ATLANTIC POWER CORP
Form 10-K
February 28, 2014

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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, 2013**

**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**<br>**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, and the associated Rights to Purchase Common Shares | 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 o  No ý

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 o | Accelerated Filer ý | Non-Accelerated Filer o<br>(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 28, 2013, the aggregate market value of the voting and nonvoting common equity held by non-affiliates of the registrant was $0.47 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, 2014, 120,279,798 of the registrant's Common Shares were outstanding.

**DOCUMENTS INCORPORATED BY REFERENCE**

Portions of the registrant's definitive Proxy Statement for its 2014 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.

## CAUTIONARY STATEMENT REGARDING 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:

- our ability to generate sufficient cash flow to pay dividends, service our debt obligations or finance internal or external growth opportunities;
- our ability to evaluate and/or implement a broad range of potential options and the impact any such potential options may have on us or our stock price;
- our ability to meet the financial covenants under our New Senior Secured Credit Facilities and other indebtedness;
- expectations regarding the prepayment or redemption of certain debt;
- expectations regarding maintenance and capital expenditures; 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 included in the filings Atlantic Power makes from time to time with the SEC and the risk factors described under "Item 1A. Risk Factors". Our business is both highly competitive and subject to various risks.

These risks include, without limitation:

- our ability to generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities;

the ability to evaluate and/or implement a broad range of potential options, including further selected asset sales or joint ventures to raise additional capital for growth or potential debt reduction, the acquisition of assets, the dividend level, as well as broader strategic options, and the impact any such potential options may have on us or our stock price;

the impact of our failure to meet the fixed charge coverage ratio test in the restricted payments covenants of the indenture governing our 9% senior unsecured notes;

our indebtedness and financing arrangements and the terms, covenants and restrictions included in our New Senior Secured Credit Facilities;

exchange rate fluctuations;

the impact of downgrades in our credit rating or the credit rating of our outstanding debt securities, and changes in our creditworthiness;

unstable capital and credit markets;

the outcome of certain shareholder class action lawsuits;

the expiration or termination of power purchase agreements;

the dependence of our projects on their electricity and thermal energy customers;

exposure of certain of our projects to fluctuations in the price of electricity or natural gas;

the dependence of our projects on third-party suppliers;

projects not operating according to plan;

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

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

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

risks beyond our control, including but not limited to geopolitical crisis, acts of terrorism or related acts of war, natural disasters or other catastrophic events;

the adequacy of our insurance coverage;

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

- the impact of impairment of goodwill or long-lived assets;
- 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;
- risks inherent in the use of derivative instruments;
- labor disruptions;
- the impact of hostile cyber intrusions;
- the impact of our failure to comply with the U.S. Foreign Corrupt Practices Act and/or Canadian Corruption of Foreign Public Officials Act; and
- our ability to retain, motivate and recruit executives and other key employees.

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 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

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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 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, 2013, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,948 megawatts ("MW") in which our aggregate ownership interest is approximately 2,026 MW. These totals exclude our 40% interest in the Delta-Person generating station ("Delta-Person") for which we entered into an agreement to sell in December 2012, which we expect to close in 2014. Our current portfolio consists of interests in twenty-eight operational power generation projects across eleven states in the United States and two provinces in Canada. We also own Ridgeline Energy Holdings, Inc. ("Ridgeline"), a wind and solar developer in Seattle, Washington. Twenty-two of our projects are wholly owned subsidiaries.

The following charts show, based on generation capacity in MW, the diversification of our portfolio by geography, segment and 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 2014 to December 2037, we receive payments for the actual 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 long-term fixed price or hedging strategies.

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We directly operate and maintain the majority 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") and Power Plant Management Services ("PPMS"). 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, when we agreed to pay ArcLight an aggregate of $15 million to terminate its management agreement with us. 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"), 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". On July 23, 2010, we also began trading on the New York Stock Exchange ("NYSE") under the symbol "AT".

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"). 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. Capital Power Corporation employees that operated and maintained the Partnership assets and most of those who provided management support of operations, accounting, finance, tax and human resources became employees of Atlantic Power.

On December 31, 2012, we acquired Ridgeline, a wind and solar development company, which added interests in three operating wind projects totaling 150 net MW and strengthened our ability to execute development and construction stage projects. As part of the acquisition, we integrated Ridgeline's team of employees that have a broad set of competencies essential for the successful identification, resource assessment, development, construction and operation of large-scale renewable power projects. This team also assists our assessment and pursuit of other renewable acquisitions and in managing our renewable energy portfolio.

**OUR BUSINESS STRATEGY**

Our corporate strategy is to increase the value of the company through both organic growth and potential acquisitions in North America. We focus on generating stable operating margins via contracted cash flows from our existing assets. We use our depth of asset management experience to enhance the operating, contractual and financial performance of our current projects and use our

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knowledge of markets and industry relationships in North America to pursue accretive opportunities to finish development, build and/or acquire projects primarily in the electric power industry.

As previously disclosed, we have been focused on initiatives aimed at, among other things, improving our financial flexibility and addressing our near-term maturities. We believe that the execution of the New Term Loan Facility (as defined herein) and the use of the funds therefrom to address debt maturities in 2014, 2015 and 2017 and for possible further debt reduction, as discussed in more detail in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources", are important steps toward achieving these goals. The 50% cash sweep and amortization features of the New Term Loan Facility are expected to reduce leverage over time. The additional flexibility, liquidity and maturity extension associated with the New Revolving Credit Facility (as defined herein) is also a meaningful achievement with respect to these goals. We believe that these steps should improve our ability to strengthen our balance sheet and optimize our assets.

We recognize that our important next steps include considering the relative merits of further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash while continuing to focus on how to best position the Company overall to maximize shareholder value. Consistent with these objectives, we are also committed to evaluating a broad range of potential options, including further selected asset sales or joint ventures to raise additional capital for growth or potential debt reduction, the acquisition of assets, including in exchange for shares, the dividend level, as well as broader strategic options. No assurance can be given as to how the evaluation of any such potential options may evolve.

**Organic growth**

We intend to look for opportunities to enhance the operational 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 hedging arrangements;

- to the extent we have sufficient cash flow or are able to obtain financing, the expansion or redevelopment of existing projects and the acquisition of other partners' interests in our existing portfolio.

**Development and construction**

We have invested and may invest in the future in energy-related projects primarily in the electric power industry, including investments in late stage development projects or companies where the prospects for creating long-term predictable cash flows are attractive. In 2012, we acquired a 100% ownership interest in Ridgeline. With the acquisition of Ridgeline, we added an experienced renewable energy project development, construction and operations team to enhance our ability to pursue renewable assets. We continue to assess late-stage renewable, development and construction projects and believe that there are opportunities in the market to acquire such assets.

When these development opportunities arise, we have the ability and experience to manage the construction process. During 2012, Canadian Hills became our first wholly-owned 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

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("Apex"). Meadow Creek is a 120 MW wind project in Idaho that our Ridgeline team successfully brought to commercial operations in 2012. Not only did the Ridgeline team strengthen our construction management and engineering capabilities, but their experienced wind project asset management team now oversees all of our 521 MW of wind projects. Piedmont, our 53 MW biomass project in Georgia, achieved commercial operations in April 2013. Piedmont was developed by our former affiliate Rollcast. In November 2013, we completed the sale of our 60% interest in Rollcast to the other shareholders and as consideration for the sale, we were assigned asset management contracts for the Cadillac and Piedmont projects as well as the remaining 2% ownership interest in Piedmont, bringing our total ownership of the project to 100%.

**Acquisition and investment strategy**

We believe that new electricity generation projects will continue to be required in selective markets 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 renewable project opportunities. We may also work with experienced development companies to acquire additional late stage development projects and there is also a very active secondary market for the purchase and sale of existing projects. To the extent we pursue acquisitions, 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 2014 to December 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 counterparties, including traditional PPAs, tolling agreements with creditworthy energy trading firms 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 selling 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.

**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 2,948 MW, and our net ownership interest in these projects is approximately 2,026 MW. These projects are diversified by fuel type, electricity and steam customers, technologies, 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.

***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 allow us to see proprietary acquisition and partnership 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.

***Strong in-house operations and asset management teams.*** We manage the operations of twenty-one of our power generation projects, which represent 70% of our portfolio's generating capacity. The remaining seven generation projects are operated by third-parties, which are recognized leaders in the independent power business.

**ASSET MANAGEMENT**

Our asset management strategy is to optimally manage our physical assets and commercial relationships to increase shareholder value. Our preference is to own the majority of, and operate all of our businesses. We proactively seek scale opportunities and to establish best practices that result in EBITDA and cash flow growth across all of our twenty-eight operating plants. In 2013 we established six cross functional task forces to drive these initiatives: Environmental, Health & Safety ("EH&S"), Optimization Initiatives, Asset Management Synergies, Sourcing, People Development and Stakeholder Management.

Our task forces help us achieve our strategy and mission, ensure that our projects receive appropriate preventative and corrective maintenance and incur capital expenditures, if justified, to provide for their safety, efficiency, availability, flexibility, longevity, and growth in EBITDA contribution. We also proactively look for opportunities to optimize power purchase, fuel supply, long term service and other agreements to deliver strong and predictable financial performance. The teams at each of the businesses have extensive experience in managing, operating and maintaining the assets. We also have people with extensive experience in renewable project development, construction and operations.

Consistent with our goals to internalize the operations of our business, in 2014 we entered into agreements, subject to lender approval, to assume the operations of Cadillac and Piedmont from Delta Power Services. For operations and maintenance services at the seven projects in our portfolio which we do not operate, we partner with recognized leaders in the independent power business.

Examples of our third-party operators include CEM and PPMS, which 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

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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.

**OUR ORGANIZATION AND SEGMENTS**

The following tables outline by segment our portfolio of power generating assets in operations as of February 27, 2014, 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.

We have four reportable segments: East, West, Wind and Un-allocated Corporate. We revised our reportable business segments in the fourth quarter of 2013 as a result of recent significant asset sales and in order to align with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. Our financial results for the years ended December 31, 2013, 2012 and 2011 have been presented to reflect these changes in operating segments. These changes reflect our current operating focus. The segment classified as Un-allocated Corporate includes activities that support the executive and administrative 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.

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

See Note 21 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.

***East Segment***

Our East segment accounted for 54.2%, 60.7% and 70.3% of consolidated revenue in 2013, 2012 and 2011, respectively and total net generation capacity of 791 MW at December 31, 2013. Ontario Electricity Financial Corp ("OEFC") accounted for 27.7% of total revenues and 51.1% of total revenues from the East segment for the year ended December 31, 2013.

The table below provides the revenue and project income (loss) for the East 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 April 12, 2013 we completed our sale of our Auburndale Power Partners, L.P. ("Auburndale"), Lake CoGen, Ltd. ("Lake") and Pasco CoGen, Ltd. ("Pasco") projects (collectively, the "Florida Projects") and have therefore excluded their revenue and project income (loss) from the table as they are recorded in income (loss) from discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011. Revenue for the Florida Projects was $62.1 million, $188.0 million and $160.9 million for the years ended December 31, 2013, 2012 and

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2011, respectively. Project income (loss) for the Florida Projects was ($1.1) million, $31.8 million and $7.6 million for the years ended December 31, 2013, 2012 and 2011, respectively.

| | East Segment | |
|---|---|---|
| | Revenue ($ in millions) | Project income (loss) ($ in millions) |
| 2013 | $ 299.1 | $ 25.8 |
| 2012 | 267.5 | (18.1) |
| 2011[1] | 66.0 | (2.1) |

(1) The Partnership was acquired on November 5, 2011.

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

| Project | Location | Fuel | Gross MW | Economic Interest | Net MW | Primary Electric Purchasers | Power Contract Expiry | Customer Credit Rating (S&P) |
|---|---|---|---|---|---|---|---|---|
| Cadillac | Michigan | Biomass | 40 | 100.00% | 40 | Consumers Energy | December 2028 | BBB |
| Chambers[1] | New Jersey | Coal | 262 | 40.00% | 89 | Atlantic City Electric[2] | December 2024 | BBB+ |
| | | | | | 16 | DuPont | December 2024 | A |
| Kenilworth | New Jersey | Natural Gas | 30 | 100.00% | 30 | Merck, & Co., Inc. | September 2018 | AA |
| Curtis Palmer | New York | Hydro | 60 | 100.00% | 60 | Niagara Mohawk Power Corperation | December 2027 | A- |
| Selkirk[1][3] | New York | Natural Gas | 345 | 17.70% | 15 | Merchant | N/A | NR |
| | | | | | 49 | Consolidated Edison | August 2014 | A- |
| Calstock | Ontario | Biomass | 35 | 100.00% | 35 | Ontario Electricity Financial Corp | June 2020 | AA- |
| Kapuskasing | Ontario | Natural Gas | 40 | 100.00% | 40 | Ontario Electricity Financial Corp | December 2017 | AA- |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Nipigon | Ontario | Natural Gas | 40 | 100.00% | 40 | Ontario Electricity Financial Corp | December 2022 | AA- |
| North Bay | Ontario | Natural Gas | 40 | 100.00% | 40 | Ontario Electricity Financial Corp | December 2017 | AA- |
| Tunis[3] | Ontario | Natural Gas | 43 | 100.00% | 43 | Ontario Electricity Financial Corp | December 2014 | AA- |
| Piedmont | Georgia | Biomass | 53 | 100.00% | 53 | Georgia Power | December 2032 | A |
| Orlando[1] | Florida | Natural Gas | 129 | 50.00% | 65 | Progress Energy Florida | December 2023 | BBB+ |
| Morris | Illinois | Natural Gas | 177 | 100.00% | 77 | Merchant | N/A | NR |
| | | | | | 100 | Equistar Chemicals, LP | November 2023 | BBB+ |

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

(2) The base PPA with Atlantic City Electric ("ACE") makes up the majority of the 89 Net MW. For sales of energy and capacity not purchased by ACE under the base PPA and sold to the spot market, profits are shared with ACE under a separate power sales agreement.

(3) We are currently in negotiations with counter parties regarding the renewal or entry into new power purchase agreements.

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***West Segment***

Our West segment accounted for 33.0%, 38.5% and 28.4% of consolidated revenue in 2013, 2012 and 2011, respectively and total net generation capacity of 714 MW at December 31, 2013. San Diego Gas & Electric and British Columbia Hydro and Power Authority ("BC Hydro") provided for 14.4% and 10.1% of total consolidated revenues, respectively, and 43.6% and 30.5%, respectively, of total revenues from the West segment for the year ended December 31, 2013.

The table below provides the revenue and project income for the West 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).

| | West Segment | |
|---|---|---|
| | Revenue ($ in millions) | Project income ($ in millions) |
| 2013 | $ 182.3 | $ 36.4 |
| 2012 | 169.6 | 7.3 |
| 2011[(1)] | 26.7 | 0.7 |

(1) The Partnership was acquired on November 5, 2011.

On April 30, 2013 we completed our sale of our interest in the Path 15 Transmission Line ("Path 15") and have therefore excluded its revenue and project income from the table as they are recorded in income (loss) from discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011. Revenue for Path 15 was $9.5 million, $28.7 million and $30.1 million for the years ended December 31, 2013, 2012 and 2011, respectively. Project income for Path 15 was $2.1 million, $5.1 million and $7.6 million for the years ended December 31, 2013, 2012 and 2011, respectively.

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

| Project | Location | Fuel | Gross MW | Economic Interest | Net MW | Primary Electric Purchasers | Power Contract Expiry | Customer Credit Rating (S&P) |
|---|---|---|---|---|---|---|---|---|
| Mamquam | British Columbia | Hydro | 50 | 100.00% | 50 | British Columbia Hydro and Power Authority | September 2027 | AAA |
| Moresby Lake | British Columbia | Hydro | 6 | 100.00% | 6 | British Columbia Hydro and Power Authority | August 2022 | AAA |
| Williams Lake | British Columbia | Biomass | 66 | 100.00% | 66 | British Columbia Hydro and Power Authority | March 2018 | AAA |
| Frederickson[(1)] | Washington | Natural Gas | 250 | 50.15% | 50 | Benton Co. PUD | August 2022 | A+ |
| | | | | | 45 | Grays Harbor PUD | August 2022 | A |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | | | | | 30 | Franklin Co. PUD | August 2022 | A |
| Koma Kulshan[1] | Washington | Hydro | 13 | 49.80% | 6 | Puget Sound Energy | December 2037 | BBB |
| Naval Station | California | Natural Gas | 47 | 100.00% | 47 | San Diego Gas & Electric | December 2019 | A |
| Naval Training Center | California | Natural Gas | 25 | 100.00% | 25 | San Diego Gas & Electric | December 2019 | A |
| North Island | California | Natural Gas | 40 | 100.00% | 40 | San Diego Gas & Electric | December 2019 | A |
| Oxnard | California | Natural Gas | 49 | 100.00% | 49 | Southern California Edison | May 2020 | BBB+ |
| Manchief | Colorado | Natural Gas | 300 | 100.00% | 300 | Public Service Company of Colorado | October 2022 | A- |

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

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***Wind Segment***

Our Wind segment accounted for 12.8% of consolidated revenue in 2013 and total net generation capacity of 521 MW from continuing operations at December 31, 2013. Southwestern Electric Power Company, PacifiCorp and Idaho Power Co. accounted for 33.1%, 25.8% and 20.8% of total revenues from the Wind segment for the year ended December 31, 2013, respectively. No customer from the Wind segment was responsible for greater than 10% of total consolidated revenues in the year ended December 31, 2013.

The table below provides the revenue and project income (loss) for the Wind 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).

| | Wind Segment Revenue ($ in millions) | Wind Segment Project income (loss) ($ in millions) |
|---|---|---|
| 2013 | $ 70.8 | $ 18.6 |
| 2012 | 1.9 | (7.4) |
| 2011 | | (1.6) |

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

| Project | Location | Type | MW | Economic Interest | Net MW | Primary Electric Purchasers | Power Contract Expiry | Customer Credit Rating (S&P) |
|---|---|---|---|---|---|---|---|---|
| Idaho Wind[1] | Idaho | Wind | 183 | 27.56% | 50 | Idaho Power Co. | December 2030 | BBB |
| Rockland Wind Farm | Idaho | Wind | 80 | 50.00% | 40 | Idaho Power Co. | December 2036 | BBB |
| Goshen North[1] | Idaho | Wind | 125 | 12.50% | 16 | Southern California Edison | November 2030 | BBB+ |
| Meadow Creek | Idaho | Wind | 120 | 100.00% | 120 | PacifiCorp | December 2032 | A- |
| Canadian Hills | Oklahoma | Wind | 300 | 99.0% | 199 | Southwestern Electric Power Company | December 2037 | BBB |
| | | | | | 48 | Oklahoma Municipal Power Authority | December 2037 | A |
| | | | | | 48 | Grand River Dam Authority | December 2032 | A |

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

**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 December 2013, summer peak demand within the United States in the ten-year period from 2014 through 2023 is projected to increase at a compound annual growth rate of approximately 1.2%, while winter peak demand in Canada is projected to increase 1.1%. In addition, many states and regions have aggressive demand side management programs designed to reduce current load and future local growth. 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

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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. According to NERC's Reliability Assessment, renewable generation made up 15.2% of all on-peak capacity resources in 2013 and is expected to reach almost 25.2% percent in 2023.

The increase of gas and renewable capacity will be offset by large-scale retirements of coal-fired generation plants. NERC projects a net 35.1 GW reduction of coal-fired generation by 2023, with over 90% retiring by 2017 primarily due to existing and potential 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 28 power generation projects 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 $363 billion in 2012, based on information published by the Energy Information Administration in November 2013. 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 38% of total net generation in 2013. 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. Supply has surpassed demand plus appropriate reserve margins in numerous U.S. and Canadian markets contributing to reduced capacity and energy prices and increasing competition among generators to obtain power sales agreements.

We compete for acquisition opportunities with numerous private equity, infrastructure and pension funds, Canadian and U.S. independent power firms, utility non-regulated subsidiaries and other strategic and financial players. Our competitive advantages include our experienced management team, our experience as project operators and constructors and our diversified projects generally with medium to long-term power purchase agreements.

## 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 Federal Energy Regulation Commission ("FERC"), although most of our projects benefit from the special provisions accorded to Qualifying Facilities ("QFs") or Exempt Wholesale Generators ("EWGs").

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In Canada, electricity generation is subject primarily to provincial regulation. Our projects in British Columbia are therefore 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 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 project is a EWG under the Public Utility Holding Company Act of 2005, as amended ("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 in 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.

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.

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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 both the Northeast Power Coordinating Council (the "NPCC") and NERC. 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, including power contracts, were kept in OEFC. Once all of OEFC's debts (approximately $26.9 billion as of March 2012) 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 for 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. The process for awarding power purchase contracts in respect of large-scale energy projects under the feed-in-tariff program is undergoing review. No such contracts have been awarded in the past 12 months.

**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 by certain Northeast and Mid-Atlantic states as the first cap-and-trade program in the United States for $CO_2$ emissions. The nine states currently participating in RGGI have varied implementation plans and schedules. In February 2013, RGGI released an updated model rule that reduces the regional $CO_2$ budget beginning in 2014. The one RGGI state where we have project interests, New York, also provides cost mitigation for independent power projects with certain types of power contracts. 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

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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.

The Government of British Columbia has enacted a number of significant pieces of climate-action legislation that frame British Columbia's approach to reducing greenhouse gas emissions with the goal of supporting the Province's participation in the emerging low-carbon economy.

One key piece of legislation is the Greenhouse Gas Reduction Targets Act (British Columbia) ("GGRTA"), which came into force in 2008 and sets legislated targets for the reduction of greenhouse gas emissions in the Province. Using 2007 as a base year, GGRTA (along with related Ministerial Orders) requires that emissions must be reduced by a minimum of 18% by 2016, 33% by 2020 and 80% by 2050. Also required in connection with GGRTA are annual (from 2010 onward) British Columbia Greenhouse Gas Inventory Reports, Community Energy and Emissions Inventory Reports and Carbon Neutral Action Reports, all of which are designed to provide scientific, comparable and consistent reporting of greenhouse gas sources.

Other related, key pieces of legislation include the Carbon Tax Act (British Columbia) ("CTA") and the Greenhouse Gas Reduction (Cap and Trade) Act ("GGRCTA"). CTA operates to put a price on greenhouse gas emissions, providing an incentive for sustainable choices and practices by producers of greenhouse gases. GGRCTA authorizes the imposition of hard caps on greenhouse gas emissions by providing a statutory basis for establishing a market-based cap and trade framework to reduce greenhouse gas emissions from large emitters operating in the Province. GGRCTA is currently in the process of being brought into full force. British Columbia is the first Canadian province to introduce such legislation.

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 and legislative tax 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 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, 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 certain 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. To date, however, the tax credits have not been extended past these dates. Under present law, for projects that qualify, the production tax credits provide an income tax credit of 2.3 cents/kilowatt-hour for the production of electricity from utility-scale wind turbines. The EP Act of

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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.

**EMPLOYEES**

As of February 27, 2014, we had 295 employees, 189 in the United States and 106 in Canada. Of our Canadian employees, 67 are covered by two collective bargaining agreements. During 2013, we did not experience any labor stoppages or labor disputes at any of our facilities.

**AVAILABLE INFORMATION**

We make available, free of charge, on our website, www.atlanticpower.com, 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.

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.

**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 Structure**

***We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities***

We recognize that our important next steps include considering the relative merits of further debt reduction, identification of and investment in internal and external accretive growth opportunities, to the extent available, and other allocation of available cash while continuing to focus on how to best position the Company overall to maximize shareholder value. However, we may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities.

Our ability to make required payments under our outstanding indebtedness, including pursuant to the mandatory amortization feature of the New Senior Secured Credit Facilities (as defined herein), as well as the 50% cash sweep, or to prepay or redeem any such indebtedness, will depend on our financial and operating performance, including our ability to generate cash flow from operations in the future. To the extent a significant portion of our cash flow is used to pay dividends to our shareholders, any remaining cash flow may be insufficient to fund our debt service obligations or to repay or redeem any such indebtedness. As a result, we may be required to refinance such indebtedness and/or obtain third party financing in order to repay, redeem or refinance such indebtedness when it comes due. In particular, the Cdn$67.5 million aggregate principal amount of our 6.25% convertible debentures is due March 2017, the Cdn$80.5 million aggregate principal amount of our 5.60% convertible unsecured subordinated debentures is due June 2017 and the $460 million aggregate principal amount of our 9.0% notes is due in October 2018. There can be no assurance that our business will generate sufficient cash flow from operations or that future borrowings or refinancing opportunities will be available to us at an acceptable cost, in amounts sufficient, or at all, to enable us to service our debt obligations or to repay or redeem any such indebtedness at maturity, particularly because of our high levels of debt and the debt incurrence restrictions imposed by the various agreements governing our indebtedness. Steps taken to refinance our indebtedness or obtain other third party financing, if any, may not be successful and may not permit us to meet our scheduled debt service obligations, which could have a material adverse effect on our liquidity and financial condition.

In addition, a payout of a significant portion of our cash flow through any dividends, and/or to service our debt, including pursuant to the mandatory amortization feature of the New Senior Secured Credit Facilities, as well as the 50% cash sweep, may result in us not retaining a sufficient amount of cash to finance growth and reinvestment opportunities, including through the acquisition of additional projects, to the extent any such acquisitions are otherwise available to us. As a result, we may have to forego growth and reinvestment opportunities that would otherwise be desirable, if we do not find alternative sources of financing for such opportunities or modify our dividend policy to make cash available to us. In addition, even if we are able to find alternative sources of financing for such opportunities, we may be precluded from pursuing an otherwise attractive acquisition or investment if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund such acquisition or investment. This could also limit our flexibility in planning for, or reacting to, changes in our business and industry, placing us at a competitive disadvantage compared to our competitors. We cannot provide any assurance that we will be able to identify, finance or close any transactions associated with any such growth or reinvestment opportunities on acceptable terms or timing, or at all.

Further, if we are unable to generate sufficient cash flow from operations, our ability to support our liquidity needs, including, but not limited to the payment of any dividends, servicing our debt obligations, including pursuant to the mandatory amortization feature of the New Senior Secured Credit Facilities, as well as the 50% cash sweep, or financing internal or external growth opportunities, will depend on our ability to access the credit and capital markets, neither of which may be available to us on acceptable terms, or at all. Currently, because we no longer qualify as a "well-known seasoned issuer," which previously enabled us to, among other things, file automatically effective shelf registration statements, even if we were able to access the capital markets, any attempt to do so could be more expensive or subject to significant delays. Further, access to the credit and capital markets and the cost and availability of credit may be adversely affected by factors beyond our control, including turmoil in the financial services industry, volatility in securities trading markets and general economic conditions. We cannot provide any assurance that we will be able to access the credit or capital markets on acceptable terms or timing, or at all.

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***We cannot provide any assurance regarding the outcome of evaluation of the broad range of potential options we are considering or the implications any such potential options may have on our business***

As further discussed in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Strategy Update", we are committed to evaluating a broad range of potential options, including further selected asset sales or joint ventures to raise additional capital for growth or potential debt reduction, the acquisition of assets, including in exchange for shares, the dividend level, as well as broader strategic options. Some or all of such options could potentially trigger change of control provisions in certain debt and other agreements to which we are a party or impose limitations on our ability to use our net operating losses in the future. However, certain of our projects are subject to transfer restrictions, which may prevent us from transferring such projects on economically favorable terms or at all. See " Risks Related to Our Business and Our Projects Our equity interests in certain projects may be subject to transfer restrictions." No assurance can be given as to how the evaluation of any such potential options may evolve or the actual or threatened impact any such options may have on our stock price. In addition, even if we choose to implement any such potential option, we may be unsuccessful in doing so or we may implement an option that yields unexpected results. The process of reviewing, and potentially executing, any such potential option, may be very costly and time-consuming and may distract our management and otherwise disrupt our operations, which could have an adverse effect on our business, financial condition and results of operations. Further, no assurance can be given that any such option, if and when identified, will be approved by our shareholders if such approval is required.

***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 availability of cash flow from dividend payments rather than allocations of cash, the results of operations, working capital requirements, financial condition, restrictive covenants and our ability to satisfy such covenants, business opportunities, provisions of applicable law and other factors that our board of directors may deem relevant. See " We may not generate sufficent cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunitites or fund our operations" and " 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 dividend payments, acquisitions or investments or additional indebtedness, we would otherwise seek to do." Our board of directors may decrease the level of or entirely discontinue payment of dividends. In addition, if and for as long as we are in arrears on the declaration or payment of dividends on the 4.85% Cumulative Redeemable Preferred Shares, Series 1 (the "Series 1 Shares"), the 7.0% Cumulative Rate Reset Preferred Shares, Series 2 (the "Series 2 Shares"), or the Cumulative Floating Rate Preferred Shares, Series 3 (the "Series 3 Shares") of the Partnership, the Partnership will not be permitted to make any distributions on its limited partnership units and we will not pay any dividends on our common shares.

***Our New Senior Secured Credit Facilities contain certain terms, covenants and restrictions that could impact our available cash flow and results of operations and restrict our ability to make dividend payments, acquisitions or investments or issue additional indebtedness***

Our New Senior Secured Credit Facilities contain certain terms, covenants and restrictions, including a mandatory amortization feature and customary prepayment provisions, including, among others, using 50% of the cash flow of the Partnership and its subsidiaries that remains after the application of funds, in accordance with customary priority, to certain items, including, but not limited to, the operations and maintenance expenses of the Partnership and its subsidiaries, debt service on the New Senior Secured Credit Facilities and other specified indebtedness and funding of a debt service reserve account. Such terms, covenants and restrictions may impact our available cash flow and limit our ability to retain sufficient amounts of cash to pay dividends, service our debt obligations or finance internal or external growth opportunities. Our New Senior Secured Credit Facilities are a primary source of our liquidity. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Liquidity and Capital Resources".

The covenants under the New Senior Secured Credit Facilities include a requirement that the Partnership and its subsidiaries, maintain certain leverage and interest coverage ratios (each, as defined in the credit agreement governing the New Senior Secured Credit Facilities). The New Senior Secured Credit Facilities also contain customary restrictions and limitations on the Partnership's and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to customary carve-outs and exceptions and various thresholds. Any such limitations could restrict our ability to, among other things, make dividend payments, acquisitions or investments or issue additional indebtedness.

***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 dividend payments, 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 to maintain our dividend payments at the current level if and when declared by our board of directors;

- our ability in the future to obtain additional financing for, among other things, the repayment or redemption of indebtedness and other debt service obligations and investment in internal and external growth opportunities, including the acquisition of additional projects, to the extent any such acquisitions are otherwise available to us, 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.

As of December 31, 2013, our consolidated long-term debt represented approximately 63% of our total capitalization, comprised of debt and balance sheet equity. As of February 27, 2014, giving effect to the New Senior Secured Credit Facilities and the related use of proceeds thereunder our consolidated long-term debt represented approximately 65% of our total capitalization.

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, our available cash flow and results of operations 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 95% of our debt, including our share of the project-level debt associated with equity

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investments in affiliates, either bears interest at fixed rates or is financially hedged through the use of interest rate swaps.

As of December 31, 2013, we had (i) no amount outstanding and $97.9 million was issued in letters of credit under our revolving credit facility, (ii) $405.2 million of outstanding convertible debentures, (iii) $398.6 million of outstanding non-recourse project-level debt, and (iv) $1.1 billion of unsecured debt. As of February 27, 2014, we had (i) no amount outstanding and $144.1 million in letters of credit outstanding under our New Revolving Credit Facility, (ii) $405.2 million of outstanding convertible debentures, (iii) $390.5 million of outstanding non-recourse project-level debt, and (iv) $1.3 billion of unsecured debt.

As previously disclosed in our Current Report on Form 8-K filed on January 30, 2014, due to the aggregate impact of the up-front costs resulting from the prepayments on certain of our indebtedness using the proceeds of New Term Loan Facility, including the make-whole payment and charges for unamortized debt discount and fee expenses (all such up-front costs, collectively, the "Prepayment Charges"), which will be reflected as charges to our 2014 first quarter results, we are no longer in compliance with the fixed charge coverage ratio test included in the restricted payments covenant of the indenture governing our 9.0% notes. The fixed charge coverage ratio must be at least 1.75 to 1.00 and is measured on a rolling four quarter basis, including after giving effect to certain pro forma adjustments. As a consequence, further dividend payments, which are declared and paid at the discretion of our board of directors, in the aggregate cannot exceed the covenant's "basket" provision of the greater of $50 million and 2% of consolidated net assets (as defined in the indenture governing our 9.0% notes) (approximately $61 million at December 31, 2013) until such time that we are in compliance with the fixed charge coverage ratio. For the year ended December 31, 2013, dividend payments to our shareholders totaled approximately Cdn$48 million for the full year, on a pro forma basis reflecting the lower Cdn$0.03333 per common share monthly dividend first declared in March 2013. The Prepayment Charges would no longer be reflected in the calculation of the fixed charge coverage ratio test after the passage of four additional successive quarters following the quarter in which the Prepayment Charges are incurred. In addition, if we pursue further debt reduction, including the potential repurchase or redemption, by means of a tender offer or otherwise, of up to $150 million aggregate principal amount of our 9.0% notes, any similar prepayment charges incurred in connection with such debt reduction would also be reflected in the calculation of the fixed charge coverage ratio test on a rolling four quarter basis, beginning with the quarter in which such charges are incurred, as would any associated reduction in interest expense.

In addition, some of our 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 of these 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 our available cash flow. We have, in the past, failed to meet the cash flow coverage ratio tests at certain of our projects, which restricted those projects from making cash distributions. Although all of our projects with non-recourse loans are currently meeting their debt service requirements, we cannot provide any assurances that our projects will generate enough future cash flow to meet any applicable ratio tests in order to be able to make distributions to us.

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 the preferred shares of the Partnership, 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. In addition, if and for as long as we are in arrears on the declaration or payment of dividends on the Series 1 Shares, the Series 2 Shares or the Series 3 Shares, the Partnership will not make any distributions on its limited partnership units and we will not pay any dividends on our common shares. Additionally, 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 and restrict our ability to take certain actions, including paying dividends. 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.

***Exchange rate fluctuations may adversely affect our available cash flow and results of operations***

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. 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 available cash flow and results of operations.

***A downgrade in our credit rating or in the credit rating of our outstanding debt securities, 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, a downgrade in the credit rating of our outstanding debt securities, which we have recently experienced, or any 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, or obtain a guarantee agreement, 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.

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***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 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, or repay outstanding principal amounts under existing debt by issuing common shares. We may also, from time to time, decide to issue common shares to meet strategic objectives or in connection with acquiring assets or pursuing broader strategic options. See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Strategy Update". The issuance of additional common shares may have a dilutive effect on shareholders and may adversely impact the price of our common shares.

***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 our 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 turmoil in the financial services industry, volatility in securities trading markets and general economic conditions could result in an inability to support our liquidity needs, including, but not limited to, the payment of any dividends, service of our debt obligations or financing of internal or external growth opportunities. Currently, because we no longer qualify as a "well-known seasoned issuer," which previously enabled us to, among other things, file automatically effective shelf registration statements, even if we were able to access the capital markets, any attempt to do so could be more expensive or subject to significant delays. See " We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities."

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 industry, 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 not be able to pay dividends, service our debt obligations or finance internal or external growth opportunities, any of which would adversely affect our business, results of operations and financial condition.

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***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 10, 25 and 26 to the consolidated financial statements for information on our guarantee obligations.

***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; and

- Casual vacancies on our Board can be approved prior to the next annual meeting of shareholders by the directors of our Board of Directors.

If we experience a change of control, unless we elect to make a voluntary prepayment of the term loan under the New Senior Secured Credit Facilities, the Partnership will be required to offer each electing lender to prepay such lender's term loans under the New Senior Secured Credit Facilities at a price equal to 101% of par. Additionally, a change in control 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. In addition, some of our PPAs or other commercial agreements may contain change of control provisions.

We have also adopted a shareholder rights plan that may delay or prevent 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; and

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 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.

***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.

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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. The Partnership has also 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. However, 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, including as a result of implementation of any of the broad range of potential options we are committed to evaluating, our ability to realize these benefits may be limited. See " We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities or fund our operations." 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.

***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.

***We are subject to significant pending civil litigation, which if decided against us, could require us to pay substantial judgments or settlements and incur expenses that could have a material adverse effect on our business, results of operations, financial condition and liquidity.***

In addition to being subject to litigation in the ordinary course of business, we are party to numerous legal proceedings, including securities class actions, from time to time. On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints related to, among other things, claims that we made materially false and misleading statements and omissions regarding the sustainability of our common share dividend that artificially inflated the price of our common shares were filed in the United States District Court for the District of Massachusetts against us and certain of our current and former executive officers. On March 19, 2013 and April 2, 2013, two notices of action relating to purported Canadian securities class action claims were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, in the Ontario Superior Court of Justice in the Province of Ontario and on April 8, 2013, a similar claim, issued by alleged investors in Atlantic Power common shares, seeking to initiate a purported class action was filed in the Superior Court of Quebec in the Province of Quebec against us and certain of our current and former executive officers. On May 2, 2013, a statement of claim relating to the April 2, 2013 notice of action was filed with the Ontario Superior Court of Justice in the Province of Ontario. The allegations of these purported class actions are essentially the same as those asserted in the United States.

These litigations may be time consuming, expensive and distracting from the conduct of our daily business. Due to the nature of these proceedings, the lack of precise damage claims (other than in certain Canadian Actions, as defined in "Item 3. Legal Proceedings") and the type of claims we are subject to, we are unable to determine the ultimate or maximum amount of monetary liability or financial impact, if any, to us in these legal matters, which unless otherwise described in "Item 3. Legal Proceedings", seek damages from the defendants of material or indeterminate amounts. As a result, we are also unable to reasonably estimate the possible loss or range of losses, if any, arising from these litigations. Although we are unable at this time to estimate what our ultimate liability in these matters may be, it is possible that we will be required to pay substantial judgments or settlements and incur expenses that could have a material adverse effect on our business, results of operations, financial condition and liquidity. We intend to defend vigorously against these actions. For additional information with respect to these unresolved matters, see "Item 3. Legal Proceedings".

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**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 2014 and December 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 on acceptable terms or timing, if at all, the price received by the project for power under subsequent arrangements may be reduced significantly, or there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA at the project. 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. See " Impairment of goodwill or long-lived assets could have a material adverse effect on our business, results of operations and financial condition".

For example, we are currently in negotiations with purchasers of power at our Selkirk and Tunis projects, whose PPAs expire in August 2014 and December 2014, respectively, and which represented 7.7% and 3.5% of our total Project Adjusted EBITDA for the year ended December 31, 2013, respectively. If Selkirk does not obtain a new PPA, this could result in 100% of the capacity at Selkirk not contracted and therefore sold at market power prices. With respect to Tunis, because it has not been in the first group for which recontracting discussion are currently underway with the Ontario government and the process for such discussions has not been transparent, the outcome of recontracting discussions at the project is uncertain and we expect that a new PPA, if any, at Tunis, would be on significantly less favorable terms than the project's existing PPA. Beyond the expiration of the Selkirk and Tunis PPAs in 2014, our next PPA expirations do not occur until year-end 2017 and are at our North Bay and Kapuskasing projects in Ontario. The loss of significant PPAs, our inability to secure new PPAs on favorable terms or at all, 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 and thermal energy 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 2013, the largest customers of our power generation projects, including projects recorded under the equity method of accounting, are OEFC, San Diego Gas & Electric, and BC Hydro which purchase approximately 27.7%, 14.4% and 10.1%, 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.

Further, our customers generally have 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

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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 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.

***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 with 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 or retirement of existing facilities or additional transmission capacity;
- electric supply disruptions, including plant outages and transmission disruptions;
- 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 or storage 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.

The market price for electricity is affected by changes in demand for electricity. Factors such as economic slowdown, worse than expected economic conditions, milder than normal weather, the growth of energy efficiency and efforts aimed at energy conservation, among others, could reduce energy demand or significantly slow the growth in demand for electricity, thereby reducing the market price for electricity. A reduction in demand could contribute to conditions that no longer support the continued operation of certain power generation projects, which could adversely affect our results of operations through increased depreciation rates, impairment charges and accelerated future decommissioning costs, among others.

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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 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 any excess capacity. 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. The expiration of the current PPA at Selkirk is August 2014. If the project does not obtain a new PPA, this could result in an increase to 100% of the capacity not contracted and therefore sold at market power prices. 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. 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;
- additional generating capacity;
- disruption or other constraints or inefficiencies of electricity, gas or coal transmission or transportation;
- 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 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 any dividends paid to our shareholders, as debt service obligations, investments in internal or external growth opportunities or funding of our operations. 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, unexpected construction delays, latent defect, design error or operator error, or force majeure events, among other things, which could adversely affect revenues and cash flow. For example, we have previously experienced delays in achieving commercial operations at our Piedmont project as a result of repairs to the project's steam turbine from damage sustained during late-stage testing and are also currently disputing certain issues with the engineering, procurement and construction contractor of the project regarding the condition and performance of the project. Additionally, older equipment, even if maintained in accordance with good practices, is subject to operational failure, including events that are beyond our control, and may require unplanned expenditures to operate efficiently. 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 available cash flow may be adversely affected.

We provide letters of credit under our $210 million New 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 conditions, which directly influence the demand for electricity and natural gas and affect the price of energy commodities. Temperatures above normal

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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.

***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 acquiring or 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 resource 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 can also be, and have been in the past, affected by concerns over U.S. fiscal policy, as well as the U.S. federal government's debt ceiling, federal deficit and related budget and tax issues. These concerns continue to raise discussions relating to the stability 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 geopolitical crisis, 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, ability to raise capital 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 decline in energy consumption and 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 or compromise the physical or cyber security of our facilities, which could result in increased costs and could adversely affect our ability to manage our business effectively. 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. Additionally, future significant weather related events, natural disasters and other similar events that have an adverse effect on the economy could have a material adverse effect on our business, results of operations, ability to raise capital and financial condition.

***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, disruption of communication systems and technology, contamination of, or damage to, the environment and suspension of operations. The occurrence of any one of these events may result in our being subject to various litigation matters, including regulatory and administrative proceedings, 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.

***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 regulations. Compliance with the requirements under these various 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.

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

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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.

Additionally, 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, impact the viability of our renewable energy projects. 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. 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.

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.

(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 94% 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 ESA, OEFC and OPA. All these agencies may affect our projects.

***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.

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. Some of our 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

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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.

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. The Western Climate Initiative 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, in September 2013, the EPA issued a new proposed rule regulating carbon emissions from new electric generating units. For existing electric generating units, the EPA is scheduled to issue a proposed rule regulating carbon emissions by June 2014, to issue a final rule by June 2015, and to require states to submit revisions to their implementation plans addressing the new rule by June 2016. In Canada, British Columbia and Ontario have implemented greenhouse gas reporting regulations and are developing additional programs to address greenhouse gas emissions.

