydro, must be filed with and approved by the BCUC as being "in the public interest." The BCUC may hold a hearing in this regard. Furthermore, the BCUC may impose conditions to be contained in agreements entered into by public utilities for electricity. Consequently, power procurement is controlled by the BCUC and, as a result, our potential contracts with BC Hydro may be subject to terms that adversely affect us.

(ii)

Ontario

The government of Ontario has a number of specific statutes and regulations that govern our projects in that province. The statutes can be changed by act of the provincial legislature and the regulations may be changed by the provincial cabinet. Such changes could have a material effect on our projects.

In Ontario, the OEB is an administrative tribunal with authority to grant or renew, and set the terms for, licenses with respect to electricity generation facilities, including our projects. No person is permitted to generate electricity in Ontario without a license from the OEB. While all of our Ontario projects are currently licensed, the OEB has the authority to effectively modify the licenses by adopting "codes" that are deemed to form part of the licenses. Furthermore, any violations of the license or other irregularities in the relationship with the OEB can result in fines.

While the OEB provides reports to the Ontario Minister of Energy, it generally operates independently from the government. However, the Minister may issue policy directives (with Cabinet approval) concerning general policy and the objectives to be pursued by the OEB, and the OEB is required to implement such policy directives. Thus, the OEB's regulation of our projects is subject to potential political interference, to a degree.

A number of other regulators and quasi-governmental entities play a role, including the IESO, Hydro One, the Energy Safety Authority, OEFC and OPA. All these agencies may affect our projects.

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Noncompliance with federal reliability standards may subject us and our projects to penalties

Many of our operations are subject to the regulations of NERC, a self-regulatory non-governmental organization which has statutory responsibility to regulate bulk power system users and generation and transmission owners and operators. NERC groups the users, owners, and operators of the bulk power system into 17 categories, known as functional entities e.g., Generator Owner, Generator Operator, Purchasing-Selling Entity, etc. according to the tasks they perform. The NERC Compliance Registry lists the entities responsible for complying with federal mandatory reliability standards and the FERC, NERC, or a regional reliability organization may assess penalties against any responsible entity found to be in noncompliance. Violations may be discovered or identified through self-certification, compliance audits, spot checking, self-reporting, compliance investigations by NERC (or a regional reliability organization) and the FERC, periodic data submissions, exception reporting, and complaints. The penalty that could be imposed for violating the requirements of the standards is a function of the Violation Risk Factor. Penalties for the most severe violations can reach as high as $1 million per violation, per day, and our projects could be exposed to these penalties if violations occur, which could have a material adverse effect on our business, results of operations and financial condition.

Our projects are subject to significant environmental and other regulations

Our projects are subject to numerous and significant federal, state, provincial and local laws, including statutes, regulations, by-laws, guidelines, policies, directives and other requirements governing or relating to, among other things: air emissions; discharges into water; ash disposal; the storage, handling, use, transportation and distribution of dangerous goods and hazardous, residual and other regulated materials, such as chemicals; the prevention of releases of hazardous materials into the environment; the prevention, presence and remediation of hazardous materials in soil and groundwater, both on and off site; land use and zoning matters; and workers' health and safety matters. Our facilities could experience incidents, malfunctions or other unplanned events that could result in spills or emissions in excess of permitted levels and result in personal injury, penalties and property damage. As such, the operation of our projects carries an inherent risk of environmental, health and safety liabilities (including potential civil actions, compliance or remediation orders, fines and other penalties), and may result in the projects being involved from time to time in administrative and judicial proceedings relating to such matters. We have implemented environmental, health and safety management programs designed to regularly improve environmental, health and safety performance, but there is no guarantee that such programs will fully and effectively eliminate the inherent risk of environmental, health and safety liabilities related to the operation of our projects.

Environmental laws and regulations have generally become more stringent over time, and this trend may continue. In the United States, the Clean Air Act and related regulations and programs of the Environmental Protection Agency (the "EPA") extensively regulate the air emissions of sulfur dioxide, nitrogen oxides, mercury and other compounds by power plants. In March 2005, the EPA promulgated the Clean Air Interstate Rule ("CAIR"), which requires 27 states and the District of Columbia to curb emissions of sulfur dioxide and nitrogen oxides from power plants through participation in a cap and trade system or more aggressive state-by-state emissions limits. Although implementation of the CAIR is underway, the EPA is subject to a court order to develop a more stringent replacement rule. Other more stringent EPA air emission regulations currently being implemented include the more stringent national ambient air quality standards for sulfur dioxide, issued in June 2010, and for fine particulate matter, issued in December 2012, and the new mercury and air toxics emissions standards for power plants, issued in December 2011. Meeting these new standards, when implemented, may have a material adverse impact on our business, results of operations and financial condition.

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The U.S. Resource Conservation and Recovery Act has historically exempted fossil fuel combustion wastes from hazardous waste regulation. However, in June 2010 the EPA proposed two alternative sets of regulations governing coal ash. One alternative would designate coal ash as "special waste" and bring ash impoundments at coal-fired power plants under federal regulations governing hazardous solid waste under Subtitle C of the Resource Conservation and Recovery Act. Another alternative would regulate coal ash as a non-hazardous solid waste. If the EPA determines to regulate coal ash as a hazardous waste, our 40% owned coal-fired facility may be subject to increased compliance obligations and associated costs that may have a material adverse impact on our business, results of operations and financial condition.

Similar increasingly stringent environmental regulations also apply to our projects in British Columbia and Ontario.

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

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

If additional regulatory requirements are imposed on energy companies mandating limitations on greenhouse gas emissions or requiring efficiency improvements, such requirements may result in compliance costs that alone or in combination could make some of our projects uneconomical to maintain or operate

The EPA, other regulatory agencies, environmental advocacy groups and other organizations are focusing considerable attention on greenhouse gas emissions from power generation facilities and their potential role in climate change. We expect that additional EPA regulations, and possibly additional legislation and/or regulation by other regulatory authorities, may be issued, resulting in the imposition of additional limitations on greenhouse gas emissions or requiring efficiency improvements from fossil fuel-fired electric generating units.

There are also potential impacts on our natural gas businesses as greenhouse gas legislation or regulations may require greenhouse gas emission reductions from the natural gas sector and could affect demand for natural gas. Additionally, greenhouse gas requirements could result in increased demand for energy conservation and renewable products, as well as increase competition surrounding such innovation. Additionally, our reputation could be damaged due to public perception surrounding greenhouse gas emissions at our power generation projects. Any such negative public perception could ultimately result in a decreased demand for electric power generation or distribution. Several regions of the United States and Canada have moved forward with greenhouse gas emission regulation.

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For example, the multi-state carbon dioxide ("CO_2") cap-and-trade program, known as the Regional Greenhouse Gas Initiative, applies to our fossil fuel facilities in the Northeast region. The Regional Greenhouse Gas Initiative program went into effect on January 1, 2009. CO_2 allowances are now a tradable commodity.

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

In 2006, the State of California passed legislation initiating two programs to control/reduce the creation of greenhouse gases. The two laws are more commonly known as AB 32 and SB 1368. Under AB 32 (the Global Warming Solutions Act), the California Air Resources Board (the "CARB") is required to adopt a greenhouse gas emissions cap on all major sources (not limited to the electric sector) to reduce state-wide emissions of greenhouse gases to 1990 levels by 2020. Under the CARB regulations that took effect on January 1, 2013, electricity generators and certain other facilities are now subject to an allowance for greenhouse gas emissions, with allowances allocated by both formulas set by the CARB and auctions.

SB 1368 added the requirement that the California Energy Commission, in consultation with the California Public Utilities Commission (the "CPUC") and the CARB, establish greenhouse gas emission performance standards and implement regulations for PPAs for a term of five or more years entered into prospectively by publicly-owned electric utilities. The legislation directs the California Energy Commission to establish the performance standard as one not exceeding the rate of greenhouse gas emitted per megawatt-hour ("MWh") associated with combined-cycle, gas turbine baseload generation, such as our North Island project.

In addition to the regional initiatives, President Obama has declared action addressing climate change to be a major priority for his second term, and the EPA has taken several recent actions for the regulation of greenhouse gas emissions.

The EPA's actions include its December 2009 finding of "endangerment" to public health and welfare from greenhouse gases, its issuance in September 2009 of the Final Mandatory Reporting of Greenhouse Gases Rule which required large sources, including power plants, to monitor and report greenhouse gas emissions to the EPA annually, which was required beginning in 2011, and its issuance in May 2010 of its final Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule, which under a phased-in approach requires large industrial facilities, including power plants, to obtain permits to emit, and to use best available control technology to curb emissions of, greenhouse gases. In addition, final EPA regulations to impose greenhouse gas new source performance standards for electricity utility stream generating units are anticipated in 2013.

In Canada, British Columbia and Ontario have implemented greenhouse gas reporting regulations and are developing additional programs to address greenhouse gas emissions.

All of our subject generating facilities have complied on a timely basis with the new EPA and Ontario greenhouse gas reporting requirements. Compliance with greenhouse gas emission reduction requirements may require increasing the energy efficiency of equipment at our natural gas projects, committing significant capital toward carbon capture and storage technology, purchase of allowances and/or offsets, fuel switching, and/or retirement of high-emitting projects and potential replacement with lower emitting projects. The cost of compliance with greenhouse gas emission legislation and/or regulation is subject to significant uncertainties due to the outcome of several interrelated assumptions and variables, including timing of the implementation of rules, required levels of reductions, allocation requirements of the new rules, the maturation and commercialization of carbon capture and storage technology, and the selected compliance alternatives. We cannot estimate the aggregate effect of such requirements on our business, results of operations, financial condition or our customers. However,

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such expenditures, if material, could make our generation facilities uneconomical to operate, result in the impairment of assets, or otherwise adversely affect our business, results of operations and financial condition.

Our renewable energy projects are subject to uncertainties regarding regulatory incentives

We depend, in part, on government policies that support renewable energy and enhance the economic feasibility of developing and operating energy projects in the regions in which we operate. The viability of our renewable energy projects, including our windpower projects, is largely contingent on public policy mechanisms and favorable regulatory incentives in the United States and Canada, including production and investment tax credits, cash grants, loan guarantees, accelerated depreciation tax benefits, renewable portfolio standards, and carbon trading plans. These mechanisms have been implemented in the United States and Canada to support the development of renewable power generation and other clean infrastructure technologies. However, as a result of budgetary constraints, political factors or otherwise, governments from time to time may review their policies that support renewable energy and consider actions to make the policies less conducive to the development and operation of renewable energy facilities. We have reduced expectations regarding the value of renewable energy credits in certain renewable projects. Pursuant to the Sequestration Transparency Act of 2012 (the "STA"), on September 14, 2012, the White House Office of Management and Budget (the "OMB") released an initial report on the potential sequestration triggered by the failure of the Joint Select Committee on Deficit Reduction to propose, and Congress to enact, a plan to reduce the deficit by $1.2 trillion, as required by the Budget Control Act of 2011 (the "BCA"). The sequester is expected to become effective in March 2013 if Congress does not enact a comprehensive deficit reduction package. The OMB report estimated a 7.6% reduction of grants awarded by the 1603 Treasury Program ("1603 Grants") in fiscal year 2013. We expect our Piedmont and Meadow Creek projects to receive 1603 Grant proceeds from the U.S. Treasury in the first half of 2013, which we plan to use to repay project-level debt financing at the Piedmont and Meadow Creek projects. We cannot provide any assurances with respect to the timing, availability or amount, if any, of such stimulus grants, because such grants proceeds are subject to Congressional action. If we do not receive such 1603 grants, or such grants are delayed or reduced, our ability to repay the project-level debt financing at the Piedmont and Meadow Creek projects will be adversely affected. Any reductions to, or the elimination of, governmental incentives that support renewable energy, or the imposition of additional taxes or other assessments on renewable energy, could result in a material adverse effect on our business, results of operations and financial condition.

Increasing competition could adversely affect our performance and the performance of our projects

The power generation industry is characterized by intense competition and our projects encounter competition from utilities, industrial companies and other independent power producers, in particular with respect to uncontracted output. In recent years, there has been increasing competition among generators for PPAs, and this has contributed to a reduction in electricity prices in certain markets where supply has surpassed demand plus appropriate reserve margins. In addition, we continue to confront significant competition for acquisition and investment opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments on attractive terms, if at all. Increasing competition among participants in the power generation industry may adversely affect our performance and the performance of our projects.

We have limited control over management decisions at certain projects

Going forward, approximately one third of our projects are not wholly-owned by us or we have contracted for their operations and maintenance, and in some cases we have limited control over the operation of the projects. Although we generally prefer to acquire projects where we have control, we

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may make acquisitions in non-control situations to the extent that we consider it advantageous to do so and consistent with regulatory requirements and restrictions, including the Investment Company Act of 1940. Third-party operators (such as CEM, PPMS and DPS) operate many of the projects. As such, we must rely on the technical and management expertise of these third-party operators although typically we negotiate to obtain positions on a management or operating committee if we do not own 100% of a project. To the extent that such third-party operators do not fulfill their obligations to manage the operations of the projects or are not effective in doing so, the amount of cash available to pay dividends may be adversely affected. The approval of third-party operators also may be required for us to receive distributions of funds from projects or to transfer our interest in projects. Our inability to control fully certain projects could have an adverse effect on our business, results of operations and financial condition.

We may face significant competition for acquisitions and may not successfully integrate acquisitions

Our business plan includes growth through identifying suitable acquisition opportunities, pursuing such opportunities, consummating acquisitions and effectively integrating them with our business. We may be unable to identify attractive acquisition candidates in the power industry in the future, and we may not be able to make acquisitions on an accretive basis or be sure that acquisitions will be successfully integrated into our existing operations, any of which could negatively impact our ability to continue paying dividends in the future.

Although electricity demand is expected to grow, creating the need for more generation, and the U.S. power industry is continuing to undergo consolidation and may offer attractive acquisition opportunities, we are likely to confront significant competition for those opportunities and, to the extent that any opportunities are identified, we may be unable to effect acquisitions or investments.

Any acquisition or investment may involve potential risks, including an increase in indebtedness, the inability to successfully integrate operations, the potential disruption of our ongoing business, the diversion of management's attention from other business concerns and the possibility that we pay more than the acquired company or interest is worth. There may also be liabilities that we fail to discover, or are unable to discover, in our due diligence prior to the consummation of an acquisition, and we may not be indemnified for some or all these liabilities. In addition, our funding requirements associated with acquisitions and integration costs may reduce the funds available to us to make dividend payments.

Our equity interests in certain projects may be subject to transfer restrictions

The partnership or other agreements governing some of the projects may limit a partner's ability to sell its interest. Specifically, these agreements may prohibit any sale, pledge, transfer, assignment or other conveyance of the interest in a project without the consent of the other partners. In some cases, other partners may have rights of first offer or rights of first refusal in the event of a proposed sale or transfer of our interest. These restrictions may limit or prevent us from managing our interests in these projects in the manner we see fit, and may have an adverse effect on our ability to sell our interests in these projects at the prices we desire.

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

We and the projects may use derivative instruments, including futures, forwards, options and swaps, to manage commodity and financial market risks. These activities, though intended to mitigate price volatility, expose us to other risks. In the future, the project operators could recognize financial losses on these arrangements, including as a result of volatility in the market values of the underlying commodities, if a counterparty fails to perform under a contract or upon the failure or insolvency of a financial intermediary, exchange or clearinghouse used to enter, execute or clear the transactions. If

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actively quoted market prices and pricing information from external sources are not available, the valuation of these contracts would involve judgment or use of estimates. As a result, changes in the underlying assumptions or use of alternative valuation methods could affect the reported fair value of these contracts.

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

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

We do not typically hedge the entire exposure of our operations against commodity price volatility. To the extent we do not hedge against commodity price volatility, our business, results of operations and financial condition may be improved or diminished based upon movement in commodity prices.

Construction projects are subject to construction risk

We are in the process of developing or constructing new generation facilities. In any construction project, there is a risk that circumstances occur which prevent the timely completion of a project, cause construction costs to exceed the level budgeted, or result in operating performance standards or permit requirements not being met. Successful completion depends upon overcoming substantial risks, including, but not limited to, risks relating to siting, financing, construction, permitting, governmental approvals or commissioning delays. In the event a power project does not achieve commercial operation by its expected date, the project may be subject to increased construction costs associated with the continuing accrual of interest on the project's construction loan, which customarily matures at the start of commercial operation and converts to a term loan. A delay in completion of construction may also impact a project under its PPA which may include penalty provisions for a delay in commercial operation date or in situations of extreme delay, termination of the PPA.

Construction cost overruns which exceed the project's construction contingency amount may require that the project owner infuse additional funds in order to complete construction.

At the completion of construction, the power project may not meet its expected operating performance levels. Adverse circumstances may impact the design, construction, and commissioning of the project that could result in reduced output, increased heat rate or excessive air emissions.

The Piedmont project commenced construction in November 2010 and is expected to be completed in early 2013. A delay in completion could result in the delay and/or loss of the proceeds from the 1603 grant.

Certain employees are subject to collective bargaining

A number of our plant employees, from one plant in British Columbia and four plants in Ontario are subject to collective bargaining agreements. These agreements expire periodically and we may not be able to renew them without a labor disruption or without agreeing to significant increases in labor costs. Strikes, work stoppages or the inability to negotiate future collective bargaining agreements on favorable terms could have a material adverse effect on our business, results of operations and financial condition.

Our Pension Plan may require additional future contributions

Certain of our employees in Canada are participants in a defined benefit pension plan that we sponsor. As of December 31, 2012, our pension plan was under funded on a going concern basis by approximately $0.8 million. The additional amount of future contributions to our defined benefit plan will depend upon asset returns and a number of other factors and, as a result, the amounts we will be required to contribute in the future may vary. Cash contributions to the plan will reduce the cash available for our business.