Concerning our projects in British Columbia, regulatory restrictions stemming from the GGRTA and the GGRCTA, and financial commitments arising in connection with the requirements under the CTA, could affect our ability to operate our projects in British Columbia and affect our profitability.

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, 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.

***Impairment of goodwill or long-lived assets could have a material adverse effect on our business, results of operations and financial condition***

As of December 31, 2013, we had approximately $296.3 million of goodwill, which represented approximately 9% of our total assets on our consolidated balance sheets. Goodwill is not amortized, but is evaluated for impairment at least annually or more frequently if impairment indicators are present. We could be required to, and have in the past, evaluated the potential impairment of goodwill outside of the required annual evaluation process if we experience situations, including but not limited to, deterioration in general economic conditions or our operating or regulatory environment, increased competitive environment, an increase in fuel costs (particularly when we are unable to pass through the impact to customers), negative or declining cash flows, loss of a key contract or customer (particularly when we are unable to replace it on equally favorable terms), divestiture of a significant component of our business or adverse actions or assessments by a regulator. These types of events and the resulting analyses could result in goodwill impairment expense, which could substantially affect our results of operations for those periods. Additionally, goodwill may be impaired if any acquisitions we make do not perform as expected. See Note 7 to the consolidated financial statements included in this Annual Report on Form 10-K.

Long lived assets are initially recorded at fair value and are amortized or depreciated over their estimated useful lives. Long-lived assets are evaluated for impairment only when impairment indicators are present whereas goodwill is evaluated for impairment on an annual basis or more frequently if potential impairment indicators are present. Otherwise, the recoverability assessment of long-lived assets is similar to the potential impairment evaluation of goodwill particularly as it relates to the identification of potential impairment indicators, and making estimates and assumptions to determine fair value, as described above.

***Increasing competition could adversely affect our performance and the performance of our project***

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. Further, changes in technology, including fuel cells, microturbines and solar cells, may facilitate the entrance of new competitors, increase the supply of electricity or reduce the cost of methods of producing power that we do not currently use. If these technologies became cost competitive, we could face increasing competition and the value of our generating facilities could be reduced. 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. Further, a payout of a significant portion of our cash flow through dividends, and/or to service our debt, may result in us not retaining a sufficient amount of cash to finance acquisition or investment opportunities and make other capital and operating expenditures. See " Risk Related to Our Structure We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities."

***We have limited control over management decisions at certain projects***

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 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 and PPMS) operate eight of our 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, our cash flow 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 be able to finance our otherwise pursue, execute or successfully integrate acquisitions or new business initiatives***

To the extent identification of and pursuit of acquisition opportunities forms a part of our strategy, 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 at all, or be sure that such acquisitions, if any, will be successfully integrated into our existing operations. In addition, a payout of a significant portion of our cash flow through dividends, and/or to service our debt obligations, may result in us not retaining a sufficient amount of cash to finance any acquisition or other growth opportunities, to the extent any such acquisition or other opportunities are available to us. As a result, we may have to forego such opportunities, even if they would otherwise be necessary or desirable, if we

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do not find alternative sources of financing for such opportunities or modify our dividend policy to make cash available to us. In addition, even if we are able to find alternative sources of financing for such opportunities, we may be precluded from pursuing an otherwise attractive acquisition or investment if the projected short-term cash flow from the acquisition or investment is not adequate to service the capital raised to fund such acquisition or investment. This could limit our flexibility in planning for, or reacting to, changes in our business and industry, placing us at a competitive disadvantage compared to our competitors. See " Risks Related to Our Structure We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities."

Although electricity demand is expected to grow, creating the need for more generation, such growth is expected to occur at a slower rate. The U.S. power industry is continuing to undergo consolidation and may offer attractive acquisition opportunities, but 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, investment or new business initiative 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, inadequate return on capital 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 or prior to launching an initiative or entering a market. We may not be indemnified for some or all these liabilities in an acquisition transaction. In addition, our funding requirements associated with acquisitions, integration and implementation costs may reduce the funds available to us to make any 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. For example, the sale of our Delta-Person project has required us to pursue transfer of certain permits in connection with the sale of the project. 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. See " Risks Related to Our Structure We are committed to evaluating a broad range of potential options and no assurance can be given as to how the evaluation of any such potential options may evolve or the implications of any such potential options."

***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 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.

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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 increases in natural gas prices, we have incurred income 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.

***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 legacy defined benefit pension plan that we sponsor. As of December 31, 2013, our pension plan was fully funded on a going concern basis. 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, steal confidential information, and impact our ability to make collections or otherwise impact our operations. 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. Further, an aging work force in the power industry necessitates recruiting, retaining and developing the next generation of leadership. 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.

## 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 New Senior Secured Credit Facilities 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

*IRS Examination*

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. As of the date of this Annual Report on Form 10-K, the examination is before the IRS Office of Appeals. We continue 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. We believe that an adjustment, if any, would be offset by net operating loss carry forwards. No accrual has been made for any contingency related to any of the proposed adjustments as of December 31, 2013.

*Shareholder class action lawsuits*

Massachusetts District Court Actions

On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints were filed by alleged investors in Atlantic Power common shares in the United States District Court for the District of Massachusetts (the "District Court") against Atlantic Power and Barry E. Welch, our President and Chief Executive Officer and a Director of Atlantic Power, in each of the actions, and, in addition to Mr. Welch, some or all of Patrick J. Welch, our former Chief Financial Officer, Lisa Donahue, our former interim Chief Financial Officer, and Terrence Ronan, our current Chief Financial Officer, in certain of the actions (the "Individual Defendants," and together with Atlantic Power, the "Defendants") (the "U.S. Actions").

The District Court complaints differ in terms of the identities of the Individual Defendants they name, as noted above, the named plaintiffs, and the purported class period they allege (July 23, 2010 to March 4, 2013 in three of the District Court actions and August 8, 2012 to February 28, 2013 in the other two District Court actions), but in general each alleges, among other things, that in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, Atlantic Power and the Individual Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The District Court complaints assert claims under Section 10(b) and, against the Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended.

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The parties to each District Court action have filed joint motions requesting that the District Court set a schedule in the District Court actions, including: (i) setting a deadline for the lead plaintiff to file a consolidated amended class action complaint (the "Amended Complaint"), after the appointment of lead plaintiff and counsel; (ii) setting a deadline for Defendants to answer, file a motion to dismiss or otherwise respond to the Amended Complaint (and for subsequent briefing regarding any such motion to dismiss); and (iii) confirming that Defendants need not answer, move to dismiss or otherwise respond to any of the five District Court complaints prior to the filing of the Amended Complaint. On May 7, 2013, each of six groups of investors (the "U.S. Lead Plaintiff Applicants") filed a motion (collectively, the "U.S. Lead Plaintiff Motions") with the District Court seeking: (i) to consolidate the five U.S. Actions (the "Consolidated U.S. Action"); (ii) to be appointed lead plaintiff in the Consolidated U.S. Action; and (iii) to have its choice of lead counsel confirmed. On May 22, 2013, three of the U.S. Lead Plaintiff Applicants filed oppositions to the other U.S. Lead Plaintiff Motions, and on June 6, 2013, those three Lead Plaintiff Applicants filed replies in support of their respective motions. On August 19, 2013, the District Court held a status conference to address certain issues raised by the U.S. Lead Plaintiff Motions, entered an order consolidating the five U.S. Actions, and directed two of the six U.S. Lead Plaintiff Applicants to file supplemental submissions by September 9, 2013. Both of those U.S. Lead Plaintiff Applicants filed the requested supplemental submissions, and then sought leave to file additional briefing. The Court granted those requests for leave and additional submissions were filed on September 13 and September 18, 2013, which the Court will consider (along with the motion papers discussed above) in deciding who will serve as lead plaintiff and lead counsel.

Canadian Actions

On March 19, 2013, April 2, 2013 and May 10, 2013, three notices of action relating to Canadian securities class action claims against the Defendants were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, with the Ontario Superior Court of Justice in the Province of Ontario. On April 8, 2013, a similar claim issued by alleged investors in Atlantic Power common shares seeking to initiate a class action against the Defendants was filed with the Superior Court of Quebec in the Province of Quebec (the "Canadian Actions").

On April 17, May 22, and June 7, 2013 statements of claim relating to the notices of action were filed with the Ontario Superior Court of Justice in the Province of Ontario.

On August 30, 2013, the three Ontario actions were succeeded by one action with an amended claim being issued on behalf of Jacqeline Coffin and Sandra Lowry. This claim names the Company, Barry Welch and Terrence Ronan as defendants (the "Defendants"). The Plaintiffs seeks leave to commence an action for statutory misrepresentation under the Ontario Securities Act and asserts common law claims for misrepresentation. The Plaintiffs' allegations focus on among other things, claims the Defendants made materially false and misleading statements and omissions in Atlantic Power's press releases, quarterly and year end filings and conference calls with analysts and investors, regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The Plaintiffs seek to certify the statutory and common law claims under the Class Proceedings Act for security holders who purchased and held securities through a proposed class period of November 5, 2012 to February 28, 2013.

On October 4, 2013, the Plaintiffs delivered materials supporting their request for leave to commence an action for statutory misrepresentations and for certification of the statutory and common claims as class proceedings. These materials estimate the damages claimed for statutory misrepresentation at $197.4 million.

A schedule for the Plaintiffs' motions and the action was set on November 12, 2013.

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The Petitioner in the proposed class action in Quebec served and filed a motion to suspend those proceedings pending the Ontario proceedings. This motion was not granted. Nothing further has happened in the action.

Pursuant to the Private Securities Litigation Reform Act of 1995, all discovery is stayed in the U.S. Actions. Plaintiffs have not yet specified an amount of alleged damages in the U.S. Actions. As noted above, the plaintiffs in the Canadian Action have estimated their alleged statutory damages at $197.4 million. Because both the U.S. and Canadian Actions are in their early stages, Atlantic Power is unable to reasonably estimate the possible loss or range of losses, if any, arising from this litigation. Atlantic Power intends to defend vigorously each of the actions.

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, 2013 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, 2013.

## 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, 2013:

| Period | High (US$) | Low (US$) |
|---|---|---|
| Quarter ended December 31, 2013 | 5.36 | 3.06 |
| Quarter ended September 30, 2013 | 4.66 | 3.81 |
| Quarter ended June 30, 2013 | 5.57 | 3.86 |
| Quarter ended March 31, 2013 | 13.03 | 4.56 |
| 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 |

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, 2013 | 5.51 | 3.05 |
| Quarter ended September 30, 2013 | 4.86 | 4.01 |
| Quarter ended June 30, 2013 | 5.63 | 4.04 |
| Quarter ended March 31, 2013 | 13.02 | 4.64 |
| 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 |

The number of holders of common shares was approximately 63,225 on February 27, 2014.

**Dividends**

Dividends declared per common share in 2013 and 2012 were as follows (Cdn$):

| Month | 2013 | 2012 |
|---|---|---|
| | Amount | |
| January | $ 0.0958 | $ 0.0958 |
| February | 0.0958 | 0.0958 |
| March | 0.0333 | 0.0958 |
| April | 0.0333 | 0.0958 |
| May | 0.0333 | 0.0958 |
| June | 0.0333 | 0.0958 |
| July | 0.0333 | 0.0958 |
| August | 0.0333 | 0.0958 |
| September | 0.0333 | 0.0958 |
| October | 0.0333 | 0.0958 |
| November | 0.0333 | 0.0958 |
| December | 0.0333 | 0.0958 |

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See Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations Factors That May Influence Our Results" for a discussion of certain non-recourse project-level debt that can restrict the ability of our projects to make cash distributions to us and Item 1A. "Risk Factors Risk 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 dividend payments, cash distributions, acquisitions or investments or issue additional indebtedness we otherwise would seek to do."

**Securities Authorized for Issuance under Equity Compensation Plans**

The following table provides information as of December 31, 2013 regarding our Long-Term Incentive Plan. For the description of our Long-Term Incentive Plan, see Note 15, *Equity Compensation Plans* to the consolidated financial statements.

| | 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] |
|---|---|---|---|
| | (a) | (b) | (c) |
| Equity compensation plans approved by security holders | 511,325 | $ | 212,353 |
| Equity compensation plans not approved by security holders | | | |
| Total | 511,325 | $ | 212,353 |

(1) Number of securities to be issued upon exercise of outstanding awards and number of securities remaining available for future issuance reflects expected redemption of award one-third in cash and two-thirds in shares of our common stock. See Item 15. "Exhibits and Financial Statements Schedule" Note 2(r), Equity compensation plans.

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**Performance Graph**

The performance graph below compares the cumulative total shareholder return on our common shares for the period December 31, 2008, through December 31, 2013, 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, 2008, 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.

## 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, 2013 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, 2013.

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| **(in millions of U.S. dollars, except as otherwise stated)** | **2013[(a)]** | **2012[(a)]** | **2011[(a)(b)]** | **2010[(a)]** | **2009[(a)]** |
| Project revenue | $ 551.7 | $ 440.4 | $ 93.9 | $ 1.1 | $ |
| Project income (loss) | 64.3 | (29.4) | (3.6) | 16.1 | 20.1 |
| Loss from continuing operations | (17.6) | (114.2) | (69.9) | (26.7) | (63.9) |
| Income (loss) from discontinued operations, net of tax | (6.2) | 13.9 | 34.3 | 22.9 | 25.4 |
| Net loss attributable to Atlantic Power Corporation | (33.0) | (112.8) | (38.4) | (3.8) | (38.5) |
| Basic and diluted loss per share[(c)] | | | | | |
| Loss per share from continuing operations attributable to Atlantic Power Corporation | $ (0.23) | $ (1.09) | $ (0.94) | $ (0.45) | $ (1.06) |
| Income (loss) from discontinued operations, net of tax | (0.05) | 0.12 | $ 0.44 | $ 0.37 | $ 0.43 |
| Net loss attributable to Atlantic Power Corporation | $ (0.28) | $ (0.97) | $ (0.50) | $ (0.08) | $ (0.63) |
| Per IPS distribution declared | $ | $ | $ | $ | $ 0.51 |
| Per common share dividend declared | $ 0.51 | $ 1.1 | $ 1.11 | $ 1.06 | $ 0.46 |
| Total assets | $ 3,395.0 | $ 4,002.7 | $ 3,248.4 | $ 1,013.0 | $ 869.6 |
| Total long-term liabilities | $ 1,909.6 | $ 2,280.8 | $ 1,940.2 | $ 518.3 | $ 402.2 |

(a) The Florida Projects, Path 15 and Rollcast are classified as discontinued operations for the five years ended December 31, 2013. 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 each of the five years ended December 31, 2013, 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.

## 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 millions 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").*

**(in millions of U.S. dollars, except per-share amounts)**

### Overview of Our Business

Atlantic Power owns and operates a diverse fleet of power generation 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, 2013, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,948 megawatts ("MW") in which our aggregate ownership interest is approximately 2,026 MW. These totals exclude our 40% interest in the Delta-Person generating station ("Delta-Person") for which we entered into an agreement to sell in December 2012, which we expect to close in 2014. Our current portfolio consists of interests in twenty-eight operational power generation projects across eleven states in the United States and two provinces in Canada. We also own Ridgeline Energy Holdings, Inc. ("Ridgeline"), a wind and solar developer in Seattle, Washington. Twenty-two of our projects are wholly owned subsidiaries.

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 2014 to December 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.

The majority of our natural gas, coal and biomass power generation projects have long-term fuel supply agreements, typically accompanied by fuel transportation arrangements. In most cases, the term of 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 twenty-one 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 and PPMS. Under these operation, maintenance and management agreements, the operator is typically responsible for operations, maintenance and repair services.

### Strategy Update

As we have previously disclosed, we have been focused on initiatives aimed at, among other things, improving our financial flexibility and addressing our near-term maturities. We believe that the execution of the New Term Loan Facility and the use of the funds therefrom to address debt maturities in 2014, 2015 and 2017 and for possible further debt reduction, as discussed in more detail in " Liquidity and Capital Resources", are important steps toward achieving these goals. The 50% cash sweep and amortization features of the New Term Loan Facility are expected to reduce leverage over time. The additional flexibility, liquidity and maturity extension associated with the New Revolving

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Credit Facility is also a meaningful achievement with respect to these goals. We believe that these steps should improve our ability to continue with efforts to strengthen our balance sheet and optimize our assets. In addition, as previously disclosed, due to the aggregate impact of certain prepayment charges associated with the prepayments on our indebtedness described above, we are no longer in compliance with the fixed charge coverage ratio test included in the restricted payments covenant of the indenture governing our 9.0% notes. For additional information about the fixed charge coverage ratio test and its possible impact on our ability to pay dividends, if and when declared by our board of directors, see " Liquidity and Capital Resources."

We recognize that our important next steps include considering the relative merits of further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash while continuing to focus on how to best position the Company overall to maximize shareholder value. Consistent with these objectives, we are also committed to evaluating a broad range of potential options, including further selected asset sales or joint ventures to raise additional capital for growth or potential debt reduction, the acquisition of assets, including in exchange for shares, the dividend level, as well as broader strategic options. No assurance can be given as to how the evaluation of any such potential options may evolve.

**Significant Events**

*Amendment to Our Prior Credit Facility*

In August 2013, we entered into an amendment to our prior credit facility (the "Prior Credit Facility") with our lenders primarily to obtain more favorable financial covenant ratios. The amendment included changes to our borrowing capacity, financial ratios and certain other customary representations, warranties, terms and conditions and covenants. On February 26, 2014 we terminated the Prior Credit Facility in conjunction with the funding of the New Senior Secured Credit Facilities, as further described below. For a description of these changes, see " Liquidity and Capital Resources" and Note 10 to the consolidated financial statements included in this Annual Report on Form 10-K

*New Senior Secured Credit Facilities*

On February 24, 2014, the Partnership, our wholly-owned indirect subsidiary, entered into a new senior secured term loan facility (the "New Term Loan Facility"), comprising of $600 million in aggregate principal amount, and a new senior secured revolving credit facility (the "New Revolving Credit Facility') with a capacity of $210 million (collectively, the "New Senior Secured Credit Facilities") with its lenders. On February 26, 2014, $600 million was drawn under the New Term Loan Facility, and letters of credit in an aggregate face amount of $144 million were issued (but not drawn) pursuant to the revolving commitments under the New Revolving Credit Facility and used (i) to fund a debt service reserve in an amount equivalent to six months of debt service (approximately $15.8 million), and (ii) to support contractual credit support obligations of the Partnership and its subsidiaries and of certain other of our affiliates.

We and our subsidiaries have used the proceeds from the New Term Loan Facility to:

- prepay or redeem in whole, at a price equal to par plus accrued interest and applicable make-whole premium, (i) the $150 million aggregate principal amount outstanding of 5.87% Senior Guaranteed Notes, Series A, due 2015 and the $75 million aggregate principal amount outstanding of 5.97% Senior Guaranteed Notes, Series B, due 2017 issued by Atlantic Power (US) GP, and (ii) the $190 million aggregate principal amount outstanding of 5.9% Senior Notes due 2014 issued by Curtis Palmer LLC;

- pay transaction costs and expenses; and

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make a distribution to us in the range of approximately $120 million to $125 million, which we may use for any corporate purpose, including, in our discretion, additional debt reduction which may, taking into account available funds, market conditions and other relevant factors, include steps to repurchase or redeem, by means of a tender offer or otherwise, up to $150 million aggregate principal amount of our 9.0% senior unsecured notes due 2018 and up to Cdn$46 million of our 6.50% convertible debentures due October 31, 2014.

The foregoing description of the New Senior Secured Credit Facilities is qualified in its entirety by reference to the full text of the credit agreement governing the Senior Secured Credit Facilities, which is attached to this Annual Report on Form 10-K as Exhibit 10.1 and is incorporated herein by reference. For a description of the New Senior Secured Credit Facilities and use of proceeds thereunder, see "Liquidity and Capital Resources" and Note 10 to the consolidated financial statements included in this Annual Report on Form 10-K.

*Sale of Rollcast*

In November 2013, we completed the sale of our 60% interest in Rollcast to the other shareholders. As consideration for the sale, we were assigned asset management contracts for the Cadillac and Piedmont projects as well as the remaining 2% ownership interest in Piedmont bringing our total ownership to 100%. In return, we paid $0.5 million to the minority owner and forgave an outstanding $1.0 million loan that was provided by us to Rollcast to fund working capital during 2013. Rollcast's net loss is recorded as loss from discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011.

*Goodwill Impairment*

During the second quarter of 2013, based on a prolonged decline in our market capitalization we determined that it was appropriate to initiate a test of goodwill to determine if the fair value of each of our reporting units' goodwill does not exceed their carrying amounts. We concluded the test during the three months ended September 30, 2013 and determined that goodwill was impaired at the Kenilworth, Naval Station, Naval Training Center and North Island ("Naval reporting units") reporting units. The total non-cash impairment charge recorded was $34.9 million.

The $30.8 million impairment at Kenilworth was due to lower forecasted capacity and energy prices compared to the assumptions at the time of the acquisition in November 2011. When performing our two-step quantitative analysis, the increase in the intangible value associated with the new Energy Service Agreement ("ESA") entered into in July 2013 resulted in a lower implied goodwill value. At the time of its acquisition in November 2011, the fair value of the assets acquired and liabilities assumed for the Kenilworth project were valued assuming a merchant basis for the period subsequent to the expiration of the project's original PPA in July 2012. These forecasted energy revenues on a merchant basis were higher than the energy prices currently forecasted to be in effect subsequent to the expiration of the new ESA. The $4.1 million impairment at the Naval reporting units was primarily due to increased uncertainty, not assumed at the time of the reporting unit's acquisition in 2011, in our ability to extend two of the projects lease and steam agreements upon their expiration. In addition, lower currently forecasted capacity and energy prices in California after the expiration of the PPAs compared to the forecast at the time of the acquisition in 2011 result in a lower business enterprise value which resulted in a lower implied goodwill value.

During the three months ended June 30, 2013, we recorded a $3.5 million impairment of goodwill at Rollcast, which is designated as discontinued operations. We determined, based on the results of the two-step process, that the carrying amount of goodwill exceeded the implied fair value of goodwill. We also wrote-off $1.4 million of capitalized development costs at Rollcast related to the Greenway

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development project. The determination to impair goodwill and write-off the capitalized development costs was based on the reduced expectation of the Greenway project being further developed.

*Administration and Development Reductions*

In July 2013, we implemented changes in several areas that are expected to result in an approximate $8.0 million reduction to administration and development expenses relative to our previous 2014 budget for those items. The expected expense reductions are targeted to occur in three broad areas, which are, in order of significance: (1) reduction in the development budget, both for personnel and third-party expenses, consistent with de-emphasizing early-stage development projects; (2) consolidation of accounting and finance functions in two offices, down from three; and (3) additional synergies from full integration of areas such as health care, plant insurance, IT, travel and other functions. Most of the one-time costs incurred to implement these changes were recorded in 2013. The savings are expected to be realized beginning in 2014.

*Piedmont Commercial Operations, Receipt of Grant Proceeds, and Term Convert*

Piedmont achieved commercial operation under its PPA with Georgia Power Company at a declared capacity of 53.5 MW on April 19, 2013. Piedmont and its engineering, procurement and construction ("EPC") contractor, Zachry Industrial, Inc. ("Zachry"), are disputing certain issues under the EPC agreement including the condition and performance of the project, and are currently engaged in arbitration proceedings. An arbitration hearing has been tentatively scheduled in the later part of 2014 in connection with such dispute, during which time Piedmont is withholding the amount still retained under the EPC agreement.

In May 2013, Piedmont submitted an application under the federal 1603 grant program. In July, the grant was approved and $49.5 million was received from the U.S. Treasury. With the proceeds received and a $1.5 million contribution from Atlantic Power to cover the shortfall created by the U.S. federal budget sequestration, the project's outstanding $51.0 million bridge loan was fully repaid in July 2013. During the three months ended June 30, 2013 we contributed an additional $2.7 million equity investment to fund the project's working capital.

On February 14, 2014, we contributed an additional $14.2 million equity investment to Piedmont. With the contribution, the project paid down $8.1 million of the outstanding $76.6 million Piedmont project debt and converted the remaining $68.5 million principal to a term loan maturing in August 2018. We will pay interest at rate of LIBOR plus an applicable margin of 3.5% to 4.0% over the life of the term loan. The project used the remaining $6.1 million equity investment to fund various reserves required under the term loan and pay for fees associated with the term loan conversion.

*Canadian Hills Tax Equity*

In May 2013, we syndicated our $44.0 million tax equity investment in Canadian Hills to an institutional investor and received cash proceeds of $42.1 million. The cash proceeds received were based on our initial tax equity investment of $44.1 million less distributions received from Canadian Hills resulting in an immaterial loss on the sale. During this short-term ownership as a tax equity investor in the project, we generated approximately $3.0 million of production tax credits and approximately $10.9 million of net operating losses, which we will be able to use to offset against future taxable income. The syndication of our interest completes the sale of 100% of Canadian Hills' $269.0 million of tax equity interests. The cash proceeds will be held for general corporate purposes. We continue to own 99% of the project and consolidate it in our consolidated financial statements. Income (loss) and distributions attributable to the tax investors are recorded as a component of noncontrolling interests.

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*Sale of Gregory*

In April 2013, we and the other owners of Gregory entered into a purchase and sale agreement with an affiliate of NRG Energy, Inc. to sell our 17% interest in the project for approximately $274.2 million including working capital adjustments. We received net cash proceeds from our ownership interest of approximately $34.7 million in the aggregate, after repayment of project-level debt and transaction expenses. Approximately $5.0 million of these proceeds will be held in escrow for up to one year after the closing date. We intend to use the net proceeds from the sale for general corporate purposes. The sale of Gregory closed on August 7, 2013 resulting in a gain of $30.4 million and was recorded in gain on sale of equity investments in the consolidated statements of operations for the year ended December 31, 2013.

*Sale of Path 15*

On March 11, 2013 we entered into a purchase and sale agreement with Duke-American Transmission Company, a joint venture between Duke Energy Corporation and American Transmission Co., to sell our interests in Path 15. The sale closed on April 30, 2013 and we received net cash proceeds from the sale, including working capital adjustments, of approximately $52 million, plus a management agreement termination fee of $4.0 million, for a total sale price of approximately $56 million. The cash proceeds will be used for general corporate purposes. All project level debt issued by Path 15, totaling $137.2 million, transferred with the sale. Path 15 was accounted for as an asset held for sale in the consolidated balance sheets at December 31, 2012 and as a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011.

*Sale of Florida Projects*

On January 30, 2013, we entered into a purchase and sale agreement for the sale of the Florida Projects, for approximately $140 million, with working capital adjustments. The sale closed on April 12, 2013 and we received net cash proceeds of approximately $117 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. This includes approximately $92 million received at closing and cash distributions from the projects of approximately $25 million received since January 1, 2013. We used a portion of the net proceeds from the sale to fully repay our Prior Credit Facility, which had an outstanding balance of approximately $64.1 million on the closing date. The Florida Projects were accounted for as assets held for sale in the consolidated balance sheets at December 31, 2012 and are a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011.

**Factors That May Influence Our Results**

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 for 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 flows because they generally receive revenues from

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long-term contracts that provide relatively stable cash flows. Risks to the stability of these distributions include the following:

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 2014 and December 2037. When a PPA expires or is terminated, it may be difficult for us to secure a new PPA on acceptable terms or timing, if at all, or the price received by the project for power under subsequent arrangements may be reduced significantly, or there may be a delay in securing a new PPA until a significant time after the expiration of the original PPA at the project. For example, the current PPA at Selkirk (which represented 7.7% of our Project Adjusted EBITDA for the year ended December 31, 2013) expires in August 2014. If the project does not obtain a new PPA, this could result in 100% of the capacity at Selkirk not contracted and therefore sold at market power prices. Similarly, the PPA at Tunis (which represented 3.5% of our Project Adjusted EBITDA for the year ended December 31, 2013) expires in December 2014. Because Tunis has not been in the first group for which recontracting discussions are currently underway with the Ontario government and the process for such discussions has not been transparent, the outcome of recontracting discussions at the project are uncertain and we expect that a new PPA, if any, at Tunis, would be on significantly less favorable terms than the project's existing PPA. Beyond the expiration of the Selkirk and Tunis PPAs in 2014, our next PPA expirations do not occur until year end 2017 and are at our North Bay and Kapuskasing projects in Ontario. See "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."

While approximately 31% of our power generation revenue in 2013 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. 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.

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. The current PPA at Selkirk expires in August 2014, which could result in an increase to 100% of capacity not contracted and therefore sold at market power prices. 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 flows from operations is

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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 we expect to provide 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. Although all projects are currently meeting these debt service requirements, we cannot provide any assurances that these projects will generate enough future cash flow to meet any applicable ratio tests and be able to make 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, 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 dividend payments, acquisitions or investments or issue additional indebtedness we otherwise would seek to do."

The performance of our projects is impacted by a variety of operational and other factors, including planned and unplanned outages and maintenance requirements, delays in start-up, sourcing of fuel from suppliers and wind, water and waste heat levels, among others. For example, delays in the start-up of our Piedmont project and subsequent unplanned outages have resulted in increased costs and lost revenue and have affected our results. For additional details regarding the various operational and other risks that we face, see "Risk Factors Risks Related to Our Business and Our Projects."

*Non-cash gains and losses on derivatives instruments*

In the ordinary course of our business, we execute natural gas purchase agreements and natural gas swap contracts to manage our exposure to fluctuations in commodity prices, foreign currency forward 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.

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**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 electricity demand is also greatly influenced by weather, summer and winter peak electricity demand is projected to steadily increase over the next ten years. However, such increase in summer and winter peak electricity 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 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 started construction prior to January 1, 2014 and extended bonus depreciation for projects that are placed in service prior to January 1, 2014. The PTC provided an income tax credit of 2.3 cents/kilowatt-hour for the production of electricity from utility-scale wind turbines. Although the PTC has not yet been extended, further investment in renewable power remains a priority for the current U.S. administration.

*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 United States. 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 also 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.

*Retirement of fossil-fired generation*

The increase of gas and renewable capacity will be offset by large-scale retirements of coal-fired generation plants. NERC projects a net 35.1 GW reduction of coal-fired generation in the United States and Canada by 2023, with over 90% retiring by 2017 primarily due to existing and potential federal environmental regulations and low natural gas prices.

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**Consolidated Overview and Results of Operations by Segment**

We have four reportable segments: East, West, Wind and Un-allocated Corporate. We revised our reportable business segments in the fourth quarter of 2013 as the result of recent significant asset sales and in order to align with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. Our financial results for the years ended December 31, 2013, 2012 and 2011 have been presented to reflect these changes in operating segments. The segment classified as Un-allocated Corporate includes activities that support the executive and administrative offices, capital structure, costs of being a public registrant, costs to develop future projects and intercompany eliminations. 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.

Significant non-cash items included in the following discussion, 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 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.

***Performance highlights***

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **2011** |
| Project income (loss) | $ 64.3 | $ (29.4) | $ (3.6) |
| Loss from continuing operations | $ (17.6) | $ (114.2) | $ (69.9) |
| (Loss) income from discontinued operations | $ (6.2) | $ 13.9 | $ 34.3 |
| Net loss attributable to Atlantic Power Corporation | $ (33.0) | $ (112.8) | $ (38.4) |
| Loss per share from continuing operations attributable to Atlantic Power Corporation basic and diluted | $ (0.23) | $ (1.09) | $ (0.94) |
| Earnings (loss) per share from discontinued operations basic | (0.05) | 0.12 | $ 0.44 |
| Loss per share attributable to Atlantic Power Corporation basic and diluted | $ (0.28) | $ (0.97) | $ (0.50) |
| Project Adjusted EBITDA[1] | $ 270.5 | $ 227.6 | $ 86.8 |
| Cash Available for Distribution[1] | $ 108.8 | $ 131.6 | $ 79.0 |

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

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***2013 compared to 2012***

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

| | Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2013 | 2012 | $ change | % change |
| Project revenue: | | | | |
| Energy sales | $ 304.2 | $ 217.0 | $ 87.2 | 40% |
| Energy capacity revenue | 168.8 | 154.9 | 13.9 | 9% |
| Other | 78.7 | 68.5 | 10.2 | 15% |
| | 551.7 | 440.4 | 111.3 | 25% |
| Project expenses: | | | | |
| Fuel | 198.7 | 169.1 | 29.6 | 18% |
| Operations and maintenance | 152.4 | 122.8 | 29.6 | 24% |
| Development | 7.2 | | 7.2 | NM |
| Depreciation and amortization | 167.1 | 118.0 | 49.1 | 42% |
| | 525.4 | 409.9 | 115.5 | 28% |
| Project other income (expense): | | | | |
| Change in fair value of derivative instruments | 49.5 | (59.3) | 108.8 | NM |
| Equity in earnings of unconsolidated affiliates | 26.9 | 15.2 | 11.7 | 77% |
| Gain on sale of equity investments | 30.4 | 0.6 | 29.8 | NM |
| Interest expense, net | (34.4) | (16.4) | (18.0) | 110% |
| Impairment of goodwill | (34.9) | | (34.9) | NM |
| Other expense, net | 0.5 | | 0.5 | NM |
| | 38.0 | (59.9) | 97.9 | NM |
| Project income (loss) | 64.3 | (29.4) | 93.7 | NM |
| Administrative and other expenses (income): | | | | |
| Administration | 35.2 | 28.3 | 6.9 | 24% |
| Interest, net | 104.1 | 89.8 | 14.3 | 16% |
| Foreign exchange (gain) loss | (27.4) | 0.5 | (27.9) | NM |
| Other income, net | (10.5) | (5.7) | (4.8) | 84% |
| | 101.4 | 112.9 | (11.5) | -10% |
| Loss from continuing operations before income taxes | (37.1) | (142.3) | 105.2 | -74% |
| Income tax benefit | (19.5) | (28.1) | 8.6 | -31% |
| Loss from continuing operations | (17.6) | (114.2) | 96.6 | -85% |
| Income (loss) from discontinued operations, net of tax | (6.2) | 13.9 | (20.1) | NM |
| Net loss | (23.8) | (100.3) | 76.5 | -76% |
| Net loss attributable to noncontrolling interests | (3.4) | (0.6) | (2.8) | NM |

| | | | | | |
|---|---|---|---|---|---|
| Net income attributable to preferred share dividends of a subsidiary company | | 12.6 | 13.1 | (0.5) | -4% |
| Net loss attributable to Atlantic Power Corporation | $ | (33.0) | (112.8) | 79.8 | -71% |

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***Project Income (Loss) by Segment***

| | Year Ended December 31, 2013 | | | | |
|---|---|---|---|---|---|
| | East[(1)] | West[(2)] | Wind | Un-allocated Corporate[(3)] | Consolidated Total |
| Project revenue: | | | | | |
| Energy sales | $ 150.1 | $ 83.6 | $ 70.6 | $ (0.1) | $ 304.2 |
| Energy capacity revenue | 118.3 | 50.7 | | (0.2) | 168.8 |
| Other | 30.7 | 48.0 | 0.2 | (0.2) | 78.7 |
| | 299.1 | 182.3 | 70.8 | (0.5) | 551.7 |
| Project expenses: | | | | | |
| Fuel | 135.0 | 62.2 | 1.4 | 0.1 | 198.7 |
| Operations and maintenance | 63.7 | 58.5 | 19.4 | 10.8 | 152.4 |
| Development | | | | 7.2 | 7.2 |
| Depreciation and amortization | 68.9 | 55.9 | 41.8 | 0.5 | 167.1 |
| | 267.6 | 176.6 | 62.6 | 18.6 | 525.4 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | 25.5 | | 24.0 | | 49.5 |
| Equity in earnings of unconsolidated affiliates | 21.3 | 4.5 | 1.1 | | 26.9 |
| Gain on sale of equity investments | | 30.4 | | | 30.4 |
| Interest expense, net | (19.6) | (0.1) | (14.6) | (0.1) | (34.4) |
| Impairment of goodwill | (30.8) | (4.1) | | | (34.9) |
| Other expense, net | (2.1) | | (0.1) | 2.7 | 0.5 |
| | (5.7) | 30.7 | 10.4 | 2.6 | 38.0 |
| Project income (loss) | $ 25.8 | $ 36.4 | $ 18.6 | $ (16.5) | $ 64.3 |

| | Year Ended December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | East[(1)] | West[(2)] | Wind | Un-allocated Corporate[(3)] | Consolidated Total |
| Project revenue: | | | | | |
| Energy sales | $ 143.7 | $ 73.3 | $ | $ | $ 217.0 |
| Energy capacity revenue | 98.7 | 54.3 | 1.9 | | 154.9 |
| Other | 25.1 | 42.0 | | 1.4 | 68.5 |
| | 267.5 | 169.6 | 1.9 | 1.4 | 440.4 |
| Project expenses: | | | | | |
| Fuel | 123.0 | 46.0 | 0.1 | | 169.1 |
| Operations and maintenance | 52.8 | 56.5 | 1.0 | 12.5 | 122.8 |
| Development | | | | | |
| Depreciation and amortization | 61.6 | 56.3 | | 0.1 | 118.0 |

| | | | | | |
|---|---|---|---|---|---|
| | 237.4 | 158.8 | 1.1 | 12.6 | 409.9 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | (59.3) | | | | (59.3) |
| Equity in earnings of unconsolidated affiliates | 27.5 | (4.1) | (8.2) | | 15.2 |
| Gain on sale of equity investment | | 0.6 | | | 0.6 |
| Interest expense, net | (16.4) | | | | (16.4) |
| Other expense, net | | | | | |
| | (48.2) | (3.5) | (8.2) | | (59.9) |
| Project income (loss) | $ (18.1) | $ 7.3 | $ (7.4) | $ (11.2) | $ (29.4) |

(1) Excludes the Florida Projects which are classified as discontinued operations.

(2) Excludes Path 15 which is classified as discontinued operations.

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(3) Excludes Rollcast which is designated as discontinued operations.

***East***

Project income for 2013 increased $43.9 million from 2012 primarily due to:

- increased project income from Kapuskasing of $37.4 million due primarily to a positive $35.8 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives;

- increased project income from North Bay of $35.2 million due primarily to a positive $35.8 million non-cash change in the fair value of gas purchase agreements that were accounted for as derivatives;

- increased project income from Curtis Palmer of $4.0 million due primarily to increased generation resulting from higher water levels than the comparable period;

- increased project income from Calstock of $3.1 million due to increased capacity rates and generation, lower maintenance costs, and lower fuel costs than in the comparable 2012 period that had planned steam turbine maintenance; and

- increased project income from Nipigon of $2.6 million due primarily to higher availability and lower maintenance costs resulting from a planned outage in the comparable 2012 period.

These increases were partially offset by:

- decreased project income from Kenilworth of $27.2 million due primarily to a $30.8 million non-cash goodwill impairment charge recorded in the third quarter of 2013;

- decreased project income from Chambers of $6.2 million due primarily to the collection of the DuPont partial settlement associated with the dispute of the electricity price calculation under its PPA in the second quarter of 2012; and

- decreased project income from Tunis of $5.5 million due primarily to lower generation and energy prices.

Project income for the East segment excludes the Florida Projects as these projects were sold in April 2013, and are accounted for as a component of discontinued operations. Project loss for the Florida Projects was $1.1 million for the year ended December 31, 2013 as compared to project income of $13.6 million for the year ended December 31, 2012. The decrease is due primarily to the projects being sold in April 2013.

***West***

Project income for 2013 increased $29.1 million from 2012 primarily due to:

- increased project income from Gregory of $32.8 million primarily due to a $30.4 million gain on sale resulting from the project being sold in August 2013; and

- the sale of Badger Creek project in August in 2012 which had a $2.8 million project loss recorded in 2012.

These increases were partially offset by:

decreased project income of $3.7 million at Naval Station, Naval Training Center, and North Island due primarily to a $4.1 million non-cash goodwill impairment charge recorded in the third quarter of 2013; and

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- decreased project income from Mamquam of $3.5 million primarily attributable to increased maintenance costs from a scheduled outage and lower revenues due to lower water levels than the comparable period.

Project income for the West segment excludes the Path 15 project which is accounted for as a component of discontinued operations. Project income for Path 15 was $2.1 million and $5.1 million for the years ended December 31, 2013 and 2012, respectively. The decrease is due primarily to the project being sold in April 2013.

***Wind***

Project income for 2013 increased $26.0 million from 2012 primarily due to:

- increased project income from Rockland of $18.2 million attributable to the 100% consolidation of a former equity method project subsequent to an ownership change from 30% to 50% as part of the Ridgeline acquisition during the fourth quarter of 2012; and

- increased project income from Meadow Creek of $6.0 million which achieved commercial operations in December 2012. Meadow Creek was also part of the Ridgeline acquisition in December 2012. Meadow Creek's project income was primarily due to a positive $12.5 million non-cash change in the fair value of interest rate swap agreements that were accounted for as derivatives. This increase in income was offset by $8.1 million of interest expense.

***Un-allocated Corporate***

Total project loss increased $5.3 million from 2012 primarily due to $7.2 million of development expense at Ridgeline which was acquired in December 2012.

***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 and administrative 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 increased $6.9 million or 24.4% from 2012 primarily due to transactional fees during 2013 related to divestitures, the shareholder class action lawsuits and the amendment of the Prior Credit Facility in August as well as an increase in salaries and severance expenses.

*Interest, net*

Interest expense increased $14.3 million or 15.9% from 2012 primarily due to the issuance of the $130 million principal amount of convertible debentures in July of 2012 and issuance of the Cdn$100 million principal amount of convertible debentures in December of 2012 as well as interest related to the Prior Credit Facility.

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*Foreign exchange loss (gain)*

Foreign exchange gain increased $27.9 million primarily due to a $39.4 million increase in unrealized gain in the revaluation of instruments denominated in Canadian dollars, offset by a $4.1 million decrease in realized gains on the settlement of foreign currency forward contracts and a $7.4 million increase in unrealized loss on foreign exchange forward contracts. The U.S. dollar to Canadian dollar exchange rate was 1.0636 and 0.9949 at December 31, 2013 and 2012, respectively, an increase of 6.9% in 2013 compared to a decrease of 2.2% in 2012.

*Other income, net*

Other income, net increased $4.8 million or 84.2% from 2012 period primarily due to a $10.3 million gain on sale and management agreement termination fee resulting from the sale of Path 15. In 2012, we recorded a $6.0 million management agreement termination fee related to the sale of our equity interest in PERH.

*Income tax benefit*

Income tax benefit for the year ended December 31, 2013 was $19.5 million. Income tax benefit for the same period, based on the Canadian enacted statutory rate of 26%, was $9.7 million. The primary items impacting the effective tax rate relate to a benefit of $18.9 million from the 1603 Treasury Grants received in 2013, a $9.9 million benefit relating to foreign exchange differences, and $4.5 million related to production tax credits. These benefits were offset by an $12.1 million additional tax expense related to a change in the valuation allowance and an additional $13.6 million tax expense related to the goodwill impairment charge during 2013.