Hostile cyber intrusions could severely impair our operations, lead to the disclosure of confidential information, damage our reputation and otherwise have an adverse effect on our business, results of operations and financial condition

A cyber intrusion is considered to be any adverse event that threatens the confidentiality, integrity or availability of our information resources. More specifically, a cyber intrusion is an intentional attack or an unintentional event that can include gaining unauthorized access to systems to disrupt operations, corrupt data or steal confidential information. We are dependent on various information technologies throughout our company to carry out multiple business activities. Further, the computer systems that run our facilities are not completely isolated from external networks. Parties that wish to disrupt the U.S. and/or Canadian bulk power system or our operations could view our computer systems, software or networks as attractive targets for cyber attack. In addition, our business requires that we collect and maintain confidential employee and shareholder information, which is subject to electronic theft or loss.

A successful cyber attack, such as unauthorized access, malicious software or other violations on the systems that control generation and transmission at our projects could severely disrupt business operations, diminish competitive advantages through reputation damages and increase operation costs. The breach of certain business systems could affect our ability to correctly record, process and report financial information. A major cyber incident could result in significant expenses to investigate and repair security breaches or system damage and could lead to litigation, fines, other remedial action, heightened regulatory scrutiny and damage to our reputation. For these reasons, a significant cyber incident could materially and adversely affect our business, results of operations and financial condition.

Failure to comply with the U.S. Foreign Corrupt Practices Act and/or the Canadian Corruption of Foreign Public Officials Act could subject us to, among other things, penalties and legal expenses that could harm our reputation and have a material adverse effect on our business, results of operations and financial condition

We are subject to anti-corruption laws and regulations including the U.S. Foreign Corrupt Practices Act ("FCPA") and the Canadian Corruption of Foreign Public Officials Act (the "CFPOA"), which generally prohibit companies and their intermediaries from making improper payments to foreign officials for the purpose of obtaining or keeping business and/or other benefits. In addition, the FCPA imposes accounting standards and requirements on U.S. publicly traded corporations and their foreign affiliates, which are intended to prevent the diversion of corporate funds to the payment of bribes and other improper payments, and to prevent the establishment of "off books" slush funds from which improper payments can be made (similar provisions have been proposed to be added to the CFPOA). The Securities and Exchange Commission has increased its enforcement of the FCPA during the past several years. In recent years, enforcement of the CFPOA in Canada has also increased and can be attributed, in part, to the establishment of the Royal Canadian Mounted Police's International Anti-Corruption Unit in 2008. Although we have implemented policies and procedures designed to ensure that we, our employees and other intermediaries comply with the FCPA and/or the CFPOA, there is no assurance that such policies or procedures will work effectively all of the time or protect us against liability under the FCPA and/or the CFPOA for actions taken by our employees and other intermediaries with respect to our business or any businesses that we may acquire. If we are not in compliance with the FCPA and/or the CFPOA, we may be subject to criminal penalties pursuant to the CFPOA and/or criminal and civil penalties and other remedial measures pursuant to the FCPA, including changes or enhancements to our procedures, policies and control, as well as potential personnel change and disciplinary actions, which could have an adverse impact on our business, results of operations and financial condition.

Our success depends in part on our ability to retain, motivate and recruit executives and other key employees, and failure to do so could negatively affect us

Our success depends in part on our ability to retain, recruit and motivate key employees who have experience in our industry. Experienced employees in the power industry are in high demand and competition for their talents can be intense. A failure to attract and retain executives and other key employees with specialized knowledge in power generation could have an adverse impact on our business, results of operations and financial condition because of the difficulty of promptly finding qualified replacements.

Risks Related to Our Structure

Volatile capital and credit markets may adversely affect our ability to raise capital on favorable terms and may adversely affect our business, results of operations, financial condition and cash flows

Disruptions in the capital and credit markets in the United States, Canada or abroad can adversely affect our ability to access the capital markets. Our access to funds under that credit facility is dependent on the ability of the banks that are parties to the facility to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity or if they experience excessive volumes of borrowing requests within a short period of time. Longer term disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation, reduced alternatives or failures of significant financial institutions could result in an inability to execute our growth plan, the deferral of discretionary capital expenditures, changes to our hedging strategy to reduce collateral-posting requirements, or a reduction in dividend payments or other discretionary uses of cash.

Our ability to arrange for financing on a recourse or non-recourse basis and the costs of such capital are dependent on numerous factors, some of which are beyond our control, including:

- general economic and capital market conditions;
- the availability of bank credit;
- investor confidence;
- our financial condition, performance and prospects as well as companies in our industry or similar financial circumstances; and
- changes in tax and securities laws which are conducive to raising capital.

Should future access to capital not be available to us, either as a result of market conditions or our financial condition, we may have to sell assets or decide not to acquire new projects or expand or improve existing projects, either of which would adversely affect our business, results of operations and financial condition.

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Future dividends are not guaranteed

Dividends to shareholders are paid at the discretion of our board of directors. Future dividends, if any, will depend on, among other things, the results of operations, working capital requirements, financial condition, restrictive covenants, business opportunities, provisions of applicable law and other factors that our board of directors may deem relevant. Our board of directors may decrease the level of or entirely discontinue payment of dividends.

Distribution of available cash may restrict our potential growth

A payout of a significant portion of our operating cash flow may make additional capital and operating expenditures dependent on increased cash flow or additional financing in the future. Lack of these funds could limit our future growth and cash flow. In addition, we may be precluded from pursuing otherwise attractive acquisitions or investments if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund the acquisition or investment. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations for additional details on cash available for distribution.

Exchange rate fluctuations may impact the amount of cash available for dividends

Our payments to shareholders, some of our corporate-level long-term debt and convertible debenture holders are denominated in Canadian dollars. Conversely, some of our projects' revenues and expenses are denominated in U.S. dollars. Our debt instruments are revalued at each balance sheet date based on the U.S. dollar to Canadian dollar foreign exchange rate at the balance sheet date, with changes in the value of the debt recorded in the consolidated statements of operations. The U.S. dollar to Canadian dollar foreign exchange rate has been volatile in recent years, which in turn creates volatility in our results due to the revaluation of our Canadian dollar-denominated debt. As a result, we are exposed to currency exchange rate risks, against which we do not typically hedge our entire exposure. Despite our partial hedges against this risk through 2015, any arrangements to mitigate this exchange rate risk may not be sufficient to fully protect against this risk. If hedging transactions do not fully protect against this risk, changes in the currency exchange rate between U.S. and Canadian dollars could adversely affect our cash available for distribution.

Our indebtedness and financing arrangements, and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make cash distributions, acquisitions or investments or issue additional indebtedness we otherwise would seek to do

The degree to which we are leveraged on a consolidated basis could have important consequences for our shareholders and other stakeholders, including:

- our ability in the future to obtain additional financing for working capital, capital expenditures, acquisitions or other purposes;
- our ability to refinance indebtedness on terms acceptable to us or at all;
- our ability to satisfy debt service and other obligations;
- our vulnerability to general adverse industry conditions and economic conditions, including but not limited to adverse changes in foreign exchange rates and commodity prices;
- the availability of cash flow to fund other corporate purposes and grow our business;
- our flexibility in planning for, or reacting to, changes in our business and the industry; and
- placing us at a competitive disadvantage to our competitors that are not as highly leveraged.

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As of December 31, 2012, our consolidated long-term debt represented approximately 61.0% of our total capitalization, comprised of debt and balance sheet equity.

The agreements governing our indebtedness limit but do not prohibit the incurrence of additional indebtedness. Our current or future borrowings could increase the level of financial risk to us and, to the extent that the interest rates are not fixed and rise, or that borrowings are refinanced at higher rates, then cash available for dividends could be adversely affected. Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 90% of our debt, including our share of the project-level debt associated with equity investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

As of February 27, 2013, we had $64.1 million outstanding and $112.9 million was issued in letters of credit under our revolving credit facility, $424.2 million of outstanding convertible debentures, $636.4 million of outstanding non-recourse project-level debt, and $1.1 billion of unsecured notes. Although we expect to repay the amounts outstanding under the credit facility with a portion of the proceeds from the sale of the Florida Projects expected to close in the remaining part of the first quarter of 2013, our credit facility is a primary source of our liquidity, See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources."

Our credit facility contains financial covenants, covenants requiring us to take certain actions and negative covenants restricting our ability to take certain actions. Although we currently expect to remain in compliance with the covenants of the credit facility through late 2014, we are considering a variety of measures to reduce our leverage. If we are unsuccessful or other adverse events occur, we may breach one or more of these covenants, which would result in a default under the credit facility or would prevent us from taking certain actions that are not permitted under the credit facility unless certain covenants are met, including making distributions, making certain acquisitions, investments or capital expenditures, and refinancing or issuing debt, that we otherwise would seek to do. In such case, we may be required to seek waivers or consents from our lenders or amendments to our credit facility, or may be required to seek to refinance our credit facility, and we can provide no assurances that we will be able to accomplish any such actions on terms acceptable to us or at all, and we will otherwise be in default under our credit facility, which would enable lenders thereunder to accelerate the repayment of amounts outstanding and exercise remedies with respect to collateral. Our ability to amend our credit facility or otherwise obtain waivers from our lenders depends on matters that are outside of our control and there can be no assurance that we will be successful in that regard. In the event we are not able to refinance our credit facility or obtain waivers or consents, our business may be materially adversely affected, including with respect to our ability to take the actions described above.

In addition, some of the projects currently have non-recourse term loans or other financing arrangements in place with various lenders. These financing arrangements are typically secured by all of the project assets and contracts as well as our equity interests in the project. The terms of these financing arrangements generally impose many covenants and obligations on the part of the borrower. For example, some agreements contain requirements to maintain specified historical, and in some cases prospective debt service coverage ratios before cash may be distributed from the relevant project to us, which would adversely affect cash available for dividends. In many cases, an uncured default by any party under key project agreements (such as a PPA or a fuel supply agreement) will also constitute a default under the project's term loan or other financing arrangement. Failure to comply with the terms of these term loans or other financing arrangements, or events of default thereunder, may prevent cash distributions by the particular project(s) to us and may entitle the lenders to demand repayment and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition. In addition, failure to comply with the terms, restrictions or obligations of any of our revolving credit facility, convertible debentures or unsecured notes or any other financing arrangements, borrowings or indebtedness, or events of default thereunder, may entitle the lenders to demand repayment, accelerate related debt as well as any other debt to which a cross-default or cross-acceleration provision applies and/or enforce their security interests, which could have a material adverse effect on our business, results of operations and financial condition. If our lenders under our indebtedness demand payment, we may not, at that time, have sufficient cash and cash flows from operating activities to repay such indebtedness.

Our failure to refinance or repay any indebtedness when due could constitute a default under such indebtedness. Under such circumstances, it is expected that dividends to our shareholders would not be permitted until such indebtedness was refinanced or repaid. In addition, any covenant breach or event of default could harm our credit rating and our ability to obtain additional financing on acceptable terms or at all. The occurrence of any of these events could have a material adverse effect on our business, results of operations, financial condition and liquidity.

A downgrade in our credit rating or any deterioration in credit quality could negatively affect our ability to access capital and our ability to hedge, and could trigger termination rights under certain contracts

A downgrade in our credit rating or deterioration in credit quality could adversely affect our ability to renew existing, or obtain access to new, credit facilities and could increase the cost of such facilities, restrict access to our revolving credit facility and/or trigger termination rights or enhanced disclosure requirements under certain contracts to which we are a party. Any downgrade of our corporate credit rating could cause counterparties to require us to post letters of credit or other additional collateral, make cash prepayments, obtain a guarantee agreement or provide other security, all of which would expose us to additional costs and/or could adversely affect our ability to comply with covenants or other obligations under any of our revolving credit facility, convertible debentures or unsecured notes or any other financing arrangements, borrowings or indebtedness (or could constitute an event of default under any such financing arrangements, borrowings or indebtedness that we may be unable to cure), any of which could have a material adverse effect on our business, results of operations and financial condition.

Changes in our creditworthiness may affect the value of our common shares

Changes to our perceived creditworthiness and ability to meet our required covenants on an on-going basis may affect the market price or value and the liquidity of our common shares. The interest rate we pay on our credit facility may increase if certain credit ratios deteriorate.

The future issuance of additional common shares could dilute existing shareholders

From time to time, we may decide to issue additional common shares, redeem outstanding debt for common shares, to repay outstanding principal amounts under existing debt by issuing common shares or issue common shares to meet growth objectives. The issuance of additional common shares may have a dilutive effect on shareholders and may adversely impact the price of our common shares.

We have guaranteed the performance of some of our subsidiaries, which may result in substantial costs in the event of non-performance

We have issued certain guarantees of the performance of some of our subsidiaries in certain situations, which obligates us to perform in the event that the subsidiaries do not perform. In the event of non-performance by the subsidiaries, we could incur substantial cost to fulfill our obligations under these guarantees. Such performance guarantees could have a material impact on our business, results of operations, financial condition and cash flows. See Notes 9, 24 and 25 to the consolidated financial statements for information on our guarantee obligations.

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We have anti-takeover protections that may discourage, delay or prevent a change in control that could benefit our shareholders.

The BCBCA and our Articles of Continuance contain provisions that could make it more difficult for a third party to acquire us without the consent of our Board of Directors ("Board"). These provisions include:

- As a notice of meeting is required to include certain particulars in the case where a shareholder meeting is being requisitioned by shareholders, our Board must be given advance notice regarding special business that is to be brought by such requisitioning shareholders before the shareholder meeting. For special business, advance notice describing the special business to be discussed at the meeting must be provided and that notice must include any documents to be approved or ratified as an addendum or state that such document will be available for inspection at our records office or other reasonably accessible location.

- Under the BCBCA, shareholders may make proposals for matters to be considered at the annual general meeting of shareholders, provided that such shareholders represent at least 1% of the voting shares of a company or such shares have a fair market value of at least Cdn$2,000. Such proposals must be sent to us in advance of any proposed meeting by delivering a timely written notice in proper form to our registered office. The notice must include information on the business the shareholder intends to bring before the meeting. These provisions could have the effect of delaying until the next shareholder meeting shareholder actions that are favored by the holders of a majority of our outstanding voting securities.

- Casual vacancies on our Board can be filled until the next annual meeting of shareholders by the directors of our Board.

A change of control will also result in an event of default under our credit facility and will permit holders of our convertible debentures to require that we purchase the debentures upon the conditions set forth in the respective indenture governing the debentures, which may discourage, delay or prevent a change of control or the acquisition of a substantial block of our common shares.

We have also adopted a shareholder rights plan that may discourage or delay a change of control or the acquisition of a substantial block of our common shares and may make any future unsolicited acquisition attempt more difficult. Under the rights plan:

- The rights will generally become exercisable if a person or group acquires 20% or more of Atlantic Power's outstanding common shares (unless such transaction is a "permitted bid" or a transaction to which the application of the shareholders rights plan has been waived pursuant to the terms of the plan) and thus becomes an "acquiring person." A "permitted bid" is an offer pursuant to which, among other things, such person or group agrees to hold the offer open to all shareholders for a period longer than the statutorily required period.

- Each right, when exercisable, will entitle the holder, other than the "acquiring person," to acquire shares of Atlantic Power's common shares at a significant discount to the then-prevailing market price.

- As a result, the rights plan may cause substantial dilution to a person or group that becomes an "acquiring person" and may discourage or delay a merger or acquisition that shareholders may consider favorable, including transactions in which shareholders might otherwise receive a premium for their shares.

Our common shares may not continue to be qualified investments under Canadian tax laws

There can be no assurance that our common shares will continue to be qualified investments under relevant Canadian tax laws for trusts governed by registered retirement savings plans, registered

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retirement income funds, deferred profit sharing plans, registered education savings plans, registered disability savings plans and tax-free savings accounts. Canadian tax laws impose penalties for the acquisition or holding of non-qualified or ineligible investments.

We are subject to Canadian tax

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes, and dividends paid by us are generally subject to Canadian withholding tax if paid to a shareholder that is not a resident of Canada. We hold a promissory note from our primary U.S. holding company (the "Intercompany Note") and are required to include, in computing our taxable income, interest on the Intercompany Note.

On November 5, 2011, we acquired directly and indirectly, all of the outstanding limited partnership units of the Partnership pursuant to a court-approved plan of arrangement. We are required to include the income or loss from the Partnership in our taxable income. We expect that our existing tax attributes initially will be available to offset the income inclusions noted herein such that they will not result in an immediate material increase to our liability for Canadian taxes. However, once we fully utilize our existing tax attributes (or if, for any reason, these attributes were not available to us), our Canadian tax liability would materially increase. Although we intend to explore potential opportunities in the future to preserve the tax efficiency of our structure, no assurances can be given that our Canadian tax liability will not materially increase at that time.

Canadian federal income tax laws and policies could be changed in a manner which adversely affects holders of our common shares

There can be no assurance that Canadian federal income tax laws and Canada Revenue Agency administrative policies respecting the Canadian federal income tax consequences generally applicable to us, to our subsidiaries, or to a U.S. or Canadian holder of common shares will not be changed in a manner which adversely affects holders of our common shares.

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

Under our prior IPS structure, we treated the subordinated notes as debt for U.S. federal income tax purposes. Accordingly, we deducted the interest payments on the subordinated notes and reduced our net taxable income treated as "effectively connected income" for U.S. federal income tax purposes. Under our current structure, our subsidiaries that are incorporated in the United States are subject to U.S. federal income tax on their income at regular corporate rates (currently as high as 35%, plus state and local taxes), and one of our U.S. holding companies will claim interest deductions with respect to the Intercompany Note in computing its income for U.S. federal income tax purposes. The Partnership acquisition added another U.S. holding company to our structure. This holding company owns the U.S. operating assets of the Partnership. This group currently has certain intercompany financing arrangements (the "Partnership Financing Arrangements") in place. We claim interest deductions in the United States with respect to the Partnership Financing Arrangements. To the extent any interest expense under the subordinated notes, the Intercompany Note or the Partnership Financing Arrangements is disallowed or is otherwise not deductible, the U.S. federal income tax liability of our U.S. holding companies will increase, which could materially affect the after-tax cash available to distribute to us.