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***2012 compared to 2011***

The following table provides our consolidated results of operations:

| | Years Ended December 31, | | | |
|---|---|---|---|---|
| | 2012 | 2011 | $ change | % change |
| Project revenue: | | | | |
| Energy sales | $ 217.0 | $ 43.6 | $ 173.4 | NM |
| Energy capacity revenue | 154.9 | 34.0 | 120.9 | NM |
| Other | 68.5 | 16.3 | 52.2 | NM |
| | 440.4 | 93.9 | 346.5 | NM |
| Project expenses: | | | | |
| Fuel | 169.1 | 37.5 | 131.6 | NM |
| Operations and maintenance | 122.8 | 20.9 | 101.9 | NM |
| Development | | | | NM |
| Depreciation and amortization | 118.0 | 23.6 | 94.4 | NM |
| | 409.9 | 82.0 | 327.9 | NM |
| Project other income (expense): | | | | |
| Change in fair value of derivative instruments | (59.3) | (14.6) | (44.7) | NM |
| Equity in earnings of unconsolidated affiliates | 15.2 | 6.4 | 8.8 | NM |
| Gain on sale of equity investments | 0.6 | | 0.6 | NM |
| Interest expense, net | (16.4) | (7.3) | (9.1) | NM |
| Other expense, net | | | | NM |
| | (59.9) | (15.5) | (44.4) | NM |
| Project loss | (29.4) | (3.6) | (25.8) | NM |
| Administrative and other expenses (income): | | | | |
| Administration | 28.3 | 37.7 | (9.4) | -25% |
| Interest, net | 89.8 | 26.0 | 63.8 | NM |
| Foreign exchange loss | 0.5 | 13.8 | (13.3) | -96% |
| Other income, net | (5.7) | (0.1) | (5.6) | NM |
| | 112.9 | 77.4 | 35.5 | 46% |
| Loss from continuing operations before income taxes | (142.3) | (81.0) | (61.3) | 76% |
| Income tax benefit | (28.1) | (11.1) | (17.0) | NM |
| Loss from continuing operations | (114.2) | (69.9) | (44.3) | 63% |
| Income from discontinued operations, net of tax | 13.9 | 34.3 | (20.4) | -59% |
| Net loss | (100.3) | (35.6) | (64.7) | NM |
| Net loss attributable to noncontrolling interests | (0.6) | (0.5) | (0.1) | 20% |
| Net income attributable to preferred share dividends of a subsidiary company | 13.1 | 3.3 | 9.8 | NM |

| | | | | |
|---|---|---|---|---|
| Net loss attributable to Atlantic Power Corporation | $ (112.8) | $ (38.4) | $ (74.4) | NM |

The consolidated results of operation include the results of operation from the Partnership beginning on the acquisition date of November 5, 2011.

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***Project Income (Loss) by Segment***

| | Year Ended December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | East[1] | West[2] | Wind | Un-allocated Corporate[3] | Consolidated Total |
| Project revenue: | | | | | |
| Energy sales | $ 143.7 | $ 73.3 | $ | $ | $ 217.0 |
| Energy capacity revenue | 98.7 | 54.3 | 1.9 | | 154.9 |
| Other | 25.1 | 42.0 | | 1.4 | 68.5 |
| | 267.5 | 169.6 | 1.9 | 1.4 | 440.4 |
| Project expenses: | | | | | |
| Fuel | 123.0 | 46.0 | 0.1 | | 169.1 |
| Operations and maintenance | 52.8 | 56.5 | 1.0 | 12.5 | 122.8 |
| Development | | | | | |
| Depreciation and amortization | 61.6 | 56.3 | | 0.1 | 118.0 |
| | 237.4 | 158.8 | 1.1 | 12.6 | 409.9 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | (59.3) | | | | (59.3) |
| Equity in earnings of unconsolidated affiliates | 27.5 | (4.1) | (8.2) | | 15.2 |
| Gain on sale of equity investment | | 0.6 | | | 0.6 |
| Interest expense, net | (16.4) | | | | (16.4) |
| Other expense, net | | | | | |
| | (48.2) | (3.5) | (8.2) | | (59.9) |
| Project income (loss) | $ (18.1) | $ 7.3 | $ (7.4) | $ (11.2) | $ (29.4) |

| | Year Ended December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | East[1] | West[2] | Wind | Un-allocated Corporate[3] | Consolidated Total |
| Project revenue: | | | | | |
| Energy sales | $ 33.9 | $ 10.9 | $ | $ (1.2) | $ 43.6 |
| Energy capacity revenue | 27.4 | 6.4 | | 0.2 | 34.0 |
| Other | 4.7 | 9.4 | | 2.2 | 16.3 |
| | 66.0 | 26.7 | | 1.2 | 93.9 |
| Project expenses: | | | | | |
| Fuel | 27.6 | 9.9 | | | 37.5 |
| Operations and maintenance | 11.1 | 7.5 | | 2.3 | 20.9 |
| Development | | | | | |
| Depreciation and amortization | 13.6 | 10.1 | | (0.1) | 23.6 |
| | 52.3 | 27.5 | | 2.2 | 82.0 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Project other income (expense): | | | | | | | | | |
| Change in fair value of derivative instruments | | (12.6) | | | | | | (2.0) | | (14.6) |
| Equity in earnings of unconsolidated affiliates | | 4.1 | | 1.5 | | (1.6) | | 2.4 | | 6.4 |
| Gain on sale of equity investment | | (7.3) | | | | | | | | (7.3) |
| Interest expense, net | | | | | | | | | | |
| Other expense, net | | | | | | | | | | |
| | | (15.8) | | 1.5 | | (1.6) | | 0.4 | | (15.5) |
| Project income (loss) | $ | (2.1) | $ | 0.7 | $ | (1.6) | $ | (0.6) | $ | (3.6) |

(1) Excludes the Florida Projects which are classified as discontinued operations.

(2) Excludes Path 15 which is classified as discontinued operations.

(3) Excludes Rollcast which is designated as discontinued operations

***East***

Project income for 2012 decreased $16.0 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 regarding the electricity price 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;

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

- increased project income of $4.6 million from the Morris project that was acquired on November 5, 2011, and includes a full year of operations in 2012.

Project income for the East segment excludes the Florida Projects which are accounted for as 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.

***West***

Project income for 2012 increased $6.6 million from 2011 primarily due to:

- 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;

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- increased project income of $3.9 million from the Oxnard project that was acquired on November 5, 2011, and includes a full year of operations in 2012; and

- increased project income of $2.7 million from the Manchief project that was acquired on November 5, 2011, and includes a full year of operations in 2012.

These increases were partially offset by:

- 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.

Project income for the West segment excludes the Path 15 project which is accounted for 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.

***Wind***

Project loss for 2012 increased $5.8 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.

***Un-allocated Corporate***

Total project loss increased $10.6 million from 2011 primarily due higher general and administrative expenses associated with operating the newly acquired Partnership projects.

*Administration*

Administration expense decreased $9.4 million or 25% from 2011 primarily due to costs incurred related to the acquisition of the Partnership.

*Interest, net*

Interest, net increased $63.8 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 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 0.9949 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

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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.

**Project Operating Performance**

Two of the primary metrics we utilize to measure the operating performance of our projects are generation and availability. Generation measures the net output of our proportionate project ownership percentage in megawatt hours. Availability is calculated by dividing the total scheduled hours of a project less forced outage hours by the total hours in the period measured. The terms of our PPAs require the projects to maintain certain levels of availability. Although the availability in the table below fluctuates from year to year, each of the projects with reduced availability were able to achieve substantially all of its respective capacity payments. The terms of our PPAs provide for certain levels of planned and unplanned outages.

***Generation***

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| **(in Net MWh)** | **2013** | **2012** | **2011** | **% change 2013 vs. 2012** | **% change 2012 vs. 2011** |
| **Segment** | | | | | |
| East[1] | 3,889.0 | 3,533.4 | 1,680.4 | 10.1% | 110.3% |
| West[2] | 2,797.4 | 2,151.1 | 479.9 | 30.0% | NM |
| Wind | 1,749.6 | 221.7 | 119.2 | NM | 86.0% |
| Total | 8,436.0 | 5,906.2 | 2,279.5 | 42.8% | 159.1% |

(1) Excludes the Florida Projects which are classified as discontinued operations.

(2) Excludes Delta-Person for which we entered into an agreement to sell in December 2012 and expect to close in 2014.

*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Aggregate power generation for 2013 increased 42.8% from 2012 primarily due to:

- increased generation in the East segment due to Piedmont, which achieved commercial operations in April 2013;
- increased generation in the West segment due to increased dispatch at Manchief and higher generation at Frederickson; and
- increased generation in the Wind segment primarily due to Canadian Hills which achieved commercial operations in December 2012 and Meadow Creek, which was acquired as part of the Ridgeline acquisition in December 2012.

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

Aggregate power generation for 2012 increased 159.1% from 2011 primarily due to:

- increased generation in the East segment primarily due to 2,026.0 MWh from the Partnership projects acquired on November 5, 2011; and
- increased generation in the West segment primarily due to 1,674.9 MWh from the Partnership projects acquired on November 5, 2011.

***Availability***

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2013 | 2012 | 2011 | % change 2013 vs. 2012 | % change 2012 vs. 2011 |
| **Segment** | | | | | |
| East[(1)] | 95.6% | 96.3% | 96.2% | -0.7% | 0.1% |
| West[(2)] | 92.1% | 93.1% | 98.3% | -1.1% | -5.3% |
| Wind | 98.7% | 98.6% | 96.8% | 0.1% | 1.9% |
| Weighted average | 94.9% | 95.3% | 96.1% | -0.4% | -0.8% |

(1) Excludes the Florida Projects which are classified as discontinued operations.

(2) Excludes Delta-Person for which we entered into an agreement to sell in December 2012 and expect to close in 2014.

Weighted average availability for 2013 decreased to 94.9% or -0.4% from 2012 primarily due to:

- decreased availability in the West segment resulting from decreased availability at Mamquam and Moresby Lake, which underwent scheduled maintenance during 2013; and
- decreased availability in the East segment resulting from decreased availability at Morris, which underwent scheduled maintenance during 2013.

This decrease was partially offset by:

- increased availability in the Wind segment resulting from increased availability at Meadow Creek and Goshen, which were acquired in December 2012, as well as increased availability at Canadian Hills, which achieved commercial operations in December 2012.

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

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

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

- decreased availability in the East segment primarily due to boiler maintenance at Morris.

This decrease was partially offset by:

- increased availability in the East segment primarily due to increases at Chambers and Selkirk which had planned outages in 2011; and increased availability in the Wind segment primarily due to Canadian Hills which achieved commercial operations in December 2012 and Meadow Creek, which was acquired as part of the Ridgeline acquisition in December 2012.

Generation and availability statistics for the East segment exclude the Florida Projects which are accounted for as a component of discontinued operations. Total generation for Auburndale was 916.5 MWh and 654.9 MWh and availability was 94.8% and 97.4% for the years ended December 31, 2012 and 2011, respectively. Total generation for Lake was 588.9 MWh and 468.5 MWh and availability was 99.2% and 98.4% for the years ended December 31, 2012 and 2011, respectively. Total generation for Pasco was 252.0 MWh and 263.0 MWh and availability was 96.1% and 99.6% for the years ended December 31, 2012 and 2011, 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, capital expenditures, dividends paid on preferred shares of a subsidiary company, distributions to noncontrolling interests and adjusted for changes in project-level working capital and cash reserves. Project Adjusted EBITDA is defined as project income (loss) plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. A reconciliation of project income (loss) to Project Adjusted EBITDA is set out below by segment under "Project Adjusted EBITDA" and a reconciliation of project income (loss) by segment to Project Adjusted EBITDA by segment is set out in Note 21 to the consolidated financial statements. Investors are cautioned that we may calculate this measure in a manner that is different from other companies.

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**Project Adjusted EBITDA**

| | Year ended December 31, 2013 | 2012 | 2011 | $ change 2013 vs 2012 | $ change 2012 vs 2011 |
|---|---|---|---|---|---|
| **Project Adjusted EBITDA by segment** | | | | | |
| East[1] | $ 150.7 | $ 145.7 | $ 66.8 | $ 5.0 | $ 78.9 |
| West[2] | 78.8 | 82.1 | 16.4 | (3.3) | 65.7 |
| Wind | 59.6 | 10.9 | 4.3 | 48.7 | 6.6 |
| Un-allocated Corporate[3] | (18.6) | (11.1) | (0.7) | (7.5) | (10.4) |
| **Total** | 270.5 | 227.6 | 86.8 | 42.9 | 140.8 |
| **Reconciliation to project income** | | | | | |
| Depreciation and amortization | 209.8 | 164.9 | 55.5 | 44.9 | 109.4 |
| Interest expense, net | 38.5 | 24.0 | 15.2 | 14.5 | 8.8 |
| Change in the fair value of derivative instruments | (50.3) | 56.6 | 17.2 | (106.9) | 39.4 |
| Other (income) expense | 8.2 | 11.5 | 2.5 | (3.3) | 9.0 |
| **Project income (loss)** | $ 64.3 | $ (29.4) | $ (3.6) | $ 93.7 | $ (25.8) |

(1) Excludes the Florida Projects which are classified as discontinued operations.

(2) Excludes Path 15 which is classified as discontinued operations.

(3) Excludes Rollcast which is classified as discontinued operations.

*East*

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

| | Year ended December 31, 2013 | 2012 | 2011 | % change 2013 vs. 2012 | % change 2012 vs. 2011 |
|---|---|---|---|---|---|
| **East** | | | | | |
| Project Adjusted EBITDA | $ 150.7 | $ 145.7 | $ 66.8 | 3% | 118% |

*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Project Adjusted EBITDA for 2013 increased $5.0 million or 3% from 2012 primarily due to increases in Project Adjusted EBITDA of:

- $4.0 million at Curtis Palmer primarily attributable to increased generation resulting from higher water levels to the comparable period and a $2.0 million favorable water reclamation tax assessment during 2013;

$3.6 million at Kenilworth primarily attributable to increased capacity revenues under the renewal of the project's energy service agreement;

$3.0 million at Calstock which had a steam turbine maintenance outage occur in the comparable 2012 period and contractual escalation of capacity rates in the 2013 period;

$3.0 million at Selkirk due to capacity revenues resulting from higher generation, partially offset by higher fuel costs; and

$2.4 million at Kapuskasing primarily attributable to a steam turbine maintenance outage that occurred in the comparable 2012 period.

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

- $7.2 million at Chambers primarily attributable to the collection of the DuPont partial settlement associated with the dispute of the electricity price calculation in the comparable 2012 period; and

- $4.0 million at Tunis resulting from lower generation and higher maintenance costs due to a scheduled maintenance outage.

Project Adjusted EBITDA for the East segment excludes the Florida Projects as these projects were sold in April 2013, and are accounted for as a component of discontinued operations. Project Adjusted EBITDA for the Florida Projects was $27.2 million for the year ended December 31, 2013 as compared to $82.4 million for the year ended December 31, 2012.

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

Project Adjusted EBITDA for 2012 increased $78.9 million or 118% 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;

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

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

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

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

- $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 East segment excludes the Florida Projects which are accounted for as 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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*West*

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

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2013 | 2012 | 2011 | % change 2013 vs. 2012 | % change 2012 vs. 2011 |
| **West** | | | | | |
| Project Adjusted EBITDA | $ 78.8 | $ 82.1 | $ 16.4 | (5%) | NM |

*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Project Adjusted EBITDA for 2013 decreased by $3.3 million or 5% from 2012 primarily due to decreases in Project Adjusted EBITDA of:

- $3.4 million at Mamquam resulting from higher maintenance costs due to a scheduled outage and decreased revenues caused by lower water levels; and

- $2.2 million at Williams Lake due to lower energy revenues from contractual price decreases and higher maintenance costs than the comparable 2012 period.

Project Adjusted EBITDA for the West segment excludes the Path 15 project which is accounted for as a component of discontinued operations. Project Adjusted EBITDA for Path 15 was $9.0 million and $24.5 million for the years ended December 31, 2013 and 2012, respectively. The decrease is due to the project being sold during the second quarter of 2013.

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

Project Adjusted EBITDA for 2012 increased $65.7 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;

- $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;

- $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 West segment excludes the Path 15 project which is accounted for as 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.

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*Wind*

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

| | Year ended December 31, 2013 | 2012 | 2011 | % change 2013 vs. 2012 | % change 2012 vs. 2011 |
|---|---|---|---|---|---|
| **Wind** | | | | | |
| Project Adjusted EBITDA | $ 59.6 | $ 10.9 | $ 4.3 | NM | 153% |

*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Project Adjusted EBITDA for 2013 increased by $48.7 million from 2012 primarily due to increases in Project Adjusted EBITDA of:

- $24.8 million at Canadian Hills which achieved commercial operations in December 2012;
- $14.0 million at Meadow Creek which was part of the Ridgeline acquisition and achieved commercial operations in December 2012;
- $6.8 million at Rockland attributable to the 100% consolidation of a former equity method project subsequent to an ownership change from 30% to 50% as part of the Ridgeline acquisition in December 2012; and
- $3.0 million at Goshen North which was acquired as part of the Ridgeline acquisition in December 2012.

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

Project Adjusted EBITDA for 2012 increased by $6.6 million or 153% from 2011 primarily due to increases in Project Adjusted EBITDA of:

- $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.

*Un-allocate Corporate*

The following table summarizes Project Adjusted EBITDA for our Un-allocated Corporate segment for the periods indicated:

| | Year ended December 31, 2013 | 2012 | 2011 | % change 2013 vs. 2012 | % change 2012 vs. 2011 |
|---|---|---|---|---|---|
| **Un-allocated Corporate** | | | | | |
| Project Adjusted EBITDA | $ (18.6) | $ (11.1) | $ (0.7) | 68% | NM |

*Year ended December 31, 2013 compared with Year ended December 31, 2012*

Project Adjusted EBITDA for 2013 decreased by $7.5 million from 2012 primarily due to $7.2 million of administrative and development costs at Ridgeline which was acquired in December 2012.

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

Project Adjusted EBITDA for 2012 decreased by $10.4 million from 2011 primarily due to administrative costs at the Partnership which was acquired in November of 2011.

**Cash Available for Distribution**

The payout ratio associated with the cash dividends declared to shareholders was 53%, 100%, and 109% for the year ended December 31, 2013, 2012, and 2011 respectively. On February 28, 2013, we announced a reduction in the dividend level from a monthly dividend level of Cdn$0.09583 to Cdn$0.03333 commencing with the March 2013 dividend to shareholders of record on March 28, 2013. The payout ratio for the year ended December 31, 2013 as compared to the same period in 2012 was positively impacted by the reduced cash dividends declared to shareholders as well as the inclusion of operating results from Canadian Hills and Meadow Creek which achieved commercial operations in late December 2012. This was partially offset by lower operating cash flows as a result of the sale of the Florida Projects and Path 15 in April 2013. The payout ratio for the year ended December 31, 2012 as compared to the same period in 2011 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.

Due to the timing of numerous working capital adjustments and the cash payments associated with our corporate level interest payments, our payout ratio will fluctuate from quarter to quarter. For example, the interest payments on the $460 million Senior Notes are due semi-annually (May and November) and will impact our payout ratios in the second and fourth quarters.

The table below presents our calculation of Cash Available for Distribution for the years ended December 31, 2013, 2012, and 2011 and the reconciliation to cash flows from operating activities, the most directly comparable GAAP measure:

| | Year ended December 31, | | |
|---|---|---|---|
| **(unaudited)** | **2013** | **2012** | **2011** |
| Cash flows from operating activities | $ 152.4 | $ 167.1 | $ 55.9 |
| Project-level debt repayments | (15.6) | (19.6) | (21.5) |
| Purchases of property, plant and equipment[1] | (6.5) | (2.9) | (2.0) |
| Transaction costs[2] | | | 33.4 |
| Realized foreign currency losses on hedges associated with the Partnership transaction[3] | | | 16.5 |
| Distributions to noncontrolling interests[4] | (8.9) | | |
| Dividends on preferred shares of a subsidiary company | (12.6) | (13.0) | (3.2) |
| Cash Available for Distribution[5] | $ 108.8 | $ 131.6 | $ 79.1 |
| Total cash dividends declared to shareholders | $ 58.0 | $ 131.8 | $ 86.4 |
| Payout ratio[5] | 53% | 100% | 109% |

(1) Excludes construction costs related to our Piedmont biomass project and Canadian Hills and Meadow Creek wind projects.

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

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(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) Distributions to noncontrolling interests primarily include distributions, if any, to the tax equity investors at Canadian Hills and to the other 50% owner of Rockland.

(5) Cash Available for Distribution and Payout Ratio are not recognized measures under GAAP and do not have any standardized meaning prescribed by GAAP. Therefore, these measures may not be comparable to similar measures presented by other companies. See "Supplementary Non-GAAP Financial Information" above.

**Cash Flow Discussion**

The following table reflects the changes in cash flows for the periods indicated:

| | Year ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **Change** |
| Net cash provided by operating activities | $ 152.4 | $ 167.1 | $ (14.7) |
| Net cash provided by (used in) investing activities | 147.1 | (523.8) | 670.9 |
| Net cash (used in) provided by financing activities | (207.6) | 362.7 | (570.3) |

***Net cash provided by (used in) operating activities***

Changes to net cash provided by (used in) operating activities were driven by:

| | |
|---|---|
| Decrease in net loss | $ 76.5 |
| Change in the fair value of derivative instruments primarily related to a $76.2 million increase in fuel purchase agreements and a $32.1 million increase in interest rate swaps | (106.9) |
| Increase in the loss at discontinued operations from the Florida Projects, Path 15 and Rollcast | 32.8 |
| Change in unrealized foreign exchange gain on Canadian dollar denominated instruments | (32.0) |
| Gain from the sale of our equity method projects primaily related to $30.4 million recorded for the sale of Gregory | (29.8) |
| Changes in working capital primarily due to receipts of security deposits at Meadow Creek and Canadian Hills | 44.4 |
| Other | 0.3 |
| | $ (14.7) |

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***Net cash provided by (used in) investing activities***

Changes to net cash provided by (used in) investing activities were driven by:

| | |
|---|---|
| Decrease in purchases of property, plant and equipment and construction in progress primarily due to the completion of the Piedmont and Canadian Hills projects in April 2013 and December 2012, respectively | $ 414.3 |
| Increase in proceeds from the sale of acquired assets related to the sale of the Florida Projects and Path 15 during 2013 | 154.7 |
| Cash paid for the Ridgeline acqusition in December 2012 | 80.5 |
| Proceeds from the receipt of treasury grants at Piedmont and Meadow Creek | 103.2 |
| Increased restricted cash primarily due to a $75 million increase related to the requirements of the amended senior credit facility | (82.1) |
| Other | 0.3 |
| | $ 670.9 |

***Net cash (used in) provided by financing activities***

Changes to net cash (used in) provided by financing activities were driven by:

| | |
|---|---|
| Decrease in net proceeds and payments on project-level debt primarily due to the proceeds from the Canadian Hills construction loan in 2012 offset by repayments of Meadow Creek and Piedmont debt with treasury grant proceeds in 2013 | $ (105.1) |
| Proceeds from the issuance of convertible debentures in July and December of 2012 | (230.6) |
| Change in equity contributions from non-controlling interests related to proceeds from tax equity investors of Canadian Hills | (180.4) |
| Decreased payments of dividends to common shareholders and non-controlling interests primaily due to the dividend reduction in March 2013 | 60.7 |
| Change in net proceeds and payments on revolving credit facility borrowings primarily due to the payment of amounts incurred for the Ridgeline acquisition | (69.8) |
| Proceeds from issuance of equity in December 2012 | (67.3) |
| Decrease in cash used for deferred financing costs primarily related to the July and December 2012 convertible debenture issuances | 28.5 |
| Other | (6.3) |
| | $ (570.3) |

| | Year ended December 31, | | |
|---|---|---|---|
| | **2012** | **2011** | **Change** |
| Net cash provided by operating activities | $ 167.1 | $ 55.9 | $ 111.2 |
| Net cash used in investing activities | (523.8) | (682.0) | 158.2 |
| Net cash provided by financing activities | 362.7 | 641.3 | (278.6) |

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***Net cash (used in) provided by operating activities***

Changes to net cash (used in) provided by operating activities were driven by:

| | |
|---|---|
| Increase in net loss | $ (64.7) |
| Change in the fair value of derivative instruments due to fuel purchase agreements resulting from the Partnership acquisition in November 2011 | 23.9 |
| Change in deferred income taxes | (24.2) |
| Increase in asset impairment charges primarily from a $50.0 million impairment due to the sale of Lake and $7.3 million impairment recorded at Rockland for our December 2012 step-up acquisition from 30% to 50% ownership | 59.0 |
| Change in depreciation and amortization primarily due to the acquisition of the Partnership in November 2011 | 93.6 |
| Change in unrealized foreign exchange loss on Canadian dollar denominated instruments | 10.4 |
| Changes in working capital primarily due to the acquisition of the Partnership in November 2011 | 15.0 |
| Other | (1.8) |
| | $ 111.2 |

***Net cash provided by (used in) investing activities***

Changes to net cash provided by (used in) investing activities were driven by:

| | |
|---|---|
| Decrease in cash paid for investments primarily related to the acquisition of the Partnership in November 2011 | $ 511.1 |
| Increase in construction in progress related to the development of our Canadian Hills and Piedmont projects | (343.1) |
| Proceeds from the sale of our PERC and Badger Creek projects | 19.4 |
| Receipt of a related party loan receivable from Idaho Wind in 2011 | (22.8) |
| Change in restricted cash | (5.9) |
| Other | (0.5) |
| | $ 158.2 |

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***Net cash (used in) provided by financing activities***

Changes to net cash (used in) provided by financing activities were driven by:

| | |
|---|---|
| Proceeds from the issuance of the Senior Notes of Atlantic Power Corporation in November 2011 | $ (460.0) |
| Proceeds from the issuance of convertible debentures in July and December of 2012 | 230.6 |
| Decrease in proceeds from the issuance of equity primarily due to $155.4 million of equity issued for the acquisition of the Partnership in Novemeber 2011, offset by $66.3 million of equity issued in December 2012 | (89.1) |
| Change in net proceeds and payments on revolving credit facility borrowings | (49.0) |
| Equity contributions from non-controlling interests related to the proceeds from tax equity investors of Canadian Hills | 225.0 |
| Decrease in net proceeds and payments on project-level debt primarily due to the repayment of the Canadian Hills construction loan in 2012 offset by proceeds from the Piedmont construction loan in 2011 | (72.2) |
| Increased payments of dividends to common shareholders and non-controlling interests primarily due to a dividend increase in November 2011 and preferred shares assumed in the acquisition of the Partnerhsip in November 2011 | (59.1) |
| Other | (4.8) |
| | $ (278.6) |

**Liquidity and Capital Resources**

| | December 31, | |
|---|---|---|
| | **2013** | **2012** |
| Cash and cash equivalents[(1)] | $ 158.6 | $ 60.2 |
| Restricted cash[(2)] | 114.2 | 28.6 |
| Total | 272.8 | 88.8 |
| Revolving credit facility availability | 52.8 | 120.1 |
| Total liquidity | $ 325.6 | $ 208.9 |

(1) Cash and cash equivalents and restricted cash for 2012 excludes $19.1 million related to the Florida Projects and Path 15 which are classified as assets held for sale at December 31, 2012.

(2) At February 27, 2014, giving effect to the New Senior Secured Credit Facilities, release of $75 million in restricted cash in connection with the termination of the Prior Credit Facility, the net cash impact of the use of proceeds of the New Senior Secured Credit Facilities and the additional Piedmont equity contribution, unrestricted cash was approximately $325 million and total liquidity was approximately $435 million, including unused capacity under the New Revolving Credit Facility.

***Overview***

Our primary source of liquidity is distributions from our projects and availability under our New Revolving Credit Facility. Our liquidity depends in part on our ability to successfully enter into new PPAs at facilities when PPAs expire or terminate. PPAs in our portfolio have expiration dates ranging from August 2014 to December 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

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arrangements may be reduced significantly. As a result, this may reduce the cash received from project distributions and the cash available for further debt reduction, identification of and investment in accretive growth opportunities (both internal and external), to the extent available, and other allocation of available cash. See "Risk Factors Risks Related to Our Structure We may not generate sufficient cash flow to pay dividends, if and when declared by our board of directors, service our debt obligations or finance internal or external growth opportunities or fund our operations."

We expect to reinvest approximately $36 to $40 million in 2014 in our portfolio in the form of project capital expenditures and major maintenance expenses. Such investments are generally paid at the project level. See " Capital and Major Expenditures." We do not expect any other material or unusual requirements for cash outflows for 2014 for capital expenditures or other required investments. 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 at least the next 12 months.

***New Senior Secured Credit Facilities***

On February 24, 2014 the Partnership, our wholly-owned indirect subsidiary, entered into the New Senior Secured Credit Facilities, including the New Term Loan Facility, comprising of $600 million in aggregate principal amount, and the New Revolving Credit Facility with a capacity of $210 million. Borrowings under the New Senior Secured Credit Facilities are available in U.S. dollars and Canadian dollars and bear interest at a rate equal to the Adjusted Eurodollar Rate, the Base Rate or the Canadian Prime Rate, each as defined in the credit agreement governing the New Senior Secured Credit Facilities (the "Credit Agreement"), as applicable, plus an applicable margin between 2.75% and 3.75% that varies depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. The applicable margin for term loans bearing interest at the Adjusted Eurodollar Rate and the Base Rate is 3.75% and 2.75% respectively. The Adjusted Eurodollar Rate cannot be less than 1.00%.

The New Term Loan Facility matures on February 24, 2021. The revolving commitments under the New Revolving Credit Facility terminates on February 24, 2018. Letters of credit are available to be issued under the revolving commitments until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. The Partnership is required to pay a commitment fee with respect to the commitments under the New Revolving Credit Facility equal to 0.75% times the average of the daily difference between the revolving commitments and all outstanding revolving loans (excluding swing line loans) plus amounts available to be drawn under letters of credit and all outstanding reimbursement obligations with respect to drawn letters of credit. The New Senior Secured Credit Facilities are secured by a pledge of the equity interests in the Partnership and its subsidiaries, guaranties from the Partnership subsidiary guarantors and a limited recourse guaranty from the entity that holds all of the Partnership equity, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of the Partnership and its subsidiaries (subject to certain exceptions), and certain other assets. The New Senior Secured Credit Facilities are not otherwise guaranteed or secured by the Company or any of its subsidiaries (other than the Partnership subsidiary guarantors). The New Senior Secured Credit Facilities will also have the benefit of a debt service reserve account, which is required to be funded and maintained at the debt service reserve requirement, equal to six months of debt service.

The Partnership's existing Cdn$210 million aggregate principal amount of 5.95% Medium Term Notes due June 23, 2036 (the "MTNs") prohibit the Partnership (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries) to secure indebtedness, unless the MTNs are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, the Partnership has granted an equal and ratable security interest in the collateral package securing the New Senior Secured Credit Facilities in favor of the trustee under the indenture governing the MTNs for the benefit of the holders of the MTNs. The

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Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The covenants include a requirement that the Partnership and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 5.50:1.00 in 2014 to 4.00:1.00 in 2021, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 2.50:1.00 in 2014 to 3.25:1.00 in 2021. In addition, the Credit Agreement includes customary restrictions and limitations on the Partnership's and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to customary carve-outs and exceptions and various thresholds.

Under the Credit Agreement, if a change of control (as defined in the Credit Agreement) occurs, unless the Partnership elects to make a voluntary prepayment of the term loans under the New Senior Secured Credit Facilities, it will be required to offer each electing lender to prepay such lender's term loans under the New Senior Secured Credit Facilities at a price equal to 101% of par. In addition, in the event that the Partnership elects to repay, prepay or refinance all or any portion of the term loan facilities within one year from the initial funding date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid or refinanced.

The Credit Agreement also contains a mandatory amortization feature and customary mandatory prepayment provisions, including: (i) from proceeds of assets sales, insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and (ii) the payment of 50% of the excess cash flow, as defined in the Credit Agreement, of the Partnership and its subsidiaries.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of the Partnership and its subsidiaries, bankruptcy, material judgments rendered against the Partnership or certain of its subsidiaries, certain ERISA or regulatory events, a change of control of the Partnership, or defaults under certain guaranties and collateral documents securing the New Senior Secured Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

On February 26, 2014, $600 million was drawn under the New Term Loan Facility, and letters of credit in an aggregate face amount of $144 million were issued (but not drawn) pursuant to the revolving commitments under the New Revolving Credit Facility and used (i) to fund a debt service reserve in an amount equivalent to six months of debt service (approximately $15.8 million), and (ii) to support contractual credit support obligations of the Partnership and its subsidiaries and of certain other of our affiliates.

We and our subsidiaries have used the proceeds from the New Term Loan Facility under the New Senior Secured Credit Facilities to:

- optionally prepay or redeem in whole, at a price equal to par plus accrued interest and applicable make-whole premium, of (i) the $150 million aggregate principal amount outstanding of 5.87% Senior Guaranteed Notes, Series A, due 2015 and the $75 million aggregate principal amount outstanding of 5.97% Senior Guaranteed Notes, Series B, due 2017 issued by Atlantic Power (US) GP, and (ii) the $190 million aggregate principal amount outstanding of 5.9% Senior Notes due 2014 issued by Curtis Palmer LLC;

- pay transaction costs and expenses; and make a distribution to us in the range of approximately $120 million to $125 million, which we may use for any corporate purpose, including, in our discretion, additional debt reduction which may, taking into account available funds, market conditions and other relevant factors, include steps to repurchase or redeem, by means of a tender offer or otherwise, up to $150 million aggregate principal amount of the Company's 9.0% senior unsecured notes due 2018 and up to Cdn$46 million of our 6.50% convertible debentures due October 31, 2014.

In connection with the funding of the New Senior Secured Credit Facilities described above, we terminated the Prior Credit Facility on February 26, 2014.

In addition, the Prior Credit Facility contained certain guaranties, which were terminated in connection with the termination of the Prior Credit Facility. In addition, the terms of our 9.0% senior unsecured notes due 2018 (the "9.0% Notes") provide that the guarantors of the Prior Credit Facility guarantee the 9.0% Notes. As a result, upon termination of the Prior Credit Facility and the related guaranties, the guaranties under the 9.0% Notes were cancelled and the guarantors of the 9.0% Notes were automatically released from all of their obligations under such guaranties.

The foregoing description of the New Senior Secured Credit Facilities is qualified in its entirety by reference to the full text of the credit agreement governing the Senior Secured Credit Facilities, which is attached to this Annual Report on Form 10-K as Exhibit 10.1 and is incorporated herein by reference.

*Impact of the New Senior Secured Credit Facilities*

As previously disclosed in our Current Report on Form 8-K filed on January 30, 2014, due to the aggregate impact of the up-front costs resulting from the prepayments on our indebtedness described above, including the make-whole payment and charges for unamortized debt discount and fee expenses (all such up-front costs, collectively, the "Prepayment Charges"), which will be reflected as charges to our 2014 first quarter results, we can no longer satisfy the fixed charge coverage ratio test included in the restricted payments covenant of the indenture governing our 9.0% notes. The fixed charge coverage ratio must be at least 1.75 to 1.00 and is measured on a rolling four quarter basis, including after giving effect to certain pro forma adjustments. As a consequence, further dividend payments, which are declared and paid at the discretion of our board of directors, in the aggregate cannot exceed the covenant's "basket" provision of the greater of $50 million and 2% of consolidated net assets (approximately $60.6 million at December 31, 2013) until such time that we satisfy the fixed charge coverage ratio test. For the year ended December 31, 2013, dividend payments to our shareholders totaled approximately Cdn$48 million for the full year, on a pro forma basis reflecting the lower Cdn$0.03333 per common share monthly dividend first declared in March 2013. The Prepayment Charges would no longer be reflected in the calculation of the fixed charge coverage ratio test after the passage of four additional successive quarters following the quarter in which the Prepayment Charges are incurred. In addition, if we pursue further debt reduction, including the potential repurchase or redemption, by means of a tender offer or otherwise, of up to $150 million aggregate principal amount of our 9.0% notes, any similar prepayment charges incurred in connection with such debt reduction would also be reflected in the calculation of the fixed charge coverage ratio test on a rolling four quarter basis, beginning with the quarter in which such charges are incurred, as would any associated reduction in interest expense.

Separately, we expect to be in compliance with the financial maintenance covenants in the agreements governing our indebtedness for at least the next twelve months.

***Prior Credit Facility***

At December 31, 2013, we had a credit facility of $150 million on a senior secured basis, the Prior Credit Facility, which was amended on August 2, 2013, as further described below. At December 31,

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2013, all $150 million of capacity under the Prior Credit Facility could have been utilized for letters of credit and a sublimit of $25 million could have been utilized for other borrowings. At December 31, 2013, the Prior Credit Facility was undrawn and the applicable LIBOR margin was 4.25%. At December, 2013, $97.2 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects.

This Prior Credit Facility was replaced by the New Senior Secured Credit Facilities described above in February 2014.

***Corporate Debt Service Obligations***

The following table summarizes the maturities of our corporate debt at December 31, 2013:

| | Maturity Date | Interest Rates | Total Remaining Principal Repayments | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter |
|---|---|---|---|---|---|---|---|---|---|
| Atlantic Power Corporation Notes | November 2018 | 9.0% | $ 460.0 | $ | $ | $ | $ | $ 460.0 | $ |
| Atlantic Power US (GP) Note[1] | August 2015 | 6.0% | 150.0 | | 150.0 | | | | |
| Atlantic Power US (GP) Note[1] | August 2017 | 5.9% | 75.0 | | | | 75.0 | | |
| Atlantic Power Income LP Note | June 2036 | 6.0% | 197.4 | | | | | | 197.4 |
| Convertible Debenture | October 2014 | 6.5% | 42.1 | 42.1 | | | | | |
| Convertible Debenture | March 2017 | 6.3% | 63.4 | | | | 63.4 | | |
| Convertible Debenture | June 2017 | 5.6% | 75.7 | | | | 75.7 | | |
| Convertible Debenture | June 2019 | 5.8% | 130.0 | | | | | | 130.0 |
| Convertible Debenture | December 2019 | 6.0% | 94.0 | | | | | | 94.0 |
| Revolving credit facility | March 2015 | LIBOR + 4.75% | | | | | | | |
| Total Corporate Debt | | | $ 1,287.6 | $ 42.1 | $ 150.0 | $ | $ 214.1 | $ 460.0 | $ 421.4 |

(1) These notes were retired in February 2014 with a portion of the proceeds from the New Senior Secured Credit Facilities. For additional information about our corporate debt, see Note 10, *Long-term debt*.

***Project-Level Debt Service Obligations***

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, 2013. 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, 2013, all of our projects were in compliance with the covenants contained in project-level debt. 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 10, *Long-term debt Non-Recourse Debt*.

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The range of interest rates presented represents the rates in effect at December 31, 2013. The amounts listed below are in millions of U.S. dollars, except as otherwise stated.

| | Maturity Date | Range of Interest Rates | Total Remaining Principal Repayments | 2014 | 2015 | 2016 | 2017 | 2018 | Thereafter |
|---|---|---|---|---|---|---|---|---|---|
| **Consolidated Projects:** | | | | | | | | | |
| Epsilon Power Partners | January 2019 | 7.4% | $ 30.5 | $ 5.0 | $ 5.8 | $ 6.0 | $ 6.3 | $ 6.5 | $ 0.9 |
| Piedmont[1] | February 2014 | 5.2% | 76.6 | 12.6 | 4.5 | 3.3 | 4.7 | 51.5 | |
| Cadillac | August 2025 | 6.0%-8.0% | 35.4 | 2.0 | 3.9 | 2.5 | 3.0 | 3.0 | 21.0 |
| Meadow Creek | December 2024 | 2.9%-5.6% | 169.8 | 4.9 | 4.6 | 5.3 | 5.3 | 6.0 | 143.7 |
| Rockland[2] | June 2027 | 6.4%-6.7% | 85.3 | 1.5 | 1.8 | 1.9 | 2.2 | 2.5 | 75.4 |
| Curtis Palmer[3] | July 2014 | 5.9% | 190.0 | 190.0 | | | | | |
| Total Consolidated Projects | | | 587.6 | 216.0 | 20.6 | 19.0 | 21.5 | 69.5 | 241.0 |
| **Equity Method Projects:** | | | | | | | | | |
| Chambers | July 2021 | 0.3%-7.6% | 41.2 | 0.9 | 0.2 | 0.1 | | | 40.0 |
| Delta-Person[4] | December 2018 | 1.9% | 6.5 | 1.3 | 1.4 | 1.5 | 1.1 | 1.0 | 0.2 |
| Goshen | December 2022 | 2.9%-6.6% | 24.3 | 0.4 | 0.5 | 0.7 | 0.9 | 1.0 | 20.8 |
| Idaho Wind | December 2027 | 5.8% | 46.6 | 2.4 | 2.6 | 2.5 | 2.7 | 2.9 | 33.5 |
| Total Equity Method Projects | | | 118.6 | 5.0 | 4.7 | 4.8 | 4.7 | 4.9 | 94.5 |
| Total Project-Level Debt | | | $ 706.2 | $ 221.0 | $ 25.3 | $ 23.8 | $ 26.2 | $ 74.4 | $ 335.5 |

(1) The balance of $76.6 million on the Piedmont debt consists of an $82.0 million construction loan ($76.6 million at December 31, 2013) that converted to a term loan on February 14, 2014. At the time of term conversion, we paid $8.1 million in principal. The remaining $68.5 million of term loan debt will be paid over the remaining term loan period commencing in February 2014 and maturing in August 2018.

(2) 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.

(3)

The Curtis Palmer Notes were not considered non-recourse project-level debt as these notes were guaranteed by the Partnership. Interest expense associated with the Curtis Palmer notes were recorded as a component of project income (loss). These notes were retired in February 2014 with a portion of the proceeds of the New Senior Secured Credit Facilities.

(4) We entered into an agreement on December 7, 2012 to sell our 40% interest in Delta-Person. The sale is expected to close in 2014.

***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. Beginning on June 30, 2012, the Series 1 Shares were 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

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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%.

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 $12.6 million and $13.0 million on the Series 1 Shares and the Series 2 Shares for the years ended December 31, 2013 and 2012, respectively.