While we received advice from our U.S. tax counsel at the time of the issuance, based on certain representations by us and our U.S. holding companies and determinations made by our independent advisors, as applicable, that the subordinated notes and the Intercompany Note should be treated as debt for U.S. federal income tax purposes, and the Partnership has received advice from its U.S. accountants, based on certain representations by its holding companies, that the payments on the

Partnership Financing Arrangements should be deductible for U.S. federal income tax purposes, it is possible that the Internal Revenue Service (the "IRS") could successfully challenge these positions and assert that any of these arrangements should be treated as equity rather than debt for U.S. federal income tax purposes or that the interest on such arrangements is otherwise not deductible. In this case, the otherwise deductible interest would be treated as non-deductible distributions and, in the case of the Intercompany Note and the Partnership Financing Arrangements, may be subject to U.S. withholding tax to the extent our respective U.S. holding company had current or accumulated earnings and profits. The determination of debt or equity treatment for U.S. federal income tax purposes is based on an analysis of the facts and circumstances. There is no clear statutory definition of debt for U.S. federal income tax purposes, and its characterization is governed by principles developed in case law, which analyzes numerous factors that are intended to identify the nature of the purported creditor's interest in the borrower.

Not all courts have applied this analysis in the same manner, and some courts have placed more emphasis on certain factors than other courts have. To the extent it were ultimately determined that our interest expense on the subordinated notes, the Intercompany Note or the Partnership Financing Arrangements were disallowed, our U.S. federal income tax liability for the applicable open tax years would materially increase, which could materially affect the after-tax cash available to us to distribute. Alternatively, the IRS could argue that the interest on the subordinated notes, the Intercompany Note or the Partnership Financing Arrangements exceeded or exceeds an arm's length rate, in which case only the portion of the interest expense that does not exceed an arm's length rate may be deductible and the remainder may be subject to U.S. withholding tax to the extent our U.S. holding companies had current or accumulated earnings and profits. We have received advice from independent advisors that the interest rate on these debt instruments was and is, as applicable, commercially reasonable under the circumstances, but the advice is not binding on the IRS.

Furthermore, our U.S. holding companies' deductions attributable to the interest expense on the Intercompany Note and/or certain of the Partnership Financing Arrangements may be limited by the amount by which each U.S. holding company's net interest expense (the interest paid by each U.S. holding company on all debt, including the Intercompany Note and the Partnership Financing Arrangements, less its interest income) exceeds 50% of its adjusted taxable income (generally, U.S. federal taxable income before net interest expense, net operating loss carryovers, depreciation and amortization). Any disallowed interest expense may currently be carried forward to future years. In addition, if our U.S. holding companies do not make regular interest payments as required under these debt agreements, other limitations on the deductibility of interest under U.S. federal income tax laws could apply to defer and/or eliminate all or a portion of the interest deduction that our U.S. holding companies would otherwise be entitled to. Finally, the applicability of recent changes to the U.S.-Canada Income Tax Treaty to the structure associated with certain of the Partnership Financing Arrangements may result in distributions from the Partnership's U.S. group to its Canadian parent being subject to a 30% rate of withholding tax instead of the 5% rate that would otherwise have applied.

Our U.S. holding companies have existing net operating loss carryforwards that we can utilize to offset future taxable income. Our U.S. holding companies include the Partnership's U.S. holding company, Atlantic Power (US) GP, which has net operating loss carryforwards attributable to tax years prior to our acquisition. It is anticipated that these net operating loss carryforwards will be available to offset future taxable income of Atlantic Power (US) GP; however, their use may be subject to an annual limitation. While we expect these losses will be available to us as a future benefit, in the event that they are successfully challenged by the IRS or subject to additional future limitations, our ability to realize these benefits may be limited. A reduction in our net operating losses, or additional limitations on our ability to use such losses, may result in a material increase in our future income tax liability.

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Atlantic Power Preferred Equity Ltd. (formerly named CPI Preferred Equity Ltd.) is subject to Canadian tax, as is Atlantic Power's income from the Partnership

As a Canadian corporation, we are generally subject to Canadian federal, provincial and other taxes. See "Risks Related to Our Structure We are subject to Canadian tax." We are required to include in computing our taxable income any income earned by the Partnership. In addition, Atlantic Power Preferred Equity Ltd., a subsidiary of the Partnership, is also a Canadian corporation and is generally subject to Canadian federal, provincial and other taxes. Atlantic Power Preferred Equity Ltd. is liable to pay its applicable Canadian taxes.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None

ITEM 2. PROPERTIES

We have included descriptions of the locations and general character of our principal physical operating properties, including an identification of the segments that use such properties, in "Item 1. Business," which is incorporated herein by reference. A significant portion of our equity interests in the entities owning these properties is pledged as collateral under our senior credit facility or under non-recourse operating level debt arrangements.

Our principal executive office is located at One Federal Street, 30th floor, Boston, Massachusetts under a lease that expires in 2023.

ITEM 3. LEGAL PROCEEDINGS

Our Lake Project was previously involved in a dispute with Progress Energy Florida ("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 filed a claim against PEF in which the Company sought to confirm its 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 had stopped dispatching during off-peak periods pending the outcome of the dispute. On November 27, 2012, the Lake Project executed a settlement agreement with PEF that resolved the outstanding dispute and dismissed the lawsuit. The principal terms of the settlement included an agreement by PEF to (i) pay $5.0 million on or before December 31, 2012 and (ii) accept delivery and pay for off-peak energy at the Firm Energy Rate as defined under the PPA. The payment was received on December 31, 2012. Beginning on November 27, 2012, PEF began accepting off-peak energy from Lake (to be paid for at the Firm Energy Rate) over the remaining term of the PPA.

In February 2011, we filed a rate application with the 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.

In 2011, the IRS began an examination of our federal income tax returns for the tax years ended December 31, 2007 and 2009. On April 2, 2012, the IRS issued various Notices of Proposed Adjustments. The principal area of the proposed adjustments pertain to the classification of U.S. real property in the calculation of the gain related to our 2009 conversion from the previous income participating security structure to our current traditional common share structure. We intend to vigorously contest these proposed adjustments, including pursuing all administrative and judicial remedies available to us. We expect to be successful in sustaining our positions with no material impact to our financial results. No accrual has been made for any contingency related to any of the proposed adjustments as of December 31, 2012.

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 December 31, 2012 that are expected to have a material impact on our financial position or results of operations or have been reserved for as of December 31, 2012.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Market Information and Holders

The following table sets forth the price ranges of our outstanding common shares, as reported by the NYSE from the date on which our common shares were listed through December 31, 2012:

Period	High (US$)	Low (US$)
Quarter ended December 31, 2012	15.18	10.72
Quarter ended September 30, 2012	15.05	12.85
Quarter ended June 30, 2012	14.49	12.55
Quarter ended March 31, 2012	15.22	13.57
Quarter ended December 31, 2011	14.55	12.52
Quarter ended September 30, 2011	16.34	13.12
Quarter ended June 30, 2011	16.18	14.33
Quarter ended March 31, 2011	15.75	14.72

The following table sets forth the price ranges of our common shares, as applicable, as reported by the TSX for the periods indicated:

Period	High (Cdn$)	Low (Cdn$)
Quarter ended December 31, 2012	15.12	10.57
Quarter ended September 30, 2012	14.79	13.19
Quarter ended June 30, 2012	14.27	12.88
Quarter ended March 31, 2012	15.11	13.60
Quarter ended December 31, 2011	14.94	13.09
Quarter ended September 30, 2011	15.46	12.92
Quarter ended June 30, 2011	15.72	13.82
Quarter ended March 31, 2011	15.50	14.41

The number of holders of common shares was approximately 87,190 on February 27, 2013.

Dividends

Dividends declared per common share in 2012 and 2011 were as follows (Cdn$):

Month	2012	2011
	Amount	
January	$ 0.0958	$ 0.0912
February	0.0958	0.0912
March	0.0958	0.0912
April	0.0958	0.0912
May	0.0958	0.0912
June	0.0958	0.0912
July	0.0958	0.0912
August	0.0958	0.0912
September	0.0958	0.0912
October	0.0958	0.0912
November	0.0958	0.0958
December	0.0958	0.0958

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Securities Authorized for Issuance under Equity Compensation Plans

The following table provides information as of December 31, 2012 regarding our Long-Term Incentive Plan and Equity Incentive Plan. For the description of our Long-Term Incentive Plan and Equity Incentive Plan, see Item 15. "Exhibits and Financial Statements Schedule" Note 14, *Equity Compensation Plans.*

	Number of securities to be issued upon exercise of outstanding options, warrants and rights[1]	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (a))[1][2]
	(a)	(b)	(c)
Equity compensation plans approved by security holders	492,535	$	664,053
Equity compensation plans not approved by security holders			
Total	492,535	$	664,053

(1) Assumes that the plan participants elect to receive 100% in common shares upon redemption. This amount does not include future credits to the notional share accounts of participants related to monthly dividends paid on the common shares.

(2) The maximum aggregate number of common shares that may be issued under our Long-Term Incentive Plan upon redemption of notional shares is 1,350,000 shares and the maximum aggregate number of common shares that may be issued under our Equity Incentive Plan in the form of restricted or unrestricted stock awards is 250,000 shares.

Performance Graph

The performance graph below compares the cumulative total shareholder return on our common shares for the period December 31, 2005, through December 31, 2012, with the cumulative total return of the Standard & Poor's 500 Composite Stock Price Index, or S&P 500 and the Standard & Poor's TSX Composite or S&P/TSX. Our common shares trade on the NYSE under the symbol "AT" and the TSX under the symbol "ATP". The performance graph shown below is being furnished and compares each period assuming that an investment was made on December 31, 2005, in each of our common shares, the stocks included in the S&P 500 and the stocks included in the S&P/TSX, and that all dividends were reinvested.

Total Shareholder Return 2005 - 2012

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ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected historical consolidated financial information for each of the periods indicated. The annual historical information for each of the years in the three-year period ended December 31, 2012 has been derived from our audited consolidated financial statements included elsewhere in this Annual Report on Form 10-K.

You should read the following selected consolidated financial data along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and our consolidated financial statements and the accompanying notes, which describe the impact of material acquisitions and dispositions that occurred in the three-year period ended December 31, 2012.

	Year Ended December 31,				
(in thousands of U.S. dollars, except as otherwise stated)	**2012[(a)]**	**2011[(a)(b)]**	**2010[(a)]**	**2009[(a)]**	**2008[(a)]**
Project revenue	$ 440,377	$ 93,895	$ 1,051	$	$ 12,553
Project (loss) income	(31,908)	(5,443)	14,846	19,867	3,817
Loss (income) from continuing operations	(116,779)	(71,818)	(27,982)	(64,132)	(13,901)
Income from discontinued operations, net of tax	16,459	36,177	24,127	25,646	34,200
Net (loss) income attributable to Atlantic Power Corporation	(112,776)	(38,408)	(3,752)	(38,486)	48,101
Basic (loss) earnings per share:					
(Loss) income from continuing operations attributable to Atlantic Power Corporation	$ (1.11)	$ (0.96)	$ (0.45)	$ (1.06)	$ 0.23
Income from discontinued operations, net of tax	0.14	0.46	0.39	0.43	0.55
Net income (loss) attributable to Atlantic Power Corporation	$ (0.97)	$ (0.50)	$ (0.06)	$ (0.63)	$ 0.78
Diluted (loss) earnings per share[(c)]					
(Loss) income from continuing operations attributable to Atlantic Power Corporation	$ (1.11)	$ (0.96)	$ (0.45)	$ (1.06)	$ 0.23
Income from discontinued operations, net of tax	0.14	0.46	0.39	0.43	0.50
Net income (loss) attributable to Atlantic Power Corporation	$ (0.97)	$ (0.50)	$ (0.06)	$ (0.63)	$ 0.73
Per IPS distribution declared	$	$	$	$ 0.51	$ 0.60
Per common share dividend declared	$ 1.13	$ 1.11	$ 1.06	$ 0.46	$ 0.40
Total assets	$ 4,002,652	$ 3,248,427	$ 1,013,012	$ 869,576	$ 907,995
Total long-term liabilities	$ 2,280,855	$ 1,940,192	$ 518,273	$ 402,212	$ 654,499

(a) The Auburndale, Lake, Pasco and Path 15 projects are classified as assets held for sale and discontinued operations for the year ended December 31, 2012. Prior periods have been reclassified to reflect the impact.

(b) The acquisition of the Partnership was completed on November 5, 2011.

(c) Diluted earnings (loss) per share is computed including dilutive potential shares, which include those issuable upon conversion of convertible debentures and under our long term incentive plan. Because we reported a loss during the years ended December 31, 2012, 2011, 2010, and 2009, the effect of including potentially dilutive shares in the calculation during those periods is anti-dilutive. Please see the notes to our historical consolidated financial statements included elsewhere in this Form 10-K for information relating to the number of shares used in calculating basic and diluted earnings (loss) per share for the periods presented.

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ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following management's discussion and analysis of financial condition and results of operations should be read in conjunction with our audited consolidated financial statements included in this Annual Report on Form 10-K. All dollar amounts discussed below are in thousands of U.S. dollars, unless otherwise stated. The 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 PPAs, which seek to minimize exposure to changes in commodity prices. As of December 31, 2012, our power generation projects from continuing operations had an aggregate gross electric generation capacity of approximately 3,366 MW in which our aggregate ownership interest is approximately 2,117 MW. These totals exclude projects designated as held for sale at December 31, 2012. On January 30, 2013, we and certain of our subsidiaries entered into an agreement to sell our interests in the Florida Projects. We expect to enter into a purchase and sale agreement in the remaining part of the first quarter to sell our 100% interest in Path 15. Our current portfolio consists of interests in twenty-nine operational power generation projects across eleven states in the United States and two provinces in Canada. In addition, we have one 53 MW biomass project under construction in Georgia. We also own a majority interest in Rollcast, a biomass power plant developer in North Carolina and a 100% interest in Ridgeline, a wind and solar developer in Seattle, Washington. Nineteen of our projects are wholly owned subsidiaries. In the fourth quarter of 2012, we entered into a purchase and sale agreement for the sale of our 40% interest in the Delta-Person project, acquired a 100% interest in Ridgeline, achieved commercial operations at Canadian Hills and issued debentures in a public offering.

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 August 2013 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.

Our power generation projects generally have long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the term of the fuel supply and transportation arrangements corresponds to the term of the relevant PPAs. Many of the PPAs and steam sales agreements provide for the indexing or pass-through of fuel costs to our customers. In cases where there is not an effective pass-through of fuel costs, we often attempt to mitigate the market price risk of changing commodity costs through the use of financial hedging strategies.

We directly operate and maintain 20 of our power generation projects. We also partner with recognized leaders in the independent power industry to operate and maintain our other projects, including CEM, PPMS and DPS. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

Significant Events

Ridgeline Acquisition

The Ridgeline acquisition, which closed on December 31, 2012, added interests in three wind projects totaling 150 net MW. The Ridgeline acquisition strengthens our ability to execute development

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stage projects which is one of our target growth areas. It also complements our other growth area, operating project acquisitions, as exemplified by the Partnership transaction completed at the end of 2011.

Ridgeline currently has an active wind and solar development pipeline of more than 10 projects in the United States totaling in excess of 600 MW. Planned development expenditures in 2013 are focused on near-term opportunities where PPAs can be obtained quickly, including solar sites where investment tax credits remain available and construction could be completed as early as the first quarter of 2014. Wind development viability will depend on continued support from renewable portfolio standards in more than 30 states and continued federal support of production tax credits. See Item 1A. "Risk Factors Risk Related to Our Business and Our Projects Our renewable energy projects are subject to uncertainties regarding regulatory incentives."

As part of the acquisition, we will integrate Ridgeline's team of over 30 employees, which has a broad set of competencies essential for the successful identification, resource assessment, development (including permitting), construction and operation of large-scale renewable power projects. Ridgeline was responsible for developing Idaho's first utility scale wind project and has successfully developed three additional wind projects totaling 325 MW, including Rockland and Goshen North. This team will also assist our assessment and pursuit of other renewable acquisitions and in managing our growing renewable energy portfolio.

Commercial Operation of Canadian Hills and Project Debt Pay Down

The Canadian Hills project achieved commercial operations on December 22, 2012. In January 2012, we purchased a 51% interest in Canadian Hills and increased our ownership interest to 99% in March 2012 for a nominal sum. In July 2012, we funded approximately $190 million of our equity contribution (net of financing costs). In December 2012, Canadian Hills received tax equity investments in aggregate of $225 million from a consortium of four institutional tax equity investors along with an approximately $44 million of our own tax equity investment, which we expect to syndicate with additional tax equity investors in the first half of 2013, although no assurances can be provided regarding our ability to syndicate the investment on acceptable terms or at all, or the timing of any such syndication. The project's outstanding construction loan was repaid from the tax equity proceeds, decreasing the project's short-term debt by $265 million. We will oversee the ongoing operation of Canadian Hills and will act as its asset manager.

Common share and convertibles debenture offerings

On July 5, 2012, we closed a public offering of 5,567,177 common shares, at a purchase price of $12.76 per common share and Cdn$13.10 per common share, for aggregate net proceeds from the common share offering, after deducting the underwriting discounts and expenses, of approximately $67.7 million. We also issued, in a public offering, $130.0 million aggregate principal amount of 5.75% convertible unsecured subordinated debentures due June 30, 2019, (the "July 2012 Debentures"), after deducting the underwriting discounts and offering expenses, for net proceeds of $124.0 million. The July 2012 Debentures pay interest semi-annually on the last day of June and December of each year. The July 2012 Debentures are convertible into our common shares at an initial conversion rate of 57.9710 common shares per $1,000 principal amount of debentures representing a conversion price of $17.25 per common share, subject to anti-dilution adjustments in certain circumstances. The July 2012 Debentures may not be redeemed prior to June 30, 2015 (except in limited circumstances). After June 30, 2015, the July 2012 Debentures may be redeemed, in whole or in part from time to time, upon certain conditions. Upon a change of control of the company, each holder may require that we purchase the July 2012 Debentures upon the conditions set forth in the indenture governing the debentures. We used the net proceeds from the offerings to fund our equity commitment in Canadian Hills.