***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 $36 to $40 million in 2014 in our portfolio in the form of project capital expenditures and major maintenance expenses. As explained above, these investments are 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 provide a source of data to assess major maintenance needs. In addition, we utilize predictive and risk based analysis to refine our expectations, prioritize our spending and balance the funding requirements necessary for these expenditures over time. Future capital expenditures and major maintenance expenses may exceed the projected level in 2014 as a result of the timing of more infrequent events such as steam turbine overhauls and/or gas turbine and hydroelectric turbine upgrades.

We invested approximately $41.0 million of project capital expenditures and major maintenance expenses for the year ended December 31, 2013. In all cases, scheduled maintenance outages during the year ended December 31, 2013 occurred at such times that did not adversely impact the facilities' availability requirements under their respective PPAs.

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***Restricted Cash***

At December 31, 2013, restricted cash totaled $114.2 million, of which $75.0 million was pledged to the lenders as security for the Prior Credit Facility. This $75 million was released from restricted cash to cash and cash equivalents in February 2014 as a result of the New Senior Secured Credit Facilities, which, unlike the Prior Credit Facility, does not require us to maintain a $75 million restricted cash reserve. Therefore, giving effect to the New Senior Secured Credit Facilities, unrestricted cash increased by $75 million to $233.6 million as a result of the release of the restricted cash to cash and cash equivalents in February 2014. Additionally, 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.

***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, including common shares issued under our dividend reinvestment program. At that time, because we were a well-known seasoned issuer, as defined in Rule 405 under the Securities Act, the registration statement was effective immediately upon filing. As of the date of the filing of this Annual Report on Form 10-K, as a result of the decrease in our market capitalization we can no longer offer and sell securities under that shelf registration. However, immediately following the filing of this Annual Report on Form 10-K, we intend to file a new registration statement, which will be effectively immediately upon filing, for the continued and uninterrupted issuance of common shares under our dividend reinvestment program.

**Contractual Obligations and Commercial Commitments**

The following table summarizes our contractual obligations as of February 27, 2013:

| | Payment Due by Period | | | | |
|---|---|---|---|---|---|
| | Less than 1 year | 1 - 3 Years | 4 - 5 Years | Thereafter | Total |
| Long-term debt including estimated interest[(1)(2)] | $ 264.3 | $ 769.2 | $ 1,066.6 | $ 923.0 | $ 3,023.1 |
| Operating leases | 1.6 | 5.1 | 3.0 | 11.4 | 21.1 |
| Operations and maintenance commitments | 6.8 | 23.7 | 12.7 | 30.2 | 73.4 |
| Fuel purchase and transportation obligations | 83.0 | 176.4 | 42.4 | 51.6 | 353.4 |
| Interconnection obligations | 3.5 | 15.1 | 10.1 | 19.2 | 47.9 |
| Other liabilities | 0.2 | | | 0.9 | 1.1 |
| Total contractual obligations | $ 359.4 | $ 989.5 | $ 1,134.8 | $ 1,036.3 | $ 3,520.0 |

(1) Debt represents our proportionate 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, 2013 was 0.3% to 9.0%.

(2) Includes the mandatory amortization payments and an estimate of the 50% excess cash flow payments, as defined in the Credit Agreement, of the New Senior Secured Credit Facilities.

**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, fuel

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purchase and transportation 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 tax investors for certain representations and warranties made by a wholly-owned subsidiary with respect to matters which we believe are remote, in our control 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.

**Off-Balance Sheet Arrangements**

As of December 31, 2013, 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 fair value of our derivatives instruments and the allocation of taxable income and losses, tax credits and cash distributions using Hypothetical Liquidation Book Value ("HLBV").

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 and assumptions

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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, 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 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.

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*Goodwill*

Goodwill is not amortized; instead, it is reviewed for impairment annually (in the fourth quarter) or more frequently if indicators of impairment exist. A significant amount of judgment is involved in determining if an indicator of impairment has occurred. Such indicators may include a prolonged decline in our market capitalization, deterioration in general economic conditions, adverse changes in the market in which a reporting unit operates, decreases in energy or capacity revenues as the result of re-contracting or increases in input costs that have a negative effect on earnings and cash flows, or a trend of negative or declining cash flows over multiple periods, among others. The fair value that could be realized in an actual transaction may differ from that used to evaluate the impairment of goodwill.

Our goodwill is allocated among and evaluated for impairment at the reporting unit level, which is one level below our operating segments. The goodwill is allocated among twelve of our reporting units, of which seven are included in the East segment ($107.8 million at December 31, 2013) and five are included in the West segment ($188.5 million at December 31, 2013).

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. We performed our annual goodwill impairment assessment for the year ended December 31, 2012 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, we determined that the fair value of goodwill attributed to these reporting units was not less than its carrying amount. As such, the annual two-step impairment test was deemed not necessary to be performed for these reporting units.

During the second quarter of 2013, based on a prolonged decline in our market capitalization as compared to our market capitalization at the time of our 2012 qualitative test, we determined that it was appropriate to initiate a test of goodwill prior to our annual goodwill impairment test that would have occurred in the fourth quarter of 2013. We proceeded directly to the two-step quantitative impairment test for all of the reporting units and concluded the test during the third quarter of 2013. This test was updated as of November 30, 2013 for our annual goodwill impairment assessment,

Under the two-step quantitative impairment test, the evaluation of impairment involves comparing the current fair value of each reporting unit to its carrying value, including goodwill. For step one of the quantitative test, we determine the fair value of our reporting units using an income approach with discounted cash flow ("DCF") models, as we believe forecasted cash flows are the best indicator of such fair value. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including assumptions about discount rates, projected power prices, generation, fuel costs and capital expenditure requirements. Most of these assumptions vary significantly among the reporting units. The discount rate applied to the DCF models represents the weighted average cost of capital ("WACC") consistent with the risk inherent in future cash flows and based upon an assumed capital structure, cost of long-term debt and cost of equity consistent with comparable independent power producers. The betas used in calculating the individual reporting units' WACC rate are estimated for each business with the assistance of valuation experts. Cash flow forecasts are generally based on approved reporting unit operating plans for years with contracted PPAs and historical relationships for estimates at the expiration of PPAs. These forecasts utilize historical plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. We use historical experience to determine estimated future capital investment requirements.

In the event the estimated fair value of a reporting unit per the DCF model is less than the carrying value, additional analysis would be required. The additional analysis would compare the carrying amount of the reporting unit's goodwill with the implied fair value of that goodwill, which may involve the use of valuation experts. The implied fair value of goodwill is the excess of the fair value of the reporting unit over the fair value amounts assigned to all of the assets and liabilities of that unit as if the reporting unit was acquired in a business combination and the fair value of the reporting unit represented the purchase price. If the carrying value of goodwill exceeds its implied fair value, an impairment loss equal to such excess would be recognized, which could significantly and adversely impact reported results of operations and shareholders' equity.

As a result of the event-driven goodwill assessment completed in the third quarter of 2013, it was determined that goodwill was impaired at the Kenilworth reporting unit (East segment) and the Naval reporting units (West segment). The total impairment recorded in the three months ended September 30, 2013 was $34.9 million. The $30.8 million impairment at Kenilworth was due to lower forecasted capacity and energy prices compared to the assumptions at the time of the acquisition in November 2011. When performing our step two quantitative analysis, the increase in the intangible value associated with the new ESA entered into in July 2013 resulted in a lower implied goodwill value. At the time of its acquisition in November 2011, the fair value of the assets acquired and liabilities assumed for the Kenilworth project were valued assuming a merchant basis for the period subsequent to the expiration of the project's original PPA in July 2012. As discussed above, these forecasted energy revenues on a merchant basis were higher than the energy prices currently forecasted to be in effect subsequent to the expiration of the new ESA. The $4.1 million impairment at the Naval reporting units was primarily due to increased uncertainty, not assumed at the time of the reporting unit's acquisition in 2011, in our ability to extend two of the projects lease and steam agreements upon their expiration. In addition, lower currently forecasted capacity and energy prices in California after the expiration of the PPAs compared to the forecast at the time of the acquisition in 2011 result in a lower business enterprise value which resulted in a lower implied goodwill value.

Under step one of our goodwill impairment tests performed during the fourth quarter of 2013, the fair value of seven of our reporting units exceeded their carrying value. Under the income approach described above, we estimated the fair value of these reporting units exceeded their carrying value by a weighted average of approximately 88%. For the five reporting units that failed step one of the quantitative tests, we utilized the assistance of valuation experts to perform step two of the quantitative impairment test. For each of these reporting units, the implied fair value of their goodwill exceeded the carrying amount of the reporting unit's goodwill resulting in no impairment.

The valuation of goodwill for the second step of the goodwill impairment analysis is considered a level 3 fair value measurement, which means that the valuation of the assets and liabilities reflect management's own judgments regarding the assumptions market participants would use in determining the fair value of the assets and liabilities.

Fair value determinations require considerable judgment and are sensitive to changes in these underlying assumptions and factors. As a result, there can be no assurance that the estimates and assumptions made for purposes of a goodwill impairment test will prove to be accurate predictions of the future. Examples of events or circumstances that could reasonably be expected to negatively affect the underlying key assumptions and ultimately impact the estimated fair value of our reporting units may include macroeconomic factors that significantly differ from our assumptions in timing or degree, increased input costs such as higher fuel prices and maintenance costs, or lower power prices than incorporated in our long-term forecasts. See "Risk Factors Risks Related to Our Business and Our Projects Impairment of goodwill or long-lived assets could have a material adverse effect on our business, results of operations and financial condition."

*Fair value of derivatives*

We utilize derivative contracts to mitigate our exposure to fluctuations in fuel commodity prices and foreign currency rates 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, 2013, we have recorded a valuation allowance of $128.1 million.

*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 HLBV. 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, 2013, we adopted changes issued by the Financial Accounting Standards Board ("FASB") to the reporting of amounts reclassified out of accumulated other comprehensive income. These changes require an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required to be reclassified in its entirety to net income. For other amounts that are not required to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures that provide additional detail about those amounts. These requirements are to be applied to each component of accumulated other comprehensive income. Other than the additional disclosure requirements, the adoption of these changes had no impact on the consolidated financial statements.

On January 1, 2013, we adopted changes issued by the FASB 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. The adoption of these changes had no impact on the consolidated financial statements.

On January 1, 2012, we adopted changes issued by the 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 (loss). 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 (loss) 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 (loss) as part of the statement of changes in shareholders' equity was eliminated. The items that must be reported in other comprehensive income (loss) or when an item of other comprehensive income (loss) 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.

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

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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.

*Issued*

In July 2013, the FASB issued changes to the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. These changes require an entity to present an unrecognized tax benefit as a liability in the financial statements if (i) a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or (ii) the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset to settle any additional income taxes that would result from the disallowance of a tax position. Otherwise, an unrecognized tax benefit is required to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. Previously, there was diversity in practice as no explicit guidance existed. These changes become effective for us on January 1, 2014. We have determined that the adoption of these changes will not have a material impact on the consolidated financial statements.

In March 2013, the FASB issued changes to a parent entity's accounting for the cumulative translation adjustment upon derecognition of certain subsidiaries or groups of assets within a foreign entity or of an investment in a foreign entity. A parent entity is required to release any related cumulative foreign currency translation adjustment from accumulated other comprehensive income into net income in the following circumstances: (i) a parent entity ceases to have a controlling financial interest in a subsidiary or group of assets that is a business within a foreign entity if the sale or transfer results in the complete or substantially complete liquidation of the foreign entity in which the subsidiary or group of assets had resided; (ii) a partial sale of an equity method investment that is a foreign entity; (iii) a partial sale of an equity method investment that is not a foreign entity whereby the partial sale represents a complete or substantially complete liquidation of the foreign entity that held the equity method investment; and (iv) the sale of an investment in a foreign entity. These changes become effective for us on January 1, 2014. We have determined that the adoption of these changes will not have a material impact on the consolidated financial statements.

In February 2013, the FASB issued changes to the accounting for obligations resulting from joint and several liability arrangements. These changes require an entity to measure such obligations for which the total amount of the obligation is fixed at the reporting date as the sum of (i) the amount the reporting entity agreed to pay on the basis of its arrangement among its co-obligors, and (ii) any additional amount the reporting entity expects to pay on behalf of its co-obligors. An entity will also be required to disclose the nature and amount of the obligation as well as other information about those obligations. Examples of obligations subject to these requirements are debt arrangements and settled litigation and judicial rulings. These changes become effective for us on January 1, 2014. We have determined that the adoption of these changes will not have a material 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 13, *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, biomass 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" in this Annual Report on Form 10-K for the year ended December 31, 2013. We often employ (i) tolling structures, whereby an offtaker is responsible for fuel procurement, (ii) long term fuel contracts, whereby the Company locks in a set quantity of fuel at a predetermined price or (iii) passthrough arrangements, whereby the cost of fuel is borne by the ultimate offtaker. 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 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. As of November 7, 2013, we had entered into natural gas swaps in order to effectively fix approximately 74% of our share of the expected natural gas purchases at the project during 2014 and 2015 and approximately 38% of our share of the expected natural gas purchases at the project during 2016 and 2017.

In February 2014, we paid $4.0 million to terminate these contracts as a result of terminating the Prior Credit Facility. The cash payments of these contracts will be recorded to fuel expense in the first quarter of 2014. We may enter into new natural gas swap agreements for Orlando in order to mitigate the exposure to changes in natural gas prices.

In 2013, we entered into contracts for the purchase of natural gas expiring on March 31, 2014 for the Tunis project in order to fix approximately 50% of the expected natural gas purchase requirement of the project through the contracts' expiration. Adjusted for these transactions, projected annual cash distributions at Tunis in 2014 would change by approximately $1.7 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.

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**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 at projects that operate with PPAs that are based on spot market pricing. Our most significant exposure to market power prices is at the Chambers, Morris, and Selkirk (whose PPA expires in August 2014) 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 2014, projected cash distributions from Chambers would change by approximately $0.9 million per 10% change in the PJM-East spot price of electricity based on a forecasted around the clock ("ATC") price of $38.31 and certain other assumptions. 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 2014, projected cash distributions from Morris would change by approximately $0.7 million per 10% change in the spot price of electricity based on the current level of approximately 175,000 MWh grid sales and all other variables being held constant. We own 100% of the Morris project. At Selkirk, 80 MW, or 23% of the total 345 MW net project capacity is currently not contracted and is sold into the spot power market or not sold at all if market prices do not support profitable operation of that portion of the facility. The current PPA at Selkirk expires in August 2014, which could result in an increase to 100% of capacity not contracted and therefore sold at market power prices. In 2014, projected distributions at Selkirk through the term of the PPA would change by approximately $0.2 million per 10% change in the forecasted spot price of electricity. 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" in this Annual Report on Form 10-K for the year ended December 31, 2013.

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 project may not be able to secure a new agreement and could be exposed to sell power at spot market price. 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." It is possible that subsequent PPAs or the spot market 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.

**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, if and when declared by the board of directors, and interest on corporate level long-term debt and all but one of our convertible debentures, predominantly in Canadian dollars. We have a hedging strategy for the purpose of mitigating the currency risk impact on any future payments of dividends to shareholders. From time to time, we execute this strategy utilizing cash flows from our projects that generate Canadian dollars and by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge an average of approximately 74% of any dividend and expected 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.

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At December 31, 2013, the forward contracts consisted of contracts assumed in our acquisition of the Partnership with various expiration dates through December 2015 to purchase a total of Cdn$34.9 million at an average exchange rate of Cdn$1.108 per U.S. dollar.

These foreign exchange forward contracts were 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.

In February 2014, we paid $0.4 million to terminate these contracts as a result of terminating the Prior Credit Facility. The termination of these contracts will be recorded to foreign exchange in the first quarter of 2014. We may enter into new foreign exchange contracts in order to mitigate the exposure to changes in foreign currency exchange rates.

The following table contains the components of recorded foreign exchange (gain) loss for years ended December 31, 2013, 2012, and 2011:

| | Year ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **2011** |
| Unrealized foreign exchange (gain) loss: | | | |
| Convertible debentures | $ (32.4) | $ 7.0 | $ (5.6) |
| Forward contracts and other | 19.4 | 12.0 | 14.2 |
| | (13.0) | 19.0 | 8.6 |
| Realized foreign exchange (gain) loss on forward contract settlements | (14.4) | (18.5) | 5.2 |
| | $ (27.4) | $ 0.5 | $ 13.8 |

A 10% hypothetical change in the value of the U.S. dollar compared to the Canadian dollar would have a $25.0 million impact on the carrying value of convertible debentures denominated in Canadian dollars at December 31, 2013.

**Interest Rate Risk**

Changes in interest rates do not have a significant impact on cash payments that are required on our debt instruments as approximately 95% 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 at December 31, 2013. After considering the impact of interest rate swaps described below, a hypothetical change in the average interest rate of 100 basis points would change annual interest costs, including interest at equity investments, by approximately $0.9 million at December 31, 2013.

We will enter to an interest rate swap agreement in 2014 to mitigate the risk of changing interest rates on the New Senior Secured Credit Facilities.

*Cadillac*

We have an interest rate swap at our consolidated Cadillac project to economically fix its exposure to changes in interest rates related to the variable-rate debt. The interest rate swap agreement was designated as a cash flow hedge of the forecasted interest payments under the project-level Cadillac debt and changes in their fair market value are recorded in other comprehensive income (loss). The interest rate swap expires on September 30, 2025.

In accounting for the cash flow hedge, gains and losses on the derivative contract are reported in other comprehensive income (loss), but only to the extent that the gains and losses from the change in value of the derivative contracts can later offset the loss or gain from the change in value of the hedged future cash flows during the period in which the hedged cash flows affect net income (loss).

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That is, for cash flow hedge, all effective components of the derivative contract's gains and losses are recorded in other comprehensive income (loss), pending occurrence of the expected transaction. Other comprehensive income (loss) consists of those financial items that are included in "Accumulated other comprehensive loss" in our accompanying consolidated balance sheets but not included in our net income (loss). Thus, in highly effective cash flow hedges, where there is no ineffectiveness, other comprehensive income changes by exactly as much as the derivative contracts and there is no impact on net income (loss) until the expected transaction occurs.

*Piedmont*

We executed two interest rate swaps at our consolidated Piedmont project to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreements are not designated as hedges and changes in their fair market value are recorded in the statements of operations. The interest rate swaps expire on February 29, 2016 and November 30, 2030, respectively. As a result of the Piedmont term loan conversion on February 14, 2013, these swap agreements were amended to reduce the notional amounts to match the outstanding $68.5 million principal of the term loan. We will record $0.6 million of interest expense related to this transaction in the first quarter of 2014.

*Epsilon Power Partners*

At December 31, 2013, Epsilon Power Partners had an interest rate swap to economically fix the exposure to changes in interest rates related to the variable-rate non-recourse debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 7.4% and a maturity date of July 2019. The notional amount of the swap matched the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. This interest rate swap agreement was not designated as a hedge and changes in its fair market value were recorded in the consolidated statements of operations.

In February 2014, we paid $2.6 million to terminate this contract as a result of terminating the Prior Credit Facility. We will record interest expense related to its settlement in the first quarter of 2014. We expect to enter into a new interest rate swap agreement for Epsilon Power Partners in order to mitigate the exposure to changes in interest rates.

*Meadow Creek*

Meadow Creek executed two interest rate swaps to economically fix the exposure to changes in interest rates related to 75% of the outstanding variable-rate non-recourse debt. These swaps effectively modify the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is for the notional amount due of the term loan commencing on December 30, 2012 and ending December 31, 2024 and fixes the interest rate at 2.3% plus an applicable margin of 2.8% - 3.3%. The second tranche is the post-term portion of the loan, or the balloon payment and commences on December 31, 2024 and ends on December 31, 2030 fixing the interest rate at 7.2%.

*Rockland*

Rockland executed two interest rate swaps to manage interest rate risk exposure. These swaps effectively mitigate the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap 100% of the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is for the notional amount due on the term loan which ends December 31, 2026 and fixes the interest rate at 4.2% plus an applicable margin of 2.3% - 2.8%. The second tranche is the post-term portion of the loan, or the balloon payment and commences on December 31, 2026 and ends on December 31, 2031 fixing the interest rate at 7.8%.

For additional information, see Note 13 to the consolidated financial statements included in this Annual Report on Form 10-K.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our consolidated financial statements are appended to the end of this Annual Report on Form 10-K, beginning on page F-1.

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## ITEM 9A. CONTROLS AND PROCEDURES

(a) Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer and Chief Financial Officer have evaluated the company's disclosure controls and procedures, as defined in Rules 13a-15(e) and 15d-15(e) of the Exchange Act, as of the end of the period covered by this report, and they have concluded that these controls and procedures are effective.

(b) Management's Report on Financial Statements and Practices

The accompanying Consolidated Financial Statements of Atlantic Power Corporation were prepared by management, which is responsible for their integrity and objectivity. The statements were prepared in accordance with generally accepted accounting principles and include amounts that are based on management's best judgments and estimates. The other financial information included in this annual report is consistent with that in the financial statements.

Management also recognizes its responsibility for conducting the Company's affairs according to the highest standards of personal and corporate conduct. This responsibility is characterized and reflected in key policy statements issued from time to time regarding, among other things, conduct of its business activities within the laws of the host countries in which the Company operates and potentially conflicting outside business interests of its employees. The Company maintains a systematic program to assess compliance with these policies.

(c) Management's Annual Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting as defined in Rules 13a-15(f) and 15d-14(f) under the Exchange Act. Under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting as of December 31, 2013 using the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO").

Based on our evaluation under the COSO framework, management has concluded that our internal control over financial reporting is effective to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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

(d) Attestation Report of the Registered Public Accounting Firm

The effectiveness of our internal control over financial reporting as of December 31, 2013 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report, which is included in Item 15 of this annual report Form 10-K on page F-2.

(e) Changes in Internal Control over Financial Reporting

There have been no changes in internal controls over financial reporting during the fourth quarter of 2013 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

## ITEM 9B. OTHER INFORMATION

None.

# PART III

## ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information concerning our directors and executive officers required by Item 10 will be included in the Proxy Statement and is incorporated herein by reference.

We have adopted a code of ethics that applies to directors, managers, officers and employees. This code of ethics, titled "Code of Business Conduct and Ethics," is posted on our website. The internet address for our website is *www.atlanticpower.com*, and the "Code of Business Conduct and Ethics" may be found from our main Web page by clicking first on "About Us" and then on "Code of Conduct."

We intend to satisfy any disclosure requirement under Item 5.05 of Form 8-K regarding an amendment to, or waiver from, a provision of the "Code of Business Conduct and Ethics" by posting such information on our website, on the Web page found by clicking through to "Conduct of Conduct" as specified above.

## ITEM 11. EXECUTIVE COMPENSATION

The information concerning our directors and executive officers required by Item 11 will be included in the Proxy Statement and is incorporated herein by reference.

## ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The information concerning security ownership and other matters required by Item 12 will be included in the Proxy Statement and is incorporated herein by reference.

## ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information concerning certain relationships and related transactions required by Item 13 will be included in the Proxy Statement and is incorporated herein by reference.

## ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information concerning principal accountant fees and services required by Item 14 will be included in the Proxy Statement and is incorporated herein by reference.

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## PART IV

### ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a)(1) Financial Statements

See "Index to Consolidated Financial Statements" on page F-1 of this Annual Report on Form 10-K.

(a)(2) Financial Statement Schedules

See "Index to Consolidated Financial Statements" on page F-1 of this Annual Report on Form 10-K. Schedules other than that listed have been omitted because of the absence of the conditions under which they are required or because the information required is shown in the consolidated financial statements or the notes thereto.

(a)(3) Exhibits

### EXHIBIT INDEX

| Exhibit No. | Description |
|---|---|
| 2.1 | Plan of Arrangement of Atlantic Power Corporation, dated as of November 24, 2005 (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 2.2 | Arrangement Agreement, dated as of June 20, 2011, among Capital Power Income L.P., CPI Income Services Ltd., CPI Investments Inc. and Atlantic Power Corporation (incorporated by reference to our Current Report on Form 8-K filed on June 24, 2011) |
| 3.1 | Articles of Continuance of Atlantic Power Corporation, dated as of June 29, 2010 (incorporated by reference to our registration statement on Form 10-12B filed on July 9, 2010) |
| 4.1 | Form of common share certificate (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.2 | Trust Indenture, dated as of October 11, 2006 between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.3 | First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Secured Debentures, dated November 27, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.4 | Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 17, 2009, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 4.5 | Form of First Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our registration statement on Form S-1/A (File No. 33-138856) filed on September 27, 2010) |

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| Exhibit No. | Description |
|---|---|
| 4.6 | Second Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated July 5, 2012, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our Current Report on Form 8-K filed on July 6, 2012) |
| 4.7 | Third Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated August 17, 2012, between Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our Current Report on Form 8-K filed on August 20, 2012) |
| 4.8 | Fourth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of November 29, 2012, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A. (incorporated by reference to our Current Report on Form 8-K filed on November 30, 2012) |
| 4.9 | Fifth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of December 11, 2012, among Atlantic Power Corporation, Computershare Trust Company of Canada and Computershare Trust Company, N.A. (incorporated by reference to our Current Report on Form 8-K filed on December 11, 2012) |
| 4.10 | Sixth Supplemental Indenture to the Trust Indenture Providing for the Issue of Convertible Unsecured Subordinated Debentures, dated as of March 22, 2013, among Atlantic Power Corporation and Computershare Trust Company of Canada (incorporated by reference to our Current Report on Form 8-K filed on March 26, 2013) |
| 4.11 | Indenture, dated as of November 4, 2011, by and among Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Current Report on Form 8-K filed on November 7, 2011) |
| 4.12 | First Supplemental Indenture, dated as of November 5, 2011, by and among the New Guarantors signatory thereto, Atlantic Power Corporation, the Existing Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Current Report on Form 8-K filed on November 7, 2011) |
| 4.13 | Second Supplemental Indenture, dated as of November 5, 2011, by and among Curtis Palmer LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Current Report on Form 8-K filed on November 7, 2011) |
| 4.14 | Third Supplemental Indenture, dated as of February 22, 2012, by and among Atlantic Oklahoma Wind, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Annual Report on Form 10-K filed on March 1, 2013) |
| 4.15 | Fourth Supplemental Indenture, dated as of August 3, 2012, by and among Atlantic Rockland Holdings, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Annual Report on Form 10-K filed on March 1, 2013) |

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| Exhibit No. | Description |
|---|---|
| 4.16 | Fifth Supplemental Indenture, dated as of November 29, 2012, by and among Atlantic Ridgeline Holdings, LLC, Atlantic Power Corporation, the Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Annual Report on Form 10-K filed on March 1, 2013) |
| 4.17 | Sixth Supplemental Indenture, dated as of January 29, 2013, by and among the New Guarantors named therein, Atlantic Power Corporation, the Existing Guarantors named therein and Wilmington Trust, National Association (incorporated by reference to our Annual Report on Form 10-K filed on March 1, 2013) |
| 4.18 | Registration Rights Agreement, dated as of November 4, 2011, by and among, Atlantic Power Corporation, the Guarantors listed on Schedule A thereto and Morgan Stanley & Co. LLC and TD Securities (USA) LLC, as representatives of the several Initial Purchasers (incorporated by reference to our Current Report on Form 8-K filed on November 7, 2011) |
| 4.19 | Shareholder Rights Plan Agreement, dated effective as of February 28, 2013, between Atlantic Power Corporation and Computershare Investor Services, Inc., which includes the Form of Right Certificate as Exhibit A (incorporated by reference to our Current Report on Form 8-K filed on February 28, 2013) |
| 4.20 | Advance Notice Policy, dated April 1, 2013 (incorporated by reference to our Current Report on Form 8-K filed on April 3, 2013) |
| 10.1* | Credit and Guaranty Agreement, dated as of February 24, 2014, among Atlantic Power Limited Partnership, as Borrower, Certain Subsidiaries of Atlantic Power Limited Partnership, as Guarantors, Various Lenders, Goldman Sachs Bank USA and Bank of America, N.A., as L/C Issuers, Goldman Sachs Lending Partners LLC and Bank of American, N.A., as Joint Syndication Agents, Goldman Sachs Lending Partners LLC and Merrill Lynch, Pierce, Fenner & Smith Incorporated, as Joint Lead Arrangers and Joint Bookrunners, Union Bank, N.A. and RBC Capital Markets, as Revolver Joint Lead Arrangers and Revolver Joint Bookrunners, Union Bank, N.A. and Royal Bank of Canada, as Revolver Co-Documentation Agents, and Goldman Sachs Lending Partners LLC, as Administrative Agent and Collateral Agent. |
| 10.2 | Second Amended and Restated Credit Agreement dated August 2, 2013, as amended, among Atlantic Power Corporation, Atlantic Power Generation, Inc. and Atlantic Power Transmission, Inc., the Lenders signatory thereto and Bank of Montreal, as Administrative Agent (incorporated by reference to our Current Report on Form 8-K filed on August 5, 2013) |
| 10.3 | Consent, dated as of November 19, 2012, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc. the Lenders signatory thereto and Bank of Montreal, as Administrative Agent (incorporated by reference to our Current Report on Form 8-K filed on November 21, 2012) |
| 10.4 | Consent and Release, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., the Subsidiaries signatory thereto, the Lenders signatory thereto and Bank of Montreal, as Administrative Agent and Collateral Agent (incorporated by reference to our Annual Report on From 10-K filed on March 1, 2013) |

| Exhibit No. | Description |
|---|---|
| 10.5 | Modification and Joinder Agreement, dated as of January 15, 2013, among Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Ridgeline Energy LLC, PAH RAH Holding Company LLC, Ridgeline Eastern Energy LLC, Ridgeline Energy Solar LLC, Lewis Ranch Wind Project LLC, Hurricane Wind LLC, Ridgeline Power Services LLC, Ridgeline Energy Holdings, Inc., Ridgeline Alternative Energy LLC, Frontier Solar LLC, PAH RAH Project Company LLC, Monticello Hills Wind LLC, Dry Lots Wind LLC, Smokey Avenue Wind LLC, Saunders Bros. Transportation Corporation, Bruce Hill Wind LLC, South Mountain Wind LLC, Great Basin Solar Ranch LLC, Goshen Wind Holdings LLC, Meadow Creek Holdings LLC, Ridgeline Holdings Junior Inc., Rockland Wind Ridgeline Holdings LLC, Meadow Creek Intermediate Holdings LLC and the other Subsidiaries party thereto in favor of Bank of Montreal, as Administrative Agent (incorporated by reference to our Quarterly Report on Form 10-K filed on March 1, 2013) |
| 10.6+ | Amended and Restated Employment Agreement, dated as of April 15, 2013 between Atlantic Power Corporation and Barry Welch (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.7+ | Amended and Restated Employment Agreement, dated as of April 15, 2013 between Atlantic Power Corporation and Paul Rapisarda (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.8+ | Employment Agreement, dated April 15, 2013, between Atlantic Power Corporation and Terrence Ronan (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.9+ | Employment Agreement, dated April 15, 2013, between Atlantic Power Corporation and Edward C. Hall (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.10+ | Addendum to Executive Employment Agreements of each of Terrence Ronan and Edward Hall, dated August 30, 2013 (incorporated by reference to our Current Report on Form 8-K filed on September 5, 2013) |
| 10.11+ | Deferred Share Unit Plan, dated as of April 24, 2007 of Atlantic Power Corporation (incorporated by reference to our registration statement on Form 10-12B filed on April 13, 2010) |
| 10.12+ | Third Amended and Restated Long-Term Incentive Plan (incorporated by reference to our registration statement on Form 10-12B filed on July 9, 2010) |
| 10.13+ | Fourth Amended and Restated Long-Term Incentive Plan (incorporated by reference to our Annual Report on Form 10-K filed on February 29, 2012) |
| 10.14+ | Fifth Amended and Restated Long-Term Incentive Plan (incorporated by reference to our Current Report on Form 8-K filed on April 11, 2013) |
| 10.15+ | Participation Agreement and Confirmation between the Company and Paul H. Rapisarda, dated April 11, 2013 (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.16+ | Participation Agreement and Confirmation (performance-based vesting) between the Company and Terrence Ronan, dated April 11, 2013 (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |

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| Exhibit No. | Description |
|---|---|
| 10.17+ | Participation Agreement and Confirmation between the Company and Edward C. Hall, dated April 2, 2013 (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.18+ | Participation Agreement and Confirmation (time-vesting) between the Company and Terrence Ronan, dated April 11, 2013 (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.19+ | Offer Letter between the Company and Edward C. Hall, dated March 26, 2013 (incorporated by reference to our Quarterly Report on Form 10-Q filed on August 8, 2013) |
| 10.20 | Amended and Restated Operating Agreement, dated as of March 30, 2012, between Atlantic Oklahoma Wind, LLC and Apex Wind Energy Holdings, LLC (incorporated by reference to our Quarterly Report on Form 10-Q filed November 4, 2011) |
| 10.21 | Termination of the Operating Agreement of Canadian Hills Wind, LLC, dated as of December 28, 2012 (incorporated by reference to our Current Report on Form 8-K filed on January 2, 2013) |
| 10.22 | Purchase and sale agreement, dated as of January 30, 2013 among Quantum Lake LP, LLC, Quantum Lake GP, LLC, Quantum Pasco LP, LLC, Quantum Pasco GP, LLC, Quantum Auburndale LP, LLC and Quantum Auburndale GP, LLC (as Buyers) and Lake Investment, LP, NCP Lake Power, LLC, Teton New Lake, LLC, NCP Dadee Power, LLC, Dade Investment, LP, Auburndale, LLC and Auburndale GP, LLC (as Sellers) (incorporated by reference to our Quarterly Report on Form 10-Q filed on May 8, 2013) |
| 16.1 | Letter from KPMG LLP, Chartered Accountants, to the Securities and Exchange Commission, dated August 10, 2010 (incorporated by reference to our Current Report on Form 8-K filed on August 10, 2010) |
| 21.1* | Subsidiaries of Atlantic Power Corporation |
| 23.1* | Consent of KPMG LLP |
| 31.1* | Certification of Chief Executive Officer pursuant to Rule 13a-14(a)/15d-14(a) under the Exchange Act |
| 31.2* | Certification of Chief Financial Officer pursuant to Rule 13a-14(a)/15d-14(a) under the Exchange Act |
| 32.1** | Certification of the Chief Executive Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 32.2** | Certification of the Chief Financial Officer pursuant to 18 U.S.C. 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 |
| 101* | The following materials from our Annual Report on Form 10-K for the year ended December 31, 2013 formatted in XBRL (eXtensible Business Reporting Language): (i) the Consolidated Balance Sheets, (ii) the Consolidated Statements of Operations, (iii) the Consolidated Statements of Shareholders' Equity, (iv) the Consolidated Statements of Cash Flows, and (v) related notes to these financial statements. |

+ Indicates management contract or compensatory plan or arrangement.

* Filed herewith.

** Furnished herewith.

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(b) Exhibits:

See Item 15(a)(3) above.

(c) Financial Statement Schedules:

See Item 15(a)(2) above.

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## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this annual report to be signed on its behalf by the undersigned, thereunto duly authorized.

Date: February 27, 2014

Atlantic Power Corporation

By: /s/ TERRENCE RONAN

Name: Terrence Ronan
Title: *Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer)*

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

| Signature | Title | Date |
|---|---|---|
| /s/ BARRY E. WELCH<br>Barry E. Welch | President, Chief Executive Officer and Director (principal executive officer) | February 27, 2014 |
| /s/ TERRENCE RONAN<br>Terrence Ronan | Chief Financial Officer (Duly Authorized Officer and Principal Financial and Accounting Officer) | February 27, 2014 |
| /s/ IRVING R. GERSTEIN<br>Irving R. Gerstein | Chairman of the Board | February 27, 2014 |
| /s/ KENNETH M. HARTWICK<br>Kenneth M. Hartwick | Director | February 27, 2014 |
| /s/ R. FOSTER DUNCAN<br>R. Foster Duncan | Director | February 27, 2014 |
| /s/ JOHN A. MCNEIL<br>John A. McNeil | Director | February 27, 2014 |
| /s/ HOLLI LADHANI<br>Holli Ladhani | Director | February 27, 2014 |

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**Atlantic Power Corporation**

**Index to Consolidated Financial Statements**

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**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Shareholders
Atlantic Power Corporation:

We have audited Atlantic Power Corporation's internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Atlantic Power Corporation's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Atlantic Power Corporation maintained, in all material respects, effective internal control over financial reporting as of December 31, 2013, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Atlantic Power Corporation and subsidiaries as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2013, and our report dated February 27, 2014 expressed an unqualified opinion on those consolidated financial statements.

/s/ KPMG LLP

New York, New York
February 27, 2014

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**Report of Independent Registered Public Accounting Firm**

The Board of Directors and Shareholders
Atlantic Power Corporation:

We have audited the accompanying consolidated balance sheets of Atlantic Power Corporation and subsidiaries (the "Company") as of December 31, 2013 and 2012, and the related consolidated statements of operations, comprehensive income, shareholders' equity and cash flows for each of the years in the three-year period ended December 31, 2013. In connection with our audit of the consolidated financial statements, we also have audited financial statement schedule "Schedule II Valuation and Qualifying Accounts." These consolidated financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Atlantic Power Corporation and subsidiaries as of December 31, 2013 and 2012, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2013, in conformity with U.S. generally accepted accounting principles. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Atlantic Power Corporation's internal control over financial reporting as of December 31, 2013, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 27, 2014 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

/s/ KPMG LLP

New York, New York
February 27, 2014

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**ATLANTIC POWER CORPORATION**

**CONSOLIDATED BALANCE SHEETS**

**(in millions of U.S. dollars)**

| | December 31, 2013 | December 31, 2012 |
|---|---|---|
| **Assets** | | |
| Current assets: | | |
| Cash and cash equivalents | $ 158.6 | $ 60.2 |
| Restricted cash | 114.2 | 28.6 |
| Accounts receivable | 64.3 | 58.5 |
| Current portion of derivative instruments asset (Note 13) | 0.2 | 9.5 |
| Inventory (Note 5) | 16.0 | 16.9 |
| Prepayments and other current assets | 16.1 | 13.4 |
| Security deposits | | 19.0 |
| Assets held for sale (Note 20) | | 351.4 |
| Refundable income taxes | 4.0 | 4.2 |
| Total current assets | 373.4 | 561.7 |
| Property, plant, and equipment, net (Note 6) | 1,813.4 | 2,055.5 |
| Equity investments in unconsolidated affiliates (Note 4) | 394.3 | 428.7 |
| Power purchase agreements and intangible assets, net (Note 8) | 451.5 | 524.9 |
| Goodwill (Note 7) | 296.3 | 334.7 |
| Derivative instruments asset (Notes 13) | 13.0 | 11.1 |
| Other assets | 53.1 | 86.1 |
| Total assets | $ 3,395.0 | $ 4,002.7 |
| **Liabilities** | | |
| Current liabilities: | | |
| Accounts payable | $ 14.0 | $ 17.8 |
| Accrued interest | 17.7 | 19.0 |
| Other accrued liabilities | 58.8 | 73.7 |
| Revolving credit facility (Note 10) | | 67.0 |
| Current portion of long-term debt (Note 10) | 216.2 | 121.2 |
| Current portion of convertible debentures (Note 11) | 42.1 | |
| Current portion of derivative instruments liability (Note 13) | 28.5 | 33.0 |
| Dividends payable | 6.8 | 11.5 |
| Liabilities associated with assets held for sale (Note 20) | | 189.0 |
| Other current liabilities | 5.3 | 3.3 |
| Total current liabilities | 389.4 | 535.5 |
| Long-term debt (Note 10) | 1,254.8 | 1,459.1 |
| Convertible debentures (Note 11) | 363.1 | 424.2 |
| Derivative instruments liability (Note 13) | 76.1 | 118.1 |
| Deferred income taxes (Note 14) | 111.5 | 164.0 |
| Power purchase and fuel supply agreement liabilities, net (Note 8) | 38.7 | 44.0 |
| Other long-term liabilities (Note 9) | 65.4 | 71.4 |

| | | |
|---|---|---|
| Commitments and contingencies (Note 23) | | |
| Total liabilities | 2,299.0 | 2,816.3 |
| **Equity** | | |
| Common shares, no par value, unlimited authorized shares; 120,205,813 and 119,446,865 issued and outstanding at December 31, 2013 and December 31, 2012, respectively | 1,286.1 | 1,285.5 |
| Preferred shares issued by a subsidiary company (Note 18) | 221.3 | 221.3 |
| Accumulated other comprehensive income (loss) | (22.4) | 9.4 |
| Retained deficit | (655.4) | (565.2) |
| Total Atlantic Power Corporation shareholders' equity | 829.6 | 951.0 |
| Noncontrolling interest | 266.4 | 235.4 |
| Total equity | 1,096.0 | 1,186.4 |
| Total liabilities and equity | $ 3,395.0 | $ 4,002.7 |

See accompanying notes to consolidated financial statements.

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**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF OPERATIONS**

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

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **2011** |
| Project revenue: | | | |
| Energy sales | $ 304.2 | $ 217.0 | $ 43.6 |
| Energy capacity revenue | 168.8 | 154.9 | 34.0 |
| Other | 78.7 | 68.5 | 16.3 |
| | 551.7 | 440.4 | 93.9 |
| Project expenses: | | | |
| Fuel | 198.7 | 169.1 | 37.5 |
| Operations and maintenance | 152.4 | 122.8 | 20.9 |
| Development | 7.2 | | |
| Depreciation and amortization | 167.1 | 118.0 | 23.6 |
| | 525.4 | 409.9 | 82.0 |
| Project other income (expense): | | | |
| Change in fair value of derivative instruments (Notes 12 and 13) | 49.5 | (59.3) | (14.6) |
| Equity in earnings of unconsolidated affiliates (Note 4) | 26.9 | 15.2 | 6.4 |
| Gain on sale of equity investments | 30.4 | 0.6 | |
| Interest expense, net | (34.4) | (16.4) | (7.3) |
| Impairment of goodwill (Note 7) | (34.9) | | |
| Other income, net | 0.5 | | |
| | 38.0 | (59.9) | (15.5) |
| Project income (loss) | 64.3 | (29.4) | (3.6) |
| Administrative and other expenses (income): | | | |
| Administration | 35.2 | 28.3 | 37.7 |
| Interest, net | 104.1 | 89.8 | 26.0 |
| Foreign exchange loss (gain) (Note 13) | (27.4) | 0.5 | 13.8 |
| Other income, net | (10.5) | (5.7) | (0.1) |
| | 101.4 | 112.9 | 77.4 |
| Loss from continuing operations before income taxes | (37.1) | (142.3) | (81.0) |
| Income tax benefit (Note 14) | (19.5) | (28.1) | (11.1) |
| Loss from continuing operations | (17.6) | (114.2) | (69.9) |
| Net income (loss) from discontinued operations, net of tax (Note 20) | (6.2) | 13.9 | 34.3 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Net loss | | (23.8) | | (100.3) | | (35.6) |
| Net loss attributable to noncontrolling interests | | (3.4) | | (0.6) | | (0.5) |
| Net income attributable to preferred shares dividends of a subsidiary company | | 12.6 | | 13.1 | | 3.3 |
| Net loss attributable to Atlantic Power Corporation | $ | (33.0) | $ | (112.8) | $ | (38.4) |
| Basic and diluted loss per share: (Note 19) | | | | | | |
| Loss from continuing operations attributable to Atlantic Power Corporation | $ | (0.23) | $ | (1.09) | $ | (0.94) |
| Income (loss) from discontinued operations, net of tax | | (0.05) | | 0.12 | | 0.44 |
| Net loss attributable to Atlantic Power Corporation | $ | (0.28) | $ | (0.97) | $ | (0.50) |
| Weighted average number of common shares outstanding: (Note 19) | | | | | | |
| Basic | | 119.9 | | 116.4 | | 77.5 |
| Diluted | | 119.9 | | 116.4 | | 77.5 |

See accompanying notes to consolidated financial statements.

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**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME**

**(in millions of U.S. dollars)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **2011** |
| Net loss | $ (23.8) | $ (100.3) | $ (35.6) |
| Other comprehensive income (loss), net of tax: | | | |
| Unrealized income (loss) on hedging activities | $ 0.7 | $ (0.9) | $ (2.6) |
| Net amount reclassified to earnings | 0.9 | 0.9 | 1.0 |
| Net unrealized gain (loss) on derivatives | 1.6 | | (1.6) |
| Defined benefit plan, net of tax | 1.4 | (1.3) | (0.5) |
| Foreign currency translation adjustments | (34.8) | 15.9 | (3.3) |
| Other comprehensive income (loss), net of tax | (31.8) | 14.6 | (5.4) |
| Comprehensive loss | (55.6) | (85.7) | (41.0) |
| Less: Comprehensive income attributable to noncontrolling interests | 9.2 | 12.5 | 2.8 |
| Comprehensive loss attributable to Atlantic Power Corporation | $ (64.8) | $ (98.2) | $ (43.8) |

See accompanying notes to consolidated financial statements.

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**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF SHAREHOLDERS' EQUITY**

**(in millions of U.S. dollars)**

| | Common Shares (Shares) | Common Shares (Amount) | Retained Deficit | Accumulated Other Comprehensive Income (loss) | Noncontrolling Interests | Preferred Shares | Total Shareholders' Equity |
|---|---|---|---|---|---|---|---|
| December 31, 2010 | 67.1 | 626.1 | (196.5) | 0.3 | 3.5 | | 433.4 |
| Net (loss) income | | | (38.4) | | | 3.3 | (35.1) |
| Convertible debenture conversion | 2.1 | 26.4 | | | | | 26.4 |
| Common shares issuance, net of costs | 12.7 | 155.4 | | | | | 155.4 |
| Common shares issued for LTIP | 0.2 | 2.0 | | | | | 2.0 |
| Shares issued in connection with CPILP acquisition | 31.5 | 407.4 | | | | | 407.4 |
| Preferred shares of a subsidiary company assumed in connection with CPILP acquisition | | | | | | 221.3 | 221.3 |
| Noncontrolling interest | | | | | (0.5) | | (0.5) |
| Dividends declared on common shares | | | (85.7) | | | | (85.7) |
| Dividends declared on preferred shares of a subsidiary company | | | | | | (3.3) | (3.3) |
| Unrealized loss on hedging activities, net of tax of $0.3 million | | | | (1.7) | | | (1.7) |
| Foreign currency translation adjustments | | | | (3.3) | | | (3.3) |
| Defined benefit plan, net of tax of $0.3 million | | | | (0.5) | | | (0.5) |
| December 31, 2011 | 113.6 | $ 1,217.3 | $ (320.6) | $ (5.2) | $ 3.0 | $ 221.3 | $ 1,115.8 |
| Net (loss) income | | | (112.8) | | | 13.1 | (99.7) |
| Common shares issuance, net of issuance costs | 5.5 | 66.3 | | | | | 66.3 |
| Common shares issued for Equity Incentive Plan | | 0.1 | | | | | 0.1 |
| Common shares issued for LTIP | 0.2 | 1.8 | | | | | 1.8 |
| Common shares issued for DRIP | 0.2 | | | | | | |
| Noncontrolling interests | | | | | 233.0 | | 233.0 |
| Loss from noncontrolling interests | | | | | (0.6) | | (0.6) |
| Dividends declared on common shares | | | (131.8) | | | | (131.8) |
| Dividends declared on preferred shares of a subsidiary company | | | | | | (13.1) | (13.1) |
| Foreign currency translation adjustments | | | | 15.9 | | | 15.9 |
| Defined benefit plan, net of tax of $0.8 million | | | | (1.3) | | | (1.3) |
| December 31, 2012 | 119.5 | $ 1,285.5 | $ (565.2) | $ 9.4 | $ 235.4 | $ 221.3 | $ 1,186.4 |
| Net (loss) income | | | (33.0) | | | 12.6 | (20.4) |
| Common shares issued for LTIP | 0.1 | 0.6 | | | | | 0.6 |
| Common shares issued for DRIP | 0.6 | | | | | | |
| Noncontrolling interests | | | | | 43.3 | | 43.3 |
| Loss from noncontrolling interests | | | | | (3.4) | | (3.4) |
| Dividends declared on common shares | | | (57.2) | | | | (57.2) |
| Dividends paid to noncontrolling interests | | | | | (8.9) | | (8.9) |
| Dividends declared on preferred shares of a subsidiary company | | | | | | (12.6) | (12.6) |
| Unrealized gain on hedging activities, net of tax of $1.0 million | | | | 1.5 | | | 1.5 |
| Foreign currency translation adjustments | | | | (34.7) | | | (34.7) |
| Defined benefit plan, net of tax of $0.6 million | | | | 1.4 | | | 1.4 |
| December 31, 2013 | 120.2 | $ 1,286.1 | $ (655.4) | $ (22.4) | $ 266.4 | $ 221.3 | $ 1,096.0 |

See accompanying notes to consolidated financial statements.

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**ATLANTIC POWER CORPORATION**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**

**(in millions of U.S. dollars)**

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2013** | **2012** | **2011** |
| Cash flows from operating activities: | | | |
| Net loss | $ (23.8) | $ (100.3) | $ (35.6) |
| Adjustments to reconcile to net cash provided by operating activities: | | | |
| Depreciation and amortization | 176.4 | 157.2 | 63.6 |
| Loss of discontinued operations | 32.8 | | |
| (Gain) loss on sale of assets & other charges | (5.1) | 0.8 | |
| Long-term incentive plan expense | 2.2 | 2.5 | 3.2 |
| Asset and goodwill impairment charges | 39.7 | 60.5 | 1.5 |
| Gain on sale of equity investments | (30.4) | (0.6) | |
| Equity in earnings from unconsolidated affiliates | (26.9) | (25.7) | (7.9) |
| Distributions from unconsolidated affiliates | 40.9 | 38.4 | 21.9 |
| Unrealized foreign exchange (gain) loss | (13.0) | 19.0 | 8.6 |
| Change in fair value of derivative instruments | (60.2) | 46.7 | 22.8 |
| Change in deferred income taxes | (27.3) | (34.1) | (9.9) |
| Change in other operating balances | | | |
| Accounts receivable | 3.4 | 2.3 | (15.6) |
| Inventory | 0.8 | (6.2) | (0.4) |
| Prepayments, refundable income taxes and other assets | 51.5 | (13.3) | 2.1 |
| Accounts payable | (8.4) | 21.1 | 4.9 |
| Accruals and other liabilities | (0.2) | (1.2) | (3.3) |
| Cash provided by operating activities | 152.4 | 167.1 | 55.9 |
| Cash flows provided by (used in) investing activities: | | | |
| Change in restricted cash | (93.7) | (11.6) | (5.7) |
| Proceeds from sale of assets and equity investments, net | 182.6 | 27.9 | 8.5 |
| Cash paid for acquisitions and investments, net of cash acquired | | (80.5) | (591.6) |
| Proceeds from related party | | | 22.8 |
| Proceeds from treasury grants | 103.2 | | |
| Biomass development costs | (0.2) | (0.5) | (0.9) |
| Construction in progress | (38.3) | (456.2) | (113.1) |
| Purchase of property, plant and equipment | (6.5) | (2.9) | (2.0) |
| Cash provided by (used in) investing activities | 147.1 | (523.8) | (682.0) |
| Cash flows (used in) provided by financing activities: | | | |
| Proceeds from issuance of long-term debt | | | 460.0 |
| Proceeds from issuance of convertible debentures | | 230.6 | |
| Proceeds from issuance of equity, net of offering costs | (1.0) | 66.3 | 155.4 |
| Proceeds from project-level debt | 20.8 | 291.9 | 100.8 |
| Repayment of project-level debt | (118.8) | (284.8) | (21.5) |
| Payments for revolving credit facility borrowings | (67.0) | (60.8) | |
| Proceeds from revolving credit facility borrowings | | 69.8 | 58.0 |
| Deferred financing costs | (2.8) | (31.2) | (26.4) |
| Equity contribution from noncontrolling interest | 44.6 | 225.0 | |
| Dividends paid to common shareholders | (65.1) | (131.0) | (81.8) |
| Dividends paid to noncontrolling interests | (18.3) | (13.1) | (3.2) |
| Cash (used in) provided by financing activities | (207.6) | 362.7 | 641.3 |
| Net increase in cash and cash equivalents | 91.9 | 6.0 | 15.2 |

| | | | |
|---|---|---|---|
| Less cash at discontinued operations | | (6.5) | |
| Cash and cash equivalents at beginning of period at discontinued operations | 6.5 | | |
| Cash and cash equivalents at beginning of period | 60.2 | 60.7 | 45.5 |
| Cash and cash equivalents at end of period | $ 158.6 | $ 60.2 | $ 60.7 |

| | | | |
|---|---|---|---|
| Supplemental cash flow information | | | |
| Interest paid | $ 130.4 | $ 40.2 | $ 40.2 |
| Income taxes paid (refunded), net | $ 5.9 | $ 1.1 | $ 1.1 |
| Accruals for construction in progress | $ 8.9 | $ 4.1 | $ 4.1 |

See accompanying notes to consolidated financial statements.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**

**(in millions U.S. dollars, except per-share amounts)**

## 1. Nature of business

*General*

Atlantic Power owns and operates a diverse fleet of power generation 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, 2013, our power generation projects in operation had an aggregate gross electric generation capacity of approximately 2,948 megawatts ("MW") in which our aggregate ownership interest is approximately 2,026 MW. These totals exclude our 40% interest in the Delta-Person generating station ("Delta-Person") for which we entered into an agreement to sell in December 2012, which we expect to close in 2014. Our current portfolio consists of interests in twenty-eight operational power generation projects across eleven states in the United States and two provinces in Canada. We also own Ridgeline Energy Holdings, Inc. ("Ridgeline"), a wind and solar developer in Seattle, Washington. Twenty-two of our projects are wholly owned subsidiaries.

Atlantic Power is a corporation established under the laws of the Province of Ontario, Canada on June 18, 2004 and continued to the Province of British Columbia on July 8, 2005. Our shares trade on the Toronto Stock Exchange under the symbol "ATP" and on the New York Stock Exchange under the symbol "AT." Our registered office is located at 355 Burrard Street, Suite 1900, Vancouver, British Columbia V6C 2G8 Canada and our headquarters is located at One Federal Street, 30th Floor, Boston, Massachusetts 02110, USA.

## 2. Summary of significant accounting policies

(a) Principles of consolidation and basis of presentation:

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

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

(b) Cash and cash equivalents:

Cash and cash equivalents include cash deposited at banks and highly liquid investments with original maturities of 90 days or less when purchased.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

(c) Restricted cash:

Restricted cash represents cash and cash equivalents that are maintained by the projects or corporate to support payments for major maintenance costs and meet project level and corporate contractual debt obligations.

(d) Deferred financing costs:

Deferred financing costs represent costs to obtain long-term financing and are amortized using the effective interest method over the term of the related debt which range from 5 to 28 years. The net carrying amount of deferred financing costs recorded in other assets on the consolidated balance sheets was $41.7 million and $47.2 million at December 31, 2013 and 2012, respectively. Amortization expense for the years ended December 31, 2013, 2012, and 2011 was $8.0 million, $4.4 million, and $1.3 million, respectively.

(e) Inventory:

Inventory represents small parts and other consumables and fuel, the majority of which is consumed by our projects in provision of their services, and are valued at the lower of cost or net realizable value. Cost includes the purchase price, transportation costs and other costs to bring the inventories to their present location and condition. The cost of inventory items that are interchangeable are determined on an average cost basis. For inventory items that are not interchangeable, cost is assigned using specific identification of their individual costs.

(f) Property, plant and equipment:

Property, plant and equipment are stated at cost, net of accumulated depreciation. Depreciation is provided on a straight-line basis over the estimated useful life of the related asset, up to 45 years. Significant additions or improvements extending asset lives are capitalized as incurred, while repairs and maintenance that do not improve or extend the life of the respective asset are charged to expense as incurred. Certain assets and their related accumulated depreciation amounts are adjusted for asset retirements and disposals with the resulting gain or loss included in the consolidated statements of operations.

(g) Project development costs and capitalized interest:

Project development costs are expensed in the preliminary stages of a project and capitalized when the project is deemed to be commercially viable. Commercial viability is determined by one or a series of actions including among others, obtaining a PPA.

Interest incurred on funds borrowed to finance capital projects is capitalized, until the project under construction is ready for its intended use. The amount of interest capitalized for the years ended December 31, 2013, 2012, and 2011 was $1.9 million, $17.0 million, and $3.0 million, respectively.

When a project is available for operations, capitalized interest and project development costs are reclassified to property, plant and equipment and amortized on a straight-line basis over the estimated

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

useful life of the project's related assets. Capitalized costs are charged to expense if a project is abandoned or management otherwise determines the costs to be unrecoverable.

(h) Other intangible assets:

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

(i) Investments accounted for by the equity method:

We make investments in entities that own power producing assets with the objective of generating accretive cash flow that is available to be distributed to our shareholders. The equity method of accounting is applied to such investments in affiliates, which include joint ventures and partnerships, because the ownership structure prevents us from exercising a controlling influence over the operating and financial policies of the projects. Our investments in partnerships and limited liability companies with 50% or less ownership, but greater than 5% ownership in which we do not have a controlling interest are accounted for under the equity method of accounting. We apply the equity method of accounting to investments in limited partnerships and limited liability companies with greater than 5% ownership because our influence over the investment's operating and financial policies is considered to be more than minor.

Under the equity method, equity in pre-tax income or losses of our investments is reflected as equity in earnings of unconsolidated affiliates. The cash flows that are distributed to us from these unconsolidated affiliates are directly related to the operations of the affiliates' power producing assets and are classified as cash flows from operating activities in the consolidated statements of cash flows. We record the return of our investments in equity investees as cash flows from investing activities. Cash flows from equity investees are considered a return of capital when distributions are generated from proceeds of either the sale of our investment in its entirety or a sale by the investee of all or a portion of its capital assets.

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

Long-lived assets, such as property, plant and equipment, 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. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to estimated undiscounted future cash flows expected to be generated by the asset. If the carrying amount of an asset exceeds its estimated future cash flows, an impairment charge is recognized in the amount by which the carrying amount of the asset exceeds its fair value.

Investments in and the operating results of 50%-or-less owned entities not consolidated are included in the consolidated financial statements on the basis of the equity method of accounting. We

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

review our investments in such unconsolidated entities for impairment whenever events or changes in business circumstances indicate that the carrying amount of the investments may not be fully recoverable. 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 that are insufficient to recover the carrying amount of the investment. Our assessment as to whether any decline in value is other than temporary is based on our ability and intent to hold the investment and whether evidence indicating the carrying value of the investment is recoverable within a reasonable period of time outweighs evidence to the contrary. We generally consider our investments in our equity method investees to be strategic long-term investments. Therefore, we complete our assessments with a long-term view. If the fair value of the investment is determined to be less than the carrying value and the decline in value is considered to be other than temporary, the asset is written down to its fair value.

(k) Goodwill:

Goodwill is the residual amount that results when the purchase price of an acquired business exceeds the sum of the amounts allocated to the assets acquired, less liabilities assumed, based on their fair values. Goodwill is allocated, as of the date of the business combination, to our reporting units that are expected to benefit from the synergies of the business combination.

Goodwill is not amortized and is tested for impairment, annually in the fourth quarter, or more frequently if events or changes in circumstances indicate that the asset might be impaired. In September 2011, the Financial Accounting Standards Board ("FASB") issued ASU 2011-08 "Intangibles Goodwill and Other." This guidance on testing goodwill provides the option to first perform a qualitative assessment ("step zero") to determine whether it is more likely than not that the fair value of a reporting unit is less than its carrying amount. If we determine that this is the case, we are required to perform a two-step goodwill impairment test, as described below, to identify potential goodwill impairment and measure the amount of goodwill impairment loss to be recognized for that reporting unit (if any). If we determine that the fair value of a reporting unit is not less than its carrying amount, the two-step goodwill impairment test is not required.

In our test, we first perform step zero to determine whether the existence of events or circumstances leads to a determination that it is more likely than not (i.e. 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 the qualitative assessment determines that an impairment is more likely than not, then we perform a two-step quantitative impairment test. In the first step of the quantitative analysis, the carrying amount of the reporting unit is compared with its fair value. When the fair value of a reporting unit exceeds its carrying amount, goodwill of the reporting unit is considered not to be impaired and the second step of the impairment test is unnecessary.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

The second step is carried out when the carrying amount of a reporting unit exceeds its fair value, in which case, the implied fair value of the reporting unit's goodwill is compared with its carrying amount to measure the amount of the impairment loss, if any. The implied fair value of goodwill is determined in the same manner as the value of goodwill is determined in a business combination, using the fair value of the reporting unit as if it were the purchase price. When the carrying amount of reporting unit goodwill exceeds the implied fair value of the goodwill, an impairment loss is recognized in an amount equal to the excess and is recorded in the consolidated statements of operations.

(l) Discontinued operations:

Long-lived assets or disposal groups are classified as discontinued operations when all of the required criteria are met. Criteria include, among others, existence of a qualified plan to dispose of an asset or disposal group, an assessment that completion of a sale within one year is probable and approval of the appropriate level of management. In addition, upon completion of the transaction, the operations and cash flows of the disposal group must be eliminated from our ongoing operations, and the disposal group must not have any significant continuing involvement with us. Discontinued operations are reported at the lower of the asset's carrying amount or fair value less cost to sell.

(m) Derivative financial instruments:

We use derivative financial instruments in the form of interest rate swaps and foreign exchange forward contracts to manage our current and anticipated exposure to fluctuations in interest rates and foreign currency exchange rates. We have also entered into natural gas supply contracts and natural gas forwards or swaps to minimize the effects of the price volatility of natural gas, which is a major production cost. We do not enter into derivative financial instruments for trading or speculative purposes. Certain derivative instruments qualify for a scope exception to fair value accounting because they are considered normal purchases or normal sales in the ordinary course of conducting business. This exception applies when we have the ability to, and it is probable that we will deliver or take delivery of the underlying physical commodity.

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

Derivative financial instruments not designated as a hedge are measured at fair value with changes in fair value recorded in the consolidated statements of operations. The following table summarizes derivative financial instruments that are not designated as hedges for accounting purposes and the

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

accounting treatment in the consolidated statements of operations of the changes in fair value and cash settlements of such derivative financial instrument:

| Derivative financial instrument | Classification of changes in fair value | Classification of cash settlements |
|---|---|---|
| Natural gas swaps | Changes in fair value of derivative instrument | Fuel expense |
| Gas purchase agreements | Changes in fair value of derivative instrument | Fuel expense |
| Interest rate swaps | Changes in fair value of derivative instrument | Interest expense |
| Foreign currency forward contract | Foreign exchange (gain) loss | Foreign exchange (gain) loss |

(n) Income taxes:

Income tax expense includes the current tax obligation or benefit and change in deferred income tax asset or liability for the period. We use the asset and liability method of accounting for deferred income taxes and record deferred income taxes for all significant temporary differences. Income tax benefits associated with uncertain tax positions are recognized when we determine that it is more-likely-than-not that the tax position will be ultimately sustained. Refer to Note 14 for more information.

(o) Revenue recognition:

We recognize energy sales revenue on a gross basis when electricity and steam are delivered under the terms of the related contracts. PPAs, steam purchase arrangements and energy services agreements are long-term contracts to sell power and steam on a predetermined basis.

*Energy* Energy revenue is recognized upon transmission to the customer. Physical transactions, or the sale of generated electricity to meet supply and demand, are recorded on a gross basis in our consolidated statements of operations.

*Capacity* Capacity payments under the PPAs are recognized as the lesser of (1) the amount billable under the PPA or (2) an amount determined by the kilowatt hours made available during the period multiplied by the estimated average revenue per kilowatt hour over the term of the PPA.

(p) Power purchase arrangements containing a lease:

We have entered into PPAs to sell power at predetermined rates. PPAs are assessed as to whether they contain leases which convey to the counterparty the right to the use of the project's property, plant and equipment in return for future payments. Such arrangements are classified as either capital or operating leases. PPAs that transfer substantially all of the benefits and risks of ownership of property to the PPA counterparty are classified as direct financing leases.

Finance income related to leases or arrangements accounted for as direct financing leases is recognized in a manner that produces a constant rate of return on the net investment in the lease. The net investment is comprised of net minimum lease payments and unearned finance income. Unearned finance income is the difference between the total minimum lease payments and the carrying value of the leased property. Unearned finance income is deferred and recognized in net income (loss) over the lease term.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

For PPAs accounted for as operating leases, we recognize lease income consistent with the recognition of energy revenue. When energy is delivered, we recognize lease income in energy revenue.

(q) Foreign currency translation and transaction gains and losses:

The local currency is the functional currency of our U.S. and Canadian projects. Our reporting currency is the U.S. dollar. Foreign currency denominated assets and liabilities are translated at end-of-period rates of exchange. Revenues, expenses, and cash flows are translated at the weighted-average rates of exchange for the period. The resulting currency translation adjustments are not included in the determination of our statements of operations for the period, but are accumulated and reported as a separate component of shareholders' equity until sale of the net investment in the project takes place. Foreign currency transaction gains or losses are reported within foreign exchange (gain) loss in our statements of operations.

(r) Equity compensation plans:

The officers and certain other employees are eligible to participate in the Long-Term Incentive Plan ("LTIP"). Some of the notional units that vest are based, in part, on certain financial performance metrics and the total shareholder return of Atlantic Power compared to a group of peer companies. In addition, vesting of certain notional units for officers of Atlantic Power occurs on a three-year cliff basis as opposed to ratable vesting over three years for non-officers. During April 2012, the Compensation Committee of the Board approved certain changes to the award process and vesting criteria of the LTIP, and on April 11, 2013, the Board adopted the Fifth Amended and Restated Atlantic Power Holdings, Inc. LTIP (the "Fifth Amended and Restated LTIP"), which reflected such changes. Awards to senior officers under the Fifth Amended and Restated LTIP are made annually based on the performance over the applicable fiscal year and will vest as to one third over each of the three years following the year of the award. Notional shares granted prior to the amendment are still subject to three-year cliff vesting.

Vested notional units are expected to be redeemed one-third in cash and two-thirds in shares of our common stock. Notional units granted that are expected to be redeemed in cash upon vesting are accounted for as liability awards. Notional units granted that are expected to be redeemed in common shares upon vesting are accounted for as equity awards. Unvested notional units are entitled to receive dividends equal to the dividends per common share during the vesting period in the form of additional notional units. Unvested units are subject to forfeiture if the participant is not an employee at the vesting date or if we do not meet certain ongoing cash flow performance targets.

For awards that are subject to a performance-based vesting condition, the final number of notional units for officers that will vest, if any, at the end of the three-year vesting period is based on our achievement of certain financial performance metrics and meeting target levels of relative total shareholder return, which is the change in the value of an investment in our common stock, including reinvestment of dividends, compared to that of a peer group of companies during the performance period. The total number of notional units vesting will range from zero up to a maximum 150% of the number of notional units in the executives' accounts on the vesting date for that award, depending on the level of achievement of relative total shareholder return during the measurement period.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

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 granted under the LTIP with market vesting conditions is based upon a Monte Carlo simulation model on the grant date. Compensation expense is recognized regardless of the relative total shareholder return performance, provided that the LTIP participant remains employed by Atlantic Power.

(s) Asset retirement obligations:

The fair value for an asset retirement obligation is recorded in the period in which it is incurred. Retirement obligations associated with long-lived assets are those for which a legal obligation exists under enacted laws, statutes, and written or oral contracts, including obligations arising under the doctrine of promissory estoppel, and for which the timing and/or method of settlement may be conditional on a future event. When the liability is initially recorded, we capitalize the cost by increasing the carrying amount of the related long-lived asset. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. Upon settlement of the liability, we either settle the obligation for its recorded amount or incur a gain or loss.

(t) Pensions:

We offer pension benefits to certain employees through a defined benefit pension plan. We recognize the funded status of our defined benefit plan in the consolidated balance sheet in other long-term liabilities and record an offset to other comprehensive income (loss). In addition, we also recognize on an after-tax basis, as a component of other comprehensive income (loss), gains and losses as well as all prior service costs that have not been included as part of our net periodic benefit cost. The determination of our obligation and expenses for pension benefits is dependent on the selection of certain assumptions. These assumptions determined by management include the discount rate, the expected rate of return on plan assets and the rate of future compensation increases. Our actuarial consultants use assumptions for such items as retirement age. The assumptions used may differ materially from actual results, which may result in a significant impact to the amount of our pension obligation or expense recorded.

(u) Business combinations:

We account for our business combinations in accordance with the acquisition method of accounting, which requires an acquirer to recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree at fair value at the acquisition date. It also recognizes and measures the goodwill acquired or a gain from a bargain purchase in the business combination and determines what information to disclose to enable users of an entity's financial statements to evaluate the nature and financial effects of the business combination. In addition, transaction costs are expensed as incurred.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

(v) Concentration of credit risk:

The financial instruments that potentially expose us to credit risk consist primarily of cash and cash equivalents, restricted cash, derivative instruments and accounts receivable. Cash and restricted cash are held by major financial institutions that are also counterparties to our derivative instruments. We have long-term agreements to sell electricity, gas and steam to public utilities and corporations. We have exposure to trends within the energy industry, including declines in the creditworthiness of our customers. We do not normally require collateral or other security to support energy-related accounts receivable. We do not believe there is significant credit risk associated with accounts receivable due to the credit worthiness and payment history of our customers. See Note 21, *Segment and geographic information*, for a further discussion of customer concentrations.

(w) Use of estimates:

The preparation of financial statements requires us to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the year. Actual results could differ from those estimates. During the periods presented, we have made a number of estimates and valuation assumptions, including the fair values of acquired assets, the useful lives and recoverability of property, plant and equipment, valuation of goodwill, intangible assets and liabilities related to PPAs and fuel supply agreements, the recoverability of equity investments, the recoverability of deferred tax assets, tax provisions, the fair value of financial instruments and derivatives, pension obligations, asset retirement obligations and the allocation of taxable income and losses, tax credits and cash distributions using the hypothetical liquidation book value ("HLBV") method. In addition, estimates are used to test long-lived assets and goodwill for impairment and to determine the fair value of impaired assets. These estimates and valuation assumptions are based on present conditions and our planned course of action, as well as assumptions about future business and economic conditions. As better information becomes available or actual amounts are determinable, the recorded estimates are revised. Should the underlying valuation assumptions and estimates change, the recorded amounts could change by a material amount.

(x) Federal grants:

Certain projects are eligible to receive grants and similar government incentives for the construction of renewable energy facilities. Proceeds from these grants reduce the basis of the corresponding asset balance when the cash is received.

(y) Allocation of net income or losses to certain investors using HLBV:

For consolidated investments with flip structures that allocate taxable income and losses, tax credits and cash distributions under 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 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

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

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.

(z) Recently issued accounting standards:

*Adopted*

On January 1, 2013, we adopted changes issued by the FASB to the reporting of amounts reclassified out of accumulated other comprehensive income. These changes require an entity to report the effect of significant reclassifications out of accumulated other comprehensive income on the respective line items in net income if the amount being reclassified is required to be reclassified in its entirety to net income. For other amounts that are not required to be reclassified in their entirety to net income in the same reporting period, an entity is required to cross-reference other disclosures that provide additional detail about those amounts. These requirements are to be applied to each component of accumulated other comprehensive income. Other than the additional disclosure requirements (see below), the adoption of these changes had no impact on the consolidated financial statements.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

The changes in accumulated other comprehensive income (loss) by component were as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| **Foreign currency translation** | | | |
| Balance at beginning of period | $ 12.6 | $ (3.3) | $ |
| Other comprehensive income (loss): | | | |
| Foreign currency translation adjustments[1] | (34.8) | 15.9 | (3.3) |
| Balance at end of period | $ (22.2) | $ 12.6 | $ (3.3) |
| **Pension** | | | |
| Balance at beginning of period | $ (1.8) | $ (0.5) | $ |
| Other comprehensive income (loss): | | | |
| Unrecognized net actuarial gain (loss) | 2.4 | (2.1) | (0.8) |
| Tax benefit (expense) | (0.7) | 0.8 | 0.3 |
| Total Other comprehensive income (loss) before reclassifications, net of tax | 1.7 | (1.3) | (0.5) |
| Amortization of net actuarial gain[2] | (0.4) | | |
| Tax benefit (expense)[5] | 0.1 | | |
| Total amount reclassified from Accumulated other comprehensive loss, net of tax[5] | (0.3) | | |
| Total Other comprehensive income (loss) | 1.4 | (1.3) | (0.5) |
| Balance at end of period | $ (0.4) | $ (1.8) | $ (0.5) |
| **Cash flow hedges** | | | |
| Balance at beginning of period | $ (1.4) | $ (1.4) | $ 0.2 |
| Other comprehensive income (loss): | | | |
| Net change from periodic revaluations | 1.2 | (1.5) | (4.4) |
| Tax benefit (expense) | (0.5) | 0.6 | 1.8 |
| Total Other comprehensive income (loss) before reclassifications, net of tax | 0.7 | (0.9) | (2.6) |
| Net amount reclassified to earnings: | | | |
| Interest rate swaps[3] | 1.7 | 1.9 | 2.3 |
| Fuel commodity swaps[4] | (0.2) | (0.4) | (0.7) |

| | | | |
|---|---|---|---|
| Sub-total | 1.5 | 1.5 | 1.6 |
| Tax benefit[5] | (0.6) | (0.6) | (0.6) |
| Total amount reclassified from Accumulated other comprehensive loss, net of tax[6] | 0.9 | 0.9 | 1.0 |
| Total Other comprehensive income (loss) | 1.6 | | (1.6) |
| Balance at end of period | $ 0.2 | $ (1.4) | $ (1.4) |

(1) In all periods presented, there were no tax impacts related to rate changes and no amounts were reclassified to earnings.

(2) This amount was included in Administration on the accompanying Consolidated Statements of Operations.

(3) This amount was included in Interest, net on the accompanying Consolidated Statements of Operations.

(4) These amounts were included in Fuel on the accompanying Consolidated Statements of Operations.

(5) These amounts were included in Income tax expense (benefit) on the accompanying Consolidated Statements of Operations.

(6) A positive amount indicates a corresponding charge to earnings and a negative amount indicates a corresponding benefit to earnings. These amounts were reflected on the accompanying Consolidated Statements of Operations in the line items indicated in footnotes 2 through 5.

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**2. Summary of significant accounting policies (Continued)**

In July 2012, the Financial Accounting Standards Board ("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 became effective for us for any indefinite-lived intangible asset impairment test performed on January 1, 2013 or later. The adoption of these changes did not impact the consolidated financial statements.

In December 2011, the FASB issued changes to the disclosure of offsetting assets and liabilities. These changes require an entity to disclose both gross information and net information about both instruments and transactions eligible for offset in the statement of financial position and instruments and transactions subject to an agreement similar to a master netting arrangement. The enhanced disclosures will enable users of an entity's financial statements to understand and evaluate the effect or potential effect of master netting arrangements on an entity's financial position, including the effect or potential effect of rights of setoff associated with certain financial instruments and derivative instruments. These changes became effective for us on January 1, 2013. Other than the additional disclosure requirements, the adoption of these changes did not impact the consolidated financial statements.

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

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

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

*Issued*

In July 2013, the FASB issued changes to the presentation of an unrecognized tax benefit when a net operating loss carryforward, a similar tax loss, or a tax credit carryforward exists. These changes require an entity to present an unrecognized tax benefit as a liability in the financial statements if (i) a net operating loss carryforward, a similar tax loss, or a tax credit carryforward is not available at the reporting date under the tax law of the applicable jurisdiction to settle any additional income taxes that would result from the disallowance of a tax position, or (ii) the tax law of the applicable jurisdiction does not require the entity to use, and the entity does not intend to use, the deferred tax asset to settle any additional income taxes that would result from the disallowance of a tax position. Otherwise, an unrecognized tax benefit is required to be presented in the financial statements as a reduction to a deferred tax asset for a net operating loss carryforward, a similar tax loss, or a tax credit carryforward. Previously, there was diversity in practice as no explicit guidance existed. These changes become effective for us on January 1, 2014. We have determined that the adoption of these changes will not have a material impact on the consolidated financial statements.

In March 2013, the FASB issued changes to a parent entity's accounting for the cumulative translation adjustment upon derecognition of certain subsidiaries or groups of assets within a foreign entity or of an investment in a foreign entity. A parent entity is required to release any related cumulative foreign currency translation adjustment from accumulated other comprehensive income into net income in the following circumstances: (i) a parent entity ceases to have a controlling financial interest in a subsidiary or group of assets that is a business within a foreign entity if the sale or transfer results in the complete or substantially complete liquidation of the foreign entity in which the subsidiary or group of assets had resided; (ii) a partial sale of an equity method investment that is a foreign entity; (iii) a partial sale of an equity method investment that is not a foreign entity whereby the partial sale represents a complete or substantially complete liquidation of the foreign entity that held the equity method investment; and (iv) the sale of an investment in a foreign entity. These changes become effective for us on January 1, 2014. We have determined that the adoption of these changes will not have a material impact on the consolidated financial statements.

In February 2013, the FASB issued changes to the accounting for obligations resulting from joint and several liability arrangements. These changes require an entity to measure such obligations for which the total amount of the obligation is fixed at the reporting date as the sum of (i) the amount the reporting entity agreed to pay on the basis of its arrangement among its co- obligors, and (ii) any additional amount the reporting entity expects to pay on behalf of its co-obligors. An entity will also be required to disclose the nature and amount of the obligation as well as other information about those obligations. Examples of obligations subject to these requirements are debt arrangements and settled litigation and judicial rulings. These changes become effective for us on January 1, 2014. We have

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**2. Summary of significant accounting policies (Continued)**

determined that the adoption of these changes will not have a material impact on the consolidated financial statements.

**3. Acquisitions and divestments**

***2012 Acquisitions***

(a) Ridgeline

On November 5, 2012 we entered into a purchase and sale agreement to acquire a 100% ownership interest in Ridgeline for approximately $81.3 million. Ridgeline develops, constructs and operates wind and solar energy projects across the United States. As a result of the acquisition, we increased our ownership in Rockland Wind Farm, LLC. ("Rockland") from a 30% to a 50% managing member interest (which is 100% consolidated) and our net generation capacity increased from 24 to 40 MW. We also acquired a 12.5% equity ownership in Goshen North, a 124.5 MW (16 MW, net) wind project operating in Idaho. Additionally, we purchased a 100% ownership interest in Meadow Creek, a 119.7 MW wind project operating in Idaho, which completed construction and became operational on December 22, 2012. The acquisition of Ridgeline provides a pipeline of potential wind and solar projects in various phases of development.

We closed on this transaction on December 31, 2012 and financed the acquisition through the issuance of Cdn$100 million (approximately Cdn$95 million after underwriting and transaction costs) aggregate principal amount of series D extendible convertible unsecured subordinated debentures (the "December 2012 Debentures").

Our acquisition of Ridgeline was accounted for under the acquisition method of accounting as of the transaction closing date. The final purchase price allocation for the business combination is as follows:

| | | |
|---|---|---|
| **Fair value of consideration transferred:** | | |
| Cash | $ | 81.3 |
| Other items to be allocated to identifiable assets acquired and liabilities assumed: | | |
| Fair value of our investment in Rockland at the acquisition date | | 12.1 |
| Loss recognized on the step acquisition | | (7.4) |
| Total purchase price | $ | 86.0 |

| | | |
|---|---|---|
| **Final purchase price allocation** | | |
| Cash | $ | 1.0 |
| Working capital | | (8.1) |
| Property, plant, and equipment | | 373.9 |
| Deferred tax asset | | 9.6 |
| Other long-term assets | | 36.0 |
| Long-term debt | | (295.5) |
| Interest rate swaps | | (21.6) |
| Other long-term liabilities | | (1.3) |
| Minority interest | | (8.0) |

| | | |
|---|---|---|
| Total identifiable net assets | $ | 86.0 |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**3. Acquisitions and divestments (Continued)**

The fair values of the assets acquired and liabilities assumed were estimated by applying an income approach using the discounted cash flow method. These measurements were based on significant inputs not observable in the market and thus represent a level 3 fair value measurement. The primary considerations and assumptions that affected the discounted cash flows included the operational characteristics and financial forecasts of acquired facilities, remaining useful lives and discount rates based on the weighted average cost of capital ("WAAC") adjusted for the risk and characteristics of each plant.

During the fourth quarter of 2013, we adjusted the fair value of the net deferred taxes recorded in the preliminary purchase price allocation. The adjustment was based on the final determination of deferred taxes on net operating loss carryforwards and other tax attributes that were acquired as part of the Ridgeline acquisition. As a result, the opening deferred tax liability of $14.2 million was adjusted to a deferred tax asset of $9.6 million with a corresponding reduction to property, plant and equipment of $23.9 million. The Ridgeline purchase price allocation is final at December 31, 2013.

(b) Canadian Hills

On January 31, 2012, Atlantic Oklahoma Wind, LLC ("Atlantic OW"), a Delaware limited liability company and our wholly owned subsidiary, entered into a purchase and sale agreement with Apex Wind Energy Holdings, LLC, a Delaware limited liability company ("Apex"), pursuant to which Atlantic OW acquired a 51% interest in Canadian Hills Wind, LLC, an Oklahoma limited liability company ("Canadian Hills") for a nominal sum. Canadian Hills is the owner of a 300 MW wind energy project in the state of Oklahoma.

On March 30, 2012, we completed the purchase of an additional 48% interest in Canadian Hills for a nominal amount, bringing our total interest in the project to 99%. Apex retained a 1% interest in the project. We also closed a $310 million non-recourse, project-level construction financing facility for the project, which included a $290 million construction loan and a $20 million 5-year letter of credit facility. In July 2012, we funded approximately $190 million of our equity contribution (net of financing costs). 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 tax equity investment of our own. The project's outstanding construction loan was repaid by the proceeds from these tax equity investments, decreasing the project's short-term debt by $265 million as of December 31, 2012. Canadian Hills has no debt at December 31, 2013. On May 2, 2013, we syndicated our $44 million tax equity investment in Canadian Hills to an institutional investor and received net cash proceeds of $42.1 million. The syndication of our interest completes the sale of 100% of Canadian Hills' $269 million of tax equity interests. The cash proceeds will be held for general corporate purposes.

The acquisition of Canadian Hills was accounted for as an asset purchase and is consolidated in our consolidated balance sheet at December 31, 2013. We own 99% of the project and consolidate it in our consolidated financial statements. Income attributable to noncontrolling interests is allocated utilizing HLBV.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**3. Acquisitions and divestments (Continued)**

***2011 Acquisitions***

(a) Capital Power Income L.P.

On November 5, 2011, we completed the acquisition of all of the outstanding limited partnership units of Capital Power Income, LP (renamed Atlantic Power Limited Partnership on February 1, 2012, the "Partnership") pursuant to the terms and conditions of an arrangement agreement, dated June 20, 2011, as amended by Amendment No. 1, dated July 15, 2011 (the "Arrangement Agreement"), by and among us, the Partnership, CPI Income Services, Ltd., the general partner of the Partnership and CPI Investments, Inc., a unitholder of the Partnership that was then owned by EPCOR Utilities Inc. and Capital Power Corporation. The transactions contemplated by the Arrangement Agreement were effected through a court-approved plan of arrangement under the *Canada Business Corporations Act* (the "Plan of Arrangement"). The Plan of Arrangement was approved by the unitholders of the Partnership, and the issuance of our common shares to the Partnership unitholders pursuant to the Plan of Arrangement was approved by our shareholders, at respective special meetings held on November 1, 2011. A Final Order approving the Plan of Arrangement was granted by the Court of Queen's Bench of Alberta on November 1, 2011. Pursuant to the Plan of Arrangement, the Partnership sold its Roxboro and Southport facilities located in North Carolina to an affiliate of Capital Power Corporation, for approximately Cdn$121.4 million which equates to approximately Cdn$2.15 per unit of the Partnership. In addition, in connection with the Plan of Arrangement, the management agreements between certain subsidiaries of Capital Power Corporation and the Partnership and certain of its subsidiaries were terminated in consideration of a payment of Cdn$10.0 million. Atlantic Power and its subsidiaries assumed the management of the Partnership upon closing and entered into a transitional services agreement with Capital Power Corporation for a term of six to twelve months to facilitate and support the integration of the Partnership into Atlantic Power.

The acquisition expanded and diversified our asset portfolio to include projects in Canada and regions of the United States where we did not have a presence. At the time of the acquisition of the Partnership, our average PPA term increased from 8.8 years to 9.1 years and enhanced the credit quality of our portfolio of off takers.

Pursuant to the Plan of Arrangement, we directly and indirectly acquired each outstanding limited partnership unit of the Partnership in exchange for Cdn$19.40 in cash ("Cash Consideration") or 1.3 Atlantic Power common shares ("Share Consideration") in accordance with elections and deemed elections in accordance with the Plan of Arrangement.

As a result of the elections made by the Partnership unitholders and pro-ration in accordance with the Plan of Arrangement, those unitholders who elected to receive Cash Consideration received in exchange for each limited partnership unit of the Partnership (i) cash equal to approximately 73% of the Cash Consideration and (ii) Share Consideration in respect of the remaining approximately 27% of the consideration payable for the unit. Any limited partnership units of the Partnership not exchanged for cash consideration in accordance with the Plan of Arrangement were exchanged for Share Consideration.