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On December 11, 2012, we issued, in a public offering, Cdn$100 million aggregate principal amount of 6.00% convertible unsecured subordinated debentures due December 31, 2019 (the "December 2012 Debentures") for net proceeds, after deducting the underwriting discounts and offering expenses, of Cdn$95.5 million. The December 2012 Debentures pay interest semi-annually on the last day of June and December of each year beginning on June 30, 2013. The December 2012 Debentures are convertible into our common shares at an initial conversion rate of 68.9655 common shares per Cdn$1,000 principal amount of December 2012 Debentures representing a conversion price of Cdn$14.50 per common share. We used the proceeds to acquire all of the outstanding shares of capital stock of Ridgeline and to fund certain working capital commitments and acquisition expenses related to Ridgeline.

Rationalization of Project Portfolio

During 2012, we initiated a strategy to divest non-core assets from our project portfolio. These non-core assets include projects that provide immaterial cash distributions, fall outside of our core competency of natural gas, biomass, hydro and renewable power generation, or are less than wholly owned investments where we do not have the ability to make decisions that most directly impact project operations. In response to this strategy, we sold our 50% interest in Badger Creek on September 4, 2012 for proceeds of approximately $3.7 million. In May 2012, we sold our 14.3% interest in PERH for $24.2 million, plus a management agreement termination fee of approximately $6.0 million, for a total sale price of $30.2 million. We also entered into a purchase and sale agreement for the sale of our 40% interest in the Delta-Person project for approximately $9.0 million. The Delta-Person transaction is expected to close in the third quarter of 2013. Other non-core assets that are currently for sale include our approximately 17% interest in Gregory, which is being sold together with the interests of the project's other partners.

We are also conducting a sales process that began in 2012 for our 100% interest in Path 15. We expect to enter into a purchase and sale agreement in the remaining part of the first quarter of 2013 to sell Path 15. The sale would be expected to close in the first half of 2013. The project is our only transmission project and it makes a relatively small contribution to overall cash flows.

Sale of Florida Projects

On January 30, 2013, we and certain of our subsidiaries entered into an agreement to sell our interests in the Florida Projects for a purchase price, including working capital adjustments, of approximately $136 million. We expect to receive net cash proceeds of approximately $111 million in the aggregate, after repayment of project-level debt at Auburndale and settlement of all outstanding natural gas swap agreements at Lake and Auburndale. We intend to use the net proceeds from the sale to fully repay our senior credit facility, which is expected to have an outstanding balance of approximately $64 million at close, and for general corporate purposes. The sale is expected to close in the remaining part of the first quarter of 2013. Given our projections that the Florida energy market will not recover in the near-term to allow us to secure economic PPAs, we concluded in December 2012, after considering all available options, that the sale of these projects maximizes shareholder value. In the fourth quarter of 2012, we recognized a non-cash impairment charge of approximately $50.0 million related to our interest in Lake.

Factors That May Influence Our Results

Our primary objective is to generate consistent levels of cash flow to support dividends to our shareholders, which we refer to as "Cash Available for Distribution." Because we believe that our shareholders are primarily focused on income and secondarily on capital appreciation, we provide supplementary cash flow-based non-GAAP information in Item 7 and discuss our results in terms of

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these non-GAAP measures, in addition to analysis of our results on a GAAP basis. See "Supplementary Non-GAAP Financial Information" below for additional details.

The primary components of our financial results are (i) the financial performance of our projects, (ii) non-cash unrealized gains and losses associated with derivative instruments and (iii) interest expense and foreign exchange impacts on corporate-level debt. We have recorded net losses in four of the past five years, primarily as a result of non-cash losses associated with items (ii) and (iii) above, which are described in more detail in the following paragraphs.

Financial performance of our projects

The operating performance of our projects supports cash distributions that are made to us after all operating, maintenance, capital expenditures and debt service requirements are satisfied at the project-level. Our projects are able to generate Cash Available for Distribution because they generally receive revenues from long-term contracts that provide relatively stable cash flows. Risks to the stability of these distributions include the following:

While approximately 35% of our power generation revenue in 2012 was related to contractual capacity payments, commodity prices do influence our variable revenues and the cost of fuel. Our PPAs are generally structured to minimize our risk to fluctuations in commodity prices by passing the cost of fuel through to the utility and its customers, but some of our projects do have exposure to market power and fuel prices. For example, a portion of the natural gas required for projects in our Southeast segment is purchased at spot market prices but not effectively passed through in their PPAs. Our Orlando project should benefit from switching to market prices for natural gas when its fuel contract expires at the end of 2013 since the contract prices are above current and projected spot prices. We have executed a hedging strategy to partially lock in this margin. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects" and Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our hedging arrangements at our Southeast segment projects. Our most significant exposure to market power prices exists at the Selkirk, Chambers and Morris projects. At Chambers, our utility customer has the right to sell a portion of the plant's output to the spot power market if it is economical to do so, and the Chambers project shares in the profits from those sales. With low demand for electricity the utility reduces its dispatch to minimum contracted levels during off-peak hours. At Selkirk, approximately 23% of the capacity of the facility is currently not contracted and is sold at market power prices or not sold at all if market prices do not support profitable operation of that portion of the facility. Additionally at Morris, approximately 56% of the facility's capacity is currently not contracted and is sold at market power prices or not sold at all if market prices do not support profitable operation of the facility. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating margin of these projects and on our business, results of operations and financial condition."

When revenue or fuel contracts at our projects expire, we may not be able to sell power or procure fuel under new arrangements that provide the same level or stability of project cash flows. If re-contracted, the degree of the expected decline in Cash Available for Distribution is subject to market conditions when we execute new PPAs for these projects and is difficult to estimate at this time. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business, results of operations and financial condition." These projects will be free of debt when their PPAs expire, which provides us with some flexibility to pursue the most economic type of contract without restrictions that might be imposed by project-level debt.

Some of our projects have non-recourse project-level debt that can restrict the ability of the project to make cash distributions. The project level debt agreements typically contain cash flow coverage ratio tests that restrict the project's cash distributions if project cash flows do not exceed project-level debt service requirements by a specified amount. The Delta-Person and Gregory project and Epsilon Power Partners, the holding company for our ownership in the Chambers project, are currently not meeting their cash flow coverage ratio tests and they are restricted from making cash distributions. Although we expect to resume receiving distributions from Epsilon Power Partners in 2013 and Delta-Person and Gregory in 2014, we cannot provide any assurances that these projects will generate enough cash flow to meet the ratio tests and be able to resume distributions to us. See "Liquidity and Capital Resources Project- level debt" and Item 1A. "Risk Factors Risks Related to Our Structure Our indebtedness and financing arrangements could negatively impact our business and our projects" for additional details.

Non-cash gains and losses on derivatives instruments

In the ordinary course of our business, we execute natural gas swap contracts to manage our exposure to fluctuations in commodity prices, forward foreign currency contracts to manage our exposure to fluctuations in foreign exchange rates and interest rate swaps to manage our exposure to changes in interest rates on variable rate project-level debt. Most of these contracts are recorded at fair value with changes in fair value recorded currently in earnings, resulting in significant volatility in our income that does not significantly affect current period cash flows or the underlying risk management purpose of the derivative instruments. See Item 7A. "Quantitative and Qualitative Disclosures About Market Risk" for additional details about our derivative instruments.

Interest expense and other costs associated with debt

Interest expense relates to both non-recourse project-level debt and corporate-level debt. A portion of our convertible debentures and long-term corporate level debt are denominated in Canadian dollars. These debt instruments are revalued at each balance sheet date based on the U.S. dollar to Canadian dollar foreign exchange rate at the balance sheet date, with changes in the value of the debt recorded in the consolidated statements of operations. The U.S. dollar to Canadian dollar foreign exchange rate has been volatile in recent years, which in turn creates volatility in our results due to the revaluation of our Canadian dollar-denominated debt.

Current Trends in Our Business

Macroeconomic impacts

The 2008-2009 recession caused significant decreases in both peak electricity demand and consumption that varied by region. The recovery from the recession continues on a slow path with a low economic growth rate leading to a slower recovery in employment. While summer and winter peak demand is also greatly influenced by weather, summer and winter peak demand is projected to steadily increase over the next ten years. However, such increase in summer and winter peak demand is dependent on the speed of the economic recovery. As electricity peak demand recovers, base load (plants that typically operate at all times) and peaking plants (those that only operate in periods of very high demand) will be impacted more than mid-merit plants (those that operate for a portion of most days, but not at night or in other lower demand periods). Base load plants may be called on for increased levels of off-peak generation and peaking plants may be called on more frequently as a function of their efficiency and the overall peak demand level. The actual financial impacts on

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particular plants depend on whether contractual provisions, such as minimum load levels and/or significant capacity payments, partially mitigate the impact of reduced demand.

Increased renewable power projects

The combination of federal stimulus and other tax provisions in the United States and Canada, state renewable portfolio standards and state or regional CO_2/greenhouse gases reduction programs has provided powerful incentives to build new renewable power capacity. The American Taxpayer Relief Act, enacted in January 2013 extended production tax credits ("PTC") and investment tax credits for projects that start construction prior to January 1, 2014 and extended bonus depreciation for projects that are placed in service prior to January 1, 2014. Under present law, the PTC provides an income tax credit of 2.2 cents/kilowatt-hour for the production of electricity from utility-scale wind turbines. Pursuant to the STA, on September 14, 2012, the OMB released an initial report on the potential sequestration triggered by the failure of the Joint Select Committee on Deficit Reduction to propose, and Congress to enact, a plan to reduce the deficit by $1.2 trillion, as required by the BCA. The sequester is expected to become effective in March 2013 if Congress does not enact a comprehensive deficit reduction package. The OMB report estimated a 7.6% reduction of 1603 Grants in fiscal year 2013. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects Our renewable energy projects are subject to uncertainties regarding regulatory incentives."

Increased shale gas resources

The substantial additions of economically viable shale gas reserves and increasing production levels have put strong downward pressure on natural gas prices in both the spot and forward markets. One impact of the reduced prices is that gas-fired generators have displaced some generation from base load coal plants, particularly in the southeast U.S. Lower natural gas prices also have compressed, and in some cases turned negative, the "spark spread," which is the industry term for the profit margin between spot market fuel and power prices. Reduced spark spreads directly impact the profitability of plants selling power into the spot market with no contract, which are referred to as merchant plants.

The lower power prices can have an adverse impact on development of new renewable projects whose owners are attempting to negotiate PPAs at favorable levels to support the financing and construction of the projects. The expectation of reduced future volatility of gas prices due to increased supply has reinforced a growing expectation of the role of natural gas as a "bridging fuel," helping from a carbon policy perspective to bridge the desired U.S. transition to both cleaner fuels and more commercially viable carbon removal and sequestration technologies.

Retirement of fossil-fired generation

The increase of gas and renewable capacity will be offset by large-scale retirements of coal-fired generation. NERC projects 71 GW of fossil-fired generation retirement by 2022, with over 90 percent retiring by 2017 primarily due to potential and existing federal environmental regulations and low natural gas prices.

Credit markets

Credit markets have strengthened over the past several years and the mix of lenders providing power project financing has changed. Base lending rates such as LIBOR have stayed quite low by historical standards and credit market conditions for project-lending have improved to approach pre-recession levels. This expands the number of new power projects that could be feasibly financed and built. Corporate-level credit markets have experienced similar improvement and the availability of alternative forms of financing projects such as tax equity investment have enhanced the ability of many development companies to finance new power projects. However, we cannot provide any assurance that

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such trends will continue or will not reverse. See Item 1A. "Risk Factors Risks Related to Our Structure Unstable capital and credit markets may adversely affect our ability to raise capital on favorable terms and may adversely affect our business, results of operations, financial condition and cash flows."

Consolidated Overview and Results of Operations

Performance highlights

	Year Ended December 31,		
	2012	2011	2010
Project income (loss)	$ (31,908)	$ (5,443)	$ 14,846
Loss from continuing operations	$ (116,779)	$ (71,818)	$ (27,982)
Income from discontinued operations, net of tax	$ 16,459	$ 36,177	$ 24,127
Net loss attributable to Atlantic Power Corporation	$ (112,776)	$ (38,408)	$ (3,752)
Loss per share from continuing operations attributable to Atlantic Power Corporation basic	$ (1.11)	$ (0.96)	$ (0.45)
Earnings per share from discontinued operations basic	0.14	0.46	0.39
Loss per share attributable to Atlantic Power Corporation basic	$ (0.97)	$ (0.50)	$ (0.06)
Loss per share from continuing operations attributable to Atlantic Power Corporation diluted	$ (1.11)	$ (0.96)	$ (0.45)
Earnings per share from discontinued operations diluted	0.14	0.46	0.39
Loss per share attributable to Atlantic Power Corporation diluted	$ (0.97)	$ (0.50)	$ (0.06)
Project Adjusted EBITDA[1]	$ 225,570	$ 84,911	$ 53,915
Cash Available for Distribution[1]	$ 131,553	$ 78,958	$ 65,522

(1) See reconciliation and definition below under Supplementary Non-GAAP Financial Information.

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2012 compared to 2011

The following table and discussion summarizes our consolidated results of operations:

	Years Ended December 31,	
	2012	2011
Project revenue:		
Energy sales	$ 217,038	$ 43,590
Energy capacity revenue	154,851	34,009
Other	68,488	16,296
	440,377	93,895
Project expenses:		
Fuel	169,093	37,471
Operations and maintenance	124,759	22,723
Depreciation and amortization	118,031	23,682
	411,883	83,876
Project other income (expense):		
Change in fair value of derivative instruments	(59,272)	(14,594)
Equity in earnings of unconsolidated affiliates	15,246	6,356
Gain on sale of equity investments	578	
Interest expense, net	(16,438)	(7,244)
Other expense, net	(516)	20
	(60,402)	(15,462)
Project loss	(31,908)	(5,443)
Administrative and other expenses (income):		
Administration	28,267	37,688
Interest, net	89,868	25,953
Foreign exchange loss	547	13,838
Other income, net	(5,728)	
	112,954	77,479
Loss from continuing operations before income taxes	(144,862)	(82,922)
Income tax benefit	(28,083)	(11,104)
Loss from continuing operations	(116,779)	(71,818)
Income from discontinued operations, net of tax	16,459	36,177
Net loss	(100,320)	(35,641)
Net loss attributable to noncontrolling interests	(593)	(480)
Net income attributable to Preferred share dividends of a subsidiary company	13,049	3,247
Net loss attributable to Atlantic Power Corporation	$ (112,776)	$ (38,408)

Project Income (loss) by Segment

We have five reportable segments: Northeast, Southeast, Northwest, Southwest and Un-allocated Corporate. We revised our reportable business segments on November 5, 2011 upon completion of the Partnership acquisition in order to align with changes in management's resource allocation and performance assessment in making decisions regarding our operations. The segment classified as Un-allocated Corporate includes activities that support the executive offices, capital structure, costs of being a public registrant, costs to develop future projects and intercompany eliminations. Unallocated

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Corporate also includes Rollcast, a 60% owned company, which develops, owns and operates renewable power plants that use wood or biomass fuel and Ridgeline, which develops and operates wind and solar renewable projects. These costs are not allocated to the operating segments when determining segment profit or loss. Project income (loss) is the primary GAAP measure of our operating results and is discussed below by reportable segment. A significant non-cash item that impacts project income (loss) and is subject to potentially significant fluctuations is the change in fair value of certain derivative financial instruments. These instruments are required by GAAP to be revalued at each balance sheet date (see Item 7A. " Quantitative and Qualitative Disclosures About Market Risk" for additional information).

	Year Ended December 31, 2012					
	Northeast	Southeast[(1)]	Northwest	Southwest[(2)]	Un-allocated Corporate	Consolidated Total
Project revenue:						
Energy sales	$ 126,929	$	$ 37,329	$ 52,780	$	$ 217,038
Energy capacity revenue	79,925			74,926		154,851
Other	14,189		22,485	30,386	1,428	68,488
	221,043		59,814	158,092	1,428	440,377
Project expenses:						
Fuel	97,304		9,411	62,378		169,093
Operations and maintenance	40,222	118	23,962	46,034	14,423	124,759
Depreciation and amortization	58,166		26,295	33,421	149	118,031
	195,692	118	59,668	141,833	14,572	411,883
Project other income (expense):						
Change in fair value of derivative instruments	(56,458)	(2,814)				(59,272)
Equity in earnings of unconsolidated affiliates	24,289	3,199	(6,765)	(5,467)	(10)	15,246
Gain on sale of equity investment				578		578
Interest expense, net	(16,283)		(2)	(111)	(42)	(16,438)
Other expense, net	(46)		17		(487)	(516)
	(48,498)	385	(6,750)	(5,000)	(539)	(60,402)
Project income (loss)	$ (23,147)	$ 267	$ (6,604)	$ 11,259	$ (13,683)	$ (31,908)

	Year Ended December 31, 2011					
	Northeast	Southeast[(1)]	Northwest	Southwest[(2)]	Un-allocated Corporate	Consolidated Total
Project revenue:						
Energy sales	$ 31,486	$	$ 3,257	$ 10,027	$ (1,180)	$ 43,590
Energy capacity revenue	24,079			9,738	192	34,009
Other	2,636		5,726	5,649	2,285	16,296
	58,201		8,983	25,414	1,297	93,895
Project expenses:						
Fuel	22,111		2,003	13,357		37,471
Operations and maintenance	9,615	88	2,641	6,284	4,095	22,723
Depreciation and amortization	12,751		4,565	6,306	60	23,682
	44,477	88	9,209	25,947	4,155	83,876
Project other income (expense):						
Change in fair value of derivative instruments	(1,065)	(11,492)			(2,037)	(14,594)
Equity in earnings of unconsolidated affiliates	5,572	(1,494)	(636)	558	2,356	6,356
Interest expense, net	(7,246)			(15)	17	(7,244)
Other expense, net	(46)				66	20
	(2,785)	(12,986)	(636)	543	402	(15,462)

Project income (loss)	$ 10,939	$ (13,074)	$ (862)	$ 10	$ (2,456)	$ (5,443)

(1) Excludes the Florida Projects which are designated as assets held for sale and discontinued operations.

(2) Excludes the Path 15 which is designated as assets held for sale and discontinued operations.