At closing, the consideration paid to acquire the Partnership totaled $1.0 billion, consisting of $601.8 million paid in cash and $407.4 million in shares of our common shares (31.5 million shares issued) less cash acquired of $22.7 million.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**3. Acquisitions and divestments (Continued)**

Our acquisition of the Partnership is accounted for under the acquisition method of accounting as of the transaction closing date. The final purchase price allocation for the business combination is as follows:

| | | |
|---|---|---|
| **Fair value of consideration transferred:** | | |
| Cash | $ | 601.8 |
| Equity | | 407.4 |
| Total purchase price | $ | 1,009.2 |

| | | |
|---|---|---|
| **Final purchase price allocation** | | |
| Working capital | $ | 38.0 |
| Property, plant, and equipment | | 1,024.0 |
| Intangibles | | 528.5 |
| Other long-term assets | | 224.3 |
| Long-term debt | | (621.6) |
| Other long-term liabilities | | (129.3) |
| Deferred tax liability | | (164.5) |
| Total identifiable net assets | | 899.4 |
| Preferred shares | | (221.3) |
| Goodwill | | 331.1 |
| Total purchase price | | 1,009.2 |
| Less cash acquired | | (22.7) |
| Cash paid, net of cash acquired | $ | 986.5 |

The purchase price was computed using the Partnership's outstanding units as of June 30, 2011, adjusted for the exchange ratio at November 5, 2011. The purchase price reflects the market value of our common shares issued in connection with the transaction based on the closing price of the Partnership's units on the TSX on November 5, 2011. The goodwill was attributable to the expansion of our asset portfolio to include projects in Canada and regions of the United States where we did not have a presence. It is not expected to be deductible for tax purposes.

The fair values of the assets acquired and liabilities assumed were estimated by applying an income approach using the discounted cash flow method. These measurements were based on significant inputs not observable in the market and thus represent a level 3 fair value measurement. The primary considerations and assumptions that affected the discounted cash flows included the operational characteristics and financial forecasts of acquired facilities, remaining useful lives and discount rates based on the WACC on a merchant basis. The WACCs were based on a set of comparable companies as well as existing yields for debt and equity as of the acquisition date.

The Partnership contributed revenues of $73.8 million and a loss of less than $0.1 million to our consolidated statements of operations for the period from November 5, 2011 to December 31, 2011. The following unaudited pro-forma consolidated results of operations for years ended December 31, 2011 and 2010, assume the Partnership acquisition occurred as of January 1 of each year. The pro forma results of operations are presented for informational purposes only and are not indicative of the

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**3. Acquisitions and divestments (Continued)**

results of operations that would have been achieved if the acquisition had taken place on January 1, 2011 and January 1, 2010 or of results that may occur in the future:

| | Unaudited Years ended December 31, | |
|---|---|---|
| | **2011** | **2010** |
| Total project revenue | $ 694.2 | $ 670.0 |
| Net loss attributable to Atlantic Power Corporation | (95.8) | (2.5) |
| Net loss per share attributable to Atlantic Power Corporation shareholders: | | |
| Basic | $ (0.85) | $ (0.02) |
| Diluted | $ (0.85) | $ (0.02) |

(b) Rockland

On December 28, 2011, we purchased a 30% interest for $12.5 million in Rockland, an 80 MW wind farm near American Falls, Idaho, that began operations in early December 2011. Rockland sells power under a 25-year power purchase agreement with Idaho Power. Rockland was accounted for under the equity method of accounting through December 30, 2012. On December 31, 2012, we finalized our purchase of an additional 20% interest in Rockland through our acquisition of Ridgeline and consolidated the project. See Note 3(a) for further discussion of the Ridgeline acquisition.

***2013 Divestments***

(a) Rollcast

On November 5, 2013, we completed the sale of our 60% interest in Rollcast to its remaining shareholders. As consideration for the sale, we were assigned asset management contracts valued at $0.5 million for the Cadillac and Piedmont projects as well as the remaining 2% ownership interest in Piedmont bringing our total ownership to 100%. In return, we paid $0.5 million in cash to the minority owner and forgave an outstanding $1.0 million loan that was provided by us to Rollcast to fund working capital during 2013. We recorded a $1.0 million gain on sale which is recorded in other income, net in the consolidated statements of operations for the year ended December 31, 2013. Rollcast's net loss is recorded as loss from discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011.

(b) Gregory

On April 2, 2013, we and the other owners of Gregory entered into a purchase and sale agreement with an affiliate of NRG Energy, Inc. to sell the project for approximately $274.2 million, including working capital adjustments. The sale of Gregory closed on August 7, 2013 resulting in a gain on sale of $30.4 million that was recorded in gain on sale of equity investments in the consolidated statements of operations for the year ended December 31, 2013. We received net cash proceeds for our ownership interest of approximately $34.7 million in the aggregate, after repayment of project-level debt and transaction expenses. Approximately $5 million of these proceeds will be held in escrow for up to one year after the closing date. We intend to use the net proceeds from the sale for general corporate purposes.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**3. Acquisitions and divestments (Continued)**

(c) Auburndale, Lake and Pasco

On January 30, 2013, we entered into a purchase and sale agreement for the sale of our Auburndale Power Partners, L.P. ("Auburndale"), Lake CoGen, Ltd. ("Lake") and Pasco CoGen, Ltd. ("Pasco") projects (collectively, the "Florida Projects") for approximately $140.0 million, with working capital adjustments. The sale closed on April 12, 2013 and we received net cash proceeds of approximately $117.0 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. This includes approximately $92.0 million received at closing and cash distributions from the Florida Projects of approximately $25.0 million received since January 1, 2013. We used a portion of the net proceeds from the sale to fully repay our senior credit facility, which had an outstanding balance of approximately $64.1 million on the closing date. The remaining cash proceeds will be used for general corporate purposes. The Florida Projects were accounted for as assets held for sale in the consolidated balance sheets at December 31, 2012 and as a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011. See Note 20, *Assets held for sale*, for further information.

(d) Path 15

On March 11, 2013, we entered into a purchase and sales agreement with Duke Energy Corporation and American Transmission Co., to sell our interests in the Path 15 transmission line ("Path 15"). The sale closed on April 30, 2013 and we received net cash proceeds from the sale, including working capital adjustments, of approximately $52.0 million, plus a management agreement termination fee of $4.0 million, for a total sale price of approximately $56.0 million. The cash proceeds will be used for general corporate purposes. All project level debt issued by Path 15, totaling $137.2 million, transferred with the sale. Path 15 was accounted for as an asset held for sale in the consolidated balance sheets at December 31, 2012 and as a component of discontinued operations in the consolidated statements of operations for the years ended December 31, 2013, 2012 and 2011. See Note 20, *Assets held for sale*, for further information.

(e) Delta-Person

On December 7, 2012, we entered into a purchase and sale agreement for the sale of our 40% interest in Delta-Person. We will receive approximately $9.0 million in proceeds and the transaction is expected to close in 2014.

***2012 Divestments***

(a) Badger Creek

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

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**3. Acquisitions and divestments (Continued)**

(b) Primary Energy Recycling Corporation

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

***2011 Divestments***

(a) Onondaga Renewables

In the fourth quarter of 2011, the partners of Onondaga Renewables initiated a plan to sell their interests in the project. We determined that the carrying value of the Onondaga Renewables project was impaired and recorded a pre-tax long-lived asset impairment of $1.5 million. Our estimate of the fair market value of our 50% investment in the Onondaga Renewables project was determined based on quoted market prices for the remaining land and equipment. The Onondaga Renewables project is accounted for under the equity method of accounting and the impairment charge is included in equity earnings from unconsolidated affiliates in the consolidated statements of operations.

(b) Topsham

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

**4. Equity method investments in unconsolidated affiliates**

The following tables summarize our equity method investments:

| Entity name | Percentage of Ownership as of December 31, 2013 | Carrying value as of December 31. 2013 | 2012 |
|---|---|---|---|
| Frederickson | 50.0% | $ 153.9 | $ 167.7 |
| Orlando Cogen, LP | 50.0% | 14.3 | 19.9 |
| Onondaga Rewables, LLC | 50.0% | | 0.2 |
| Koma Kulshan Associates | 49.8% | 5.8 | 6.4 |
| Chambers Cogen, LP | 40.0% | 153.7 | 154.3 |
| Delta-Person, LP | 40.0% | | |
| Idaho Wind Partners 1, LLC | 27.6% | 33.2 | 34.7 |
| Selkirk Cogen Partners, LP | 18.5% | 24.4 | 33.7 |
| Goshen North | 12.5% | 9.0 | 9.0 |
| Gregory Power Partners, LP | | | 2.8 |
| Total | | $ 394.3 | $ 428.7 |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**4. Equity method investments in unconsolidated affiliates (Continued)**

Equity (deficit) in earnings (loss) of equity method investments was as follows:

| | Year Ended December 31, | | |
|---|---|---|---|
| **Entity name** | **2013** | **2012** | **2011** |
| Chambers Cogen, LP | $ 9.6 | $ 17.1 | $ 7.7 |
| Orlando Cogen, LP | 3.3 | 3.2 | 0.9 |
| Koma Kulshan Associates | 0.3 | 0.5 | 0.5 |
| Frederickson | 2.1 | 0.9 | 0.4 |
| Idaho Wind Partners 1, LLC | (0.3) | (0.2) | (1.6) |
| Selkirk Cogen Partners, LP | 8.7 | 7.6 | (0.4) |
| Goshen North | 1.4 | | |
| Gregory Power Partners, LP[(1)] | 1.6 | (0.7) | 0.5 |
| Onondaga Rewables, LLC | (0.3) | (0.4) | (1.8) |
| Rockland Wind Farm[(2)] | | (8.0) | |
| Other | 0.5 | (4.8) | 0.2 |
| Total | 26.9 | 15.2 | 6.4 |
| Distributions from equity method investments | (40.9) | (38.4) | (21.9) |
| Deficit in earnings (loss) of equity method investments, net of distributions | $ (14.0) | $ (23.2) | $ (15.5) |

(1) We sold Gregory in August 2013, resulting in a gain $30.4 million, which is recorded in gain on sale of equity investments in the consolidated statements of operations for the year ended December 31, 2013.

(2) Due to an ownership change from 30% to 50% as part of the Ridgeline acquisition during the fourth quarter of 2012, Rockland Wind Farm was consolidated as of December 31, 2012.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**4. Equity method investments in unconsolidated affiliates (Continued)**

The following summarizes the financial position at December 31, 2013, 2012 and 2011, and operating results for the years ended December 31, 2013, 2012 and 2011, respectively, for our proportional ownership interest in equity method investments:

| | 2013 | 2012 | 2011 |
|---|---|---|---|
| **Assets** | | | |
| Current assets | | | |
| Chambers Cogen, LP | $ 11.8 | $ 16.1 | $ 9.9 |
| Selkirk Cogen Partners, LP | 12.9 | 12.9 | 15.9 |
| Other | 24.6 | 32.0 | 22.3 |
| Non-current assets | | | |
| Chambers Cogen, LP | 224.0 | 235.2 | 245.8 |
| Selkirk Cogen Partners, LP | 14.1 | 26.0 | 47.7 |
| Other | 286.6 | 322.3 | 359.1 |
| | $ 574.0 | $ 644.5 | $ 700.7 |

| | 2013 | 2012 | 2011 |
|---|---|---|---|
| **Liabilities** | | | |
| Current liabilities | | | |
| Chambers Cogen, LP | $ 4.4 | $ 15.2 | $ 16.0 |
| Selkirk Cogen Partners, LP | 2.3 | 4.8 | 14.7 |
| Other | 13.9 | 16.4 | 19.1 |
| Non-current liabilities | | | |
| Chambers Cogen, LP | 77.7 | 81.8 | 96.0 |
| Selkirk Cogen Partners, LP | 0.3 | 0.3 | 1.5 |
| Other | 81.1 | 97.3 | 79.0 |
| | $ 179.7 | $ 215.8 | $ 226.3 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**4. Equity method investments in unconsolidated affiliates (Continued)**

| **Operating results** | **2013** | **2012** | **2011** |
|---|---|---|---|
| Revenue | | | |
| Chambers Cogen, LP | $ 52.7 | $ 58.1 | $ 49.3 |
| Selkirk Cogen Partners, LP | 50.5 | 48.7 | 54.6 |
| Other | 101.2 | 109.8 | 91.8 |
| | 204.4 | 216.6 | 195.7 |
| Project expenses | | | |
| Chambers Cogen, LP | 40.6 | 39.1 | 39.4 |
| Selkirk Cogen Partners, LP | 40.3 | 42.4 | 49.6 |
| Other | 88.9 | 92.7 | 85.4 |
| | 169.8 | 174.2 | 174.4 |
| Project other income (expense) | | | |
| Chambers Cogen, LP | (2.5) | (1.9) | (2.2) |
| Selkirk Cogen Partners, LP | (1.5) | 1.3 | (5.4) |
| Other | (3.7) | (26.6) | (7.3) |
| | (7.7) | (27.2) | (14.9) |
| Project income (loss) | | | |
| Chambers Cogen, LP | $ 9.6 | $ 17.1 | $ 7.7 |
| Selkirk Cogen Partners, LP | 8.7 | 7.6 | (0.4) |
| Other | 8.6 | (9.5) | (0.9) |
| | 26.9 | 15.2 | 6.4 |

**5. Inventory**

Inventory consists of the following:

| | **December 31,** | |
|---|---|---|
| | **2013** | **2012** |
| Parts and other consumables | $ 11.3 | $ 8.6 |
| Fuel | 4.7 | 8.3 |
| Total inventory | $ 16.0 | $ 16.9 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

### 6. Property, plant and equipment

| | December 31, 2013 | December 31, 2012 | Depreciable Lives |
|---|---|---|---|
| Land | $ 5.9 | $ 7.3 | |
| Office equipment, machinery and other | 3.3 | 2.9 | 3 - 10 years |
| Leasehold improvements | 0.4 | 0.4 | 7 - 15 years |
| Asset retirement obligation | 34.8 | 35.8 | 1 - 42 years |
| Plant in service | 1,938.4 | 1,895.0 | 1 - 45 years |
| Construction in progress | 5.7 | 193.7 | |
| | 1,988.5 | 2,135.1 | |
| Less accumulated depreciation | (175.1) | (79.6) | |
| | $ 1,813.4 | $ 2,055.5 | |

Depreciation expense of $106.0 million, $58.6 million and $13.2 million was recorded for the years ended December 31, 2013, 2012 and 2011, respectively.

### 7. Goodwill

Our goodwill balance was $296.3 million and $334.7 million as of December 31, 2013 and December 31, 2012, respectively. We recorded $331.1 million of goodwill in connection with the acquisition of Capital Power Income L.P. (the "Partnership") in 2011 and $3.5 million associated with the step-up acquisition of Rollcast in March 2010.

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 at the project level and, the lowest level below the operating segments for which discrete financial information is available. Based on a prolonged decline in our market capitalization, we determined that it was appropriate to initiate a test of goodwill to determine if the fair value of each of our reporting units' goodwill does not exceed their carrying amounts. The impairment analysis was performed as of August 31, 2013. For reporting units that failed step one of the goodwill impairment test, we performed a step two test to quantify the amount, if any, of non-cash impairment to goodwill to record.

As a result of the event-driven goodwill assessment completed in the third quarter of 2013, it was determined that goodwill was impaired at the Kenilworth reporting unit (East segment) and the Naval reporting units (West segment). The total impairment recorded in the three months ended September 30, 2013 was $34.9 million. The $30.8 million impairment at Kenilworth was due to lower forecasted capacity and energy prices as compared to the assumptions used at the time of the acquisition in November 2011. When performing our step two quantitative analysis, the increase in the intangible value associated with the new ESA entered into in July 2013 resulted in a lower implied goodwill value. At the time of its acquisition in November 2011, the fair value of the assets acquired and liabilities assumed for the Kenilworth project were valued assuming a merchant basis for the period subsequent to the expiration of the project's original PPA in July 2012. As discussed above, these forecasted energy revenues on a merchant basis were higher than the energy prices currently

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**7. Goodwill (Continued)**

forecasted to be in effect subsequent to the expiration of the new ESA. The $4.1 million impairment at the Naval reporting units was primarily due to increased uncertainty, not assumed at the time of the reporting unit's acquisition in 2011, in our ability to extend two of the projects lease and steam agreements upon their expiration. In addition, lower currently forecasted capacity and energy prices in California after the expiration of the PPAs compared to the forecast at the time of the acquisition in 2011 result in a lower business enterprise value which resulted in a lower implied goodwill value.

During the three months ended June 30, 2013, we recorded a $3.5 million impairment of goodwill at Rollcast which is a component of our Un-allocated corporate segment. We determined, based on the results of the two-step process, that the carrying amount of goodwill exceeded the implied fair value of goodwill. We also wrote-off $1.4 million of capitalized development costs at Rollcast related to the Greenway development project. The determination to test goodwill for impairment and to write-off the capitalized development costs was based on the reduced expectation of the Greenway project being further developed. Rollcast was sold in November 2013 and is classified as a component of discontinued operations for the years ended December 31, 2013, 2012 and 2011.

We updated our goodwill impairment analysis as of November 30, 2013 which resulted in no additional impairments.

Under the two-step quantitative impairment tests performed, the evaluation of impairment involved comparing the current fair value of each reporting unit to its carrying value, including goodwill. For step one of the quantitative tests, we determined the fair value of our reporting units using an income approach with discounted cash flow ("DCF") models, as we believe forecasted cash flows are the best indicator of such fair value. A number of significant assumptions and estimates are involved in the application of the DCF model to forecast operating cash flows, including assumptions about discount rates, projected power prices, generation, fuel costs and capital expenditure requirements. Most of these assumptions vary significantly among the reporting units. The discount rate applied to the DCF models represents the weighted average cost of capital ("WACC") consistent with the risk inherent in future cash flows and based upon an assumed capital structure, cost of long-term debt and cost of equity consistent with comparable independent power producers. The betas used in calculating the individual reporting units' WACC rate are estimated for each business with the assistance of valuation experts. Cash flow forecasts are generally based on approved reporting unit operating plans for years with contracted PPAs and historical relationships for estimates at the expiration of PPAs. These forecasts utilize historical plant output for determining assumptions around future generation and industry data forward power and fuel curves to estimate future power and fuel prices. We use historical experience to determine estimated future capital investment requirements.

The valuation of goodwill for the second step of the goodwill impairment analysis is considered a level 3 fair value measurement, which means that the valuation of the assets and liabilities reflect management's own judgments regarding the assumptions market participants would use in determining the fair value of the assets and liabilities.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**7. Goodwill (Continued)**

The following table details the changes in the carrying amount of goodwill by operating segment:

| | East | West | Wind | Un-allocated corporate | Total |
|---|---|---|---|---|---|
| Balance at December 31, 2011 | $ 138.6 | $ 201.5 | $ | $ 3.5 | $ 343.6 |
| Reclass to assets held for sale | | (8.9) | | | (8.9) |
| Balance at December 31, 2012 | 138.6 | 192.6 | | 3.5 | 334.7 |
| Impairment of goodwill | (30.8) | (4.1) | | (3.5) | (38.4) |
| Balance at December 31, 2013 | $ 107.8 | $ 188.5 | $ | $ | $ 296.3 |

**8. Power purchase agreements and other intangible assets and liabilities**

Other intangible assets and liabilities include power purchase agreements, fuel supply agreements and development costs.

The following tables summarize the components of our intangible assets and other liabilities subject to amortization for the years ended December 31, 2013 and 2012:

| | Other Intangible Assets, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Development Costs | Total |
| Gross balances, December 31, 2013 | $ 597.4 | $ 4.8 | $ 602.2 |
| Less: accumulated amortization | (139.8) | (0.3) | (140.1) |
| Foreign currency translation adjustment | (10.6) | | (10.6) |
| Net carrying amount, December 31, 2013 | $ 447.0 | $ 4.5 | $ 451.5 |

| | Other Intangible Assets, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Development Costs | Total |
| Gross balances, December 31, 2012 | $ 590.9 | $ 6.2 | $ 597.1 |
| Less: accumulated amortization | (76.9) | | (76.9) |

| | | | | | | |
|---|---|---|---|---|---|---|
| Foreign currency translation adjustment | | 4.7 | | | | 4.7 |
| Net carrying amount, December 31, 2012 | $ | 518.7 | $ | 6.2 | $ | 524.9 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**8. Power purchase agreements and other intangible assets and liabilities (Continued)**

| | Power Purchase and Fuel Supply Agreement Liabilities, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Fuel Supply Agreements | Total |
| Gross balances, December 31, 2013 | $ (35.9) | $ (12.6) | $ (48.5) |
| Less: accumulated amortization | 5.3 | 2.5 | 7.8 |
| Foreign currency translation adjustment | 2.0 | | 2.0 |
| Net carrying amount, December 31, 2013 | $ (28.6) | $ (10.1) | $ (38.7) |

| | Power Purchase and Fuel Supply Agreement Liabilities, Net | | |
|---|---|---|---|
| | Power Purchase Agreements | Fuel Supply Agreements | Total |
| Gross balances, December 31, 2012 | $ (35.3) | $ (12.6) | $ (47.9) |
| Less: accumulated amortization | 2.9 | 1.6 | 4.5 |
| Foreign currency translation adjustment | (0.6) | | (0.6) |
| Net carrying amount, December 31, 2012 | $ (33.0) | $ (11.0) | $ (44.0) |

The following table presents amortization expense of intangible assets for the years ended December 31, 2013, 2012 and 2011:

| | 2013 | 2012 | 2011 |
|---|---|---|---|
| Power purchase agreements | $ 60.8 | $ 59.5 | $ 11.6 |
| Fuel supply agreements | (1.2) | (1.2) | (1.4) |
| Total amortization expense | $ 59.6 | $ 58.3 | $ 10.2 |

The following table presents estimated future amortization expense for the next five years related to power purchase agreements and fuel supply agreements:

| Year Ended December 31, | Power Purchase Agreements | Fuel Supply Agreements |
|---|---|---|

| | | |
|---|---|---|
| 2014 | $ 58.4 | $ (1.2) |
| 2015 | 55.0 | (1.2) |
| 2016 | 55.0 | (1.2) |
| 2017 | 55.1 | (1.2) |
| 2018 | 47.3 | (1.2) |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**8. Power purchase agreements and other intangible assets and liabilities (Continued)**

The following table presents the weighted average remaining amortization period related to our intangible assets as of December 31, 2013:

| As of December 31, 2013 | Power Purchase Agreements | Fuel Supply Agreements |
|---|---|---|
| (in years) | | |
| Weighted average remaining amortization period | 9.0 | 9.0 |

**9. Other long-term liabilities**

Other long-term liabilities consist of the following:

| | 2013 | 2012 |
|---|---|---|
| Asset retirement obligations | $ 57.7 | $ 57.8 |
| Net pension liability | 0.8 | 4.8 |
| Deferred revenue | 4.0 | 4.9 |
| Other | 2.9 | 3.9 |
| | $ 65.4 | $ 71.4 |

We assumed asset retirement obligations ("ARO") in our acquisition of the Partnership. During 2012, we also recorded asset retirement obligations related to the Canadian Hills project. We recorded these retirement obligations as we are legally required to remove these facilities at the end of their useful lives and restore the sites to their original condition. The following table represents the fair value of ARO at the date of acquisition along with the additions, reductions and accretion related to our ARO for the year ended December 31, 2013:

| | 2013 |
|---|---|
| Asset retirement obligations beginning of year | $ 57.8 |
| Accretion of asset retirement obligations | 1.6 |
| Translation adjustments | (1.7) |
| Asset retirement obligations, end of year | $ 57.7 |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**10. Long-term debt**

Long-term debt consists of the following:

| | December 31, 2013 | December 31, 2012 | Interest Rate |
|---|---|---|---|
| **Recourse Debt:** | | | |
| Senior unsecured notes, due 2018 | $ 460.0 | $ 460.0 | 9.0% |
| Senior unsecured notes, due June 2036 (Cdn$210.0) | 197.4 | 211.1 | 6.0% |
| Senior unsecured notes, due July 2014[(3)] | 190.0 | 190.0 | 5.9% |
| Series A senior unsecured notes, due August 2015[(3)] | 150.0 | 150.0 | 5.9% |
| Series B senior unsecured notes, due August 2017[(3)] | 75.0 | 75.0 | 6.0% |
| **Non-Recourse Debt:** | | | |
| Epsilon Power Partners term facility, due 2019 | 30.5 | 33.5 | 7.4% |
| Cadillac term loan, due 2025 | 35.4 | 37.8 | 6.0% - 8.0% |
| Piedmont construction loan, due 2014[(1)] | 76.6 | 127.4 | Libor plus 3.5% |
| Meadow Creek term loan, due 2024[(2)] | 169.8 | 208.7 | 2.9% - 5.6% |
| Rockland term loan, due 2027 | 85.3 | 86.5 | 6.4% |
| Other long-term debt | 1.0 | 0.3 | 5.5% - 6.7% |
| Less: current maturities | (216.2) | (121.2) | |
| Total long-term debt | $ 1,254.8 | $ 1,459.1 | |

Current maturities consist of the following:

| | December 31, 2013 | December 31, 2012 | Interest Rate |
|---|---|---|---|
| **Current Maturities:** | | | |
| Senior unsecured notes, due July 2014 | $ 190.0 | $ | 5.9% |
| Epsilon Power Partners term facility, due 2019 | 5.0 | 3.0 | 7.4% |
| Cadillac term loan, due 2025 | 2.0 | 2.4 | 6.0% - 8.0% |
| Piedmont construction loan, due 2014[(1)] | 12.6 | 55.1 | Libor plus 3.5% |
| Meadow Creek term loan, due 2024[(2)] | 4.9 | 59.5 | 2.9% - 5.6% |
| Rockland term loan, due 2027 | 1.5 | 1.2 | 6.4% |
| Other short-term debt | 0.2 | | 5.5 - 6.7% |
| Total current maturities | $ 216.2 | $ 121.2 | |

(1) The terms of the Piedmont project-level debt financing included a $51.0 million bridge loan and an $82.0 million construction loan ($76.6 million at December 31, 2013). On April 19, 2013, Piedmont achieved commercial operations and submitted an application under the 1603 federal grant program to recover approximately 30% of its capital cost. The grant application was approved and we received a $49.5 million grant from the U.S. Treasury in July 2013. Upon receipt of the grant, we repaid in full the $51.0 million bridge loan with the proceeds of the grant and a $1.5 million contribution from us to cover the shortfall resulting from the federal sequester on spending. On February 14, 2014, we paid down $8.1 million of principal on the construction loan and converted

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**10. Long-term debt (Continued)**

the remaining $68.5 million to a term loan due August 2018 with an interest rate of LIBOR plus an applicable margin ranging from 3.5% to 4.0%.

(2) The terms of the Meadow Creek project-level debt financing included a $56.5 million cash grant loan and a $169.8 million term loan. The cash grant loan was repaid in April 2013 with $49.0 million of proceeds from the 1603 grant with the U.S. Treasury, $4.7 million from the former owners to cover the shortfall resulting from the federal sequester on spending and a $2.8 million contribution from us to cover the shortfall from lower grant-eligible costs than anticipated, primarily as a result of a lower project cost as compared to budget.

(3) The Curtis Palmer Notes, Series A senior guaranteed notes due August 2015 and Series B senior guaranteed notes due August 2017 were retired on February 26, 2014 with a portion of the proceeds from the New Senior Secured Credit Facilities described below.

Principal payments on the maturities of our debt due in the next five years and thereafter are as follows:

| | |
|---|---|
| 2014 | $ 216.2 |
| 2015 | 170.6 |
| 2016 | 19.0 |
| 2017 | 96.5 |
| 2018 | 529.5 |
| Thereafter | 439.2 |
| | $ 1,471.0 |

***Notes of Atlantic Power Corporation***

On November 5, 2011, we completed a private placement of $460.0 million aggregate principal amount of 9.0% senior notes due 2018 (the "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 Atlantic 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 ($197.4 million as of December 31, 2013) 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.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**10. Long-term debt (Continued)**

***Notes of Curtis Palmer LLC***

See New Senior Secured Credit Facilities below for discussion of the retirement of the 5.90% senior unsecured notes, due July 2014 (the "Curtis Palmer Notes") in February 2014.

The Curtis Palmer Notes had $190.0 million aggregate principal outstanding at December 31, 2013. 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.

***Notes of Atlantic Power (US) GP***

See New Senior Secured Credit Facilities below for discussion of the retirement of these Notes of Atlantic Power (US) GP in February 2014.

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" and together with the Series A Notes, the "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 Senior Notes, our senior credit facility and refinancings thereof would provide guarantees of the Notes; (ii) to shorten the maturity of the Series A Notes from August 15, 2017 to August 15, 2015; (iii) to shorten the maturity of the Series B Notes from August 15, 2019 to August 15, 2017; (iv) to include an event of default that would be triggered if certain defaults occurred under the debt instruments of Atlantic Power and certain of its subsidiaries; and (v) to add certain covenants, including covenants that limit the ability of Curtis Palmer LLC ("Curtis Palmer"), a wholly-owned subsidiary of 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. 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

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**10. Long-term debt (Continued)**

our acquisition of the Partnership in return for Atlantic Power and its subsidiaries entering into the amendment.

***Non-Recourse Debt***

Project-level debt of our consolidated projects is secured by the respective project and its contracts with no other recourse to us. Project-level debt generally amortizes during the term of the respective revenue generating contracts of the projects. The loans have certain financial covenants that must be met. At December 31, 2013, all of our projects were in compliance with the covenants contained in project-level debt.

***Senior Credit Facility***

See the discussion of the New Senior Secured Credit Facilities below for the replacement of this facility in February 2014.

On November 5, 2011, we entered into an amended and restated credit agreement, pursuant to which we increased the capacity under our then existing credit facility from $100 million to $300 million on a senior secured basis, $200 million of which could be utilized for letters of credit (the "old credit facility"). Borrowings under the old credit facility were available in U.S. dollars and Canadian dollars and bore 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 old credit facility had a maturity date of November 4, 2015.

On November 2, 2012, we amended the old 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 old credit facility, as amended on November 12, 2012, contained 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 included limitations on investments, limitations on dividends and other restricted payments, limitations on entering into certain types of restrictive agreements, limitations on transactions with affiliates and limitations on the use of proceeds from the amended credit facility. We were required to meet certain financial covenants under the terms of the amended credit facility, which were generally based on ratios of debt to EBITDA and EBITDA to interest. At a ratio of 7.25 of debt to EBITDA, we were restricted from paying dividends to our shareholders. The old credit facility, as amended on November 12, 2012, was secured by pledges of certain assets and interests in certain subsidiaries.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**10. Long-term debt (Continued)**

On August 2, 2013 we entered into an amendment to the old credit facility with our lenders (the old credit facility, as amended by the August 2, 2013 amendment, the "prior credit facility"). The most significant changes to the prior credit facility include the following:

- a decrease in capacity from $300 million to $150 million, all of which could have been utilized for letters of credit (as compared to the previous $200 million that could have been utilized for letters of credit) and a sublimit of $25 million which could have been utilized for other borrowings.

- a requirement to cash collateralize outstanding letters of credit in an amount equal to the excess above $125 million if the aggregate amount of letters of credit and borrowings outstanding under the prior credit facility exceeded $125 million;

- a requirement to maintain at all times unrestricted cash and cash equivalents of at least $75 million (inclusive of any cash collateral provided as described above), which shall have been pledged to the lenders as security for the prior credit facility;

- an amendment to the maximum permissible Consolidated Total Net Debt to Consolidated EBITDA (each as defined in the prior credit facility) to 7.75 to 1.00 (as compared to a prior ratio of 7.50 to 1.00 declining to 7.00 to 1.00 over time);

- an amendment to the minimum permissible Consolidated EBITDA to Consolidated Interest Expense (each as defined in the prior credit facility) ratio to 1.60 to 1.00 (as compared to a prior ratio of 2.25 to 1.00);

- a requirement to pay a commitment fee of between 0.75% and 1.75% per year based on a percentage of the amount committed under the prior credit facility, which fee varies based on our unsecured debt rating (currently, the applicable commitment fee is 1.50%); and

- an amendment to the maturity date from November 4, 2015 to March 4, 2015.

Among other restrictions set forth in the prior credit facility, we were restricted from paying cash dividends to our shareholders if we did not comply with the financial covenants specified above. The prior credit facility was secured by pledges of certain assets and interests in certain subsidiaries. The old credit facility contained customary representations, warranties, terms and conditions, and covenants, certain of which were amended in the prior credit facility. The amended covenants limited our ability to, among other things, incur additional indebtedness, merge or consolidate with others, make acquisitions, change our business and sell or dispose of assets. These amended covenants also included limitations on investments, limitations on dividends and other restricted payments, limitations on entering into certain types of restrictive agreements, limitations on transactions with affiliates and limitations on the use of proceeds from the prior credit facility. Specifically, under the prior credit facility, we were effectively only permitted to make voluntary prepayments or repurchases of our outstanding debt (including for these purposes subsidiary debt guaranteed by us) from the proceeds of debt permitted to be incurred to refinance that outstanding debt or during the 60-day period preceding the maturity of that outstanding debt. Under the prior credit facility, we had the right generally to repurchase substantially more of our outstanding debt issuances, subject to the satisfaction of certain conditions. Under the prior credit facility, the lenders also consented to (i) our previously announced

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**10. Long-term debt (Continued)**

sale of Delta-Person and (ii) the sale of AP Onondaga, LLC, Onondaga Renewables, LLC and their property.

Borrowings under the prior credit facility were available in U.S. dollars and Canadian dollars and bore interest at a variable rate equal to the US Prime Rate, the Eurocurrency LIBOR Rate or the Cdn. Prime Rate (each as defined in the August credit facility), as applicable, plus a margin of between 2.75% and 4.75% that varies based on our unsecured debt rating. At December 31, 2013, the prior credit facility was undrawn and the applicable LIBOR margin was 4.25%. At December 31, 2013, $97.2 million was issued in letters of credit, but not drawn, to support contractual credit requirements at several of our projects.

***New Senior Secured Credit Facilities***

On February 24, 2014 the Partnership, our wholly-owned indirect subsidiary, entered into the New Senior Secured Credit Facilities, including the New Term Loan Facility, comprising of $600 million in aggregate principal amount, and the New Revolving Credit Facility with a capacity of $210 million. Borrowings under the New Senior Secured Credit Facilities are available in U.S. dollars and Canadian dollars and bear interest at a rate equal to the Adjusted Eurodollar Rate, the Base Rate or the Canadian Prime Rate, each as defined in the credit agreement governing the New Senior Secured Credit Facilities (the "Credit Agreement"), as applicable, plus an applicable margin between 2.75% and 3.75% that varies depending on whether the loan is a Eurodollar Rate Loan, Base Rate Loan, or Canadian Prime Rate Loan. The applicable margin for term loans bearing interest at the Adjusted Eurodollar Rate and the Base Rate is 3.75% and 2.75% respectively. The Adjusted Eurodollar Rate cannot be less than 1.00%.

The New Term Loan Facility matures on February 24, 2021. The revolving commitments under the New Revolving Credit Facility terminates on February 24, 2018. Letters of credit are available to be issued under the revolving commitments until 30 days prior to the Letter of Credit Expiration Date under, and as defined in, the Credit Agreement. The Partnership is required to pay a commitment fee with respect to the commitments under the New Revolving Credit Facility equal to 0.75% times the average of the daily difference between the revolving commitments and all outstanding revolving loans (excluding swing line loans) plus amounts available to be drawn under letters of credit and all outstanding reimbursement obligations with respect to drawn letters of credit.

The New Senior Secured Credit Facilities are secured by a pledge of the equity interests in the Partnership and its subsidiaries, guaranties from the Partnership subsidiary guarantors and a limited recourse guaranty from the entity that holds all of the Partnership equity, a pledge of certain material contracts and certain mortgages over material real estate rights, an assignment of all revenues, funds and accounts of the Partnership and its subsidiaries (subject to certain exceptions), and certain other assets. The New Senior Secured Credit Facilities are not otherwise guaranteed or secured by us or any of our subsidiaries (other than the Partnership subsidiary guarantors). The New Senior Secured Credit Facilities will also have the benefit of a debt service reserve account, which is required to be funded and maintained at the debt service reserve requirement, equal to six months of debt service.

The Partnership's existing Cdn$210 million Notes of the Partnership prohibit the Partnership (subject to certain exceptions) from granting liens on its assets (and those of its material subsidiaries)

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**10. Long-term debt (Continued)**

to secure indebtedness, unless the Notes of the Partnership are secured equally and ratably with such other indebtedness. Accordingly, in connection with the execution of the Credit Agreement, the Partnership has granted an equal and ratable security interest in the collateral package securing the New Senior Secured Credit Facilities under the indenture governing the Notes of the Partnership for the benefit of the holders of the Notes of the Partnership.

The Credit Agreement contains customary representations, warranties, terms and conditions, and covenants. The covenants include a requirement that the Partnership and its subsidiaries maintain a Leverage Ratio (as defined in the Credit Agreement) ranging from 5.50:1.00 in 2014 to 4.00:1.00 in 2021, and an Interest Coverage Ratio (as defined in the Credit Agreement) ranging from 2.50:1.00 in 2014 to 3.25:1.00 in 2021. In addition, the Credit Agreement includes customary restrictions and limitations on the Partnership's and its subsidiaries' ability to (i) incur additional indebtedness, (ii) grant liens on any of their assets, (iii) change their conduct of business or enter into mergers, consolidations, reorganizations, or certain other corporate transactions, (iv) dispose of assets, (v) modify material contractual obligations, (vi) enter into affiliate transactions, (vii) incur capital expenditures, and (viii) make dividend payments or other distributions, in each case subject to customary carve-outs and exceptions and various thresholds.

Under the Credit Agreement, if a change of control (as defined in the Credit Agreement) occurs, unless the Partnership elects to make a voluntary prepayment of the term loans under the New Senior Secured Credit Facilities, it will be required to offer each electing lender to prepay such lender's term loans under the New Senior Secured Credit Facilities at a price equal to 101% of par. In addition, in the event that the Partnership elects to repay, prepay or refinance all or any portion of the term loan facilities within one year from the initial funding date under the Credit Agreement, it will be required to do so at a price of 101% of the principal amount so repaid, prepaid or refinanced.

The Credit Agreement also contains a mandatory amortization feature and customary mandatory prepayment provisions, including: (i) from proceeds of assets sales, insurance proceeds, and incurrence of indebtedness, in each case subject to applicable thresholds and customary carve-outs; and (ii) the payment of 50% of the excess cash flow, as defined in the Credit Agreement, of the Partnership and its subsidiaries.

Under certain conditions the lending commitments under the Credit Agreement may be terminated by the lenders and amounts outstanding under the Credit Agreement may be accelerated. Such events of default include failure to pay any principal, interest or other amounts when due, failure to comply with covenants, breach of representations or warranties in any material respect, non-payment or acceleration of other material debt of the Partnership and its subsidiaries, bankruptcy, material judgments rendered against the Partnership or certain of its subsidiaries, certain ERISA or regulatory events, a change of control of the Partnership, or defaults under certain guaranties and collateral documents securing the New Senior Secured Credit Facilities, in each case subject to various exceptions and notice, cure and grace periods.

On February 26, 2014, $600 million was drawn under the New Term Loan Facility, and letters of credit in an aggregate face amount of $144 million were issued (but not drawn) pursuant to the revolving commitments under the New Revolving Credit Facility and used (i) to fund a debt service reserve in an amount equivalent to six months of debt service (approximately $15.8 million), and (ii) to

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**10. Long-term debt (Continued)**

support contractual credit support obligations of the Partnership and its subsidiaries and of certain other of our affiliates.

We and our subsidiaries have used the proceeds from the New Term Loan Facility under the New Senior Secured Credit Facilities to:

- optionally prepay or redeem in whole, at a price equal to par plus accrued interest and applicable make-whole premium, of (i) the $150 million aggregate principal amount outstanding of 5.87% Senior Guaranteed Notes, Series A, due 2015 and the $75 million aggregate principal amount outstanding of 5.97% Senior Guaranteed Notes, Series B, due 2017 issued by Atlantic Power (US) GP, and (ii) the $190 million aggregate principal amount outstanding of 5.9% Senior Notes due 2014 issued by Curtis Palmer LLC;

- pay transaction costs and expenses; and

- make a distribution to us in the range of approximately $120 million to $125 million, which we may use for any corporate purpose, including, at our discretion, additional debt reduction which may, taking into account available funds, market conditions and other relevant factors, include steps to repurchase or redeem, by means of a tender offer or otherwise, up to $150 million aggregate principal amount of the Notes of Atlantic Power Corporation and up to Cdn$46 million of our 6.50% convertible debentures due October 31, 2014.

In connection with the funding of the New Senior Secured Credit Facilities described above, we terminated the prior credit facility on February 26, 2014.

In addition, the Prior Credit Facility contained certain guaranties, which were terminated in connection with the termination of the Prior Credit Facility. In addition, the terms of the Notes of Atlantic Power Corporation provide that the guarantors of the Prior Credit Facility guarantee the Notes of Atlantic Power Corporation. As a result, upon termination of the Prior Credit Facility and the related guaranties, the guaranties under the Notes of Atlantic Power Corporation were cancelled and the guarantors of the Notes of Atlantic Power Corporation were automatically released from all of their obligations under such guaranties.

The foregoing description of the New Senior Secured Credit Facilities is qualified in its entirety by reference to the full text of the credit agreement governing the Senior Secured Credit Facilities, which is attached to this Annual Report on Form 10-K as Exhibit 10.1 and is incorporated herein by reference.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**11. Convertible debentures**

The following table provides details related to outstanding convertible debentures:

| | 6.5% Debentures due October 2014 | 6.25% Debentures due March 2017 | 5.6% Debentures due June 2017 | 5.75% Debentures due June 2019 | 6.00% Debentures due December 2019 | Total |
|---|---|---|---|---|---|---|
| Balance at December 31, 2011 | $ 44.1 | $ 66.3 | $ 79.2 | $ | $ | $ 189.6 |
| Issuance of convertible debentures | | | | 130.0 | 100.6 | 230.6 |
| Foreign exchange (gain) loss | 1.0 | 1.5 | 1.8 | | (0.3) | 4.0 |
| Balance at December 31, 2012 | $ 45.1 | $ 67.8 | $ 81.0 | $ 130.0 | $ 100.3 | $ 424.2 |
| Foreign exchange (gain) loss | (3.0) | (4.4) | (5.3) | | (6.3) | (19.0) |
| Balance at December 31, 2013 | $ 42.1 | $ 63.4 | $ 75.7 | $ 130.0 | $ 94.0 | $ 405.2 |

Aggregate interest expense related to the convertible debentures was $24.2 million, $12.1 million, and $12.1 million for the years ended December 31, 2013, 2012, and 2011, respectively.

In 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 2006 Debentures had an initial 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. As of December 31, 2013, Cdn$15.2 million of the 2006 Debentures, have been converted to 1.2 million common shares. The 2006 Debentures are classified as a current liability for the year ended December 31, 2013.