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Northeast

Project income for 2012 decreased $34.1 million from 2011 primarily due to:

- decreased project income from Kapuskasing of $30.4 million due primarily to a negative $24.5 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives; and

- decreased project income from North Bay of $26.8 million due primarily to a negative $24.5 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives.

These decreases were partially offset by:

- increased project income of $10.7 million at Chambers primarily attributable to the collection of the DuPont settlements associated with the dispute of the revenue calculation under the ESA of $9.6 million and decreased operations and maintenance costs of $1.5 million. A steam turbine leak forced the plant to shut down for 25 days in July 2011;

- increased project income of $8.2 million at Selkirk attributable to lower operations and maintenance costs, higher capacity revenue and a positive $5.8 million non-cash change in the fair value of gas supply agreements from 2011 and lower interest expense of $1.0 million; and

- increased project income of $6.2 million at Tunis which was acquired on November 5, 2011 and includes twelve months of operations for 2012.

Southeast

Project income for 2012 increased $13.3 million from 2011 due to increased project income of $9.9 million at the Piedmont project. This increase is attributable to an increase of $10.0 million related to the non-cash change in fair value of derivative instruments associated with its interest rate swaps.

Project income for the Southeast segment excludes the Florida Projects, which are accounted for as assets held for sale and a component of discontinued operations.

Project income for Auburndale was $22.6 million and $10.9 million for the years ended December 31, 2012 and 2011, respectively.

- The increase is due primarily to an increase of $9.0 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as higher capacity revenues due to contractual escalation clauses and higher dispatch than 2011.

Project loss for Lake was $7.7 million for the year ended December 31, 2012 as compared to project income of $21.6 million for the year ended December 31, 2011.

- The decrease is due primarily to a $50.0 million non-cash impairment charge recorded in the fourth quarter based on our estimation of the recoverability of the long-term asset value of the project. This was partially offset by an increase of $11.7 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps and a $5.0 million settlement payment from PEF in December 2012.

Project loss for Pasco was $1.3 million and $0.7 million for the years ended December 31, 2012 and 2011, respectively and did not change meaningfully from 2011.

Northwest

Project loss for 2012 increased $5.7 million from 2011 primarily due to:

- increased project loss at Rockland of $8.0 million due to a $7.3 million non-cash impairment recognized as a result of our step acquisition from 30% to 50% ownership interest ; and decreased project income of $3.7 million at Williams Lake which was acquired on November 5, 2011 and includes a full year of operations in 2012. The Williams Lake project had lower than expected revenues due to higher than budgeted curtailments from BC Hydro.

This increased loss was partially offset by:

increased project income of $5.1 million at Mamquam which was acquired on November 5, 2011 and includes a full year of operations in 2012.

Southwest

Project income for 2012 increased $11.2 million from 2011 primarily due to:

increased project income of $4.6 million from the Morris project that was acquired on November 5, 2011;

increased project income of $3.9 million from the Oxnard project that was acquired on November 5, 2011; and

increased project income of $2.7 million from the Manchief project that was acquired on November 5, 2011.

Project income for the Southwest segment excludes the Path 15 project which is accounted for as an asset held for sale and a component of discontinued operations. Project income for Path 15 was $5.1 million and $7.6 million for the years ended December 31, 2012 and 2011, respectively. The decrease is due primarily to $1.6 million increased maintenance costs associated with an erosion control initiative and $1.3 million in lower transmission revenue under the new rate agreement that became effective in April 2012.

Un-allocated Corporate

Total project loss increased $11.2 million from 2011 primarily due to higher general and administrative expenses associated with operating the Partnership projects acquired on November 5, 2011.

Administrative and other expenses (income)

Administrative and other expenses (income) include the income and expenses not attributable to our projects and are allocated to the Un-allocated Corporate segment. These costs include the activities that support the executive offices, capital structure, costs of being a public registrant, costs to develop future projects, interest costs on our corporate obligations, the impact of foreign exchange fluctuations and corporate tax. Significant non-cash items that impact Administrative and other expenses (income), which are subject to potentially significant fluctuations, include 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 the related deferred income tax expense (benefit) associated with these non-cash items.

Administration

Administration expense decreased $9.4 million or 25% from 2011 primarily due to a decrease in transaction related costs from the comparable period related to the acquisition of the Partnership in 2011. This was offset by increases in legal costs, salaries related to an increase in headcount and professional services related to our interim CFO.

Interest, net

Interest expense increased $63.9 million from 2011 primarily due to the issuance of $460 million principal amount of senior notes in the fourth quarter of 2011, interest costs from the debt assumed in the acquisition of the Partnership, issuance of the $130 million principal amount of convertible

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debentures in the third quarter of 2012 and issuance of the Cdn$100 million principal amount of convertible debentures in the fourth quarter of 2012.

Foreign exchange loss (gain)

Foreign exchange loss decreased $13.3 million primarily due to a $23.7 million increase in realized gains on the settlement of foreign currency forward contracts and a $2.2 million decrease in unrealized loss on foreign exchange forward contracts offset by a $12.6 million increase in unrealized loss in the revaluation of instruments denominated in Canadian dollars. The U.S. dollar to Canadian dollar exchange rate was 0.9832 at December 31, 2012 and decreased by 2.2% in 2012 compared to an increase of 2.3% in 2011.

Income tax benefit

Income tax benefit for 2012 was $28.1 million. For the year ended December 31, 2012, the difference between the actual tax benefit of $28.1 million and the expected income tax benefit of $36.2 million, based on the Canadian enacted statutory rate of 25%, is primarily due to a $20.2 million increase in the valuation allowance, $5.9 million of dividend withholding and preferred share taxes, $1.5 million and $1.8 million relating to foreign exchange and changes in tax rates, respectively. These amounts are partially offset by $8.5 million related to operating projects in higher tax rate jurisdictions, $5.1 million of change in tax basis estimates of equity method investments, and $6.5 million of other permanent differences. The income tax benefit for 2011 was $11.1 million. The difference between the actual tax benefit of $11.1 million and the expected income tax expense, based on the Canadian enacted statutory rate of 26.5%, of $22.0 million for the year ended December 31, 2011 is primarily due to a $21.7 million increase in the valuation allowance offset by a $10.5 million decrease related to operating projects in higher tax rate jurisdictions.

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2011 compared to 2010

The following table provides our consolidated results of operations:

	Years Ended December 31, 2011	Years Ended December 31, 2010
Project revenue:		
Energy sales	$ 43,590	$
Energy capacity revenue	34,009	786
Other	16,296	265
	93,895	1,051
Project expenses:		
Fuel	37,471	193
Operations and maintenance	22,723	1,060
Depreciation and amortization	23,682	88
	83,876	1,341
Project other income (expense):		
Change in fair value of derivative instruments	(14,594)	3,275
Equity in earnings of unconsolidated affiliates	6,356	13,777
Gain on sale of equity investments		1,511
Interest expense, net	(7,244)	(3,638)
Other expense, net	20	211
	(15,462)	15,136
Project income (loss)	(5,443)	14,846
Administrative and other expenses (income):		
Administration	37,688	16,149
Interest, net	25,953	11,701
Foreign exchange loss	13,838	(1,014)
Other expense (income), net		(26)
	77,479	26,810
Loss from continuing operations before income taxes	(82,922)	(11,964)
Income tax expense (benefit)	(11,104)	16,018
Loss from continuing operations	(71,818)	(27,982)
Income from discontinued operations, net of tax	36,177	24,127
Net loss	(35,641)	(3,855)
Net loss attributable to noncontrolling interest	(480)	(103)
Net income attributable to Preferred share dividends of a subsidiary company	3,247	
Net loss attributable to Atlantic Power Corporation	$ (38,408)	$ (3,752)

The consolidated results of operation include the results of operation from the Partnership beginning on the acquisition date of November 5, 2011. Project income is the primary GAAP measure of our operating results and is discussed in "Project Operations Performance" below. In addition, an analysis of non-project expenses impacting our results is set out in "Administrative and Other Expenses (Income)" below.

Significant non-cash items, which are subject to potentially significant fluctuations, include: (1) the change in fair value of certain derivative financial instruments that are required by GAAP to be revalued at each balance sheet date (see "Item 7A. Quantitative and Qualitative Disclosures About Market Risk" for additional information); (2) the non-cash impact of foreign exchange fluctuations

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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.

Project Income (Loss) by Segment

	Year Ended December 31, 2011					
	Northeast	Southeast[1]	Northwest	Southwest[2]	Un-allocated Corporate	Consolidated Total
Project revenue:						
Energy sales	$ 31,486	$	$ 3,257	$ 10,027	$ (1,180)	$ 43,590
Energy capacity revenue	24,079			9,738	192	34,009
Other	2,636		5,726	5,649	2,285	16,296
	58,201		8,983	25,414	1,297	93,895
Project expenses:						
Fuel	22,111		2,003	13,357		37,471
Operations and maintenance	9,615	88	2,641	6,284	4,095	22,723
Depreciation and amortization	12,751		4,565	6,306	60	23,682
	44,477	88	9,209	25,947	4,155	83,876
Project other income (expense):						
Change in fair value of derivative instruments	(1,065)	(11,492)			(2,037)	(14,594)
Equity in earnings of unconsolidated affiliates	5,572	(1,494)	(636)	558	2,356	6,356
Interest expense, net	(7,246)			(15)	17	(7,244)
Other expense, net	(46)				66	20
	(2,785)	(12,986)	(636)	543	402	(15,462)
Project income (loss)	$ 10,939	$ (13,074)	$ (862)	$ 10	$ (2,456)	$ (5,443)

	Year Ended December 31, 2010					
	Northeast	Southeast[1]	Northwest	Southwest[2]	Un-allocated Corporate	Consolidated Total
Project revenue:						
Energy sales	$	$	$	$	$	$
Energy capacity revenue	331				455	786
Other	265					265
	596				455	1,051
Project expenses:						
Fuel	193					193
Operations and maintenance	204	10			846	1,060
Depreciation and amortization	44				44	88
	441	10			890	1,341
Project other income (expense):						
Change in fair value of derivative instruments	127	3,298			(150)	3,275
Equity in earnings of unconsolidated affiliates	10,085	1,883	326	2,911	(1,428)	13,777
Gain on sale of equity investments					1,511	1,511
Interest expense, net	(3,373)				(265)	(3,638)
Other expense, net					211	211

		6,839		5,181		326		2,911		(121)		15,136
Project income (loss)	$	6,994	$	5,171	$	326	$	2,911	$	(556)	$	14,846

(1) Excludes the Florida Projects which are designated as assets held for sale and discontinued operations.

(2) Excludes Path 15 which is designated as assets held for sale and discontinued operations.

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Northeast

Project income for 2011 increased $3.9 million or 56% from 2010 primarily due to:

- increased project income of $2.8 million at Cadillac which was acquired in December 2010;
- increased project income of $3.0 million at Selkirk attributable to higher capacity revenues resulting from the recognition of previously deferred revenues; and
- project income from the newly acquired Curtis Palmer project of $3.6 million and Tunis project of $1.7 million.

These increases were partially offset by:

- decreased project income of $6.3 million at Chambers primarily attributable to increased operations and maintenance costs incurred in connection with a forced outage during July 2011, lower dispatch compared to 2010 and $3.2 million non-cash adjustment to the project's asset retirement obligation;
- lower project income of $1.4 million at Onondaga Renewables which recorded a $1.5 million asset impairment; and
- elimination of project income at Rumford which was sold in 2010 for $1.2 million.

Southeast

Project income for 2011 decreased $18.2 million from 2010 primarily due to:

- decreased project income of $14.9 million at Piedmont due to non-cash change in the fair value of the interest rate swaps related to the project's non-recourse construction financing; and
- decreased project income of $3.5 million at Orlando primarily due to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as higher operations and maintenance expenses resulting from a planned major gas turbine overhaul.

Project income for the Southeast segment excludes the Florida Projects which are accounted for as assets held for sale and a component of discontinued operations. Project income for Auburndale was $10.9 million and $4.2 million for the years ended December 31, 2011 and 2010, respectively.

- The increase is primarily attributable to $2.4 million increased revenue from annual contractual escalation of capacity payments, a decrease of $2.1 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as higher dispatch in 2011.

Project income for Lake was $21.6 million for the year ended December 31, 2011 as compared to project income of $13.6 million for the year ended December 31, 2010.

- The increase is attributable to a decrease of $7.0 million related to the non-cash change in fair value of derivative instruments associated with its natural gas swaps as well as lower fuel expenses attributable to lower prices on natural gas swaps. Project loss for Pasco was $0.7 million for the year ended December 31, 2011 and project income was $1.7 million for the year ended December 31, 2010.

The decrease is due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine components and unplanned repairs on the generator and boiler during 2011.

Northwest

Project income for 2011 decreased $1.2 million from 2010 primarily due to a $1.6 million project loss at Idaho Wind which became operational in 2011. This was offset by $0.4 million of project income from the newly acquired Frederickson project.

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Southwest

Project income for 2011 decreased $2.9 million from 2010 primarily due to:

- decreased project income of $1.6 million at Gregory attributable to higher gas prices due to a favorable gas hedge that expired at the end of 2010;

- decreased project income of $0.7 million at Badger due to lower capacity payments under a new one-year interim PPA beginning in April 2011; and

- project loss of $1.6 million from the newly acquired Oxnard project.

These decreases were partially offset by project income of $1.5 million from the newly acquired Manchief project.

Project income for the Southwest segment excludes the Path 15 project which is accounted for as an asset held for sale and a component of discontinued operations. Project income for Path 15 was $7.6 million and $7.5 million for the years ended December 31, 2011 and 2010, respectively.

Un-allocated Corporate

Total project loss increased $1.9 million from 2010 primarily due higher general and administrative expenses associated with operating the newly acquired Partnership projects.

Administration

Administration expense increased $21.5 million from 2010 primarily due to costs incurred related to the acquisition of the Partnership.

Interest, net

Interest, net increased $14.3 million from 2010 primarily due to interest expense resulting from the issuance of the senior notes in the fourth quarter of 2011 as well as debt assumed in our acquisition of the Partnership.

Foreign exchange loss (gain)

Foreign exchange loss increased $14.9 million from 2010 primarily due to a $17.8 million increase in unrealized losses on foreign exchange forward contracts and an $11.8 million increase in realized losses on foreign exchange contract settlements, offset by a $14.7 million unrealized gain in the revaluation of instruments denominated in Canadian dollars. The U.S. dollar to Canadian dollar exchange rate increased by 2.3% in 2011 compared to a decrease of 5.7% in 2010.

Income tax benefit

The income tax benefit for 2011 was $11.1 million. The difference between the actual tax benefit of $11.1 million and the expected income tax expense, based on the Canadian enacted statutory rate of 26.5%, of $22.0 million for the year ended December 31, 2011 is primarily due to a $21.7 million increase in the valuation allowance offset by a $10.5 million decrease related to operating projects in higher tax jurisdictions. The income tax expense for 2010 was $16.0 million. The difference between the actual tax expense of $16.0 million and the expected income tax expense, based on the Canadian enacted statutory rate of 28.5%, of $3.4 million for the year ended December 31, 2010 is primarily due to a $19.8 million increase in the valuation allowance and a $1.2 million additional tax expense related to operating projects in higher tax rate jurisdictions.

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Generation and Availability

	Year ended December 31,				
	2012	2011	2010	% change 2012 vs. 2011	% change 2011 vs. 2010
Aggregate power generation (Net MWh)					
Northeast	2,476,258	1,207,961	784,683	105.0%	53.9%
Southeast[(1)]	403,548	384,302	436,791	5.0%	-12.0%
Northwest	1,129,899	338,678	21,418	233.6%	NM
Southwest	2,398,241	877,338	643,811	173.4%	36.3%
Total	6,407,946	2,808,279	1,886,703	128.2%	48.8%
Weighted average availability					
Northeast	96.0%	93.0%	92.6%	3.2%	0.4%
Southeast[(1)]	98.2%	97.9%	99.5%	0.3%	-1.6%
Northwest	94.2%	99.7%	98.8%	-5.5%	0.9%
Southwest	93.6%	96.5%	96.9%	-3.0%	-0.4%
Total	95.3%	96.1%	95.4%	-0.8%	0.7%

(1) Excludes the Florida Projects which are designated as assets held for sale and discontinued operations.

Year ended December 31, 2012 compared with Year ended December 31, 2011

Aggregate power generation for 2012 increased 128.2% from 2011 primarily due to:

- increased generation in the Northeast segment primarily due to 1,460,519 MWh from the Partnership projects acquired on November 5, 2011;
- increased generation in the Northwest segment primarily due to 687,914 MWh from the Partnership projects acquired on November 5, 2011 as well as generation from Rockland which was acquired in December 2011; and
- increased generation in the Southwest segment primarily due to 1,552,530 MWh from the Partnership projects acquired on November 5, 2011.

Weighted average availability for 2012 decreased to 95.3% or 0.8% from 2011 primarily due to:

- decreased availability in the Northwest segment primarily due to maintenance performed at the Mamquam and Williams Lake projects in the fourth quarter of 2012, partially offset by increased availability at Rockland which was acquired in December 2011; and
- 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, boiler maintenance at Morris, an outage for an overhaul at Naval Station and a forced outage at North Island in the fourth quarter of 2012.

This decrease was partially offset by:

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

Generation and availability statistics for the Southeast segment exclude the Florida Projects which are accounted for as assets held for sale and a component of discontinued operations. Total generation for Auburndale was 916,529 MWh and 654,920 MWh and availability was 94.8% and 97.4% for the years ended December 31, 2012 and 2011, respectively. Total generation for Lake was 588,865 MWh and 468,529 MWh and availability was 99.2% and 98.4% for the years ended December 31, 2012 and

2011, respectively. Total generation for Pasco was 252,015 MWh and 263,049 MWh and availability was 96.1% and 99.6% for the years ended December 31, 2012 and 2011, respectively.