On December 17, 2009, we issued, in a public offering, Cdn$86.3 million aggregate principal amount of 6.25% convertible unsecured 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. As of December 31, 2013, Cdn$18.8 million of the 2009 Debentures, have been converted to 1.4 million common shares.

On October 20, 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

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**11. Convertible debentures (Continued)**

Cdn$1,000 principal amount of 2010 Debentures, at any time, at the option of the holder, representing an initial conversion price of approximately Cdn$18.10 per common share.

On July 5, 2012, we issued, in a public offering, $130.0 million aggregate principal amount of 5.75% convertible unsecured subordinated debentures due June 30, 2019, (the "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.

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 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.

**12. Fair value of financial instruments**

The estimated carrying values and fair values of our recorded financial instruments related to operations are as follows:

| | December 31, | | | |
|---|---|---|---|---|
| | 2013 | | 2012 | |
| | Carrying Amount | Fair Value | Carrying Amount | Fair Value |
| Cash and cash equivalents | $ 158.6 | $ 158.6 | $ 60.2 | $ 60.2 |
| Restricted cash | 114.2 | 114.2 | 28.6 | 28.6 |
| Derivative assets current | 0.2 | 0.2 | 9.5 | 9.5 |
| Derivative assets non-current | 13.0 | 13.0 | 11.1 | 11.1 |
| Derivative liabilities current | 28.5 | 28.5 | 33.0 | 33.0 |
| Derivative liabilities non-current | 76.1 | 76.1 | 118.1 | 118.1 |
| Revolving credit facility and long-term debt, including current portion | 1,471.0 | 1,435.2 | 1,647.3 | 1,701.8 |
| Convertible debentures | 405.2 | 281.1 | 424.2 | 416.7 |

Our financial instruments that are recorded at fair value have been classified into levels using a fair value hierarchy.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**12. Fair value of financial instruments (Continued)**

The three levels of the fair value hierarchy are defined below:

Level 1 Unadjusted quoted prices available in active markets for identical assets or liabilities as of the reporting date. Financial assets utilizing Level 1 inputs include active exchange-traded securities.

Level 2 Quoted prices available in active markets for similar assets or liabilities, quoted prices for identical or similar assets or liabilities in inactive markets, inputs other than quoted prices that are directly observable, and inputs derived principally from market data.

Level 3 Unobservable inputs from objective sources. These inputs may be based on entity-specific inputs. Level 3 inputs include all inputs that do not meet the requirements of Level 1 or Level 2.

The following represents the recurring measurements of fair value hierarchy of our financial assets and liabilities that were recognized at fair value as of December 31, 2013 and December 31, 2012. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement.

| | December 31, 2013 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Assets: | | | | |
| Cash and cash equivalents | $ 158.6 | $ | $ | $ 158.6 |
| Restricted cash | 114.2 | | | 114.2 |
| Derivative instruments asset | | 13.2 | | 13.2 |
| Total | $ 272.8 | $ 13.2 | $ | $ 286.0 |
| Liabilities: | | | | |
| Derivative instruments liability | $ | $ 104.6 | $ | $ 104.6 |
| Total | $ | $ 104.6 | $ | $ 104.6 |

| | December 31, 2012 | | | |
|---|---|---|---|---|
| | Level 1 | Level 2 | Level 3 | Total |
| Assets: | | | | |
| Cash and cash equivalents | $ 60.2 | $ | $ | $ 60.2 |
| Restricted cash | 28.6 | | | 28.6 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Derivative instruments asset | | | | 20.6 | | | | 20.6 |
| Total | $ | 88.8 | $ | 20.6 | $ | | $ | 109.4 |
| Liabilities: | | | | | | | | |
| Derivative instruments liability | $ | | $ | 151.1 | $ | | $ | 151.1 |
| Total | $ | | $ | 151.1 | $ | | $ | 151.1 |

The fair values of our derivative instruments are based upon trades in liquid markets. Valuation model inputs can generally be verified and valuation techniques do not involve significant judgment.

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**12. Fair value of financial instruments (Continued)**

The fair values of such financial instruments are classified within Level 2 of the fair value hierarchy. We use our best estimates to determine the fair value of commodity and derivative contracts we hold. These estimates consider various factors including closing exchange prices, time value, volatility factors and credit exposure. The fair value of each contract is discounted using a risk free interest rate.

We also adjust the fair value of financial assets and liabilities to reflect credit risk, which is calculated based on our credit rating and the credit rating of our counterparties. As of December 31, 2013, the credit valuation adjustments resulted in an $11.1 million net increase in fair value, which consists of a $0.5 million pre-tax gain in other comprehensive income and a $10.6 million gain in change in fair value of derivative instruments. As of December 31, 2012, the credit valuation adjustments resulted in an $18.4 million net increase in fair value, which consists of a $1.1 million pre-tax gain in other comprehensive income and a $13.8 million gain in change in fair value of derivative instruments and $3.6 million related to interest rate swaps assumed in the acquisition of Ridgeline.

The carrying amounts for cash and cash equivalents and restricted cash approximate fair value due to their short-term nature. The fair value of long-term debt and convertible debentures was determined using quoted market prices, as well as discounting the remaining contractual cash flows using a rate at which we could issue debt with a similar maturity as of the balance sheet date.

**13. Accounting for derivative instruments and hedging activities**

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

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

*Gas purchase agreements*

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

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

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**13. Accounting for derivative instruments and hedging activities (Continued)**

In April, June and August 2013, the Tunis project entered into contracts for the purchase of natural gas beginning on October 1, 2013 and expiring on March 31, 2014. These contracts are accounted for as derivative financial instruments and are recorded in the consolidated balance sheet at fair value as of December 31, 2013. Changes in the fair market value of the contracts are recorded in the consolidated statement of operations.

*Natural gas swaps*

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

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

In February 2014, we paid $4.0 million to terminate these contracts as a result of terminating the Prior Credit Facility to the New Senior Secured Credit Facilities. We and will record fuel expense related to the settlement in the first quarter of 2014.

*Interest rate swaps*

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

The Piedmont project has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreement effectively converts the floating rate debt to a fixed interest rate of 1.7% plus an applicable margin ranging from 3.5% to 3.75% through February 29, 2016. From February 2016 until the maturity of the debt in November 2017, the fixed rate of the swap is 4.47% and the applicable margin is 4.0%, resulting in an all-in rate of 8.47%. The swap continues at the fixed rate of 4.47% from the maturity of the debt in November 2017 until November 2030. The notional amounts of the interest rate swap agreements match the estimated outstanding principal balance of Piedmont's construction loan facility that will convert to a term loan. The interest rate swaps were executed on October 21, 2010 and November 2, 2010 and expire on February 29, 2016 and November 30, 2030, respectively. The interest rate swap

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**13. Accounting for derivative instruments and hedging activities (Continued)**

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

As a result of the Piedmont term loan conversion on February 14, 2013, these swap agreements were amended to reduce the notional amounts to match the outstanding $68.5 million principal of the term loan. We will record $0.6 million of interest expense related to this transaction in the first quarter of 2014.

Epsilon Power Partners, a wholly owned subsidiary, has an interest rate swap to economically fix the exposure to changes in interest rates related to the variable-rate non-recourse debt. The interest rate swap agreement effectively converted the floating rate debt to a fixed interest rate of 7.37% and has a maturity date of July 2019. The notional amount of the swap matches the outstanding principal balance over the remaining life of Epsilon Power Partners' debt. This interest rate swap agreement is not designated as a hedge and changes in its fair market value are recorded in the consolidated statements of operations.

In February 2014, we paid $2.6 million to terminate this contract as a result of terminating the Prior Credit Facility. We will record interest expense related to its settlement in the first quarter of 2014.

Rockland Wind Farm, LLC ("Rockland") entered into interest rate swaps to manage interest rate risk exposure. These swaps effectively modify the project's exposure by converting the project's floating rate debt to a fixed basis. The interest rate swaps are with various counterparties and swap 100% of the expected interest payments from floating LIBOR to fixed rates structured in two tranches. The first tranche is for the notional amount due on the term loan through December 31, 2026 and fixes the interest rate at 4.2% plus an applicable margin of 2.3% - 2.8%. The second tranche is the post-term portion of the loan, or the balloon payment and commences on December 31, 2026 and ends on December 31, 2031, fixing the interest rate at 7.8%. The interest rate swap agreements are not designated as a hedge and changes in their fair market value are recorded in the consolidated statements of operations.

The Meadow Creek project ("Meadow Creek") has interest rate swap agreements to economically fix its exposure to changes in interest rates related to its variable-rate debt. The interest rate swap agreements effectively converted 75% of the floating rate debt to a fixed interest rate of 2.3% plus an applicable margin of 2.8% - 3.3% through December 31, 2024. The second tranche is the post-term portion of the loan, or the balloon payment and commences on December 31, 2024 and ends on December 31, 2030, fixing the interest rate at 7.2%. The interest rate swaps were both executed on September 17, 2012 and expire on December 31, 2024 and December 31, 2030, respectively. The interest rate swap agreements are not designated as hedges, and changes in their fair market value are recorded in the consolidated statements of operations.

*Foreign currency forward contracts*

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, if and when declared by the board of directors, and interest on corporate level long-term debt and convertible debentures, predominantly in Canadian dollars. We have a hedging

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**13. Accounting for derivative instruments and hedging activities (Continued)**

strategy for the purpose of mitigating the currency risk impact on any future payments of dividends to shareholders. We have executed this strategy utilizing cash flows from our projects that generate Canadian dollars and by entering into forward contracts to purchase Canadian dollars at a fixed rate to hedge an average of approximately 74% of any dividend and expected 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, 2013, the forward contracts consist of contracts assumed in our acquisition of the Partnership with various expiration dates through December 2015 to purchase a total of Cdn$34.9 million at an average exchange rate of Cdn$1.108 per U.S. dollar. It is our intention to periodically consider extending or terminating these forward contracts.

In February 2014, we paid $0.4 million to terminate these contracts as a result of terminating the Prior Credit Facility. We will record a foreign exchange related to their settlement in the first quarter of 2014.

*Volume of forecasted transactions*

We have entered into derivative instruments in order to economically hedge the following notional volumes of forecasted transactions as summarized below, by type, excluding those derivatives that qualified for the NPNS exemption as of year ended December 31, 2013 and December 31, 2012:

| | Units | December 31, 2013 | December 31, 2012 |
|---|---|---|---|
| Natural gas swaps | Natural Gas (Mmbtu) | 5.6 | 10.6 |
| Gas purchase agreements | Natural Gas (Gigajoules) | 41.1 | 49.8 |
| Interest rate swaps | Interest (US$) | 161.2 | 172.0 |
| Currency forwards | Cdn$ | 34.9 | 176.6 |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**13. Accounting for derivative instruments and hedging activities (Continued)**

*Fair value of derivative instruments*

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

| | December 31, 2013 | |
|---|---|---|
| | Derivative Assets | Derivative Liabilities |
| Derivative instruments designated as cash flow hedges: | | |
| Interest rate swaps current | $ | $ 1.3 |
| Interest rate swaps long-term | | 2.6 |
| Total derivative instruments designated as cash flow hedges | | 3.9 |
| Derivative instruments not designated as cash flow hedges: | | |
| Interest rate swaps current | | 7.3 |
| Interest rate swaps long-term | 11.5 | 8.1 |
| Foreign currency forward contracts current | 0.5 | 0.7 |
| Foreign currency forward contracts long-term | 1.2 | |
| Natural gas swaps current | 0.3 | 1.3 |
| Natural gas swaps long-term | | 3.5 |
| Gas purchase agreements current | 0.2 | 18.4 |
| Gas purchase agreements long-term | | 61.9 |
| Total derivative instruments not designated as cash flow hedges | 13.7 | 101.2 |
| Total derivative instruments | $ 13.7 | $ 105.1 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**13. Accounting for derivative instruments and hedging activities (Continued)**

| | December 31, 2012 Derivative Assets | December 31, 2012 Derivative Liabilities |
|---|---|---|
| Derivative instruments designated as cash flow hedges: | | |
| Interest rate swaps current | $ | $ 1.3 |
| Interest rate swaps long-term | | 5.2 |
| Total derivative instruments designated as cash flow hedges | | 6.5 |
| Derivative instruments not designated as cash flow hedges: | | |
| Interest rate swaps current | | 7.3 |
| Interest rate swaps long-term | 0.1 | 27.7 |
| Foreign currency forward contracts current | 9.5 | |
| Foreign currency forward contracts long-term | 11.0 | |
| Natural gas swaps current | | |
| Natural gas swaps long-term | 0.1 | 3.9 |
| Gas purchase agreements current | 0.1 | 24.5 |
| Gas purchase agreements long-term | | 81.4 |
| Total derivative instruments not designated as cash flow hedges | 20.8 | 144.8 |
| Total derivative instruments | $ 20.8 | $ 151.3 |

*Accumulated other comprehensive income*

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

| For the year ended December 31, 2013 | Interest Rate Swaps | Natural Gas Swaps | Total |
|---|---|---|---|
| Accumulated OCI balance at January 1, 2013 | $ (1.5) | $ 0.1 | $ (1.4) |
| Change in fair value of cash flow hedges | 0.7 | | 0.7 |
| Realized from OCI during the period | 1.0 | (0.1) | 0.9 |
| Accumulated OCI balance at December 31, 2013 | $ 0.2 | $ | $ 0.2 |

| | | | | | | |
|---|---|---|---|---|---|---|
| Gains expected to be realized from OCI in the next 12 months, net of $0.6 tax | $ | 1.0 | $ | | $ | 1.0 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**13. Accounting for derivative instruments and hedging activities (Continued)**

| For the year ended December 31, 2012 | Interest Rate Swaps | Natural Gas Swaps | Total |
|---|---|---|---|
| Accumulated OCI balance at January 1, 2012 | $ (1.7) | $ 0.3 | $ (1.4) |
| Change in fair value of cash flow hedges | (0.9) | | (0.9) |
| Realized from OCI during the period | 1.1 | (0.2) | 0.9 |
| Accumulated OCI balance at December 31, 2012 | $ (1.5) | $ 0.1 | $ (1.4) |

| For the year ended December 31, 2011 | Interest Rate Swaps | Natural Gas Swaps | Total |
|---|---|---|---|
| Accumulated OCI balance at January 1, 2011 | $ (0.4) | $ 0.6 | $ 0.2 |
| Change in fair value of cash flow hedges | (2.6) | | (2.6) |
| Realized from OCI during the period | 1.4 | (0.4) | 1.0 |
| Accumulated OCI balance at December 31, 2011 | $ (1.6) | $ 0.2 | $ (1.4) |

*Impact of derivative instruments on the consolidated statements of operations*

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

| | Classification of (gain) loss recognized in income | Year ended December 31, 2013 | 2012 | 2011 |
|---|---|---|---|---|
| Gas purchase agreements | Fuel | $ 56.5 | $ 43.5 | $ |
| Interest rate swaps | Interest, net | 9.9 | 4.6 | 4.2 |
| Foreign currency forwards | Foreign exchange (gain) loss | (14.4) | (18.5) | 5.2 |

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

| Classification of (gain) loss recognized in income | Year ended December 31, 2013 | 2012 | 2011 |
|---|---|---|---|

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Natural gas swaps | Change in fair value of derivatives | $ | (0.7) | $ | (1.2) | $ | (2.4) |
| Gas purchase agreements | Change in fair value of derivatives | | 19.2 | | (57.0) | | |
| Interest rate swaps | Change in fair value of derivatives | | 31.0 | | (1.1) | | (12.2) |
| | | $ | 49.5 | $ | (59.3) | $ | (14.6) |
| Foreign currency forwards | Foreign exchange loss | $ | 19.4 | $ | 12.0 | $ | 14.2 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**14. Income taxes**

| | Year ended December 31 | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| Current income tax expense (benefit) | $ 7.8 | $ 6.0 | $ (1.2) |
| Deferred tax benefit | (27.3) | (34.1) | (9.9) |
| Total income tax benefit, net | $ (19.5) | $ (28.1) | $ (11.1) |

The following is a reconciliation of income taxes calculated at the Canadian enacted statutory rate of 26.0%, 25.0%, and 26.5% at December 31, 2013, 2012 and 2011, respectively, to the provision for income taxes in the consolidated statements of operations:

| | Year ended December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| Computed income taxes at Canadian statutory rate | $ (9.7) | $ (36.2) | $ (22.0) |
| Decreases resulting from: | | | |
| Operating countries with different income tax rates | (2.9) | (8.5) | (10.6) |
| | $ (12.6) | $ (44.7) | $ (32.6) |
| Change in valuation allowance | 12.1 | 20.2 | 21.7 |
| | (0.5) | (24.5) | (10.9) |
| Dividend withholding tax and other cash taxes | 3.7 | 5.9 | 0.4 |
| Foreign exchange | (9.9) | 1.5 | (0.1) |
| Permanent differences | | (6.5) | (1.5) |
| Non-deductible acquisition costs | | 0.6 | 4.3 |
| Non-deductible interest expense | | | 2.1 |
| Changes in tax rates | (4.1) | 1.8 | |
| Federal grant | (18.9) | | (6.6) |
| Production tax credits | (4.5) | | |
| Changes in estimates of tax basis of equity method investments | (1.4) | (5.1) | 2.2 |
| Goodwill impairment | 13.6 | | |
| Other | 2.5 | (1.8) | (1.0) |
| | (19.0) | (3.6) | (0.2) |
| | $ (19.5) | $ (28.1) | $ (11.1) |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**14. Income taxes (Continued)**

The tax effect of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities at December 31, 2013 and 2012 are presented below:

| | 2013 | 2012 |
|---|---|---|
| Deferred tax assets: | | |
| Loss carryforwards | $ 254.1 | $ 130.2 |
| Other accrued liabilities | 0.4 | 10.9 |
| Finance and share issuance costs | 6.7 | 8.3 |
| Disallowed interest carryforward | 1.7 | 2.2 |
| Derivative contracts | 27.8 | 3.5 |
| Other | 8.0 | 6.1 |
| Total deferred tax assets | 298.7 | 161.2 |
| Valuation allowance | (128.1) | (116.0) |
| | 170.6 | 45.2 |
| Deferred tax liabilities: | | |
| Intangible assets | (74.2) | (113.3) |
| Property, plant and equipment | (194.8) | (94.7) |
| Other long-term investments | (13.1) | (1.2) |
| Total deferred tax liabilities | (282.1) | (209.2) |
| Net deferred tax liability | $ (111.5) | $ (164.0) |

The following table summarizes the net deferred tax position as of December 31, 2013 and 2012:

| | 2013 | 2012 |
|---|---|---|
| Long-term deferred tax liabilities | $ (111.5) | $ (164.0) |
| Net deferred tax liability | $ (111.5) | $ (164.0) |

As of December 31, 2013, we have recorded a valuation allowance of $128.1 million. This amount is comprised primarily of provisions against available Canadian and U.S. net operating loss carryforwards. In assessing the recoverability of our deferred tax assets, we consider whether it is more likely than not that some portion or the entire deferred tax asset will be realized. The ultimate realization of the deferred tax assets is dependent upon projected future taxable income in the United States and in Canada and available tax planning strategies.

Tax benefits related to uncertain tax positions taken or expected to be taken on a tax return are recorded when such benefits meet a more likely than not threshold. Otherwise, these tax benefits are recorded when a tax position has been effectively settled, which means that the statute of limitation has expired or the appropriate taxing authority has completed their examination even though the statute of limitations remains open. Interest and penalties related to uncertain tax positions are recognized as part of the provision for income taxes and are accrued beginning in the period that such interest and penalties would be applicable under relevant tax law until such time that the related tax benefits are recognized. As of December 31, 2013, we have not recorded any tax benefits related to uncertain tax positions.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**14. Income taxes (Continued)**

As of December 31, 2013, we had the following net operating loss carryforwards that are scheduled to expire in the following years:

| | |
|---|---|
| 2027 | $ 50.3 |
| 2028 | 101.6 |
| 2029 | 82.5 |
| 2030 | 25.8 |
| 2031 | 57.3 |
| 2032 | 85.6 |
| 2033 | 299.3 |
| | $ 702.4 |

**15. Equity compensation plans**

*Long-term incentive plan*

The following table summarizes the changes in outstanding LTIP notional units during the years ended December 31, 2013, 2012 and 2011:

| | Units | Grant Date Weighted-Average Fair Value per Unit |
|---|---|---|
| Outstanding at December 31, 2010 | 600,981 | $ 10.28 |
| Granted | 216,110 | 14.02 |
| Additional shares from dividends | 36,204 | 11.04 |
| Forfeitures | (103,991) | 11.55 |
| Vested and redeemed | (263,523) | 9.40 |
| Outstanding at December 31, 2011 | 485,781 | 11.49 |
| Granted | 233,752 | 14.67 |
| Additional shares from dividends | 38,667 | 13.43 |
| Forfeitures | (28,932) | 13.63 |
| Vested and redeemed | (236,733) | 10.18 |
| Outstanding at December 31, 2012 | 492,535 | 13.90 |
| Granted | 597,031 | 4.91 |
| Additional shares from dividends | 64,576 | 8.74 |
| Forfeitures | (184,458) | 8.17 |
| Vested and redeemed | (202,696) | 13.48 |
| Outstanding at December 31, 2013 | 766,988 | $ 7.86 |

The fair value of all outstanding notional units under the LTIP was \$4.8 million and \$6.3 million for the years ended December 31, 2013 and 2012. Compensation expense related to LTIP was \$2.2 million, \$2.5 million and \$3.2 million for the years ended December 31, 2013, 2012 and 2011,

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**15. Equity compensation plans (Continued)**

respectively. Cash payments made for vested notional units were $0.9 million, $1.1 million and $1.5 million for the years ended December 31, 2013, 2012 and 2011, respectively.

The fair value of awards granted under the amended LTIP with market vesting conditions is based upon a Monte Carlo simulation model on their grant date. The Monte Carlo simulation model utilizes multiple input variables over the performance period in order to determine the likely relative total shareholder return. The Monte Carlo simulation model simulated our total shareholder return and for our peer companies during the remaining time in the performance period with the following inputs: (i) stock price on the measurement date, (ii) expected volatility, (iii) risk-free interest rate, (iv) dividend yield and (v) correlations of historical common stock returns between Atlantic Power Corporation and the peer companies. Expected volatilities utilized in the Monte Carlo model are based on our historical volatility and of our peer companies' stock prices over a period equal in length to that of the remaining vesting period. The risk free interest rate is derived from the U.S. Treasury yield curve in effect at the time of grant with a term equal to the performance period assumption at the time of grant. Both the total shareholder return performance and the fair value of the notional units under the Monte Carlo simulation are determined with the assistance of a third party.

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

| | December 31, 2013 | December 31, 2012 |
|---|---|---|
| Weighted average risk free rate of return | 0.1 - 0.5% | 0.1 - 0.3% |
| Dividend yield | 10.8% | 10.1% |
| Expected volatility Atlantic Power | 50.4% | 22.5% |
| Expected volatility peer companies | 11.4 - 56.4% | 11.9 - 97.1% |
| Weighted average remaining measurement period | 1.82 years | 1.39 years |

**16. Defined benefit plan**

We sponsor and operate a defined benefit pension plan that is available to certain legacy employees of the Partnership. The Atlantic Power Services Canada LP Pension Plan (the "Plan") is maintained solely for certain eligible legacy Partnership participants. The Plan is a defined benefit pension plan that allows for employee contributions. We expect to contribute $1.4 million to the pension plan in 2014.

The net annual periodic pension cost related to the pension plan for the years ended December 31, 2013 and 2012 includes the following components:

| | 2013 | 2012 |
|---|---|---|
| Service cost benefits earned | $ 0.9 | $ 0.8 |
| Interest cost on benefit obligation | 0.7 | 0.6 |
| Expected return on plan assets | (0.8) | (0.6) |
| Gain amortization | 0.1 | |
| Net period benefit cost | $ 0.9 | $ 0.8 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**16. Defined benefit plan (Continued)**

A comparison of the pension benefit obligation and related plan assets for the pension plan is as follows:

| | 2013 | 2012 |
|---|---|---|
| Benefit obligation at January 1 | $ (16.8) | $ (12.7) |
| Service cost | (0.9) | (0.8) |
| Interest cost | (0.7) | (0.6) |
| Actuarial (gain) loss | 1.4 | (2.3) |
| Employee contributions | (0.1) | (0.1) |
| Benefits paid | 0.1 | |
| Foreign currency translation adjustment | 1.0 | (0.3) |
| Benefit obligation at December 31 | (16.0) | (16.8) |
| Fair value of plan assets at January 1 | $ 12.0 | 10.5 |
| Actual return on plan assets | 1.8 | 0.8 |
| Employer contributions | 2.3 | 0.4 |
| Employee contributions | 0.1 | 0.1 |
| Benefits paid | (0.1) | |
| Foreign currency translation adjustment | (1.0) | 0.2 |
| Fair value of plan assets at December 31 | 15.1 | 12.0 |
| Funded status at December 31 excess of obligation over assets | $ (0.9) | $ (4.8) |

Amounts recognized in the balance sheet were as follows:

| | 2013 | 2012 |
|---|---|---|
| Non-current liabilities | $ 0.9 | $ 4.8 |

Amounts recognized in accumulated OCI that have not yet been recognized as components of net periodic benefit cost were as follows, net of tax:

| | 2013 | 2012 |
|---|---|---|
| Unrecognized loss | $ 0.3 | $ 1.3 |

We estimate that there will be no amortization of net loss for the pension plan from accumulated OCI to net periodic cost over the next fiscal year.

The following table presents the balances of significant components of the pension plan:

| | 2013 | 2012 |
|---|---|---|
| Projected benefit obligation | $ 16.0 | $ 16.8 |
| Accumulated benefit obligation | 12.4 | 13.1 |
| Fair value of plan assets | 15.1 | 12.0 |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**16. Defined benefit plan (Continued)**

The market-related value of the pension plan's assets is the fair value of the assets. Plan assets are invested in a common collective trust which totaled $15.1 million and $11.9 million for the years ended December 31, 2013 and 2012 respectively.

We determine the level in the fair value hierarchy within which the fair value measurement in its entirety falls, based on the lowest level input that is significant to the fair value measurement in its entirety. The fair value of the common/collective trust is valued at a fair value which is equal to the sum of the market value of the fund's investments, and is categorized as Level 2. There are no investments categorized as Level 1 or 3.

The following table presents the significant assumptions used to calculate our benefit obligations:

| | 2013 | 2012 |
|---|---|---|
| **Weighted-Average Assumptions** | | |
| Discount rate | 5.0% | 4.0% |
| Rate of compensation increase | 4.0% | 4.0% |

The following table presents the significant assumptions used to calculate our benefit expense:

| | 2013 | 2012 |
|---|---|---|
| **Weighted-Average Assumptions** | | |
| Discount rate | 4.0% | 4.0% |
| Rate of return on plan assets | 6.00% | 5.5% |
| Rate of compensation increase | 3.0% - 4.0% | 3.0% - 4.0% |

We use December 31 as the measurement date for the Plan, and we set the discount rate assumptions on an annual basis on the measurement date. This rate is determined by management based on information provided by our actuary. The discount rate assumptions reflect the current rate at which the associated liabilities could be effectively settled at the end of the year. The discount rate assumptions used to determine future pension obligations as of the year ended December 31, 2013 and 2012, was based on the CIA / Natcan curve, which was designed by the Canadian Institute of Actuaries and Natcan Investment Management to provide a means for sponsors of Canadian plans to value the liabilities of their postretirement benefit plans. The CIA / Natcan curve is a hypothetical yield curve represented by extrapolating the corporate AA-rated yield curve beyond 10 years using yields on provincial AA bonds with a spread added to the provincial AA yields to approximate the difference between corporate AA and provincial AA credit risk. The CIA / Natcan curve utilizes this approach because there are very few corporate bonds rated AA or above with maturities of 10 years or more in Canada.

We employ a balanced total return investment approach, whereby a mix of equities and fixed income investments are used to maximize the long-term return of plan assets for a prudent level of risk. Risk tolerance is established through careful consideration of plan liabilities, and the plan's funded status. Plan assets in the common collective trust are currently invested in a diversified blend of equity and fixed-income investments. Furthermore, equity investments are diversified across Canadian, U.S. and other international equities, as well as among growth, value and small and large capitalization stocks.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**16. Defined benefit plan (Continued)**

The pension plan assets weighted average allocations in the common collective trust were as follows:

| | 2013 | 2012 |
|---|---|---|
| Canadian equity | 30% | 30% |
| U.S. equity | 17% | 13% |
| International equity | 15% | 14% |
| Canadian fixed income | 38% | 40% |
| International fixed income | | 3% |
| | 100% | 100% |

Our expected future benefit payments for each of the next five years and in the aggregate for the five years thereafter, are as follows in Cdn$:

| | 2013 |
|---|---|
| 2014 | $ 0.1 |
| 2015 | 0.2 |
| 2016 | 0.3 |
| 2017 | 0.3 |
| 2018 | 0.4 |
| 2019-2023 | 3.4 |

**17. Common shares**

On July 5, 2012, we closed a public offering of 5,567,177 common shares, at a purchase price of $12.76 per common share and Cdn$13.10 per common share, for an aggregate net proceeds from the common share offering, after deducting the underwriting discounts and expenses, of approximately $68.5 million. We used the proceeds to fund our equity commitment in Canadian Hills.

On November 5, 2011, we issued 31,500,215 common shares as part of the consideration paid in the acquisition of the Partnership. See Note 3(c) for further details.

On October 19, 2011, we closed a public offering of 12,650,000 of our common shares, which included 1,650,000 common shares issued pursuant to the exercise in full of the underwriters' over-allotment option, at a purchase price of $13.00 per common share sold in U.S. dollars and Cdn$13.26 per common share sold in Canadian dollars, for net proceeds of $155.4 million. We used the net proceeds from the offering to fund a portion of the cash portion of our acquisition of the Partnership.

***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, including common shares issued under our dividend reinvestment program. At that time, because we were a well-known seasoned issuer, as defined in Rule 405 under the Securities Act, the registration statement was effective immediately upon filing. As of the date of the filing of this Annual Report on Form 10-K, as a

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**17. Common shares (Continued)**

result of the decrease in our market capitalization we can no longer offer and sell securities under that shelf registration. However, immediately following the filing of this Annual Report on Form 10-K, we intend to file a new registration statement, which will be effectively immediately upon filing, for the continued and uninterrupted issuance of common shares under our dividend reinvestment program.

**18. 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. Beginning on June 30, 2012, the Series 1 Shares were 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%.

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 $12.6 million on the Series 1 Shares and the Series 2 Shares in 2013 as compared to $13.0 million in 2012.

**19. Basic and diluted earnings (loss) per share**

Basic earnings (loss) per share is calculated by dividing net income (loss) by the weighted average common shares outstanding during their respective period. Diluted earnings (loss) per share is computed including dilutive potential shares as if they were outstanding shares during the year. Dilutive potential shares include shares that would be issued if all of the convertible debentures were converted

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**19. Basic and diluted earnings (loss) per share (Continued)**

into shares at January 1, 2013. Dilutive potential shares also include the weighted average number of shares, as of the date such notional units were granted, that would be issued if the unvested notional units outstanding under the LTIP were vested and redeemed for shares under the terms of the LTIP.

Because we reported a loss for the years ended December 31, 2013, 2012 and 2011, diluted earnings per share are equal to basic earnings per share as the inclusion of potentially dilutive shares in the computation is anti-dilutive.

The following table sets forth the diluted net income and potentially dilutive shares utilized in the per share calculation for the years ended December 31, 2013, 2012 and 2011:

| | 2013 | 2012 | 2011 |
|---|---|---|---|
| **Numerator:** | | | |
| Loss from continuing operations attributable to Atlantic Power Corporation | $ (26.8) | $ (126.7) | $ (72.7) |
| Income (loss) from discontinued operations, net of tax | (6.2) | 13.9 | 34.3 |
| Net loss attributable to Atlantic Power Corporation | $ (33.0) | $ (112.8) | $ (38.4) |
| **Denominator:** | | | |
| Weighted average basic shares outstanding | 119.9 | 116.4 | 77.5 |
| Dilutive potential shares: | | | |
| Convertible debentures | 27.7 | 17.4 | 14.0 |
| LTIP notional units | 0.7 | 0.5 | 0.4 |
| Potentially dilutive shares | 148.3 | 134.3 | 91.9 |
| Diluted loss per share from continuing operations attributable to Atlantic Power Corporation | $ (0.23) | $ (1.09) | $ (0.94) |
| Diluted earnings (loss) per share from discontinued operations | (0.05) | 0.12 | 0.44 |
| Diluted loss per share attributable to Atlantic Power Corporation | $ (0.28) | $ (0.97) | $ (0.50) |

Potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units have been excluded from fully diluted shares in the years ended December 31, 2013, 2012 and 2011 because their impact would be anti-dilutive.

**20. Assets held for sale**

During the fourth quarter of 2013, we sold our 60% interest in Rollcast. Rollcast's net income (loss) is recorded as income (loss) from discontinued operations, net of tax in the statements of operations for the years ended December 31, 2013, 2012 and 2011. The Florida Projects and Path 15 were sold on April 12, 2013 and April 30, 2013, respectively. Accordingly, the projects' net income (loss) is recorded as income (loss) from discontinued operations, net of tax in the statements of operations for the years ended December 31, 2013, 2012 and 2011. The following tables summarize the

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**20. Assets held for sale (Continued)**

revenue, income (loss) from operations, and income tax expense of Rollcast, Path 15 and the Florida Projects for the years ended December 31, 2013, 2012, and 2011:

| | December 31, | | |
|---|---|---|---|
| | 2013 | 2012 | 2011 |
| Revenue | $ 71.6 | $ 216.7 | $ 191.0 |
| Income (loss) from discontinued operations | (5.4) | 15.7 | 37.1 |
| Income tax expense | 0.8 | 1.8 | 2.8 |
| Income (loss) from discontinued operations, net of tax | $ (6.2) | $ 13.9 | $ 34.3 |

Basic and diluted earnings (loss) per share related to income (loss) from discontinued operations for the Florida Projects, Path 15 and Rollcast was $(0.05), $0.12, and $0.44 for the years ended December 31, 2013, 2012, and 2011 respectively.

The following table sets forth the assets and liabilities held for sale for the year ended December 31, 2012:

| | December 31, 2012 |
|---|---|
| Current assets: | |
| Cash and cash equivalents | $ 6.5 |
| Restricted cash | 12.6 |
| Accounts receivable | 21.9 |
| Other current assets | 6.3 |
| | 47.3 |
| Non-current assets: | |
| Property, plant, and equipment | 111.9 |
| Transmission system rights | 172.4 |
| Goodwill | 8.9 |
| Other assets | 10.9 |
| Assets held for sale | $ 351.4 |

| | | |
|---|---|---|
| Current liabilities: | | |
| Accounts payable and other accrued liabilities | $ | 16.5 |
| Current portion of long-term debt | | 14.3 |
| Current portion of derivative instrument asset | | 20.0 |
| Other liabilities | | 0.5 |
| | | 51.3 |
| Long term liabilities | | |
| Long-term debt | | 137.7 |
| Liabilities held for sale | $ | 189.0 |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

### 21. Segment and geographic information

We have four reportable segments: East, West, Wind and Un-allocated Corporate. We revised our reportable business segments in the fourth quarter of 2013 as the result of recent significant asset sales and in order to align with changes in management's structure, resource allocation and performance assessment in making decisions regarding our operations. Our financial results for the years ended December 31, 2013, 2012 and 2011 have been presented to reflect these changes in operating segments. We analyze the performance of our operating segments based on Project Adjusted EBITDA which is defined as project income plus interest, taxes, depreciation and amortization (including non-cash impairment charges) and changes in fair value of derivative instruments. Project Adjusted EBITDA is not a measure recognized under GAAP and does not have a standardized meaning prescribed by GAAP and is therefore unlikely to be comparable to similar measures presented by other companies. We use Project Adjusted EBITDA to provide comparative information about project performance without considering how projects are capitalized or whether they contain derivative contracts that are required to be recorded at fair value. Path 15, a component of the West segment, and the Auburndale, Lake and Pasco projects, which are components of the East segment, and Rollcast a component of Un-allocated corporate, are included in the income from discontinued operations line item in the table below. We have adjusted prior periods to reflect this reclassification. A reconciliation of project income to Project Adjusted EBITDA is included in the table below:

| | East | West | Wind | Un-allocated Corporate | Consolidated |
|---|---|---|---|---|---|
| **Year ended December 31, 2013** | | | | | |
| Project revenues | $ 299.1 | $ 182.3 | $ 70.8 | $ (0.5) | $ 551.7 |
| Segment assets | 1,395.2 | 1,001.5 | 853.9 | 144.4 | 3,395.0 |
| Goodwill | 107.8 | 188.5 | | | 296.3 |
| Capital expenditures | 13.8 | 1.1 | 11.1 | 0.2 | 26.2 |
| Project Adjusted EBITDA | $ 150.7 | $ 78.8 | $ 59.6 | $ (18.6) | $ 270.5 |
| Change in fair value of derivative instruments | (24.4) | | (25.9) | | (50.3) |
| Depreciation and amortization | 93.7 | 68.3 | 47.3 | 0.5 | 209.8 |
| Interest, net | 20.7 | 0.4 | 19.5 | (2.1) | 38.5 |
| Other project (income) expense | 34.9 | (26.3) | 0.1 | (0.5) | 8.2 |
| Project income (loss) | 25.8 | 36.4 | 18.6 | (16.5) | 64.3 |
| Administration | | | | 35.2 | 35.2 |
| Interest, net | | | | 104.1 | 104.1 |
| Foreign exchange gain | | | | (27.4) | (27.4) |
| Other income, net | | | | (10.5) | (10.5) |
| Income (loss) from continuing operations before income taxes | 25.8 | 36.4 | 18.6 | (117.9) | (37.1) |
| Income tax benefit | | | | (19.5) | (19.5) |
| Net income (loss) from continuing operations | 25.8 | 36.4 | 18.6 | (98.4) | (17.6) |
| Income (loss) from discontinued operations | (1.1) | 1.3 | | (6.4) | (6.2) |
| Net income (loss) | $ 24.7 | $ 37.7 | $ 18.6 | $ (104.8) | $ (23.8) |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**21. Segment and geographic information (Continued)**

| | East | West | Wind | Un-allocated Corporate | Consolidated |
|---|---|---|---|---|---|
| **Year ended December 31, 2012** | | | | | |
| Project revenues | $ 267.5 | $ 169.6 | $ 1.9 | $ 1.4 | $ 440.4 |
| Segment assets | 1,600.2 | 1,305.3 | 956.3 | 140.9 | 4,002.7 |
| Goodwill | 138.6 | 192.6 | | 3.5 | 334.7 |
| Capital expenditures | 25.5 | 0.2 | 441.6 | 0.8 | 468.1 |
| Project Adjusted EBITDA | $ 145.7 | $ 82.1 | $ 10.9 | $ (11.1) | $ 227.6 |
| Change in fair value of derivative instruments | 56.6 | | | | 56.6 |
| Depreciation and amortization | 87.5 | 71.4 | 5.9 | 0.1 | 164.9 |
| Interest, net | 18.5 | 0.4 | 5.1 | | 24.0 |
| Other project expense | 1.2 | 3.0 | 7.3 | | 11.5 |
| Project (loss) income | (18.1) | 7.3 | (7.4) | (11.2) | (29.4) |
| Administration | | | | 28.3 | 28.3 |
| Interest, net | | | | 89.8 | 89.8 |
| Foreign exchange loss | | | | 0.5 | 0.5 |
| Other income, net | | | | (5.7) | (5.7) |
| Income (loss) from continuing operations before income taxes | (18.1) | 7.3 | (7.4) | (124.1) | (142.3) |
| Income tax benefit | | | | (28.1) | (28.1) |
| Net income (loss) from continuing operations | (18.1) | 7.3 | (7.4) | (96.0) | (114.2) |
| Income (loss) from discontinued operations | 13.6 | 2.9 | | (2.6) | 13.9 |
| Net income (loss) | $ (4.5) | $ 10.2 | $ (7.4) | $ (98.6) | $ (100.3) |

| | East | West | Wind | Un-allocated Corporate | Consolidated |
|---|---|---|---|---|---|
| **Year ended December 31, 2011** | | | | | |
| Project revenues | $ 66.0 | $ 26.6 | $ | $ 1.3 | $ 93.9 |
| Segment assets | 1,683.9 | 1,392.1 | 48.6 | 123.8 | 3,248.4 |
| Goodwill | 138.6 | 201.5 | | 3.5 | 343.6 |
| Capital expenditures | 115.0 | 0.1 | | | 115.1 |
| Project Adjusted EBITDA | $ 66.8 | $ 16.4 | $ 4.3 | $ (0.7) | $ 86.8 |
| Change in fair value of derivative instruments | 17.5 | | | (0.3) | 17.2 |
| Depreciation and amortization | 37.3 | 15.2 | 3.0 | | 55.5 |
| Interest, net | 11.5 | 0.8 | 2.9 | | 15.2 |
| Other project (income) expense | 2.6 | (0.3) | | 0.2 | 2.5 |

| | | | | | |
|---|---|---|---|---|---|
| Project (loss) income | (2.1) | 0.7 | (1.6) | (0.6) | (3.6) |
| Administration | | | | 37.7 | 37.7 |
| Interest, net | | | | 26.0 | 26.0 |
| Foreign exchange loss | | | | 13.8 | 13.8 |
| Other income, net | | | | (0.1) | (0.1) |
| Income (loss) from continuing operations before income taxes | (2.1) | 0.7 | (1.6) | (78.0) | (81.0) |
| Income tax benefit | | | | (11.1) | (11.1) |
| Net income (loss) from continuing operations | (2.1) | 0.7 | (1.6) | (66.9) | (69.9) |
| Income (loss) from discontinued operations | 31.8 | 4.4 | | (1.9) | 34.3 |
| Net income (loss) | $ 29.7 | $ 5.1 | $ (1.6) | $ (68.8) | $ (35.6) |

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**21. Segment and geographic information (Continued)**

The following table provides the reconciliation of project income to Project Adjusted EBITDA for the year ended December 31, 2013 presented under our former reportable segments:

| | Northeast | Southeast | Northwest | Southwest | Un-allocated Corporate | Consolidated |
|---|---|---|---|---|---|---|
| **Year ended December 31, 2013** | | | | | | |
| Project revenues | $ 227.2 | $ 22.0 | $ 88.6 | $ 214.4 | $ (0.5) | $ 551.7 |
| Segment assets | 1,136.1 | 170.7 | 1,050.8 | 893.0 | 144.4 | 3,395.0 |
| Goodwill | 104.5 | | 138.3 | 53.5 | | 296.3 |
| Capital expenditures | 4.3 | 9.5 | 4.7 | 7.5 | 0.2 | 26.2 |
| Project Adjusted EBITDA | $ 133.1 | $ 11.3 | $ 67.2 | $ 77.5 | $ (18.6) | 270.5 |
| Change in fair value of derivative instruments | (19.4) | (5.0) | (25.9) | | | (50.3) |
| Depreciation and amortization | 79.4 | 10.7 | 60.3 | 58.9 | 0.5 | 209.8 |
| Interest, net | 17.0 | 3.6 | 18.9 | 1.1 | (2.1) | 38.5 |
| Other project (income) expense | 34.5 | 0.1 | 0.1 | (26.0) | (0.5) | 8.2 |
| Project income (loss) | 21.6 | 1.9 | 13.8 | 43.5 | (16.5) | 64.3 |
| Administration | | | | | 35.2 | 35.2 |
| Interest, net | | | | | 104.1 | 104.1 |
| Foreign exchange gain | | | | | (27.4) | (27.4) |
| Other income, net | | | | | (10.5) | (10.5) |
| Income (loss) from continuing operations before income taxes | 21.6 | 1.9 | 13.8 | 43.5 | (117.9) | (37.1) |
| Income tax benefit | | | | | (19.5) | (19.5) |
| Net income (loss) from continuing operations | 21.6 | 1.9 | 13.8 | 43.5 | (98.4) | (17.6) |
| Income (loss) from discontinued operations | | (1.1) | | 1.3 | (6.4) | (6.2) |
| Net income (loss) | $ 21.6 | $ 0.8 | $ 13.8 | $ 44.8 | $ (104.8) | $ (23.8) |

The table below provides information, by country, about our consolidated operations for each of the years ended December 31, 2013, 2012 and 2011 and Property, Plant & Equipment as of December 31, 2013 and 2012, respectively. Revenue is recorded in the country in which it is earned and assets are recorded in the country in which they are located.

| Revenue | Property, Plant & Equipment, net |
|---|---|

| | 2013 | 2012 | 2011 | 2013 | 2012 |
|---|---|---|---|---|---|
| United States | $ 343.4 | $ 227.2 | $ 58.1 | $ 1,330.5 | $ 1,504.8 |
| Canada | 208.3 | 213.2 | 35.8 | 482.9 | 550.7 |
| Total | $ 551.7 | $ 440.4 | $ 93.9 | $ 1,813.4 | $ 2,055.5 |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**21. Segment and geographic information (Continued)**

Ontario Electricity Financial Corp ("OEFC"), San Diego Gas & Electric, and BC Hydro provided 27.7%, 14.4%, and 10.1%, respectively, of total consolidated revenues for the year ended December 31, 2013. OEFC, San Diego Gas & Electric and BC Hydro provided for 34.7%, 9.8% and 13.6% of total consolidated revenues for the year ended December 31, 2012. OEFC purchases electricity from the Calstock, Kapuskasing, Nipigon, North Bay and Tunis projects in the East segment. San Diego Gas & Electric purchases electricity from the Naval Station, Naval Training Center, and North Island projects in the West segment. BC Hydro purchases electricity from the Mamquam, Moresby Lake, and Williams Lake projects in the West segment.