Year ended December 31, 2011 compared with Year ended December 31, 2010

Aggregate power generation for 2011 increased 48.8% from 2010 primarily due to:

- increased generation in the Northeast segment primarily due to 314,211 MWh from the Partnership projects;
- increased generation in the Northwest segment primarily due to 198,821 MWh from the Partnership projects as well as generation from Idaho Wind which became operational in the first quarter of 2011; and
- increased generation in the Southwest segment primarily due to 340,498 MWh from the Partnership projects.

These increases were partially offset by:

- decreased generation in the Southeast segment attributable to scheduled major maintenance at the Orlando project during 2011.

Weighted average availability for 2011 increased to 96.1% or 0.7% from 2010 primarily due to:

- increased availability in the Northwest segment primarily due to Idaho Wind which became fully operational in 2011

Generation and availability statistics for the Southeast segment excludes the Florida Projects which are accounted for as assets held for sale and a component of discontinued operations. Total generation for Auburndale was 654,920 MWh and 624,517 MWh and availability was 97.4% and 92.0% for the years ended December 31, 2011 and 2010, respectively. Total generation for Lake was 468,529 MWh and 605,177 MWh and availability was 98.4% and 94.5% for the years ended December 31, 2011 and 2010, respectively. Total generation for Pasco was 263,049 MWh and 269,164 MWh and availability was 99.6% and 99.6% for the years ended December 31, 2011 and 2010, respectively.

Supplementary Non-GAAP Financial Information

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

The primary factor influencing Cash Available for Distribution is cash distributions received from the projects. These distributions received are generally funded from Project Adjusted EBITDA generated by the projects, reduced by project-level debt service and capital expenditures, and adjusted for changes in project-level working capital and cash reserves. Project Adjusted EBITDA is defined as project income 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 (loss) to Project Adjusted EBITDA is set out below under "Project Adjusted EBITDA" and a reconciliation of project income

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(loss) by segment to Project Adjusted EBITDA by segment is set out in Note 20 to the consolidated financial statements. Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

Project Adjusted EBITDA

	Year ended December 31,			$ change	
	2012	2011	2010	2012 vs 2011	2011 vs 2010
Project Adjusted EBITDA by segment					
Northeast	$ 128,611	$ 59,299	$ 36,030	$ 69,312	$ 23,269
Southeast[1]	8,840	6,567	7,873	2,273	(1,306)
Northwest	48,422	11,363	736	37,059	10,627
Southwest[2]	52,841	10,228	9,733	42,613	495
Un-allocated corporate	(13,144)	(2,546)	(457)	(10,598)	(2,089)
Total	225,570	84,911	53,915	140,659	30,996
Reconciliation to project income					
Depreciation and amortization	164,958	55,608	25,493	109,350	30,115
Interest expense, net	24,122	15,178	9,613	8,944	5,565
Change in the fair value of derivative instruments	56,579	17,152	321	39,427	16,831
Other (income) expense	11,819	2,416	3,642	9,403	(1,226)
Project income (loss)	$ (31,908)	$ (5,443)	$ 14,846	$ (26,465)	$ (20,289)

(1) Excludes the Florida Projects which are designated as assets held for sale and discontinued operations.

(2) Excludes the Path 15 which is designated as assets held for sale and discontinued operations.

Northeast

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

	Year ended December 31,				
	2012	2011	2010	% change 2012 vs. 2011	% change 2011 vs. 2010
Northeast					
Project Adjusted EBITDA	128,611	59,299	36,030	NM	65%

Year ended December 31, 2012 compared with Year ended December 31, 2011

Project Adjusted EBITDA for 2012 increased $69.3 million from 2011 primarily due to increases in Project Adjusted EBITDA of:

- $11.2 million at Chambers attributable to the collection of the DuPont settlement associated with the dispute of the revenue calculation under the PPA of $9.6 million and decreased operations and maintenance costs of $1.5 million. A steam turbine leak forced the plant to shut down for 25 days in July 2011;

- $19.9 million at the Curtis Palmer project that was acquired on November 5, 2011;

- $12.8 million at the Nipigon project that was acquired on November 5, 2011;

$6.2 million at the North Bay project that was acquired on November 5, 2011;

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- $3.7 million at the Calstock project that was acquired on November 5, 2011; and

- $2.7 million at the Kapuskasing project that was acquired on November 5, 2011.

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project Adjusted EBITDA for 2011 increased $23.3 million or 65% from 2010 primarily due to increases in Project Adjusted EBITDA of:

- $8.7 million at Cadillac which was acquired in December 2010;

- $8.2 million at the Curtis Palmer project acquired on November 5, 2011;

- $2.8 million at the Tunis project acquired on November 5, 2011; and

These increases were partially offset by decreases in Project Adjusted EBITDA of:

- $2.8 million at Chambers attributable to lower dispatch and increased operations and maintenance costs incurred in connection with a forced outage during July 2011 compared to 2010; and

- $1.9 million at Topsham which was sold during the second quarter of 2011 and generated no Project Adjusted EBITDA during 2011.

Southeast

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

	Year ended December 31,				
	2012	2011	2010	% change 2012 vs. 2011	% change 2011 vs. 2010
Southeast					
Project Adjusted EBITDA	8,840	6,567	7,873	35%	-17%

Year ended December 31, 2012 compared with Year ended December 31, 2011

Project Adjusted EBITDA for 2012 increased $2.3 million or 35% from 2011 primarily due to increases in Project Adjusted EBITDA of:

- $2.3 million at Orlando due to higher capacity revenues from contractual escalation and increased generation as well as lower operations and maintenance costs.

Project Adjusted EBITDA for the Southeast segment excludes the Florida Projects which are accounted for as assets held for sale and a component of discontinued operations. Project Adjusted EBITDA for Auburndale was $39.5 million and $38.3 million for the years ended December 31, 2012 and 2011, respectively.

- The increase is due primarily to higher capacity revenues due to contractual escalation clauses as well higher dispatch than 2011.

Project Adjusted EBITDA for Lake was $41.1 million and $32.3 million for the years ended December 31, 2012 and 2011, respectively.

The increase is due primarily to a $5.0 million settlement payment from PEF in December 2012, $2.0 million in increased capacity revenue due to contractual escalation and decreased operations and maintenance of $1.6 million from 2011.

Project Adjusted EBITDA for Pasco was $1.8 million and $2.3 million for the years ended December 31, 2012 and 2011, respectively and did not change meaningfully from 2011.

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Year ended December 31, 2011 compared with Year ended December 31, 2010

Project Adjusted EBITDA for 2011 decreased $1.3 million or 17% from 2010 primarily due to decreased Project Adjusted EBITDA of $1.2 million at Orlando. The decrease is due to higher operations and maintenance expenses resulting from a planned major gas turbine overhaul.

Project Adjusted EBITDA for the Southeast segment excludes the Florida Projects which are accounted for as assets held for sale and a component of discontinued operations. Project Adjusted EBITDA for Auburndale was $38.3 million and $34.2 million for the years ended December 31, 2011 and 2010, respectively.

The increase is due primarily to higher dispatch and increased capacity payments under contractual escalation of the PPA.

Project Adjusted EBITDA for Lake was $32.3 million and $31.4 million for the years ended December 31, 2012 and 2011, respectively and did not change meaningfully from 2010.

Project Adjusted EBITDA for Pasco was $2.3 million and $4.7 million for the years ended December 31, 2011 and 2010, respectively.

The decrease is due to higher operations and maintenance expenses attributable to the unplanned replacement of gas turbine components and unplanned repairs to the generator and boiler during 2011.

Northwest

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

	Year ended December 31,				
	2012	**2011**	**2010**	**% change 2012 vs. 2011**	**% change 2011 vs. 2010**
Northwest					
Project Adjusted EBITDA	48,422	11,363	736	NM	NM

Year ended December 31, 2012 compared with Year ended December 31, 2011

Project Adjusted EBITDA for 2012 increased by $37.1 million from 2011 primarily due to increases in Project Adjusted EBITDA of:

- $15.9 million at the Williams Lake project that was acquired on November 5, 2011;
- $8.7 million at the Frederickson project that was acquired on November 5, 2011;
- $6.5 million at the Mamquam project that was acquired on November 5, 2011;
- $3.5 million at the Rockland project that was acquired in December, 2011; and
- $2.3 million at Idaho Wind primarily due to $2.8 in higher revenue from increased generation partially offset by increased operations and maintenance expense.

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project Adjusted EBITDA for 2011 increased $10.6 million from 2010 primarily due to increases in Project Adjusted EBITDA of:

$4.4 million at Idaho Wind which became operational in the first quarter of 2011;

$2.7 million from the Williams Lake project acquired on November 5, 2011; and

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$2.1 million from the Frederickson project acquired on November 5, 2011.

Southwest

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

	Year ended December 31,				
	2012	**2011**	**2010**	**% change 2012 vs. 2011**	**% change 2011 vs. 2010**
Southwest					
Project Adjusted EBITDA	52,841	10,228	9,733	NM	5%

Year ended December 31, 2012 compared with Year ended December 31, 2011

Project Adjusted EBITDA for 2012 increased by $42.6 million from 2011 primarily due to increases in Project Adjusted EBITDA of:

$11.5 million at the Manchief project that was acquired on November 5, 2011;

$7.5 million at the Oxnard project that was acquired on November 5, 2011;

$7.3 million at the Morris project that was acquired on November 5, 2011;

$6.8 million at the Naval Station project that was acquired on November 5, 2011;

$3.7 million at the Naval Training Center project that was acquired on November 5, 2011; and

$3.7 million at the North Island project that was acquired on November 5, 2011.

Project Adjusted EBITDA for the Southwest segment excludes the Path 15 project which is accounted for as an asset held for sale and a component of discontinued operations. Project Adjusted EBITDA for Path 15 was $24.5 million and $27.5 million for the years ended December 31, 2012 and 2011, respectively. The decrease is due primarily to $1.6 million increased maintenance costs associated with an erosion control initiative and $1.3 million in lower transmission revenue under the new rate agreement that became effective in April 2012.

Year ended December 31, 2011 compared with Year ended December 31, 2010

Project Adjusted EBITDA for 2011 increased by $0.5 million 5% from 2010 primarily due to increases in Project Adjusted EBITDA of:

$3.6 million from the Manchief project acquired on November 5, 2011; and

$2.4 million from the Oxnard, Naval Training Center, Naval Station, North Island, Morris and projects acquired on November 5, 2011.

These increases were partially offset by decreases in Project Adjusted EBITDA of:

$2.4 million at Badger Creek due to lower capacity payments under the new one year interim PPA beginning in April 2011; and

$2.9 million at Gregory attributable to higher gas prices due to a favorable gas hedge that expired at the end of 2010.

Project Adjusted EBITDA for the Southwest segment excludes the Path 15 project which is accounted for as an asset held for sale and a component of discontinued operations. Project Adjusted EBITDA for Path 15 was $27.5 million and $28.3 million for the years ended December 31, 2011 and 2010, respectively.

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Cash Available for Distribution

Initially in 2011, holders of our common shares received monthly cash dividends at an annual rate of Cdn$1.094 per share. This dividend was increased to an annual rate of Cdn$1.15 per share in November 2011 upon the closing of the Partnership acquisition. The payout ratio associated with the cash dividends declared was 100%, 109% and 100% for the years ended December 31, 2012, 2011 and 2010, respectively. The payout ratio for 2012 was positively impacted by the termination of the management service contract as part of the sale of our interest in PERH, the proceeds from the sale of Badger Creek as well as reducing our combined foreign currency forward positions as a result of the Partnership acquisition, partially offset by interest payments associated with newly acquired debt from the Partnership acquisition and the additional convertible debentures offered in July and December 2012.

The table below presents our calculation of Cash Available for Distribution for the years ended December 31, 2012, 2011 and 2010:

	Year ended December 31,		
(unaudited) **(in thousands of U.S. dollars, except as otherwise stated)**	**2012**	**2011**	**2010**
Cash flows from operating activities	$ 167,078	$ 55,935	$ 86,953
Project-level debt repayments	(19,574)	(21,589)	(18,882)
Purchases of property, plant and equipment[1]	(2,902)	(2,035)	(2,549)
Transaction costs[2]		33,402	
Realized foreign currency losses on hedges associated with the Partnership transaction[3]		16,492	
Dividends on preferred shares of a subsidiary company	(13,049)	(3,247)	
Cash Available for Distribution[4]	131,553	78,958	65,522
Total cash dividends declared to shareholders	131,832	86,357	65,648
Payout ratio	100%	109%	100%

(1) Excludes construction-in-progress costs related to our Piedmont biomass project and construction costs for our completed Canadian Hills project.

(2) Represents costs incurred associated with the Partnership acquisition.

(3) Represents realized foreign currency losses associated with foreign exchange forwards entered into in order to hedge a portion of the foreign currency exchange risks associated with the closing of the Partnership acquisition.

(4) 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.

Consolidated Cash Flows

At December 31, 2012, cash and cash equivalents decreased $0.5 million from December 31, 2011 to $60.1 million. The decrease in cash and cash equivalents was due to $167.1 million provided by operating activities and $362.7 million of cash provided by financing activities offset by $523.7 million of cash used for investing activities. The operating, investing and financing activities include the Florida Projects and Path 15 assets held for sale. At December 31, 2012, there is $6.5 million of cash located at these projects.

At December 31, 2011, cash and cash equivalents increased $15.2 million from December 31, 2010 to $60.7 million. The increase in cash and cash equivalents was due to $55.9 million provided by

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operating activities and $641.2 million of cash provided by financing activities offset by $682.0 million of cash used for investing activities.

	2012	2011	2010	$ Change 2012 vs. 2011	$ Change 2011 vs. 2010
Net cash provided by operating activities	$ 167,078	$ 55,935	$ 86,953	$ 111,143	$ (31,018)
Net cash used in investing activities	(523,747)	(682,008)	(146,997)	158,261	(535,011)
Net cash provided by financing activities	362,682	641,227	55,691	(278,545)	585,536

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 flow from operating activities increased by $111.1 million for the year ended December 31, 2012 over the comparable period in 2011. The change from the prior year is primarily attributable to the increases in Project Adjusted EBITDA noted above as well $33.0 million in transaction expenses related to the Partnership acquisition that occurred in 2011.

Cash flow from operating activities decreased by $31.0 million for the year ended December 31, 2011 over the comparable period in 2010. The change from the prior year is primarily attributable to approximately $33.0 million in transaction expenses related to the Partnership acquisition that occurred in 2011 and the timing of the five Ontario projects in the Northeast segment November receivables received in early January of approximately $15.0 million. These decreases were offset by an increase of approximately $12.0 million of earnings and distributions from our equity investment projects.

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 flow used in investing activities includes cash used to fund accretive acquisitions in North American markets. Cash flows used in investing activities for the year ended December 31, 2012 were $523.7 million compared to cash flows used in investing activities of $682.0 million for the year ended December 31, 2011. The change is due to a $511.1 decrease in cash paid for acquisitions as the Partnership was acquired in 2011. The decrease was partially offset by a $343.1 million increase in construction in progress cost related to the Piedmont and Canadian Hills projects.

Cash flows used in investing activities for the year ended December 31, 2011 were $682.0 million compared to cash flows used in investing activities of $147.0 million for the year ended December 31, 2010. The change is due to the $579.1 million cash paid for the Partnership acquisition net of cash acquired. We also invested $113.0 million in 2011 for the construction-in-progress for our Piedmont biomass project.

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Financing Activities

Cash provided by financing activities for the year ended December 31, 2012 resulted in a net inflow of $362.7 million compared to a net inflow of $641.2 million for the same period in 2011. The change from the prior year is primarily attributable to the $460.0 million of long term debt issued and net proceeds of $155.4 million in equity raised in 2011 related to the acquisition of the Partnership. The decrease is partially offset by the $230.1 million of proceeds from the July and December 2012 convertible debentures offering and $67.7 million of net proceeds from our July 2012 equity offering. In December 2012 we received $225.0 million from a noncontrolling interest for the funding of the Canadian Hills construction project.

Cash provided by financing activities for the year ended December 31, 2011 resulted in a net inflow of $641.2 million compared to a net inflow of $55.7 million for the same period in 2010. The change from the prior year is primarily attributable to $460.0 million of long term debt issued in November 2011 and $155.4 million in net proceeds from our equity offering in October 2011 to fund a portion of the cash portion of the Partnership acquisition. In 2011, we also received proceeds of $100.8 million of project-level debt related to our Piedmont biomass construction project and borrowed $58.0 million from our credit facility. This was offset by a $20.0 million increase in dividends paid.

Liquidity and Capital Resources

	December 31,	
(in thousands of U.S. dollars, except as otherwise stated)	**2012**	**2011**
Cash and cash equivalents	$ 60,191	$ 60,651
Restricted cash	28,618	21,412
Total	88,809	82,063
Revolving credit facility availability	120,132	134,700
Total liquidity	$ 208,941	$ 216,763

Overview

Our primary source of liquidity is distributions from our projects and availability under our revolving credit facility. A significant portion of the cash received from project distributions is used to pay dividends to our shareholders and interest on our outstanding convertible debentures, senior notes and other corporate-level debt. Our liquidity depends in part on our ability to successfully enter into new PPAs at facilities where PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from August 2013 to 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly, which may reduce the cash received from project distributions. 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. Cash and cash equivalents and restricted cash for 2012 excludes $19.1 million related to the Florida Projects and Path 15 projects which are classified as assets held for sale at December 31, 2012. See Restricted Cash below.

We do not expect any material unusual requirements for cash outflows for 2013 for capital expenditures or other required investments. In addition, there are no debt instruments with maturities in 2013. We intend to use the net proceeds from the sales of the Florida Projects and Path 15 projects to fully repay our senior credit facility, which is expected to have an outstanding balance of approximately $64 million at close of the transactions, as well as for general corporate purposes.

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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 for the next 12 months.