**22. Related party transactions**

Prior to December 31, 2009, Atlantic Power was managed by Atlantic Power Management, LLC (the "Manager"), which was owned by two private equity funds managed by Arclight Capital Partners, LLC ("ArcLight"). On December 31, 2009, we terminated our management agreements with the Manager and agreed to pay ArcLight an aggregate of $15.0 million, to be satisfied by a payment of $6.0 million that was made at the termination date, and additional payments of $5.0 million, $3.0 million and $1.0 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. As of December 31, 2012, all payments to ArcLight have been made and no further liability remains on our balance sheet.

During 2010, we made a short-term $22.8 million loan to Idaho Wind to provide temporary funding for construction of the project until a portion of the project-level construction financing was completed. As of December 31, 2011, the project repaid the loan in full with a combination of excess proceeds from the federal stimulus cash grant after repaying the cash grant facility, funds from additional debt, and project cash flow. We received $1.6 million of interest income related to this loan in the year ended December 31, 2011.

**23. Commitments and contingencies**

***Commitments***

***Operating Lease Commitments***

We lease our office properties and equipment under operating leases expiring on various dates through 2021. Certain operating lease agreements over their lease term include provisions for scheduled rent increases. We recognize the effects of these scheduled rent increases on a straight-line basis over the lease term. Lease expense under operating leases was $1.0 million, $2.0 million and $1.0 million for the years ended December 31, 2013, 2012, and 2011, respectively. Future minimum lease commitments under operating leases for the years ending after December 31, 2013, are as follows:

| | |
|---|---|
| 2014 | $ 1.6 |
| 2015 | 1.8 |
| 2016 | 1.7 |
| 2017 | 1.6 |
| 2018 | 1.5 |
| Thereafter | 12.9 |
| | $ 21.1 |

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**23. Commitments and contingencies (Continued)**

***Long-Term Service Commitments***

Our projects have entered into long-term contractual arrangements to obtain maintenance services for turbine equipment expiring on various dates through 2022. As of December 31, 2013, our commitments under such outstanding agreements are estimated as follows:

| | |
|---|---|
| 2014 | $ 3.5 |
| 2015 | 5.0 |
| 2016 | 5.0 |
| 2017 | 5.0 |
| 2018 | 5.0 |
| Thereafter | 24.4 |
| | $ 47.9 |

***Fuel Supply and Transportation Commitments***

We have entered into long-term contractual arrangements to procure fuel and transportation services for our projects. As of December 31, 2013, our commitments under such outstanding agreements are estimated as follows:

| | |
|---|---|
| 2014 | $ 83.0 |
| 2015 | 80.0 |
| 2016 | 73.0 |
| 2017 | 23.4 |
| 2018 | 23.6 |
| Thereafter | 70.4 |
| | $ 353.4 |

***Contingencies***

*Shareholder class action lawsuits*

Massachusetts District Court Actions

On March 8, 14, 15 and 25, 2013 and April 23, 2013, five purported securities fraud class action complaints were filed by alleged investors in Atlantic Power common shares in the United States District Court for the District of Massachusetts (the "District Court") against Atlantic Power and Barry E. Welch, our President and Chief Executive Officer and a Director of Atlantic Power, in each of the actions, and, in addition to Mr. Welch, some or all of Patrick J. Welch, our former Chief Financial Officer, Lisa Donahue, our former interim Chief Financial Officer, and Terrence Ronan, our current Chief Financial Officer, in certain of the actions (the "Individual Defendants," and together with Atlantic Power, the "Defendants") (the "U.S. Actions").

The District Court complaints differ in terms of the identities of the Individual Defendants they name, as noted above, the named plaintiffs, and the purported class period they allege (July 23, 2010 to March 4, 2013 in three of the District Court actions and August 8, 2012 to February 28, 2013 in the

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**23. Commitments and contingencies (Continued)**

other two District Court actions), but in general each alleges, among other things, that in Atlantic Power's press releases, quarterly and year-end filings and conference calls with analysts and investors, Atlantic Power and the Individual Defendants made materially false and misleading statements and omissions regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The District Court complaints assert claims under Section 10(b) and, against the Individual Defendants, under Section 20(a) of the Securities Exchange Act of 1934, as amended.

The parties to each District Court action have filed joint motions requesting that the District Court set a schedule in the District Court actions, including: (i) setting a deadline for the lead plaintiff to file a consolidated amended class action complaint (the "Amended Complaint"), after the appointment of lead plaintiff and counsel; (ii) setting a deadline for Defendants to answer, file a motion to dismiss or otherwise respond to the Amended Complaint (and for subsequent briefing regarding any such motion to dismiss); and (iii) confirming that Defendants need not answer, move to dismiss or otherwise respond to any of the five District Court complaints prior to the filing of the Amended Complaint. On May 7, 2013, each of six groups of investors (the "U.S. Lead Plaintiff Applicants") filed a motion (collectively, the "U.S. Lead Plaintiff Motions") with the District Court seeking: (i) to consolidate the five U.S. Actions (the "Consolidated U.S. Action"); (ii) to be appointed lead plaintiff in the Consolidated U.S. Action; and (iii) to have its choice of lead counsel confirmed. On May 22, 2013, three of the U.S. Lead Plaintiff Applicants filed oppositions to the other U.S. Lead Plaintiff Motions, and on June 6, 2013, those three Lead Plaintiff Applicants filed replies in support of their respective motions. On August 19, 2013, the District Court held a status conference to address certain issues raised by the U.S. Lead Plaintiff Motions, entered an order consolidating the five U.S. Actions, and directed two of the six U.S. Lead Plaintiff Applicants to file supplemental submissions by September 9, 2013. Both of those U.S. Lead Plaintiff Applicants filed the requested supplemental submissions, and then sought leave to file additional briefing. The Court granted those requests for leave and additional submissions were filed on September 13 and September 18, 2013, which the Court will consider (along with the motion papers discussed above) in deciding who will serve as lead plaintiff and lead counsel.

Canadian Actions

On March 19, 2013, April 2, 2013 and May 10, 2013, three notices of action relating to Canadian securities class action claims against the Defendants were also issued by alleged investors in Atlantic Power common shares, and in one of the actions, holders of Atlantic Power convertible debentures, with the Ontario Superior Court of Justice in the Province of Ontario. On April 8, 2013, a similar claim issued by alleged investors in Atlantic Power common shares seeking to initiate a class action against the Defendants was filed with the Superior Court of Quebec in the Province of Quebec (the "Canadian Actions").

On April 17, May 22, and June 7, 2013 statements of claim relating to the notices of action were filed with the Ontario Superior Court of Justice in the Province of Ontario.

On August 30, 2013, the three Ontario actions were succeeded by one action with an amended claim being issued on behalf of Jacqeline Coffin and Sandra Lowry. This claim names the Company, Barry Welch and Terrence Ronan as defendants (the "Defendants"). The Plaintiffs seeks leave to

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**23. Commitments and contingencies (Continued)**

commence an action for statutory misrepresentation under the Ontario Securities Act and asserts common law claims for misrepresentation. The Plaintiffs' allegations focus on among other things, claims the Defendants made materially false and misleading statements and omissions in Atlantic Power's press releases, quarterly and year end filings and conference calls with analysts and investors, regarding the sustainability of Atlantic Power's common share dividend that artificially inflated the price of Atlantic Power's common shares. The Plaintiffs seek to certify the statutory and common law claims under the Class Proceedings Act for security holders who purchased and held securities through a proposed class period of November 5, 2012 to February 28, 2013.

On October 4, 2013, the Plaintiffs delivered materials supporting their request for leave to commence an action for statutory misrepresentations and for certification of the statutory and common claims as class proceedings. These materials estimate the damages claimed for statutory misrepresentation at $197.4 million.

A schedule for the Plaintiffs' motions and the action was set on November 12, 2013.

The Petitioner in the proposed class action in Quebec served and filed a motion to suspend those proceedings pending the Ontario proceedings. This motion was not granted. Nothing further has happened in the action.

Pursuant to the Private Securities Litigation Reform Act of 1995, all discovery is stayed in the U.S. Actions. Plaintiffs have not yet specified an amount of alleged damages in the U.S. Actions. As noted above, the plaintiffs in the Canadian Action have estimated their alleged statutory damages at $197.4 million. Because both the U.S. and Canadian Actions are in their early stages, Atlantic Power is unable to reasonably estimate the possible loss or range of losses, if any, arising from this litigation. Atlantic Power intends to defend vigorously each of the actions.

*IRS Examination*

In 2011, the Internal Revenue Service ("IRS") began an examination of our federal income tax returns for the tax years ended December 31, 2007 and 2009. On April 2, 2012, the IRS issued various Notices of Proposed Adjustments. The principal area of the proposed adjustments pertain to the classification of U.S. real property in the calculation of the gain related to our 2009 conversion from the previous Income Participating Security structure to our current traditional common share structure. At December 31, 2013, the examination is before the IRS Office of Appeals.

We continue 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. We believe an adjustment, if any, would be offset by net operating loss carry forwards. No accrual has been made for any contingency related to any of the proposed adjustments as of December 31, 2013.

*Other*

In addition to the other matters listed, 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

**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**23. Commitments and contingencies (Continued)**

reasonably estimated. There are no matters pending which are expected to have a material adverse impact on our financial position or results of operations or have been reserved for as of December 31, 2013.

**24. Unaudited selected quarterly financial data**

Unaudited selected quarterly financial data are as follows:

| | Quarter Ended 2013 | | | | |
|---|---|---|---|---|---|
| | December 31, | September 30, | June 30, | March 31, | Total |
| Project revenue | $ 130.7 | $ 141.8 | $ 139.1 | $ 140.1 | $ 551.7 |
| Project income | 7.2 | 4.8 | 20.8 | 31.5 | 64.3 |
| Income (loss) from continuing operations | 8.2 | (40.2) | 7.2 | 7.2 | (17.6) |
| Income (loss) from discontinued operations | (0.2) | (0.4) | (6.0) | 0.4 | (6.2) |
| Net income (loss) attributable to Atlantic Power Corporation | 4.9 | (41.3) | (3.0) | 6.4 | (33.0) |
| Income (loss) per share from continuing operations attributable to Atlantic Power Corporation | $ 0.04 | $ (0.34) | $ 0.02 | $ 0.05 | $ (0.23) |
| Loss per share from discontinued operations | | | (0.05) | | (0.05) |
| Income (loss) per share attributable to Atlantic Power Corporation | $ 0.04 | $ (0.34) | $ (0.03) | $ 0.05 | $ (0.28) |
| Weighted average number of common shares outstanding-basic | 120.1 | 120.0 | 119.9 | 119.5 | 119.9 |
| Diluted income (loss) per share from continuing operations attributable to Atlantic Power Corporation | $ 0.04 | $ (0.34) | $ 0.02 | $ 0.05 | $ (0.23) |
| Diluted loss per share from discontinued operations | | | (0.05) | | (0.05) |
| Diluted income (loss) per share attributable to Atlantic Power Corporation | $ 0.04 | $ (0.34) | $ (0.03) | $ 0.05 | $ (0.28) |
| Weighted average number of common shares outstanding-diluted[1] | 120.1 | 120.0 | 119.9 | 119.5 | 119.9 |

(1) The calculation excludes potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units because their impact would be anti-dilutive.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**24. Unaudited selected quarterly financial data (Continued)**

| | Quarter Ended 2012 | | | | |
|---|---|---|---|---|---|
| | December 31, | September 30, | June 30, | March 31, | Total |
| Project revenue | $ 114.0 | $ 106.3 | $ 101.4 | $ 118.7 | $ 440.4 |
| Project (loss) income | (5.8) | 19.7 | (6.9) | (36.4) | (29.4) |
| Loss from continuing operations | (19.7) | (23.5) | (20.8) | (50.2) | (114.2) |
| (Loss) income from discontinued operations | (34.8) | 19.0 | 18.7 | 11.0 | 13.9 |
| Net loss attributable to Atlantic Power Corporation | (58.0) | (7.4) | (5.1) | (42.3) | (112.8) |
| Loss per share from continuing operations attributable to Atlantic Power Corporation | $ (0.20) | $ (0.22) | $ (0.20) | $ (0.47) | $ (1.09) |
| Earnings (loss) per share from discontinued operations | (0.30) | 0.16 | 0.16 | 0.10 | 0.12 |
| Loss per share attributable to Atlantic Power Corporation | $ (0.50) | $ (0.06) | $ (0.04) | $ (0.37) | $ (0.97) |
| Weighted average number of common shares outstanding-basic | 119.4 | 119.0 | 113.7 | 113.6 | 116.4 |
| Diluted loss per share from continuing operations attributable to Atlantic Power Corporation | $ (0.20) | $ (0.22) | $ (0.20) | $ (0.47) | $ (1.09) |
| Diluted (loss) earnings per share from discontinued operations | (0.30) | 0.16 | 0.16 | 0.10 | 0.12 |
| Diluted loss per share attributable to Atlantic Power Corporation | $ (0.50) | $ (0.06) | $ (0.04) | $ (0.37) | $ (0.97) |
| Weighted average number of common shares outstanding-diluted[1] | 119.4 | 119.0 | 113.7 | 113.6 | 116.4 |

(1) The calculation excludes potentially dilutive shares from convertible debentures and potentially dilutive shares from LTIP notional units because their impact would be anti-dilutive.

**25. Guarantees**

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.

We and our subsidiaries enter 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 tax, environmental liability, litigation and other matters, as well as breaches of representations, warranties and covenants set forth in these agreements.

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**ATLANTIC POWER CORPORATION**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**

**(in millions U.S. dollars, except per-share amounts)**

**26. Consolidating financial information**

As of December 31, 2013 and December 31, 2012, we had $460.0 million of Senior Notes. These notes are guaranteed by certain of our 100% owned subsidiaries, or guarantor subsidiaries. These guarantees are joint and several.

Unless otherwise noted below, each of the following 100% owned guarantor subsidiaries fully and unconditionally guaranteed the Senior Notes as of December 31, 2013:

Atlantic Power Limited Partnership, Atlantic Power GP Inc., Atlantic Power (US) GP, Atlantic Oklahoma Wind LLC, Atlantic Power Corporation, Atlantic Power Generation, Inc., Atlantic Power Transmission, Inc., Atlantic Power Holdings, Inc.,. Atlantic Power Services Canada GP Inc., Atlantic Power Services Canada LP, Atlantic Power Services, LLC, Atlantic Rockland Holdings, LLC, Teton Power Funding, LLC, Harbor Capital Holdings, LLC, Epsilon Power Funding, LLC, Atlantic Cadillac Holdings, LLC, Atlantic Idaho Wind Holdings, LLC, Atlantic Idaho Wind C, LLC, Baker Lake Hydro, LLC, Olympia Hydro, LLC, Teton East Coast Generation, LLC, Atlantic Renewables Holdings, LLC, Orlando Power Generation I, LLC, Orlando Power Generation II, LLC, Atlantic Piedmont Holdings LLC, Teton Selkirk, LLC, Teton Operating Services, LLC, Atlantic Ridgeline Holdings, LLC, Ridgeline Energy Holdings, Inc., Ridgeline Energy LLC, Pah Rah Holding Company LLC, Lewis Ranch Wind Project LLC, Hurricane Wind LLC, Ridgeline Power Services LLC, Ridgeline Eastern Energy LLC, Ridgeline Alternative Energy LLC, Frontier Solar LLC, Ridgeline Energy Solar LLC, Pah Rah Project Company LLC, Monticello Hills Wind LLC, Dry Lots Wind LLC, Smokey Avenue Wind LLC, Saunders Bros. Transportation Corporation, Bruce Hill Wind LLC, South Mountain Wind LLC, Great Basin Solar Ranch LLC, Goshen Wind Holdings LLC, Meadow Creek Holdings LLC, Ridgeline Holdings Junior Inc., Rockland Wind Ridgeline Holdings LLC and Meadow Creek Intermediate Holdings LLC

These guarantees were terminated upon entering into the New Senior Secured Credit Facilities on February 26, 2014. See Note 10, *Long-term debt* for further information.

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

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

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**ATLANTIC POWER CORPORATION**

**CONDENSED CONSOLIDATING BALANCE SHEET**

**December 31, 2013**

**(in millions of U.S. dollars)**

| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ 151.0 | $ | $ 7.6 | $ | $ 158.6 |
| Restricted cash | 114.2 | | | | 114.2 |
| Accounts receivable | 181.2 | 17.6 | 4.3 | (138.8) | 64.3 |
| Prepayments, supplies, and other | 33.3 | 1.3 | 1.7 | | 36.3 |
| Total current assets | 479.7 | 18.9 | 13.6 | (138.8) | 373.4 |
| Property, plant, and equipment, net | 1,642.6 | 172.1 | | (1.3) | 1,813.4 |
| Equity investments in unconsolidated affiliates | 3,655.0 | | 943.8 | (4,204.5) | 394.3 |
| Other intangible assets, net | 304.7 | 146.8 | | | 451.5 |
| Goodwill | 238.1 | 58.2 | | | 296.3 |
| Other assets | 476.7 | | 435.1 | (845.7) | 66.1 |
| Total assets | $ 6,796.8 | $ 396.0 | $ 1,392.5 | $ (5,190.3) | $ 3,395.0 |
| **Liabilities** | | | | | |
| Current liabilities: | | | | | |
| Accounts payable and accrued liabilities | $ 141.9 | $ 6.1 | $ 81.3 | $ (138.8) | $ 90.5 |
| Current portion of long-term debt | 26.2 | 190.0 | | | 216.2 |
| Current portion convertible debentures | | | 42.1 | | 42.1 |
| Dividends payable | 6.8 | | | | 6.8 |
| Other current liabilities | 30.0 | | 3.8 | | 33.8 |
| Total current liabilities | 204.9 | 196.1 | 127.2 | (138.8) | 389.4 |
| Long-term debt | 794.8 | | 460.0 | | 1,254.8 |
| Convertible debentures | | | 363.1 | | 363.1 |
| Other non-current liabilities | 1,128.3 | 8.6 | 0.5 | (845.7) | 291.7 |
| **Equity** | | | | | |
| Common Stock | 4,226.2 | 191.3 | 1,286.1 | (4,417.5) | 1,286.1 |
| Preferred shares issued by a subsidiary company | 221.3 | | | | 221.3 |
| Accumulated other comprehensive income | (22.4) | | | | (22.4) |
| Retained (deficit) earnings | (22.7) | | (844.4) | 211.7 | (655.4) |

| | | | | | |
|---|---|---|---|---|---|
| Total Atlantic Power Corporation shareholders' equity | 4,402.4 | 191.3 | 441.7 | (4,205.8) | 829.6 |
| Noncontrolling interests | 266.4 | | | | 266.4 |
| Total equity | 4,668.8 | 191.3 | 441.7 | (4,205.8) | 1,096.0 |
| Total liabilities and equity | $ 6,796.8 | $ 396.0 | $ 1,392.5 | $ (5,190.3) | $ 3,395.0 |

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**ATLANTIC POWER CORPORATION**

**CONDENSED CONSOLIDATING BALANCE SHEET**

**December 31, 2012**

**(in millions of U.S. dollars)**

| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| **Assets** | | | | | |
| Current assets: | | | | | |
| Cash and cash equivalents | $ 43.2 | $ | $ 17.0 | $ | $ 60.2 |
| Restricted cash | 28.6 | | | | 28.6 |
| Accounts receivable | 138.8 | 35.8 | 0.9 | (117.0) | 58.5 |
| Prepayments, supplies, and other | 53.4 | 1.3 | 9.3 | (1.0) | 63.0 |
| Asset held for sale | 351.4 | | | | 351.4 |
| Total current assets | 615.4 | 37.1 | 27.2 | (118.0) | 561.7 |
| Property, plant, and equipment, net | 1,883.6 | 173.1 | | (1.2) | 2,055.5 |
| Equity investments in unconsolidated affiliates | 5,109.3 | | 1,012.0 | (5,692.6) | 428.7 |
| Other intangible assets, net | 367.1 | 157.8 | | | 524.9 |
| Goodwill | 276.5 | 58.2 | | | 334.7 |
| Other assets | 499.7 | | 440.1 | (842.6) | 97.2 |
| Total assets | $ 8,751.6 | $ 426.2 | $ 1,479.3 | $ (6,654.4) | $ 4,002.7 |
| **Liabilities** | | | | | |
| Current liabilities: | | | | | |
| Accounts payable and accrued liabilities | $ 169.8 | $ 13.7 | $ 44.0 | $ (117.0) | $ 110.5 |
| Revolving credit facility | 47.0 | | 20.0 | | 67.0 |
| Current portion of long-term debt | 121.2 | | | | 121.2 |
| Liabilities held for sale | 189.0 | | | | 189.0 |
| Other current liabilities | 37.3 | | 11.5 | (1.0) | 47.8 |
| Total current liabilities | 564.3 | 13.7 | 75.5 | (118.0) | 535.5 |
| Long-term debt | 809.1 | 190.0 | 460.0 | | 1,459.1 |
| Convertible debentures | | | 424.2 | | 424.2 |
| Other non-current liabilities | 1,230.8 | 8.3 | 1.0 | (842.6) | 397.5 |
| **Equity** | | | | | |
| Common Stock | 5,103.8 | 214.2 | 1,285.5 | (5,318.0) | 1,285.5 |
| Preferred shares issued by a subsidiary company | 221.3 | | | | 221.3 |
| Accumulated other comprehensive income | 9.4 | | | | 9.4 |
| Retained earnings (deficit) | 577.5 | | (766.9) | (375.8) | (565.2) |
| Total Atlantic Power Corporation shareholders' equity | 5,912.0 | 214.2 | 518.6 | (5,693.8) | 951.0 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Noncontrolling interests | | 235.4 | | | | | | | | 235.4 |
| Total equity | | 6,147.4 | | 214.2 | | 518.6 | | (5,693.8) | | 1,186.4 |
| Total liabilities and equity | $ | 8,751.6 | $ | 426.2 | $ | 1,479.3 | $ | (6,654.4) | $ | 4,002.7 |

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**ATLANTIC POWER CORPORATION**

**CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS**

**December 31, 2013**

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

| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| Project revenue: | | | | | |
| Energy sales | $ 268.4 | $ 35.8 | $ | $ | $ 304.2 |
| Energy capacity revenue | 168.8 | | | | 168.8 |
| Other | 79.2 | | | (0.5) | 78.7 |
| | 516.4 | 35.8 | | (0.5) | 551.7 |
| Project expenses: | | | | | |
| Fuel | 198.7 | | | | 198.7 |
| Project operations and maintenance | 148.2 | 3.8 | 0.9 | (0.5) | 152.4 |
| Project development expenses | 7.2 | | | | 7.2 |
| Depreciation and amortization | 151.7 | 15.4 | | | 167.1 |
| | 505.8 | 19.2 | 0.9 | (0.5) | 525.4 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | 49.5 | | | | 49.5 |
| Equity in earnings of unconsolidated affiliates | 26.9 | | | | 26.9 |
| Gain on sale of equity investments | 30.4 | | | | 30.4 |
| Interest expense, net | (23.3) | (11.1) | | | (34.4) |
| Other income, net | (34.7) | | 0.3 | | (34.4) |
| | 48.8 | (11.1) | 0.3 | | 38.0 |
| Project income (loss) | 59.4 | 5.5 | (0.6) | | 64.3 |
| Administrative and other expenses (income): | | | | | |
| Administration expense | 21.1 | | 14.1 | | 35.2 |
| Interest, net | 75.8 | | 28.3 | | 104.1 |
| Foreign exchange loss | (9.4) | | (18.0) | | (27.4) |
| Other income | (5.8) | | (4.7) | | (10.5) |
| | 81.7 | | 19.7 | | 101.4 |
| Loss from continuing operations before income taxes | (22.3) | 5.5 | (20.3) | | (37.1) |
| Income tax benefit | (19.5) | | | | (19.5) |
| Net loss from continuing operations | (2.8) | 5.5 | (20.3) | | (17.6) |

| | | | | | |
|---|---|---|---|---|---|
| Net loss from discontinued operations, net of tax | (6.2) | | | | (6.2) |
| Net loss | (9.0) | 5.5 | (20.3) | | (23.8) |
| Net loss attributable to noncontrolling interests | (3.4) | | | | (3.4) |
| Net income attributable to preferred share dividends of a subsidiary company | 12.6 | | | | 12.6 |
| Net loss attributable to Atlantic Power Corporation | $ (18.2) | $ 5.5 | $ (20.3) | $ | $ (33.0) |

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**ATLANTIC POWER CORPORATION**

**CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS**

**December 31, 2012**

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

| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| Project revenue: | | | | | |
| Energy sales | $ 182.8 | $ 34.2 | $ | $ | $ 217.0 |
| Energy capacity revenue | 154.9 | | | | 154.9 |
| Other | 69.1 | | | (0.6) | 68.5 |
| | 406.8 | 34.2 | | (0.6) | 440.4 |
| Project expenses: | | | | | |
| Fuel | 169.1 | | | | 169.1 |
| Project operations and maintenance | 117.3 | 6.1 | (0.2) | (0.4) | 122.8 |
| Depreciation and amortization | 102.7 | 15.3 | | | 118.0 |
| | 389.1 | 21.4 | (0.2) | (0.4) | 409.9 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | (59.3) | | | | (59.3) |
| Equity in earnings of unconsolidated affiliates | 15.8 | | | | 15.8 |
| Interest expense, net | (5.2) | (11.2) | | | (16.4) |
| | (48.7) | (11.2) | | | (59.9) |
| Project income (loss) | (31.0) | 1.6 | 0.2 | (0.2) | (29.4) |
| Administrative and other expenses (income): | | | | | |
| Administration expense | 17.6 | | 10.7 | | 28.3 |
| Interest, net | 79.6 | | 10.0 | 0.2 | 89.8 |
| Foreign exchange loss | 1.1 | | (0.6) | | 0.5 |
| Other income | (6.0) | | 0.3 | | (5.7) |
| | 92.3 | | 20.4 | 0.2 | 112.9 |
| (Loss) income from continuing operations before income taxes | (123.3) | 1.6 | (20.2) | (0.4) | (142.3) |
| Income tax benefit | (28.1) | | | | (28.1) |
| Net (loss) income from continuing operations | (95.2) | 1.6 | (20.2) | (0.4) | (114.2) |
| Net income from discontinued operations, net of tax | 13.9 | | | | 13.9 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Net (loss) income | | (81.3) | | 1.6 | | (20.2) | | (0.4) | | (100.3) |
| Net loss attributable to noncontrolling interests | | (0.6) | | | | | | | | (0.6) |
| Net income attributable to preferred share dividends of a subsidiary company | | 13.1 | | | | | | | | 13.1 |
| Net (loss) income attributable to Atlantic Power Corporation | $ | (93.8) | $ | 1.6 | $ | (20.2) | $ | (0.4) | $ | (112.8) |

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**ATLANTIC POWER CORPORATION**

**CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS**

**December 31, 2011**

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

| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| Project revenue: | | | | | |
| Energy sales | $ 34.6 | $ 9.0 | $ | $ | $ 43.6 |
| Energy capacity revenue | 34.0 | | | | 34.0 |
| Other | 16.7 | | | (0.4) | 16.3 |
| | 85.3 | 9.0 | | (0.4) | 93.9 |
| Project expenses: | | | | | |
| Fuel | 37.5 | | | | 37.5 |
| Project operations and maintenance | 19.4 | 0.9 | 0.9 | (0.3) | 20.9 |
| Depreciation and amortization | 21.0 | 2.6 | | | 23.6 |
| | 77.9 | 3.5 | 0.9 | (0.3) | 82.0 |
| Project other income (expense): | | | | | |
| Change in fair value of derivative instruments | (14.6) | | | | (14.6) |
| Equity in earnings of unconsolidated affiliates | 6.0 | | | 0.4 | 6.4 |
| Interest expense, net | (3.9) | (1.9) | 0.1 | (1.6) | (7.3) |
| | (12.5) | (1.9) | 0.1 | (1.2) | (15.5) |
| Project income (loss) | (5.1) | 3.6 | (0.8) | (1.3) | (3.6) |
| Administrative and other expenses (income): | | | | | |
| Administration expense | 12.2 | | 25.5 | | 37.7 |
| Interest, net | 67.7 | | (41.7) | | 26.0 |
| Foreign exchange loss | 4.0 | | 9.8 | | 13.8 |
| Other Income, net | (0.1) | | | | (0.1) |
| | 83.8 | | (6.4) | | 77.4 |
| (Loss) income from continuing operations before income taxes | (88.9) | 3.6 | 5.6 | (1.3) | (81.0) |
| Income tax (benefit) expense | (11.3) | | 0.2 | | (11.1) |
| Net (loss) income from continuing operations | (77.6) | 3.6 | 5.4 | (1.3) | (69.9) |
| Net income from discontinued operations, net of tax | 34.3 | | | | 34.3 |
| Net (loss) income | (43.3) | 3.6 | 5.4 | (1.3) | (35.6) |
| Net loss attributable to noncontrolling interests | (0.5) | | | | (0.5) |

| | | | | | |
|---|---|---|---|---|---|
| Net income attributable to preferred share dividends of a subsidiary company | 3.3 | | | | 3.3 |
| Net (loss) income attributable to Atlantic Power Corporation | $ (46.1) | $ 3.6 | $ 5.4 | $ (1.3) | $ (38.4) |

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**ATLANTIC POWER CORPORATION**

**CONDENSED CONSOLIDATING STATEMENT OF COMPREHENSIVE INCOME**

**December 31, 2013, 2012, and 2011**

**(in millions of U.S. dollars)**

| | Year ended December 31, 2013 | | | | |
|---|---|---|---|---|---|
| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
| Net loss | $ (9.0) | $ (14.2) | $ (0.6) | $ | $ (23.8) |
| Other comprehensive income: | | | | | |
| Unrealized income on hedging activities | 0.7 | | | | 0.7 |
| Net amount reclassified to earnings | 0.9 | | | | 0.9 |
| Net unrealized gain on derivatives | 1.6 | | | | 1.6 |
| Defined benefit plan, net of tax | 1.4 | | | | 1.4 |
| Foreign currency translation adjustments | (34.8) | | | | (34.8) |
| Other comprehensive loss, net of tax | (31.8) | | | | (31.8) |
| Comprehensive loss | (40.8) | (14.2) | (0.6) | | (55.6) |
| Less: Comprehensive income attributable to noncontrolling interests | 9.2 | | | | 9.2 |
| Comprehensive loss attributable to Atlantic Power Corporation | $ (50.0) | $ (14.2) | $ (0.6) | $ | $ (64.8) |

| | Year ended December 31, 2012 | | | | |
|---|---|---|---|---|---|
| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
| Net (loss) income | $ (81.3) | $ 1.6 | $ (20.2) | $ (0.4) | $ (100.3) |
| Other comprehensive income (loss): | | | | | |
| Unrealized loss on hedging activities | (0.9) | | | | (0.9) |
| Net amount reclassified to earnings | 0.9 | | | | 0.9 |
| Net unrealized losses on derivatives | | | | | |
| Defined benefit plan, net of tax | (1.3) | | | | (1.3) |
| Foreign currency translation adjustments | 15.9 | | | | 15.9 |

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Other comprehensive income, net of tax | | 14.6 | | | | | | | | 14.6 |
| Comprehensive (loss) income | | (66.7) | | 1.6 | | (20.2) | | (0.4) | | (85.7) |
| Less: Comprehensive income attributable to noncontrolling interests | | 12.5 | | | | | | | | 12.5 |
| Comprehensive (loss) income attributable to Atlantic Power Corporation | $ | (79.2) | $ | 1.6 | $ | (20.2) | $ | (0.4) | $ | (98.2) |

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**ATLANTIC POWER CORPORATION**

**CONDENSED CONSOLIDATING STATEMENT OF COMPREHENSIVE INCOME (Continued)**

**December 31, 2013, 2012, and 2011**

**(in millions of U.S. dollars)**

| | Year ended December 31, 2011 | | | | |
|---|---|---|---|---|---|
| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
| Net (loss) income | $ (43.3) | $ 3.6 | $ 5.4 | $ (1.3) | $ (35.6) |
| Other comprehensive income (loss): | | | | | |
| Unrealized loss on hedging activities | (2.6) | | | | (2.6) |
| Net amount reclassified to earnings | 1.0 | | | | 1.0 |
| Net unrealized losses on derivatives | (1.6) | | | | (1.6) |
| Defined benefit plan, net of tax | (0.5) | | | | (0.5) |
| Foreign currency translation adjustments | (3.3) | | | | (3.3) |
| Other comprehensive loss, net of tax | (5.4) | | | | (5.4) |
| Comprehensive (loss) income | (48.7) | 3.6 | 5.4 | (1.3) | (41.0) |
| Less: Comprehensive income attributable to noncontrolling interests | 2.8 | | | | 2.8 |
| Comprehensive (loss) income attributable to Atlantic Power Corporation | $ (51.5) | $ 3.6 | $ 5.4 | $ (1.3) | $ (43.8) |

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**ATLANTIC POWER CORPORATION**

**CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS**

**December 31, 2013**

**(in millions of U.S. dollars)**

| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| Cash flows from operating activities: | | | | | |
| Net cash provided by operating activities: | $ 61.7 | $ 3.0 | $ 87.7 | $ | $ 152.4 |
| Cash flows provided by (used in) investing activities: | | | | | |
| Proceeds from treasury grant | 103.2 | | | | 103.2 |
| Proceeds from sale of assets | 182.6 | | | | 182.6 |
| Cash (paid) received for equity investments | 11.0 | | (11.0) | | |
| Change in restricted cash | (93.7) | | | | (93.7) |
| Biomass development costs | (0.2) | | | | (0.2) |
| Construction in progress | (38.3) | | | | (38.3) |
| Purchase of property, plant and equipment | (3.5) | (3.0) | | | (6.5) |
| Net cash provided by (used in) investing activities | 161.1 | (3.0) | (11.0) | | 147.1 |
| Cash flows (used in) provided by financing activities: | | | | | |
| Proceeds from issuance of convertible debentures | | | | | |
| Offering costs related to tax equity | (1.0) | | | | (1.0) |
| Repayment of project-leve debt | (118.8) | | | | (118.8) |
| Proceeds from project-level debt | 20.8 | | | | 20.8 |
| Payments for revolving credit facilities | (47.0) | | (20.0) | | (67.0) |
| Equity investment from noncontrolling interest | 42.7 | | 1.9 | | 44.6 |
| Deferred financing costs | | | (2.8) | | (2.8) |
| Dividends paid | (18.3) | | (65.1) | | (83.4) |
| Net cash used in financing activities | (121.6) | | (86.0) | | (207.6) |
| Net increase (decrease) in cash and cash equivalents | 101.2 | | (9.3) | | 91.9 |
| Cash and cash equivalents at beginning of period | 49.8 | | 16.9 | | 66.7 |
| Cash and cash equivalents at end of period | $ 151.0 | $ | $ 7.6 | $ | $ 158.6 |

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**ATLANTIC POWER CORPORATION**

**CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS**

**December 31, 2012**

**(in millions of U.S. dollars)**

| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| Cash flows from operating activities: | | | | | |
| Net cash (used in) provided by operating activities: | $ (9.9) | $ 1.1 | $ 175.9 | $ | $ 167.1 |
| Cash flows (used in) provided by investing activities: | | | | | |
| Cash paid for acquisitions and investments, net of cash acquired | 206.5 | | (287.0) | | (80.5) |
| Proceeds from sale of assets and equity investments, net | 27.9 | | | | 27.9 |
| Construction in progress | (456.2) | | | | (456.2) |
| Change in restricted cash | (11.6) | | | | (11.6) |
| Biomass development costs | (0.5) | | | | (0.5) |
| Purchase of property, plant and equipment | (1.8) | (1.1) | | | (2.9) |
| Net cash used in investing activities | (235.7) | (1.1) | (287.0) | | (523.8) |
| Cash flows (used in) provided by financing activities: | | | | | |
| Proceeds from issuance of convertible debentures | | | 230.6 | | 230.6 |
| Proceeds from issuance of equity, net of offering costs | (1.4) | | 67.7 | | 66.3 |
| Repayment of project-level debt | (284.8) | | | | (284.8) |
| Deferred financing costs | (19.7) | | (11.5) | | (31.2) |
| Proceeds from project-level debt | 291.9 | | | | 291.9 |
| Payments for revolving credit facilities | (30.8) | | (30.0) | | (60.8) |
| Proceeds from revolving credit facility borrowings | 69.8 | | | | 69.8 |
| Equity contribution from noncontrolling interest | 225.0 | | | | 225.0 |
| Dividends paid | (13.1) | | (131.0) | | (144.1) |
| Net cash provided by financing activities | 236.9 | | 125.8 | | 362.7 |
| Net (decrease) increase in cash and cash equivalents | (8.7) | | 14.7 | | 6.0 |
| Less cash at discontinued operations | (6.5) | | | | (6.5) |
| Cash and cash equivalents at beginning of period | 58.4 | | 2.3 | | 60.7 |
| Cash and cash equivalents at end of period | $ 43.2 | $ | $ 17.0 | $ | $ 60.2 |

**ATLANTIC POWER CORPORATION**

**CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS**

**December 31, 2011**

**(in millions of U.S. dollars)**

| | Guarantor Subsidiaries | Curtis Palmer | APC | Eliminations | Consolidated Balance |
|---|---|---|---|---|---|
| Cash flows from operating activities: | | | | | |
| Net cash provided by operating activities: | $ 21.0 | $ | $ 34.9 | $ | $ 55.9 |
| Cash flows provided by (used in) investing activities: | | | | | |
| Cash paid for acquisitions and investments, net of cash acquired | 12.1 | | (603.7) | | (591.6) |
| Short-term loan to Idaho Wind | 21.5 | | 1.3 | | 22.8 |
| Proceeds from sale of assets and equity investments, net | 8.5 | | | | 8.5 |
| Change in restricted cash | (5.7) | | | | (5.7) |
| Biomass development costs | (0.9) | | | | (0.9) |
| Construction in progress | (113.1) | | | | (113.1) |
| Purchase of property, plant and equipment | (2.0) | | | | (2.0) |
| Net cash used in investing activities | (79.6) | | (602.4) | | (682.0) |
| Cash flows (used in) provided by financing activities: | | | | | |
| Proceeds from issuance of long-term debt | | | 460.0 | | 460.0 |
| Proceeds from issuance of equity, net of offering costs | | | 155.4 | | 155.4 |
| Repayment of project-level debt | (21.5) | | | | (21.5) |
| Deferred financing costs | | | (26.4) | | (26.4) |
| Proceeds from project-level debt | 100.8 | | | | 100.8 |
| Proceeds from revolving credit facility borrowings | 8.0 | | 50.0 | | 58.0 |
| Dividends paid | (3.2) | | (81.8) | | (85.0) |
| Net cash provided by financing activities | 84.1 | | 557.2 | | 641.3 |
| Net increase (decrease) in cash and cash equivalents | 25.5 | | (10.3) | | 15.2 |
| Cash and cash equivalents at beginning of period | 33.0 | | 12.5 | | 45.5 |
| Cash and cash equivalents at end of period | $ 58.5 | $ | $ 2.2 | $ | $ 60.7 |

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**ATLANTIC POWER CORPORATION**

**SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS**

**FOR THE YEARS ENDED DECEMBER 31, 2013, 2012 AND 2011**

**(in millions of U.S. dollars)**

| | Balance at Beginning of Period | Charged to Costs and Expenses | Charged to Other Accounts | Deductions | Balance at End of Period |
|---|---|---|---|---|---|
| **Income tax valuation allowance, deducted from deferred tax assets:** | | | | | |
| Year ended December 31, 2013 | $ 116.0 | $ 12.1 | $ | $ | $ 128.1 |
| Year ended December 31, 2012 | 89.0 | 20.2 | 6.8 | | 116.0 |
| Year ended December 31, 2011 | 79.4 | 9.4 | 0.2 | | 89.0 |