Strategy and Financial Outlook

In its annual review of strategy, business prospects, financial position, operating environment and outlook by management and the Board of Directors, the Company focused on its objective of providing shareholders with an attractive total return, with a view to balancing the income and growth components of total return to create long-term value. Growth in cash flows is expected to come from a combination of the development and acquisition of new assets and improvements in the performance of its existing portfolio. The Company expects to continue executing on its growth strategy by utilizing its core competencies and building on its proven track record of acquiring both operating plants and late-stage development projects, with a focus on projects with long-term PPAs and limited commodity exposure. With its recent acquisition of Ridgeline, the Company now also has a pipeline of proprietary wind and solar development projects. The mix of growth opportunities, and therefore allocation of the Company's resources, has shifted towards earlier-stage construction and development projects, including some at a greenfield stage. At the same time, the Company remains committed to a disciplined approach to growth, ensuring that new investments are accretive to cash flow, earnings and leverage metrics either immediately (in the case of operating plants) or in the first full year of operation (for construction and development projects).

Dividend Level

As part of this process, management updated the Company's cash flow projections under a variety of scenarios, factoring in the Company's cost of capital, financial leverage and near-term recontracting prospects. The assessment also considered recent developments in Ontario, including where the Company has a project with its contract expiring in 2014. The Company's project is not in the first group for which recontracting discussions are currently underway with the government. Although the process is not transparent and therefore the outcome is uncertain, recent signals are increasingly challenging. In addition, higher TransCanada pipeline tolls have reduced margins at the Company's Ontario facilities. Thus, the Company considered it appropriate to adjust expectations for these projects at least until such time as there is enhanced clarity and/or more positive signals. In addition, the updated projections incorporated the impact on distributable cash resulting from: the continued reduction of post-PPA estimated cash flows at Lake and Auburndale, and the subsequent announcement of the Florida Assets Sale; the expected sale of the Company's Path 15 transmission line; reduced recontracting expectations for the Company's Selkirk project in New York; and the impact on cash needs of a greater share of the Company's growth investments (relative to the mix of investments in the past) requiring cash upfront while cash returns from these investments would lag on average 12 to 24 months.

In light of all these considerations and in order to accomplish the Company's strategic and financial objectives, the Board, together with management, has concluded that it is in the best interest of the Company and its shareholders to target a lower and therefore more sustainable payout ratio that balances yield and growth, and is also more consistent with the Company's outlook for its current and prospective projects under a range of scenarios. The Board believes that a lower payout ratio will better allow the Company to fund its organic growth and development as well as growth from acquisitions, to strengthen its competitive positioning for acquisitions and improve access to capital, if and when needed. The dividend reduction is expected to improve the Company's operational and financial flexibility and enhance its ability to deliver on its strategic and financial objectives of creating long-term shareholder returns through a sustainable cash dividend plus growth from accretive acquisitions, and construction-ready and development projects.

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As a result of this review, the Board, with management's recommendation, has approved a reduction in the anticipated annual dividend level to Cdn$0.40 per share, or Cdn$0.03333 per share on a monthly basis. The new dividend level will commence with the March 2013 dividend to shareholders of record on March 28, 2013. Shareholders of record as of that date will receive a dividend of Cdn$0.03333 per share on April 30, 2013. The February 2013 dividend of Cdn$0.09583, declared on February 15, 2013, will be paid on March 28, 2013 to shareholders of record on February 28, 2013.

Dividends to shareholders are paid at the discretion of our board of directors and our board of directors may decrease the level, or entirely discontinue payment, of dividends at any time. See "Risk Factors Risks Related to Our Structure Future dividends are not guaranteed" for a description of the factors that may be taken into account by the board of directors in making such a determination regarding the dividend.

Corporate Debt

The following table summarizes the maturities of our corporate debt at December 31, 2012:

	Interest Rates	Total Remaining Principal Repayments	2013	2014	2015	2016	2017	Thereafter
Atlantic Power Corporation Notes	9.00%	$ 460,000	$	$	$	$	$	$ 460,000
Atlantic Power US (GP) Note	5.87%	150,000			150,000			
Atlantic Power US (GP) Note	5.97%	75,000					75,000	
Atlantic Power Income LP Note	5.95%	211,071						211,071
Convertible Debenture	6.50%	45,049		45,049				
Convertible Debenture	6.25%	67,776					67,776	
Convertible Debenture	5.60%	80,911					80,911	
Convertible Debenture	5.80%	130,000						130,000
Convertible Debenture	6.00%	100,510						100,510
Total Corporate Debt		$ 1,320,317	$	$ 45,049	$ 150,000	$	$ 223,687	$ 901,581

Senior Credit Facility

On November 5, 2011, we entered into an Amended and Restated Credit Agreement, pursuant to which we increased the capacity under our existing credit facility from $100.0 million to $300.0 million on a senior secured basis, $200.0 million of which may be utilized for letters of credit. Borrowings under the facility are available in U.S. dollars and Canadian dollars and bear interest at a variable rate equal to the U.S. Prime Rate, the London Interbank Offered Rate, or the Canadian Prime Rate, as applicable plus an applicable margin of between 0.75% and 3.00% that varies based on our corporate credit rating. The credit facility matures on November 4, 2015.

On November 2, 2012, we amended the senior credit facility in order to change certain financial and leverage ratio covenants. These changes involved the better accommodation of construction stage projects with no historical financial performance, the better accommodation of the possibility of certain asset sales, including our Florida Projects, by waiving a material disposition covenant and permitting inclusion of the disposed assets' trailing twelve months EBITDA for covenant calculations, and the better accommodation of the same possible asset sales by temporarily modifying the Total Leverage Ratio.

The credit facility contains customary representations, warranties, terms and conditions, as well as covenants limiting our ability to, among other things, incur additional indebtedness, merge or consolidate with others, change our business, and sell or dispose of assets. The covenants also include limitations on investments and acquisitions, limitations on the declarations and payment of dividends and other restricted payments, limitations on entering into certain types of restrictive agreements,

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limitations on transactions with affiliates and limitations on the use of proceeds from the credit facility. We must meet certain financial covenants under the terms of the credit facility, which are generally based on ratios of debt to EBITDA and EBITDA to interest. Although we expect to remain in compliance with the covenants of the credit facility through late 2014, we are considering a variety of measures to reduce our leverage. If we are unsuccessful, we could be restricted from taking certain actions under our credit facility in that timeframe. See "Risk Factors Risks Related to Our Structure Our indebtedness and financing arrangements, and any failure to comply with the covenants contained therein, could negatively impact our business and our projects and could render us unable to make cash distributions, acquisitions or investments or issue additional indebtedness we otherwise would seek to do." The credit facility is secured by pledges of certain assets and interests in certain subsidiaries. This description does not purport to be complete and is qualified in its entirety by reference to the Amended and Restated Credit Agreement, which is filed as Exhibit 10.1 hereto and incorporated by reference herein.

At December 31, 2012, $67.0 million has been drawn under the credit facility and the applicable margin was 2.75%. We expect to pay outstanding amounts under the credit facility with a portion of the proceeds from the sale of Florida Projects expected to close in the remaining part of the first quarter of 2013. As of December 31, 2012 and February 27, 2013, $112.9 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects, which include the newly acquired projects from the Partnership acquisition. The total letters of credit issued includes $28.7 million for the Florida Projects and Path 15 projects which are classified as assets held for sale and discontinued operations at December 31, 2012.

Notes of Atlantic Power Corporation

On November 5, 2011, we completed a private placement of US$460.0 million aggregate principal amount of 9.0% senior notes due 2018 (the "Atlantic Notes" or "Senior Notes") to qualified institutional buyers in reliance on Rule 144A under the Securities Act of 1933, as amended (the "Securities Act") and to non-U.S. persons outside of the United States in compliance with Regulation S under the Securities Act. The Senior Notes were issued at an issue price of 97.471% of the face amount of the Senior Notes for aggregate gross proceeds to us of $448.0 million. The Atlantic Notes are senior unsecured obligations, guaranteed by certain of our subsidiaries.

Notes of the Partnership

The Partnership, a wholly-owned subsidiary acquired on November 5, 2011, has outstanding Cdn$210.0 million ($211.1 million at December 31, 2012) aggregate principal amount of 5.95% senior unsecured notes, due June 2036 (the "Partnership Notes"). Interest on the Partnership Notes is payable semi-annually at 5.95%. Pursuant to the terms of the Partnership Notes, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. The Partnership Notes are guaranteed by Atlantic Power Preferred Equity Ltd., an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership and Atlantic Power.

Notes of Atlantic Power (US) GP

Atlantic Power (US) GP, an indirect, wholly-owned subsidiary acquired in connection with the acquisition of the Partnership, has outstanding $150.0 million aggregate principal amount of 5.87% senior guaranteed notes, Series A, due August 2015 (the "Series A Notes"). Interest on the Series A Notes is payable semi-annually at 5.87%. Atlantic Power (US) GP has also outstanding $75.0 million aggregate principal amount of 5.97% senior guaranteed notes, Series B, due August 2017 (the "Series B Notes"). Interest on the Series B Notes is payable semi-annually at 5.97%. Pursuant to the terms of the Series A Notes and the Series B Notes, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership and Atlantic Power (US) GP. The Series A Notes and the Series B Notes are guaranteed by Atlantic Power, the Partnership, Curtis Palmer LLC and the existing and future guarantors of Atlantic Power's Senior Notes, senior credit facility and refinancings thereof.

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

Notes of Curtis Palmer LLC

Curtis Palmer LLC has outstanding $190.0 million aggregate principal amount of 5.90% senior unsecured notes, due July 2014 (the "Curtis Palmer Notes"). Interest on the Curtis Palmer Notes is payable semi-annually at 5.90%. Pursuant to the terms of the Curtis Palmer Notes, we must meet certain financial and other covenants, including a financial covenant generally based on the ratio of debt to capitalization of the Partnership. The Curtis Palmer Notes are guaranteed by the Partnership.

Convertible Debentures

In October 2006, we issued, in a public offering, Cdn$60 million aggregate principal amount of 6.25% convertible secured debentures (the "2006 Debentures"), for gross proceeds of $52.8 million. The 2006 Debentures pay interest semi-annually on April 30 and October 31 of each year. The Debentures initially had a maturity date of October 31, 2011 and are convertible into approximately 80.6452 common shares per Cdn$1,000 principal amount of 2006 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$12.40 per common share. The 2006 Debentures are secured by a subordinated pledge of our interest in certain subsidiaries and contain certain restrictive covenants. In connection with our conversion to a common share structure on November 27, 2009, the holders of the 2006 Debentures approved an amendment to increase the annual interest rate from 6.25% to 6.50% and separately, an extension of the maturity date from October 2011 to October 2014. During fiscal year 2010 through February 27, 2013, Cdn$15.2 million of the 2006 Debentures, have been converted to 1.2 million common shares. As of February 27, 2013, the balance of the 2006 Debentures is Cdn$44.8 million ($43.6 million).

In December 2009, we issued, in a public offering, Cdn$86.25 million aggregate principal amount of 6.25% convertible unsecured subordinated debentures (the "2009 Debentures"), for gross proceeds of $82.1 million. The 2009 Debentures pay interest semi-annually on March 15 and September 15 of each year. The 2009 Debentures mature on March 15, 2017 and are convertible into approximately 76.9231 common shares per Cdn$1,000 principal amount of 2009 Debentures, at any time, at the option of the holder, representing a conversion price of Cdn$13.00 per common share. During fiscal year 2010 through February 27, 2013, Cdn$18.8 million of the 2009 Debentures, have been converted to 1.4 million common shares. As of February 27, 2013 the balance of 2009 Debentures is Cdn$67.4 million ($65.7 million).

In October 2010, we issued, in a public offering, Cdn$80.5 million aggregate principal amount of 5.60% convertible unsecured subordinated debentures (the "2010 Debentures"), for gross proceeds of $78.9 million. The 2010 Debentures pay interest semi-annually on June 30 and December 30 of each year. The 2010 Debentures mature on June 30, 2017, unless earlier redeemed. The debentures are convertible into our common shares at an initial conversion rate of 55.2486 common shares per Cdn$1,000 principal amount of debentures, representing an initial conversion price of approximately Cdn$18.10 per common share. As of February 27, 2013, the balance of the 2010 Debentures is Cdn$80.5 million ($78.4 million).

On July 5, 2012, we issued, in a public offering, $130.0 million aggregate principal amount of 5.75% convertible unsecured subordinated debentures due June 30, 2019, which we refer to as the July 2012 Debentures, for net proceeds of $124.0 million. The July 2012 Debentures pay interest semi-annually on the last day of June and December of each year. The July 2012 Debentures are convertible into our common shares at an initial conversion rate of 57.9710 common shares per $1,000 principal amount of July 2012 Debentures representing a conversion price of $17.25 per common share. We used the proceeds to fund a portion of our equity commitment in Canadian Hills. As of February 27, 2013 the balance of the July 2012 Debentures is $130.0 million.

On December 11, 2012, we issued, in a public offering, Cdn$100 million aggregate principal amount of 6.00% convertible unsecured subordinated debentures due December 31, 2019, which we refer to as the December 2012 Debentures for net proceeds of Cdn$95.5 million. The December 2012 Debentures pay interest semi-annually on the last day of June and December of each year beginning June 30, 2013. The December 2012 Debentures are convertible into our common shares at an initial conversion rate of 68.9655 common shares per Cdn$1,000 principal amount of December 2012 debentures representing a conversion price of Cdn$14.50 per common share. We used the proceeds to acquire all of the outstanding shares of capital stock of Ridgeline and to fund certain working capital commitments and acquisition expenses related to Ridgeline. As of February 27, 2013 the balance of the December 2012 Debentures is Cdn$100 million ($97.4 million).

Project-Level 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 following table summarizes the maturities of project-level debt. The amounts represent our share of the non-recourse project-level debt balances at December 31, 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. At December 31, 2012, all but one of our projects was in compliance with the covenants contained in project-level debt. Epsilon Power Partners, our 100% owned holding company for our 40% interest in Chambers, Delta-Person and Gregory 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. Although we expect to resume receiving distributions from Epsilon Power Partners in 2013 and from Delta-Person and Gregory in 2014, we cannot provide any assurances that these projects will generate enough cash flow to meet the ratio tests and be able to resume

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distributions to us. All project-level debt is non-recourse to us and substantially the entire principal is amortized over the life of the projects' PPAs. See Note 9, *Long-term debt Non-Recourse Debt*.

The range of interest rates presented represents the rates in effect at December 31, 2012. The amounts listed below are in thousands of U.S. dollars, except as otherwise stated.

	Range of Interest Rates	Total Remaining Principal Repayments	2013	2014	2015	2016	2017	Thereafter
Consolidated Projects:								
Epsilon Power Partners	7.40%	$ 33,482	$ 3,000	$ 5,000	$ 5,750	$ 6,000	$ 6,250	$ 7,482
Piedmont(1)	3.70% - 5.20%	127,446	55,061	4,467	4,452	3,442	2,937	57,087
Path 15(2)	7.90% - 9.00%	137,213	9,402	8,065	8,749	9,487	8,204	93,306
Auburndale(2)	5.10%	4,900	4,900					
Cadillac	6.00% - 8.00%	37,831	2,400	2,000	3,891	2,500	3,000	24,040
Meadow Creek(3)	1.30% - 5.10%	208,698	59,508	4,886	4,616	5,252	5,349	129,087
Rockland(4)	6.40%	86,560	1,227	1,485	1,763	1,944	2,180	77,961
Ridgeline	5.50% - 5.90%	253	7	7	1		238	
Curtis Palmer(5)	5.90%	190,000		190,000				
Total Consolidated Projects		826,383	135,505	215,910	29,222	28,625	28,158	388,963
Equity Method Projects:								
Chambers	0.30% - 7.60%	52,139	10,929	948	166	96		40,000
Delta-Person(6)	1.90%	7,684	1,219	1,308	1,402	1,504	1,094	1,157
Gregory	2.10% - 7.70%	10,660	1,987	2,148	2,245	2,423	1,857	
Goshen	3.00% - 6.60%	24,699	392	431	481	669	905	21,821
Idaho Wind	5.60%	48,836	2,198	2,364	2,554	2,511	2,696	36,513
Total Equity Method Projects		144,018	16,725	7,199	6,848	7,203	6,552	99,491
Total Project-Level Debt		$ 970,401	$ 152,230	$ 223,109	$ 36,070	$ 35,828	$ 34,710	$ 488,454

(1) The terms of the Piedmont project-level debt financing include a $51.0 million bridge loan which we expect to repay with the proceeds 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. See Item 1A. "Risk Factors Risk Related to Our Business and Our Projects Our renewable energy projects are subject to uncertainties regarding regulatory incentives." We expect to repay the $51.0 million bridge loan in the second quarter of 2013 and repayment of the expected $82.0 million term loan is scheduled to commence in 2013.

(2) The Auburndale and Path 15 projects are classified as assets held for sale as of December 31, 2012. Accordingly, the outstanding debt is recorded as a component of liabilities associated with an asset held for sale on the consolidated balance sheet at December 31, 2012.

(3) The Meadow Creek debt outstanding is funded by a $56.5 million cash grant facility and $152.2 million drawn on a $173.4 million term loan. We expect to repay the $56.5 million cash grant facility with the proceeds from the stimulus grant expected to be received from the U.S. Treasury 60 days after the start of commercial operations. The Meadow Creek project became operational as of December 31, 2012. See Item 1A. "Risk Factors Risk Related to Our Business and Our Projects Our renewable energy projects are subject to uncertainties regarding regulatory incentives."

(4) We own a 50% interest in the Rockland project. We consolidate Rockland because as the managing member of the project, we have the control to direct the most significant decisions in the day to day operations of the project. The maturities above represent 100% of the future principal payments on the Rockland debt.

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

(6) We entered into an agreement on December 7, 2012 to sell our 40% interest in Delta-Person. The sale is expected to close in the third quarter of 2013.

Guarantees

We and our subsidiaries entered into various contracts that include indemnification and guarantee provisions as a routine part of our business activities. Examples of these contracts include asset purchases and sale agreements, joint venture agreements, operation and maintenance agreements, and other types of contractual agreements with vendors and other third parties, as well as affiliates. These contracts generally indemnify the counterparty for certain tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

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

Shelf registrations

On August 8, 2012, we filed with the SEC an automatic shelf registration statement (Registration No. 333-183135) for the potential offering and sale of debt and equity securities. The registration statement allows for common shares and secured or unsecured debt securities in one or more series which may be senior, subordinate or junior subordinated, and which may be convertible into another security. In that we are a well-known seasoned issuer, as defined in Rule 405 under the Securities Act, the registration statement went effective immediately upon filing and we may offer and sell an unlimited amount of securities under the registration statement during the three year life of the registration statement.

On August 17, 2012, we filed with the securities commissions or similar regulatory authorities in each of the provinces and territories of Canada other than the Province of Quebec a shelf registration statement for the potential offering and sale of debt and equity securities. The registration statement is effective and we may offer and sell up to Cdn$750 million of securities under the registration statement during the twenty-five month life of the registration statement.

Preferred shares issued by a subsidiary company

In 2007, a subsidiary acquired in our acquisition of the Partnership issued 5.0 million 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Shares") priced at Cdn$25.00 per share. Cumulative dividends are payable on a quarterly basis at the annual rate of Cdn$1.2125 per share. On or after June 30, 2012, the Series 1 Shares are redeemable by the subsidiary company at Cdn$26.00 per share, declining by Cdn$0.25 each year to Cdn$25.00 per share on or after June 30, 2016, plus, in each case, an amount equal to all accrued and unpaid dividends thereon.

In 2009, a subsidiary company acquired in our acquisition of the Partnership issued 4.0 million 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the "Series 2 Shares") priced at Cdn$25.00 per share. The Series 2 Shares pay fixed cumulative dividends of Cdn$1.75 per share per annum, as and when declared, for the initial five-year period ending December 31, 2014. The dividend rate will reset on December 31, 2014 and every five years thereafter at a rate equal to the sum of the then five-year Government of Canada bond yield and 4.18%. On December 31, 2014 and on December 31 every five years thereafter, the Series 2 Shares are redeemable by the subsidiary company at Cdn$25.00 per share, plus an amount equal to all declared and unpaid dividends thereon to, but excluding the date fixed for redemption. The holders of the Series 2 Shares will have the right to convert their shares into Cumulative Floating Rate Preferred Shares, Series 3 (the "Series 3 Shares") of the subsidiary, subject to certain conditions, on December 31, 2014 and on December 31 of every fifth year thereafter. The holders of Series 3 Shares will be entitled to receive quarterly floating rate cumulative dividends, as and when declared by the board of directors of the subsidiary, at a rate equal to the sum of the then 90-day Government of Canada Treasury bill rate and 4.18%.

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The Series 1 Shares, the Series 2 Shares and the Series 3 Shares are fully and unconditionally guaranteed by us and by the Partnership on a subordinated basis as to: (i) the payment of dividends, as and when declared; (ii) the payment of amounts due on a redemption for cash; and (iii) the payment of amounts due on the liquidation, dissolution or winding up of the subsidiary company. If, and for so long as, the declaration or payment of dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares is in arrears, the Partnership will not make any distributions on its limited partnership units and we will not pay any dividends on our common shares.

The subsidiary company paid aggregate dividends of $13.0 million on the Series 1 Shares and the Series 2 Shares in 2012 compared to $3.2 million in 2011.

Restricted Cash

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. At December 31, 2012, restricted cash at the consolidated projects totaled $28.6 million. This amount does not include $12.7 million of restricted cash at our assets held for sale projects as of December 31, 2012.

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 to $35 million in 2013 in our project portfolio in the form of capital expenditures and major maintenance expenses. As explained above, this investment is generally paid at the project level. We believe one of the benefits of our diverse fleet is that plant overhauls and other major expenditures do not occur in the same year for each facility. Recognized industry guidelines and original equipment manufacturer recommendations allow us to predict major maintenance events and balance the funds necessary for these expenditures over time. Future capital expenditures and major maintenance expenses may exceed the level in 2012 or the projected level in 2013 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 conducted scheduled outages to complete major maintenance work. However, overall maintenance and capital expenditures was higher than in 2011 due to our acquisition of the Partnership project portfolio. There were no significant capital expenditures at our operating projects during 2012, but maintenance expenses were substantial, including outage related work performed at the Auburndale, Pasco, Chambers, Selkirk, Kapuskasing, Calstock, Morris, Naval Station and North Island facilities.

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

During 2012, we incurred approximately $23.8 million in capital expenditures for the construction of our Piedmont biomass project which is nearing commercial operation. Because the project did not achieve commercial operations by a specified date, Piedmont is collecting liquidated damages from the construction contractor until completion. These liquidated damages are expected to offset any additional construction costs incurred at the project. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects Construction projects are subject to construction risk."

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We also incurred approximately $459.9 million in capital expenditures for the construction of our Canadian Hills Wind project. Canadian Hills achieved commercial operations in December 2012.

Contractual Obligations and Commercial Commitments

The following table summarizes our contractual obligations as of December 31, 2012 (in thousands of U.S. dollars):

	Payment Due by Period				
	Less than 1 year	1 - 3 Years	3 - 5 Years	Thereafter	Total
Long-term debt including estimated interest[1]	$ 310,000	$ 767,007	$ 948,463	$ 980,769	$ 3,006,239
Operating leases	1,048	2,201	916	4,340	8,505
Operations and maintenance commitments	319	1,014	424	2,541	4,298
Fuel purchase and transporation obligations	77,329	244,505	36,679	95,624	454,137
Long-term service contracts	2,859	11,709	8,812	15,615	38,995
Other liabilities	209	209		898	1,316
Total contractual obligations	$ 391,764	$ 1,026,645	$ 995,294	$ 1,099,787	$ 3,513,490

(1) Debt represents our consolidated share of project long-term debt and corporate-level debt. Project debt is non-recourse to us and is generally amortized during the term of the respective revenue generating contracts of the projects. The range of interest rates on long-term consolidated project debt at December 31, 2012 was 1.3% to 9.0%.

Off-Balance Sheet Arrangements

As of December 31, 2012, we had no off-balance sheet arrangements as defined in Item 303(a)(4) of Regulation S-K.

Critical Accounting Policies and Estimates

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

In preparing our consolidated financial statements and related disclosures, examples of certain areas that require more judgment relative to others include our use of estimates in determining fair values of acquired assets, the useful lives and recoverability of property, plant and equipment and PPAs, the recoverability of equity investments, the recoverability of goodwill, the recoverability of deferred tax assets, the valuation of shares associated with our LTIP and the fair value of derivatives.

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For a summary of our significant accounting policies, see Note 2 to the consolidated financial statements. We believe that certain accounting policies are of more significance in our consolidated financial statement preparation process than others; these policies are discussed below.

Acquired assets

When we acquire a business, a portion of the purchase price is typically allocated to identifiable assets, such as property, plant and equipment, PPAs or fuel supply agreements. Fair value of these assets is determined primarily using the income approach, which requires us to project future cash flows and apply an appropriate discount rate. We amortize tangible and intangible assets with finite lives over their expected useful lives. Our estimates are based upon assumptions believed to be reasonable, but which are inherently uncertain and unpredictable. Assumptions may be incomplete or inaccurate, and unanticipated events and circumstances may occur. Incorrect estimates could result in future impairment charges, and those charges could be material to our results of operations.

Impairment of long-lived assets and equity investments

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

Investments in and the operating results of 50%-or-less owned entities not required to be consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We review our investments in unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. We also review a project for impairment and perform a two-step test at the earlier of executing a new PPA (or other arrangement) or six months prior to the expiration of an existing PPA. Factors such as the business climate, including current energy and market conditions, environmental regulation, the condition of assets, and the ability to secure new PPAs are considered when evaluating long-lived assets for impairment. Evidence of a loss in value that is other than temporary might include the absence of an ability to recover the carrying amount of the investment, the inability of the investee to sustain an earnings capacity which would justify the carrying amount of the investment, or, where applicable, estimated sales proceeds which are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary.

When we determine that an impairment test is required, the future projected cash flows from the equity investment are the most significant factor in determining whether impairment exists and, if so, the amount of the impairment charges. We use our best estimates of market prices of power and fuel and our knowledge of the operations of the project and our related contracts when developing these cash flow estimates. In addition, when determining fair value using discounted cash flows, the discount

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rate used can have a material impact on the fair value determination. Discount rates are based on our risk of the cash flows in the estimate, including, when applicable, the credit risk of the counterparty that is contractually obligated to purchase electricity or steam from the project.

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

Goodwill

At December 31, 2012, we reported goodwill of $334.7 million, consisting of $331.2 million resulting from the November 5, 2011 acquisition of the Partnership and $3.5 million that is associated with the step-up acquisition of Rollcast in March 2010. See Item 15. "Exhibits and Financial Statements Schedule" Note 7*, Goodwill, transmission system rights, power purchase agreements and development intangible assets and liabilities*, to the consolidated financial statements for the detail of goodwill allocated to the reportable segments.

We apply an accounting standard under which goodwill has an indefinite life and is not amortized. Goodwill is tested for impairments at least annually, or more frequently whenever an event or change in circumstances occurs that would more likely than not reduce the fair value of a reporting unit below its carrying amount. We test goodwill for impairment at the reporting unit level, which is the project level, which is the lowest level below the operating segments for which discrete financial information is available. Effective January 1, 2012, we adopted a standard that provides an entity the option to first assess qualitative factors to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (more than 50%) that the fair value of a reporting unit is less than its carrying amount. Such qualitative factors may include the following: macroeconomic conditions; industry and market considerations; cost factors; overall financial performance; and other relevant entity-specific events. In the absence of sufficient qualitative factors, goodwill impairment is determined utilizing a two-step process. If it is determined that the fair value of a reporting unit is below its carrying amount, where necessary, goodwill will be impaired at that time.

We performed our annual goodwill impairment assessment as of November 30, 2012. Based on our qualitative assessment of macroeconomic, industry, and market events and circumstances as well as the overall financial performance of the reporting units acquired in the acquisition of the Partnership, we determined it was not more likely than not that the fair value of goodwill attributed to these reporting units was less than its carrying amount. As such, the annual two-step impairment test was deemed not necessary to be performed for these reporting units for the year ended December 31, 2012.

We performed step one of the two-step impairment test for the Rollcast reporting unit. We determined the fair value of this reporting unit using an income approach by applying a discounted cash flow methodology to Rollcast's long-term development budget. The most significant input to the determination of Rollcast's fair value are the estimated future cash flows from projects currently in development and expected to be placed into service or sold. We apply a probability weighted percentage to our estimate the probability that a development project reaches commercial operations or will be sold. This methodology is consistent with prior step one tests of the Rollcast reporting unit.

If fair value of a reporting unit exceeds its carrying value, goodwill of the reporting unit is not considered impaired. Under the income approach described above, we estimated the fair value of Rollcast to exceed its carrying value by approximately $3.7 million or 71% at December 31, 2012. Our

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estimate of fair value under the income approach described above is affected primarily by assumptions of the ability of Rollcast to develop future biomass projects. If Rollcast is unable to complete development of its budgeted projects our goodwill may become impaired, which would result in a non-cash charge, not to exceed $3.5 million.

Fair value of derivatives

We utilize derivative contracts to mitigate our exposure to fluctuations in fuel commodity prices and foreign currency and to balance our exposure to variable interest rates. We believe that these derivatives are generally effective in realizing these objectives. We also enter into long term fuel purchase agreements accounted for as derivatives that do not meet the scope exclusion for normal purchase normal sales.

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

A fair value hierarchy exists for inputs used in measuring fair value that maximizes the use of observable inputs (Level 1 or Level 2) and minimizes the use of unobservable inputs (Level 3) by requiring that the observable inputs be used when available. Our derivative instruments are classified as Level 2. The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified with market data and valuation techniques do not involve significant judgment. 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.

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

Income taxes and valuation allowance for deferred tax assets

In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or all of the deferred tax assets will be realized. The ultimate realization of deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies. The valuation allowance is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards. As of December 31, 2012, we have recorded a valuation allowance of $116.0 million.

Long-term incentive plan

The officers and certain other employees of Atlantic Power are eligible to participate in the LTIP. Unvested notional units are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date or, for officers, if we do not meet certain performance targets.

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Compensation expense related to awards granted to participants in the LTIP is recorded over the vesting period based on the estimated fair value of the award on the grant date for notional units accounted for as equity awards and the fair value of the award at each balance sheet date for notional units accounted for as liability awards. The fair value of awards with market vesting conditions is based upon a Monte Carlo simulation model on their grant date. Unvested notional units are recorded as either a liability or equity award based on management's intended method of redeeming the notional units when they vest. The LTIP was amended in April 2012. Notional shares issued subsequent to the amendment will no longer have performance-based vesting conditions.

Allocation of net income or losses to investors in certain variable interest entities

For consolidated investments that allocate taxable income and losses, tax credits and cash distributions under complex allocation provisions of agreements with third-party investors, net income or loss is allocated to third-party investors for accounting purposes using the Hypothetical Liquidation Book Value ("HLBV") method. HLBV is a balance sheet oriented approach that calculates the change in the claims of each partner on the net assets of the investment at the beginning and end of each period. Each partner's claim is equal to the amount each party would receive or pay if the net assets of the investment were to liquidate at book value and the resulting cash was then distributed to investors in accordance with their respective liquidation preferences. We report the net income or loss attributable to the third-party investors as income (loss) attributable to noncontrolling interests in the consolidated statements of operations.

Recent Accounting Developments

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

In December 2010, the FASB issued changes to the testing of goodwill for impairment. These changes require an entity to perform all steps in the test for a reporting unit whose carrying value is zero or negative if it is more likely than not (more than 50%) that a goodwill impairment exists based on qualitative factors, resulting in the elimination of an entity's ability to assert that such a reporting unit's goodwill is not impaired and additional testing is not necessary despite the existence of qualitative factors that indicate otherwise. We adopted these changes beginning January 1, 2011. Based on the most recent impairment review of our goodwill (November 30, 2012), we determined these changes did not impact the consolidated financial statements.

In December 2010, the FASB issued changes to the disclosure of pro forma information for business combinations. These changes clarify that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. Also, the existing supplemental pro forma disclosures were expanded to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. We adopted these changes beginning January 1, 2011. These changes are reflected in Note 3, *Acquisitions and divestments*.

Issued

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

In May 2011, the FASB issued changes to conform existing guidance regarding fair value measurement and disclosure between US GAAP and International Financial Reporting Standards. These changes both clarify the FASB's intent about the application of existing fair value measurement

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and disclosure requirements and amend certain principles or requirements for measuring fair value or for disclosing information about fair value measurements. The clarifying changes relate to the application of the highest and best use and valuation premise concepts, measuring the fair value of an instrument classified in a reporting entity's shareholders' equity, and disclosure of quantitative information about unobservable inputs used for Level 3 fair value measurements. The amendments relate to measuring the fair value of financial instruments that are managed within a portfolio; application of premiums and discounts in a fair value measurement; and additional disclosures concerning the valuation processes used and sensitivity of the fair value measurement to changes in unobservable inputs for those items categorized as Level 3, a reporting entity's use of a nonfinancial asset in a way that differs from the asset's highest and best use, and the categorization by level in the fair value hierarchy for items required to be measured at fair value for disclosure purposes only. These changes become effective on January 1, 2012. These changes will not have an impact on the consolidated financial statements.

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

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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

Our market risk-sensitive instruments and positions have been determined to be "other than trading." Our exposure to market risk as discussed below includes forward-looking statements and represents an estimate of possible changes in fair value or future earnings that would occur assuming hypothetical future movements in fuel and electricity commodity prices, currency exchange rates or interest rates. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur, since actual gains and losses will differ from those estimated based on actual fluctuations in fuel commodity prices, currency exchange rates or interest rates and the timing of transactions. See Note 12, *Accounting for derivative instruments and hedging activities* for additional information.

Fuel Commodity Market Risk

Our current and future cash flows are impacted by changes in electricity, natural gas and coal prices. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects Our projects depend on third-party suppliers under fuel supply agreements, and increases in fuel costs may adversely affect the profitability of the projects." 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 spot purchases through 2014. The project entered into short-term contracts expiring in early 2013 to partially mitigate this risk. The projected annual cash distributions at Tunis would change by approximately $1.8 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 64% of our share of the expected natural gas purchases at the project during 2014 and 2015. We also entered into natural gas swaps to effectively fix the price of 1.3 million Mmbtu of future natural gas purchases representing approximately 25% of our share of the expected natural gas purchases at the project during 2016 and 2017.

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 and Morris projects. At Chambers, our utility customer has the right to sell a portion of the plant's output into the spot power market if it is profitable to do so, and the Chambers project shares in the profits from these sales. In addition, during periods of low spot electricity prices the utility takes less generation, which negatively affects the project's operating margin. In 2013, projected cash distributions at Chambers would change by approximately $0.6 million per 10% change in the spot price of electricity based on a forecasted level of approximately $42/MWh and certain other assumptions. 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. In 2013, projected cash distributions at Morris would change by approximately $1.0 million per 20% change in the spot price of electricity based on the current level of approximately 300,000 MWh grid sales and all other variables being held constant. We own 100% of the Morris project. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects Certain of our projects are exposed to fluctuations in the price of electricity, which may have a material adverse effect on the operating margin of these projects and on our business, results of operations and financial condition."

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. See Item 1A. "Risk Factors Risks Related to Our Business and Our Projects The expiration or termination of our power purchase agreements could have a material adverse impact on our business; results of operations and financial condition." It is possible that subsequent PPAs or the spot markets may not be available at prices that permit the operation of the project on a profitable basis. If this occurs, the affected project may temporarily or permanently cease operations. Our current exposure to these future agreements or spot market pricing is at the Greeley and Gregory projects. This exposure is not material.

Foreign Currency Exchange Risk

We use foreign currency forward contracts to manage our exposure to changes in foreign exchange rates, as many of our projects generate cash flow in U.S. dollars and Canadian dollars but we pay dividends to shareholders and interest on corporate level long-term debt and convertible debentures predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on the long-term sustainability of dividends to shareholders. We have executed this strategy utilizing cash flows from our projects that generate Canadian dollars and by entering into

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forward contracts to purchase Canadian dollars at a fixed rate to hedge an average of approximately 60% 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 December 31, 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$176.5 million at an average exchange rate of Cdn$1.14 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 years ended December 31, 2012, 2011, and 2010:

Year ended December 31,			
2012	**2011**	**2010**	**&n**